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PART 2
NATIONAL ENERGY ACT

DOCUMENTS

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HEARINGS

BEFORE THE

SUBCOMMITTEE ON ENERGY AND POWER

OF THE

COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE

HOUSE OF REPRESENTATIVES

NINETY-FIFTH CONGRESS

FIRST SESSION

ON

H.R. 6831, H.R. 687, H.R. 1562, H.R. 2088, H.R. 2818, H.R. 3317, H.R. 3664, H.R. 6660, and all similar and identical bills

BILLS TO ESTABLISH A COMPREHENSIVE NATIONAL ENERGY POLICY

MAY 12, 13, 17, AND 18, 1977

Serial No. 95–23

Printed for the use of the
Committee on Interstate and Foreign Commerce

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American Frozen Food Institute, Gordon E. Follette.
American Gas Association, Robert E. Seymour, chairman.
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    Journey, Drexel D., General Counsel.
    Williams, Kenneth, Acting Chief, Bureau of Natural Gas.
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National Council of Farmer Cooperatives, Thomas J. Devine.
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    Willis, Charles C., Jr., deputy administrator, Energy Resources Board.
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    Cleary, William D., Ph. D., vice chairman, Governor's Advisory Council on Energy.
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Texas Farmer's Union, Lane Denton, legislative director.
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    Wallace, Mack, chairman, Railroad Commission.
Wilson, J. W., & Associates, Inc.:
    Donkin, George L.
    Wilson, John W., Ph. D.

NATIONAL ENERGY ACT

THURSDAY, MAY 12, 1977

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY AND POWER,
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE,
Washington, D.C.

The subcommittee met at 10 a.m., pursuant to notice, in room 2322, Rayburn House Office Building, Hon. John D. Dingell, chairman, presiding.

Mr. DINGELL. This morning we continue hearings on parts of H.R. 6831, the National Energy Act, particularly title I, part D, relating to natural gas.

We are particularly privileged that we have with us Hon. James R. Schlesinger, Assistant to the President, accompanied by Mr. John O'Leary, Administrator of FEA, Mr. Les Goldman, and others.

Gentlemen, we express to you all our welcome and it is a pleasure you are here to assist us in this difficult process.

In view of the time constraints, my good friend from Ohio has a brief opening statement, and we will recognize him for a brief opening statement.

Mr. BROWN. Thank you, Mr. Chairman.

As we begin these hearings on what may very well be the most important aspect of one of our most important problems, energy, I would like to raise several issues which I hope all witnesses will be able to address in their testimony.

First I would urge the witnesses to compare from the standpoint of policy, economics, and legal sufficiency the various proposals before us, especially H.R. 6381, the President's bill, and H.R. 2088, a bill introduced by Mr. Krueger and myself, for which we have 75 cosponsors.

Second, I would hope the hearings will allow us to focus on many of the important issues in the natural gas area. First, how can we best provide a maximum amount of natural gas supply in the next few years when we will need the gas before we are able to develop alternate sources of energy? Secondly, how should pricing of this commodity be dealt with so as to elicit adequate supplies without undue impact upon consumers who may not be able to afford to pay significantly higher energy bills? Third, how can we best prevent or at least limit wasteful consumption of natural gas throughout the country, particularly the use of natural gas in gas-fired boilers?

I have been a little disturbed about the bill which came to us from the administration because I think it is not terribly precisely written. For example, the definition of new natural gas contains 104 words, of which nine are terms that require definition elsewhere in the bill, which definitions in turn require 322 words, an immensely complicated matrix in which we have new natural gas, old natural gas, new contracts and old gas, new wells and old leases, and creates such interesting situations as the fact that all gas from an old well is old gas but some gas from new wells is new gas while other gas from new wells is old gas.

In addition, some old gas can be from old contracts and other old gas can be sold under new contracts, which old gas is in turn produced from either a new well or an old well.

The bill also has, I think, some constitutional questions which deserve attention and some other fundamental questions of policy and logic, including the question of Btu equivalency pricing for fuels that are not comparable in areas in which the Federal Government has acted in other ways, notably the question of environmental pollution.

Btu equivalence and environmental pollution equivalency contradict and therefore would have different impacts on the pricing levels that Btu equivalency alone does not cover.

Rather than make it, if you will, lengthy, I would prefer it be included in the record at this point so we do not delay the time of the members who are here.

Mr. DINGELL. Without objection, so ordered.

[The texts of H.R. 687, H.R. 1460, H.R. 1562, H.R. 2088, H.R. 2818, H.R. 3317, H.R. 3664, and all identical and similar bills follow:]

95TH CONGRESS
1ST SESSION

H. R. 687

IN THE HOUSE OF REPRESENTATIVES

JANUARY 4, 1977

Mr. SMITH of Iowa introduced the following bill; which was referred to the Committee on Interstate and Foreign Commerce

A BILL

To assure the availability of adequate supplies of natural gas at a fair and reasonable price.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That this Act may be cited as the "Natural Gas Act Amendments of 1977".

SEC. 2. The Natural Gas Act is amended by (1) striking out section 24 thereof; and (2) amending section 1 thereof by redesignating subsections (a), (b), and (c) as subsections (b), (c), and (d), respectively, and inserting therein the following new subsection:

"(a) This Act may be cited as the 'Natural Gas Act'.".

SEC. 3. Section 1 (c) of the Natural Gas Act as redesignated by this Act, is amended (1) by striking out "The" after "(c)" and by inserting in lieu thereof the following: "Except as provided in section 24 of this Act (relating to sales of new gas by regulated producers) and section 25 of this Act (relating to prohibited boiler fuel use of natural gas)," and (2) by striking out the period at the end thereof and inserting in lieu thereof the following: "or to any independent producer sale.".

SEC. 4. (a) Section 2 of the Natural Gas Act is amended by redesignating paragraphs (7) through (9) as paragraphs (15) through (17), respectively, and by inserting the following new paragraphs:

"(7) 'Boiler fuel use of natural gas' means the use of natural gas as the source of fuel in a generating unit of more than 25 megawatts rated net generating capacity or in any generating unit which is part of an electric utilities system with a total net generating capacity of more than 150 megawatts.

"(8) 'Affiliate' means any person directly or indirectly controlling, controlled by, or under common control or ownership with any other person as determined by the Commission by rule. In promulgating the rules under this paragraph, the Commission shall consider the direct or indirect legal or beneficial interest in

another person or any direct or indirect legal power or influence over another person, arising through direct or indirect, or interlocking directorates, or officers, contractual relations, agency agreements, or leasing arrangements, in determining whether an affiliate relationship shall be deemed to exist.

"(9) 'New natural gas' means natural gas which—

"(A) is dedicated to interstate commerce for the first time after January 1, 1976, (i) except that such term does not include natural gas sold or delivered from offshore Federal lands committed for a contract term of less than fifteen years or the life of the reservoir if less than fifteen years, and (ii) natural gas sold by a producer in interstate commerce prior to the effective date of this paragraph pursuant to a limited term certificate (five years or less) or temporary emergency contract shall not be considered as having been dedicated to interstate commerce prior to such date;

"(B) which is produced from a reservoir discovered on or after January 1, 1976; or

"(C) which is produced from wells initiated and completed on or after January 1, 1976, in an extension of a reservoir discovered prior to such date.

"(10) 'Control' means the actual or legal power to dominate or determine, directly or indirectly, the policy, business practices, or decisionmaking process of a person.

"(11) 'Natural gas producer' means a person who is engaged in the production, gathering, or processing of natural gas from wells or reserves in the United States.

"(12) 'United States' means the States, the District of Columbia, Puerto Rico, the territories and possessions of the United States and any land or subsurface area within the Outer Continental Shelf as defined in section 2(a) of the Outer Continental Shelf Lands Act (43 U.S.C. 1331(a)).

"(13) 'Independent producer' means a natural gas producer whose aggregate marketed production of natural gas in the preceding calendar year, together with the marketed production during that year of any affiliate of such producer, does not exceed 100,000,000 Mcf., but such term does not include any natural gas producer whose annual gross revenue, together with the annual gross revenue of any affiliate of such person, from the operation of a pipeline for the transportation or sale for resale of natural gas in interstate commerce or the distribution of natural gas exceeds 10 per centum of the

total annual gross revenues of the person or of the affiliate of such person.

"(14) 'Exempt independent producer sale' means a sale of new natural gas that is produced by an independent producer and a sale in which (A) no natural gas producer (other than an independent producer) has any interest in the proceeds or profits other than a royalty interest and (B) the aggregate or royalty interests of natural gas producers (other than independent producers) does not exceed 20 per centum of such proceeds or such profits. The term 'exempt independent producer sale' does not include a sale of new natural gas that is produced from acreage in which the independent producer acquired an interest after January 1, 1976; if, prior to the acquisition by the independent producer, a discovery well had been drilled into the reservoir from which the natural gas is produced at a distance from the well from which the natural gas is produced of two statute miles for areas on the Outer Continental Shelf and one statute mile for other areas of the United States. The term 'exempt independent producer sale' includes a sale of new natural gas by a producer who is not an independent producer pursuant to an executory contract if such producer was an independent producer and such

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sale was an exempt independent producer sale at the time such contract was executed.".

SEC. 5. Section 4 of the Natural Gas Act is amended by adding at the end thereof the following new subsection:

"(f) The Commission shall have no power to disallow, in whole or in part, in the rates and charges made, demanded, or received by any natural-gas company the amounts actually paid by it for new natural gas under an exempt independent producer sale.".

SEC. 6. Section 5 of the Natural Gas Act is amended by adding at the end thereof the following new subsection:

"(c) The Commission shall have no power to disallow, in whole or in part, in the rates and charges made, demanded, or received by any natural-gas company the amounts actually paid by it for new exempt independent producer sale.".

SEC. 7. Section 10(a) of the Natural Gas Act is amended by adding at the end thereof the following: "The Commission may require any natural gas producer other than an independent producer to file annually a report of transfers of natural gas reserves to an independent producer. The Commission may by regulation require any independent producer to file annually (1) a report of any information that is relevant to a determination of whether such person is an independent producer; (2) a report of the volumes sold and such price received under exempt independent producer

sales during the preceding calendar year; (3) such other information as the Commission may find necessary for the evaluation of the exclusion of exempt independent producer sales from this Act; and (4) such other information as the Commission determines to be relevant to the conduct of its responsibilities under this Act.".

SEC. 8. The Natural Gas Act is amended by adding at the end thereof the following new sections:

"NEW NATURAL GAS SALES OF REGULATED PRODUCERS

"SEC. 24. (a) (1) Not later than the first day of the third full calendar month following the effective date of this section, the Commission shall, by rule promulgated in accordance with section 553 of title 5 United States Code, establish a national ceiling price applicable to any sale of new natural gas in interstate and intrastate commerce by a producer who is not an independent producer. For the purposes of this section, a sale of new natural gas in intrastate commerce means any sale of natural gas pursuant to a contract entered into on or after the effective date of the rule required to be promulgated pursuant to this subsection.

"(2) In establishing such national ceiling price, the Commission shall take into account the following:

"(A) the recovery of costs, including prospective costs; and

"(B) a reasonable rate of return which will pro-

vide incentive adequate to attract capital investment and to provide incentive for further exploration for, development of, and production of, new natural gas.

"(3) The Commission may, by rule, establish a higher ceiling price in excess of the national ceiling price established under paragraph (1) if the Commission finds that such higher ceiling is necessary to provide special relief to meet extraordinary expenses for deep vertical drilling or other high-cost or high-risk production of natural gas and limits such higher ceiling price to only those persons incurring such additional costs or risks.

"(b) The Commission shall amend rules required to be promulgated under subsection (a) from time to time as may be necessary to take into account inflation or any change in circumstances related to the factors specified in subsection (a) to be given consideration in establishing such rate.

"(c) Any sale by a producer to a natural-gas company for purposes of resale in interstate commerce which is made in accordance with the ceiling price established pursuant to subsection (a) shall be deemed just and reasonable for the purposes of sections 4 and 5 of this Act.

"(d) It shall constitute a violation of this Act for any natural gas producer who is not an independent producer to sell or transfer natural gas in contravention of the requirements of the rules promulgated by the Commission pursuant

to subsection (a). The Commission, in promulgating such rules or in making amendments thereto, shall have authority, in the case of transactions between a producer and an affiliate of such producer or among affiliates of such producer, to impute a transfer price to such producer or treat sales of an affiliate of a producer as a sale by such producer.

"NATURAL GAS CONSERVATION

"SEC. 25. (a) Except as provided in subsection (c) of this section, the Commission shall, by rule, prohibit boiler fuel use of natural gas not contracted for prior to January 1, 1976, unless, upon petition by the user of such gas, the Commission determines that—

"(1) alternative fuels, other than propane, are not available to such user; or

"(2) it is not feasible or practicable to utilize such alternative fuels at the time of such Commission determination.

"(b) Except as provided in subsection (c) of this section, the Commission shall, by rule, prohibit boiler fuel use of natural gas contracted for prior to January 1, 1976, at the expiration of such contract or ten years after the effective date of the Natural Gas Act Amendments of 1977, whichever is earlier, unless, upon petition of the user of such gas, the Commission determines that (1) alternative fuels, other than propane, are not available to such user, or (2) it is not

feasible or practicable to utilize such alternative fuels at the time of such Commission determination. The Commission shall modify or terminate certificates of public convenience and necessity relating to such contracts to the extent necessary to carry out the purpose of this subsection.

"(c) (1) The Commission may exempt from any rule under this section the burning of natural gas by powerplants for the purpose of operating pollution abatement systems.

"(2) The Commission shall not prohibit the boiler fuel use of natural gas for the necessary processes of ignition, startup, testing, and flame stabilization by a facility, or for the purpose of alleviating short-term air quality emergencies or any other danger to the public health or safety.

"(3) The Commission shall not issue any order under this subsection which applies to any powerplant which was in existence on June 30, 1975, which during the twelve-month period preceding such date did not burn petroleum products, and which the Commission determines will be operated on natural gas only for the purpose of providing electric power which would otherwise be provided by one or more of the base load powerplants of the same electric power system which cannot be operated because of an air pollution emergency or because of an unanticipated equipment outage or an act of God.

"(4) In implementing the provisions of this section, the

Commission shall, to the extent necessary, apply the provisions of section 17 of this Act.

"(5) Nothing in this section shall impair any requirement in any State or Federal law pertaining to safety or environmental protection.

"NATURAL GAS FOR ESSENTIAL AGRICULTURAL PURPOSES

"SEC. 26. (a) Except to the extent that the Commission determines that natural gas supplies are required to maintain natural gas service to residential users, small commercial users, hospitals, and other similar services vital to public health and safety, the Commission shall, in exercising its authority under this Act to require curtailment plans, shall not cause any interruption or curtailment of natural gas which it determines necessary to assure the ready availability of sufficent supplies of natural gas for use in any essential agricultural, food processing, or food packaging purpose, for which natural gas is essential, including irrigation pumping, crop drying, use as a raw material feed stock, or process fuel in the production of fertilizer and essential agricultural chemicals.

"(b) The Commission shall, in carrying out the provisions of subsection (a), review and make any modifications as it determines necessary in criteria under which curtailments of natural gas are approved.

"(c) The Secretary of Agriculture shall determine, by

rule, the essential agricultural, food processing, or food packaging purposes for which natural gas is essential and shall certify such determination to the Commission. Such determination shall include the judgment of the Secretary of Agriculture with respect to the amount of natural gas which is necessary for such essential uses in order to meet the requirements for full food and fiber production.".

[H.R. 1460, 95th Cong., 1st sess., introduced by Mr. Archer on January 6, 1977;
H.R. 2717, 95th Cong., 1st sess., introduced by Mr. Kemp on January 31, 1977;
HR. 2787, 95th Cong., 1st sess., introduced by Mr. Dickinson on February 1, 1977;
and
H.R. 3342, 95th Cong., 1st sess., introduced by Mr. Gradison on February 9, 1977,
are identical or similar as follows:]

A BILL

To provide that certain provisions of the Natural Gas Act relating to rates and charges shall not apply to persons engaged in the production or gathering and sale but not in the transmission of natural gas.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. The Congress hereby finds the following:

(1) Natural gas presently supplies approximately one-third of the Nation's energy requirements.

(2) Natural gas will continue to supply a significant portion of the Nation's energy requirement for the next several decades.

(3) Maintaining abundant supplies of this vital energy

resource is in the national interest for national security and environmental reasons.

(4) Natural gas is the ideal energy resource because it pollutes the environment least.

(5) Declining domestic exploration activity for new reserves of natural gas has resulted in insufficient producing supplies to meet current and future demand for natural gas.

(6) This decline in domestic exploration activity for new reserves of natural gas can be directly attributed to insufficient incentive to invest capital in this high-risk business.

(7) Adequate price is the best incentive.

(8) The free market mechanism is the best method for setting the price of natural gas.

(9) The Federal Power Commission presently regulates the price of natural gas paid to producers who sell gas in interstate commerce.

(10) Because of the inherent slowness and uncertainty which are intentionally a part of normal regulatory procedures, the Federal Power Commission is unable to establish prices which stimulate the free market.

(11) In the long run the consumer is not benefited by Federal Power Commission price regulation since this regulation has caused the consumer to be deprived of abundant supplies of this ideal fuel.

(12) It is in the best interest of the consumer and the Nation that the Federal Power Commission cease this regulation of the price of natural gas.

SEC. 2. (a) That section 2(6) of the Natural Gas Act is amended by inserting before the period at the end thereof a comma and the following: "except that such term does not include a person engaged in the production or gathering and sale of natural gas if such person is not engaged in (or affiliated with any person engaged in) the transmission of natural gas to consumer markets or the distribution of natural gas to the ultimate consumers".

(b) That sections 4(a) and 5(a) are amended by inserting before the period at the end thereof a comma and the following: "*Provided, however,* That the Commission shall have no power to deny, in whole or in part, that portion of the rates and charges made, demanded, or received by any natural gas company for or in connection with the purchase of natural gas from a person exempt under section 2(6)".

[H.R. 1562, 95th Cong., 1st sess., introduced by Mr. Collins of Texas on January 10, 1977;
H.R. 2834, 95th Cong., 1st sess., introduced by Mr. McDonald on February 1, 1977; and
H.R. 3142, 95th Cong., 1st sess., introduced by Mr. Collins of Texas (for himself, Mr. Crane, Mr. Badham, Mr. Myers of Indiana, Mr. Derwinski, Mr. Kindness, Mr. Hall, Mr. Burleson of Texas, Mr. Cochran, Mr. Devine, Mr. Whitehurst, Mr. Sebelius, Mr. Lott, Mr. Walker, Mr. Rousselot, Mr. McDonald, Mr. Treen, Mr. Kelly, Mr. Symms, Mr. Lagomarsino, and Mr. Martin) on January 10, 1977, are identical as follows:]

A BILL

To amend the Natural Gas Act to assure adequate supplies of natural gas in interstate commerce.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That this Act may be cited as the "Natural Gas Act Amendments of 1977".

SEC. 2. Subsection 1(b) of the Natural Gas Act (15 U.S.C. 717(b)) is amended by inserting before the period at the end thereof the following: "or to the sale or delivery by a producer of new natural gas: *Provided, however,* That nothing contained in the Natural Gas Act Amendments of 1977 shall modify or affect the authority of the Commission in effect prior to the date of enactment of such amendments

to (A) regulate the transportation in interstate commerce of natural gas or the sale in interstate commerce for resale of old natural gas, or (B) regulate the sale for resale of natural gas by any natural gas company which transports natural gas in interstate commerce or by an affiliate thereof which transports natural gas in interstate commerce".

SEC. 3. Section 1 of the Natural Gas Act (15 U.S.C. 717) is amended by adding at the end thereof the following new subsections:

"(d) The Commission shall have no power to disallow, in whole or in part, in the rates and charges made, demanded, or received by any natural gas company the amounts actually paid for natural gas exempt from the Act pursuant to subsection (b) except as otherwise provided in subsection (e).

"(e) In any case where a natural gas company which transports natural gas in interstate commerce purchases natural gas from an affiliate or produces natural gas from its own properties, the Commission may not disallow any portion of the cost thereof in the rates or charges made by such company which is not in excess of current prices paid for comparable gas to nonaffiliates.

"(f) Once a sale or delivery of natural gas in interstate commerce shall have been previously determined by the Commission to be just and reasonable and such determination has become final and no longer subject to judicial re-

view, the Commission shall have no power to order thereafter a decrease in the rate or charges made.".

SEC. 4. Section 2 of the Natural Gas Act (15 U.S.C. 717a) is amended by adding at the end thereof the following new paragraphs:

"(10) 'New natural gas' means (A) natural gas sold or delivered in interstate commerce for the first time on or after January 1, 1977: *Provided*, That any natural gas sold or delivered in interstate commerce prior to the date of enactment of the Natural Gas Act Amendments of 1977 pursuant to limited term certificates (five years or less) or temporary emergency contracts shall not be considered, for the purpose of this provision, as having been committed to interstate commerce, (B) natural gas produced from any well initiated or completed on or after January 1, 1977, or (C) natural gas continued in interstate commerce after the expiration of an existing contract by its own terms (and not through the exercise of any power to terminate or renegotiate contained therein).

"(1) 'Affiliate' of another person means any person directly or indirectly controlling, controlled by, or under common control with such other person.

"(12) 'Producer' means a person who engages in the production, gathering, or processing of natural gas from wells or reserves in the United States.

"(13) 'Old natural gas' means natural gas sold in interstate commerce other than new natural gas.".

SEC. 5. Section 7 of the Natural Gas Act (15 U.S.C. 717f) is amended by adding at the end thereof the following new subsection:

"(i) The provisions of this section shall not permit the Commission to condition the grant of or to deny a certificate of public convenience and necessity to a natural gas company which transports natural gas in interstate commerce for the transportation in interstate commerce or for the sale in interstate commerce for resale of natural gas, or for the facilities used therefor, based on the price of new natural gas: *Provided, however,* That any contract for new natural gas shall be filed with the Commission by the purchasing natural gas company which transports natural gas in interstate commerce.".

[H.R. 2088, 95th Cong., 1st sess., introduced by Mr. Krueger (for himself and Mr. Brown of Ohio) on January 19, 1977;
H.R. 2089, 95th Cong., 1st sess., introduced by Mr. Krueger (for himself, Mr. Brown of Ohio, Mr. Hubbard, Mr. Derrick, Mr. Mann, Mr. Moore, and Mr. Pickle) on January 19, 1977;
H.R. 2712, 95th Cong., 1st sess., introduced by Mr. Jones of Oklahoma on January 31, 1977;
H.R. 2966, 95th Cong., 1st sess., introduced by Mr. Broyhill (for himself, Mr. Brown of Ohio, and Mr. Krueger) on February 2, 1977;
H.R. 3136, 95th Cong., 1st sess., introduced by Mr. Brown of Ohio (for himself, Mr. Krueger, Mr. Badham, Mr. Broyhill, Mr. Burgener, Mr. Cederberg, Mr. Don H. Clausen, Mr. Cleveland, Mr. Devine, Mr. Erlenborn, Mr. Guyer, Mr. Hillis, Mr. Horton, Mr. Hyde, Mr. Kemp, Mr. Kindness, Mr. Lott, Mr. McEwen, Mr. Moorhead of California, Mr. Quayle, Mr. Regula, Mr. Robinson, Mr. Sarasin, Mr. Walker, and Mr. Whitehurst) on February 7, 1977;
H.R. 3171, 95th Cong., 1st sess., introduced by Mr. Krueger (for himself, Mr. Brown of Ohio, Mr. Abdnor, Mr. Mollohan, Mr. Butler, Mr. Ketchum, Mr. Dickinson, Mr. Waggonner, Mr. Stockman Mr. Roberts, Mr. Runnels, Mr. AuCoin, Mr. Dan Daniel, Mr. Charles Wilson of Texas, Mr. Lagomarsino, Mr. Lehman, and Mr. Glickman) on February 7, 1977;
H.R. 3669, 95th Cong., 1st sess., introduced by Mr. Krueger (for himself, Mr. Brown of Ohio, Mr. O'Brien, Mr. Barnard, Mr. Preyer, Mr. Andrews of North Dakota, Mr. Kasten, Mr. Breaux, Mr. Anderson of Illinois, Mr. Chappell, Mr. Hightower, Mr. Forsythe, Mr. Edwards of Oklahoma, Mr. English, Mr. Holland, Mr. Jones of Oklahoma, Mr. Emery, Mr. Giaimo, Mr. Hansen, Mr. Martin, Mr. Gammage, and Mr. Treen) on February 17, 1977;
H.R. 3967, 95th Cong., 1st sess., introduced by Mr. Vander Jagt on February 23, 1977;
H.R. 5130, 95th Cong., 1st sess., introduced by Mr. Wirth on March 16, 1977;
H.R. 6203, 95th Cong., 1st sess., introduced by Mr. Krueger (for himself, Mr. Brown of Ohio, Mr. Goldwater, Mr. Gammage, Mr. Montgomery, Mr. Long of Louisiana, Mr. Bowen, Mr. McClory, Mr. Hall, Mr. Young of Alaska, Mr. Goodling, Mr. McCloskey, Mr. Winn, and Mr. Trible) on April 6, 1977; and
H.R. 6471, 95th Cong., 1st sess., introduced by Mr. Brown of Ohio (for himself, Mr. Krueger, Mr. Sebelius, Mr. Frenzel, and Mr. Burgener) on April 21, 1977, are identical or similar as follows:]

A BILL

To assure the availability of adequate supplies of natural gas at reasonable prices for consumers, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That this Act may be cited as the "Natural Gas Act Amendments of 1977".

SEC. 2. The Natural Gas Act (15 U.S.C. 717 et seq.) is amended by (1) striking out section 24 thereof (15 U.S.C. 717w); and (2) amending section 1 thereof by redesignating subsections (a), (b), and (c) as subsections (b), (c), and (d), respectively, and inserting therein the following new subsection:

"(a) This Act may be cited as the 'Natural Gas Act'.".

SEC. 3. Section 1(c) of the Natural Gas Act, as re-

designated by the Natural Gas Act Amendments of 1977 (15 U.S.C. 717(b)), is amended (1) by deleting "The" at the beginning thereof and by inserting in lieu thereof immediately after "(c)" the following: "(1) Except as provided in paragraph (2) of this subsection, the"; and (2) by inserting at the end thereof the following new paragraph:

"(2) Subject only to the provisions of section 24 of this Act, after the date of enactment of the Natural Gas Act Amendments of 1977, the authority of the Commission to regulate the sale of natural gas to a natural-gas company for resale in interstate commerce pursuant to this Act shall cease to exist with respect to, and shall not apply to, new natural gas: *Provided, however,* That nothing contained in the Natural Gas Act Amendments of 1977 shall modify or affect the authority of the Commission in effect prior to the date of enactment of such amendments to (A) regulate the transportation in interstate commerce of natural gas or the sale in interstate commerce for resale of old natural gas or (B) regulate the sale for resale of natural gas by any natural-gas company which transports natural gas in interstate commerce.".

SEC. 4. (a) Section 2 of the Natural Gas Act (15 U.S.C. 717a) is amended by redesignating paragraphs (7)

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through (9) as paragraphs (13) through (15), and by inserting the following new paragraphs:

"(7) 'New natural gas' means (A) natural gas sold or delivered in interstate commerce for the first time on or after January 1, 1977: *Provided*, That such natural gas was not sold or delivered in intrastate commerce for the first time prior to January 1, 1977: *Provided further*, That new natural gas contracted for sale or delivery from offshore Federal lands shall be committed for an initial contract term of not less than fifteen years or for the life of the reservior from which it is produced if less than fifteen years: *Provided further*, That any natural gas sold or delivered in interstate commerce prior to the date of enactment of the Natural Gas Act Amendments of 1977 pursuant to limited term certificates (five years or less) or temporary emergency contracts shall not be considered, for the purpose of this provision, as having been committed to interstate commerce, or (B) (1) natural gas produced from a reservoir discovered on or after January 1, 1977 (including a reservoir discovered by the deeper drilling of an existing well), regardless of whether or not the leases covering such newly discovered reservoirs were committed by contract or otherwise dedicated to the interstate market, or (2) natural gas produced from a well or wells ini-

tiated on or after January 1, 1977, and completed within an extension of a previously discovered reservoir, regardless of whether or not the leases covering such previously discovered reservoirs were committed by contract or otherwise dedicated to the interstate market, or (3) natural gas produced from a well or wells initiated on or after January 1, 1977, and completed within a previously discovered reservoir, regardless of whether or not the leases covering such previously discovered reservoirs were committed by contract or otherwise dedicated to the interstate market: *Provided*, That the seller of such natural gas, in a proper form and manner determined by rule by the Commission within thirty days of the date of enactment of the Natural Gas Act Amendments of 1977, files (i) appropriate documentation that such well or wells are necessary to deplete in an efficient and economic manner the previously discovered reservoir and that each such well is necessary to permit the recovery of additional reserves from such previously discovered reservoir which would not otherwise be economically recoverable from an existing well or wells in such reservoir, in accordance with good operation practices, and the applicable regulations of the appropriate local, State, or Federal agency, (ii) all documentation filed with or issued by a local, State, or Federal agency

charged with authority to authorize such well or wells, and, (iii) any other documentation that may be issued by such local, State, or Federal agency relating to the need for such well or wells: *Provided further*, That any such filing shall be deemed to have been approved by the Commission if the Commission does not reject such filing as not being supported by substantial evidence within ninety days from the date that such application is received by the Commission for filing.

"(8) 'Old natural gas' means natural gas sold or delivered in interstate commerce other than new natural gas: *Provided*, That old natural gas sold or delivered in intrastate commerce for the first time prior to January 1, 1977, shall, if sold or delivered in interstate commerce for the first time after January 1, 1977, be deemed by the Commission as having been sold or delivered from wells commenced on or after January 1, 1975.

"(9) 'Boiler fuel use of natural gas' means the use of natural gas as the source of fuel in a generating unit of more than twenty-five megawatts rated net generating capacity in the previous quarter, or in any unit which is part of an electric utility system with a total net generating capacity of more than one hundred and fifty megawatts in the previous quarter, for the purpose of generating electricity for distribution.

"(10) 'Affiliate' means any person directly or indirectly controlling, controlled by, or under common control or ownership with any other person, as determined by rule by the Commission.

"(11) 'Offshore Federal lands' means any land or subsurface area within the Outer Continental Shelf, as defined in section 2(b) of the Outer Continental Shelf Lands Act (43 U.S.C. 1331(a)).

"(12) 'Intrastate commerce' means commerce within the United States other than interstate commerce.".

SEC. 5. Section 4(e) of the Natural Gas Act (15 U.S.C. 717c(e)) is amended by adding at the end thereof the following new sentence: "Notwithstanding the foregoing, the Commission shall have no power to deny, in whole or in part, any rate or charge made, demanded, or received by any natural-gas company for, or in connection with, the purchase or sale, of new natural gas, or that portion of the rates and charges of such company which relates to such purchase or sale, except (A) to the extent that such rates or charges, or such portion thereof, for new natural gas sold or delivered from offshore Federal lands exceed the national ceiling or interim ceiling established or modified by regulation of the Commission pursuant to section 24 of this Act, or (B) in any case where

a natural-gas company which transports natural gas in interstate commerce purchases new natural gas from an affiliate or produces new natural gas from its own properties, to the extent that the Commission determines that the rates and charges therefore exceed the current rates and charges, or portion thereof, made, demanded, or received for comparable sales by persons not affiliated with such natural-gas company.".

SEC. 6. Section 5(a) of the Natural Gas Act (15 U.S.C. 717d(a)) is amended by striking the period at the end thereof and by adding the following: ": *Provided further*, That the Commission shall have no power (1) to deny, in whole or in part, any rate or charge made, demanded, or received by any natural-gas company for, or in connection with, the purchase or sale of new natural gas, or that portion of the rates and charges of such natural-gas company which relates to such purchase or sale, except (A) to the extent that such rates or charges, or such portions thereof, for new natural gas sold or delivered from offshore Federal lands exceed the national ceiling, or interim ceiling, established or modified by regulation of the Commission pursuant to section 24 of this Act, or (B) in any case where a natural-gas company which transports natural gas in interstate commerce purchases new natural gas from an affiliate or produces new natural gas from its own properties, to the extent that

the Commission determines that the rates and charges therefor exceed the current rates and charges, or portion thereof, made, demanded, or received for comparable sales by persons not affiliated with such natural-gas company; or (2) to order a decrease in the rate or charge made, demanded, or received for the sale or transfer of old natural gas or new natural gas produced from offshore Federal lands by a natural-gas company if such rate or charge has been previously determined or deemed to be just and reasonable pursuant to this Act.".

SEC. 7. Section 7(c) of the Natural Gas Act (15 U.S.C. 717f(c)) is amended by inserting "(1)" after "(c)" and by adding at the end thereof the following new paragraph:

"(2) Upon enactment of the Natural Gas Act Amendments of 1977, the sale of natural gas (and any persons, activities, operations, facilities, or services involved in or relating to the transportation, delivery, transfer, or exchange of such natural gas from any source), is exempt from the provisions of this Act, except for the reporting requirements thereof, if such sale is made by a producer of natural gas, a natural gas company which transports natural gas in interstate commerce, a person who transports natural gas in other than interstate commerce, or a person engaged in the local distribution of natural gas to or with a natural-gas

company which transports natural gas in interstate commerce and is curtailing deliveries of natural gas pursuant to a curtailment plan on file with the Commission and does not have a sufficient supply of natural gas to meet the requirements of its high priority consumers of natural gas, or the high priority consumers served by its customers. Within fifteen days after the enactment of the Natural Gas Act Amendments of 1977, the Commission shall by rule designate those persons eligible to receive by purchase or otherwise supplies of natural gas exempt from regulation pursuant to this section 7(c)(2). Exemptions granted by this section 7(c)(2) shall be for periods of no more than one hundred and eighty consecutive days. The Commission may extend an exemption granted by this section 7(c)(2), if the Commission finds that such an exemption is necessary to maintain deliveries of natural gas to the high priority consumers of the purchaser or the high priority consumers of the purchaser's customers. The exemption and authority provided by this section 7(c)(2) may be terminated on or after April 15, 1978, if the Commission determines that the exemptions provided hereunder are no longer necessary to protect high priority consumers of natural gas. Such a determination shall be made by the Commission by rule sixty days or more before taking effect. The Commission shall have no power to deny, in whole or in part, recovery by

any natural gas company which transports natural gas in interstate commerce in its jurisdictional rates of the amount paid by it for natural gas delivered to it pursuant to sales and contracts exempt under this section 7 (c) (2), except to the extent that such a natural gas company purchases natural gas from an affiliate, or natural gas produced from its own properties, at a rate in excess of the price paid by it to non-affiliated sellers in comparable sales transactions. Any contractual provisions prohibiting sales or transportation entitled to any such exemption or terminating any other obligations of any gas supply or sales contracts as a result of such sales or transportation shall be unenforceable in respect to any such sale or transportation. Any activity or person or facility owned by such person exempt under sections 1 (c) or 1 (d) of this Act shall not have that exempt status affected in any way by making the sales or deliveries contemplated by this section 7 (c) (2).

SEC. 8. Section 7 of the Natural Gas Act (15 U.S.C. 717f) is further amended by adding at the end thereof the following new subsection:

"(i) Subject only to the provisions of section 24 of this Act, after the date of enactment of the Natural Gas Act Amendments of 1977, the provisions of this section shall not permit the Commission to condition the grant of or to deny a certificate of public convenience and necessity to a natural-

gas company which transports natural gas in interstate commerce for the transportation in interstate commerce or for the sale in interstate commerce for resale of natural gas, or for the facilities used therefor, based on the price of new natural gas: *Provided, however,* That any contract for new natural gas shall be filed with the Commission by the purchasing natural-gas company which transports natural gas in interstate commerce.".

SEC. 9. Section 14 of the Natural Gas Act (15 U.S.C. 717m) is amended by adding at the end thereof the following three new subsections:

"(h) The Commission is further authorized and directed to conduct studies of the private or public exploration, production, sale, transportation, distribution, and consumption of natural gas, produced in the United States or in any State, whether or not otherwise subject to the jurisdiction of the Commission, and to make an annual independent estimate of total natural gas reserves. The Commission shall, insofar as practicable, obtain and keep current information regarding (1) the ownership, operation, management, and control of all facilities for such exploration, production, sale, transportation, distribution, and consumption; (2) the independent estimate of total natural gas reserves in the United States as required by this subsection, the current utilization of natural gas, and the relationship between the two; (3)

the rates, charges, and contracts for natural gas service to residential, rural, commercial, and industrial consumers, and private and public agencies; and (4) the relationship of any and all such information to the requirements of conservation, industry, commerce, and the national defense. Notwithstanding the provisions of section 1 of this Act (15 U.S.C. 717), the provisions of sections 20, 21, and 22 of this Act (15 U.S.C. 717s, 717t, and 717u) shall be applicable to the enforcement of this section. The Commission shall report annually to the Congress and shall publish and make available the results of studies, investigations, and estimates made pursuant to this subsection.

"(i) In making studies, investigations, and reports pursuant to this section, the Commission shall utilize, insofar as practicable, the services, studies, reports, information, and programs of existing agencies and other instrumentalities of the United States, of the several States, and of the natural-gas industry. Such agencies or instrumentalities of the United States shall cooperate with the Commission to the maximum extent practical to carry out the purposes of this subsection. Nothing in this section shall be construed as modifying, reassigning, or otherwise affecting the investigative and reporting activities, duties, powers, and functions of any other agency or instrumentality of the United States.

"(j) The reports and information made public by the

Commission shall be so composited and published as to preserve the confidentiality of trade secrets and other proprietary information obtained by the Commission as provided by law.".

SEC. 10. The Natural Gas Act, as amended by the Natural Gas Act Amendments of 1977, is further amended by adding at the end thereof the following three new sections:

"NATIONAL CEILING FOR RATES AND CHARGES

"SEC. 24. (a) The Commission shall by rule, as soon as practicable after the date of enactment of the Natural Gas Act Amendments of 1977, establish, and may from time to time modify, a national ceiling for rates and charges for new natural gas sold or delivered from offshore Federal lands on or after January 1, 1977, through December 31, 1981. In establishing such national ceiling the Commission shall consider the following factors and only these factors:

"(1) the prospective costs attributable to the exploration, development, production, gathering, and sale of new natural gas from offshore Federal lands;

"(2) the rates and charges necessary to encourage the optimum levels of (A) the exploration for natural gas, (B) the development, production, and gathering of

natural gas, and (C) the maintenance of proved reserves of natural gas;

"(3) the promotion of sound conservation practices in natural gas consumption necessary to contribute to the maintenance of a supply of energy resources at reasonable prices to consumers; and

"(4) the rates and charges that will protect consumers of natural gas from price increases that would, in the absence of a national ceiling during periods of actual or anticipated shortages, exceed the rates and charges necessary to achieve the objectives of paragraphs (1) through (3) of this subsection.

"(b) The Commission shall monitor the national ceiling established pursuant to subsection (a) or the interim ceiling established pursuant to subsection (d) during the period such ceiling is in effect, and commencing on July 1, 1977, the Commission shall report to the Congress not less than annually on the effectiveness of such national ceiling or interim ceiling in meeting the factors set forth in subsection (a).

"(c) The Commission may authorize a person to charge an amount in excess of the national ceiling established pursuant to subsection (a) or the interim ceiling established pursuant to subsection (d) for new natural gas produced from offshore Federal lands from any high cost production

area or vertical drilling depth as designated by the Commission by rule.

"(d) Pending the establishment of a national ceiling pursuant to subsection (a) by a final Commission order which is no longer subject to judicial review and within thirty days after the date of enactment of the Natural Gas Act Amendments of 1977 and on January 1 of each year thereafter until such establishment of a national ceiling, the Commission shall establish an interim ceiling for rates and charges for new natural gas sold or delivered from offshore Federal lands which shall be effective January 1, 1977, and which shall be equivalent on a British thermal unit (Btu) basis to the average first sale price for new crude oil produced in the United States in effect on the date of enactment of the Natural Gas Act Amendments of 1977 as determined by the Federal Energy Administration pursuant to section 8 of the Emergency Petroleum Allocation Act of 1973 as amended (15 U.S.C. 757). After the establishment of a national ceiling pursuant to subsection (a) by final Commission order which is no longer subject to judicial review, any person who has sold or delivered new natural gas from offshore Federal lands during the period the interim ceiling price was in effect shall thereafter have the benefit of the national ceiling: *Provided, however,* That the Commission shall have no power to order a reduction in the rates

and charges for such sale or delivery below the interim ceiling price in effect on the date of the establishment of the national ceiling.

"(e) From and after January 1, 1982, there shall be no ceiling price applicable to the sale or delivery of new natural gas from offshore Federal lands.

"(f) No price established by or pursuant to the Natural Gas Act Amendments of 1977 for new natural gas produced from offshore Federal lands shall be retroactive so as to affect any price for any natural gas sold or delivered in interstate commerce prior to January 1, 1977.

"(g) The rates and charges made, demanded, or received by any natural gas company for, or in connection with, a contract for new natural gas sold or delivered from offshore Federal lands shall be deemed to be just and reasonable for the purposes of this Act, if they do not exceed the applicable national ceiling or interim ceiling established by regulation of the Commission or subsequently modified by the Commission pursuant to this section, in effect at the time when such new natural gas is either first sold or first delivered under such contract to a natural gas company.

"NATURAL GAS FOR ESSENTIAL AGRICULTURAL AND OTHER PURPOSES

"SEC. 25. (a) Except to the extent that natural-gas supplies are required to maintain natural-gas service to resi-

dential users, small users, hospitals, and similar users vital to public health and safety, as defined by the Commission, and notwithstanding any other provision of law (other than the provisions of this Act) or of any natural-gas curtailment plan in effect under existing law, the Commission shall within one hundred and twenty days of the date of enactment of the Natural Gas Act Amendments of 1977, by rule, prohibit curtailment by a natural-gas company, to the maximum extent practicable, of natural gas for essential agricultural food processing, and food packaging purposes for which natural gas is necessary, including but not limited to irrigation pumping, crop drying, the use of natural gas, as a raw material feedstock or process fuel, in the production of fertilizer and essential agricultural chemicals in existing plants (for present or expanded capacity) and in new plants. The Secretary of Agriculture shall determine by rule within sixty days of the date of enactment of the Natural Gas Act Amendments of 1977 the agricultural, food-processing, and food-packaging purposes for which natural gas is necessary. The Secretary of Agriculture shall certify to the Commission the amount of natural gas which is necessary for such essential uses to meet requirements for full food and fiber production.

"(b) Except to the extent that natural-gas supplies are required to maintain natural-gas service for purposes specified under subsection (a) of this section, the Commis-

sion shall prohibit curtailment by a natural-gas company, to the maximum extent practicable, of natural gas for industrial purposes for which natural gas is essential for uses (other than boiler fuel) for which there is no practicable substitute.

"(c) The Commission shall decide applications for special relief from a curtailment plan as soon as practicable, but in no event later than one hundred and twenty days after the date such applications are accepted for filing.

"NATURAL-GAS CONSERVATION

"SEC. 26. (a) Except as provided in subsections (c) and (e) of this section, the Commission shall by rule prohibit boiler fuel use of natural gas affecting commerce which is supplied pursuant to any delivery arrangement which becomes effective, or contract executed on or after January 4, 1977, unless, upon petition by the user the Commission determines for the subsequent twelve-month period that—

"(1) alternative fuels, other than crude oil or products refined therefrom, propane, natural-gas liquids, natural-gas condensate, or natural-gas liquid products, are not reasonably available to such user; or

"(2) it is not practicable or feasible to utilize such alternative fuels at the time of such Commission determination.

"(b) Except as provided in subsections (c) and (e) of

this section, the Commission shall by rule prohibit boiler fuel use of natural gas affecting commerce which is supplied pursuant to any delivery arrangement in effect or contract initially executed prior to January 4, 1977, at the expiration of such contract or delivery arrangement or ten years after the date of enactment of the Natural Gas Act Amendments of 1977, whichever is earlier, unless, upon petition of such user, the Commission determines for the subsequent twelve-month period that—

"(1) alternative fuels, other than crude oil or products refined therefrom, propane, natural-gas liquids, natural-gas condensate, or natural-gas liquid products are not reasonably available to such user, or

"(2) it is not practicable or feasible to utilize such alternative fuels at the time of such Commission determination.

The Commission shall modify or terminate certificates of public convenience and necessity issued pursuant to section 7 of this Act that relate to such contracts to the extent necessary to carry out the purpose of this subsection.

"(c) The Commission shall exempt from any rule under this section the boiler fuel use of natural gas by powerplants for the purpose of operating pollution abatement systems to the extent natural gas is required as

determined by the Commission for the efficient operation of such pollution abatement systems.

"(d) Nothing in this section shall impair any requirement in any State or Federal law pertaining to safety or environmental protection.

"(e) The Commission shall not prohibit the boiler fuel use of natural gas for the necessary processes of ignition, startup, testing, and flame stabilization by a facility, or for the purpose of alleviating short-term or seasonal air quality emergencies or any other significant risk to the public health or safety.

"(f) Except as expressly provided in subsections (b) and (g) of this section, the Commission, under the authority of the Natural Gas Act, shall not (1) modify, amend, or abrogate contracts entered into prior to January 4, 1977, for the sale or transportation of natural gas for boiler fuel use, (2) modify, amend, or abrogate the supply terms of certificates of public convenience and necessity issued pursuant to section 7 of this Act that authorize the sale or transportation of natural gas under such contracts, except upon application duly made by the holder of a certificate under section 7 of this Act; or (3) prevent, impair, or limit, either directly or indirectly, the deliveries under any such contract or certificate except upon application duly

made by the holder of a certificate under section 7 of this Act.

"(g) The provisions of this section shall not modify or limit the authority of the Commission to effectuate curtailments of natural gas transported and sold by a natural gas company.

"(h) Notwithstanding the provisions of section 1 of this Act (15 U.S.C. 717), the provisions of sections 20, 21, and 22 (15 U.S.C. 717s, 717t, and 717u) shall be applicable for the enforcement of this section.".

95TH CONGRESS
1ST SESSION

H. R. 2818

IN THE HOUSE OF REPRESENTATIVES

FEBRUARY 1, 1977

Mr. FINDLEY introduced the following bill; which was referred to the Committee on Interstate and Foreign Commerce

A BILL

To stimulate production of natural gas.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That all production of natural gas from wells which commenced production on or after January 1, 1977, and all new dedications to the interstate market, shall be exempt from regulation by the Federal Power Commission.

**[HR. 3317, 95th Cong., 1st sess., introduced by Mr. Allen on February 9, 1977;
H.R. 5043, 95th Cong., 1st sess., introduced by Mr. Allen (for himself, Mr. Ford of Tennessee, and Mr. Carter) on March 15, 1977; and
H.R. 6025, 95th Cong., 1st sess., introduced by Mr. Hughes on April 5, 1977,
are identical or similar as follows:**

A BILL

To amend title 15, United States Code, section 717 et seq., the Natural Gas Act, so as to extend the regulatory authority of the Federal Power Commission, to vest certain extraordinary and other powers in the President, to encourage the exploration and drilling for natural gas, to encourage the conservation of natural gas, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That this Act may be cited as the "Natural Gas Reform Act of 1977".

FINDINGS AND DECLARATION OF POLICY

SEC. 2. The Congress finds and declares that—

(1) natural gas is not a man-made commodity, but

is a natural resource, created and preserved in the Earth by our Maker for the benefit of all mankind. This most valuable, efficient, and clean-burning fuel has become a vital and valuable source of energy, essential to the welfare of our Nation. The proper and nonwasteful use of natural gas, with the purpose of assuring the proper conservation of this precious natural resource for the benefit, safety, health, education and welfare of the citizens in all fifty States of the Nation, including the District of Columbia and all territories subject to the jurisdiction of the United States, are of such importance that natural gas should be, and it is hereby declared to be, a precious natural resource of the Nation which should be, and hereby is, made subject to proper regulation by the Federal Government at the wellhead and thence to all pipelines and distributors of natural gas, except for sales thereof by local distributors to ultimate consumers in areas where such regulation is provided under the authority of the State government, whether or not such natural gas heretofore has been or is intended in the future to be sold, transported or used in interstate commerce. Accordingly, such natural gas, except that sold to consumers described above, whether it has heretofore been or is intended in the future to be sold or transported across State lines, should be and hereby is made

subject to the control and regulation of the Federal Government;

(2) any natural gas company which drills for, sells, or supplies natural gas directly or indirectly to any person engaged in interstate commerce, or to any manufacturer, wholesaler, or retailer of goods purchased or sold in interstate commerce, or any hotel, motel, or innkeeper providing sleeping or eating accommodations to persons traveling in interstate commerce, or to any other person defined by law as engaged in interstate commerce or as engaged in an activity having an effect on interstate commerce, is hereby declared to be engaged in interstate commerce, even where such natural gas is sold within the same State as such production or supplying is located, and shall be subject to the same Federal regulations and price controls administered and prescribed by the Federal Power Commission as all other such producers or suppliers selling directly in interstate commerce;

(3) the citizens of the Nation and its business, industry, and commerce are dependent to a substantial extent on the availability of natural gas for the heating of homes and places of business, for the cooking of food and the operation of essential appliances, for the production operations of said business, industry, and

commerce, for necessary travel and communication, for the operation of schools and hospitals, and for the production of other essential goods and services;

(4) the supplies of natural gas available in the marketplace are not sufficient to meet the foregoing essential needs, and the said lack of adequate supplies is causing serious detriment to the health, education, economy, and welfare of the American public;

(5) an adequate supply of natural gas for the said essential uses in the Nation has been withheld from the interstate market by certain producers of natural gas in order that such natural gas may be sold intrastate, under certain exemptions of the Natural Gas Act, at much higher prices than said producers have been permitted for sales of natural gas under Federal regulation, resulting in invidious discrimination by certain natural gas companies in the pricing of natural gas for essential uses;

(6) such withholding of natural gas from the interstate market by certain producers has resulted in an increased and unnecessarily severe curtailment of the supply of natural gas. As a consequence, the American public is experiencing ever-increasing difficulty or impossibility in obtaining sufficient quantities of natural

gas for the essential needs of heating, maintaining, and operating homes, schools, hospitals, and industries in many States of the Nation;

(7) in many parts of the Nation, schools, businesses, and industries have been forced to cease or curtail their operations because of the unavailability of sufficient supplies of natural gas;

(8) the shutdown of schools, businesses, and industries in the Nation due to the unavailability of natural gas has resulted in the sudden loss of employment of more than a million and hundreds of thousands of American citizens, forcing them into economic hardship due solely to the lack of sufficient natural gas for the operation of said schools, businesses, and industries;

(9) a substantial portion of the natural gas production in the Nation presently is not subject to regulation by the Federal Power Commission, being specifically exempted from such regulation by certain provisions of the Natural Gas Act;

(10) there is strong and credible evidence that producers, suppliers, vendors, and distributors of natural gas have been and are engaging in unwarranted and unjustifiable discrimination in the prices and rates charged for natural gas, to the ultimate detriment of the health,

education, safety, economy, and welfare of the American public, and it is declared the policy of the Nation to end such discrimination.

(11) the withholding of natural gas from the interstate market by natural gas producers and suppliers in order further to inflate the price of natural gas is found by the Congress to be causing great suffering to the American people and great hardship to the American economy, and the Congress declares that said withholding represents an intolerable burden on interstate commerce;

(12) the producers of natural gas having been selling natural gas at prices much higher than gas produced subject to Federal price regulation and jurisdiction, the Congress finds and declares that the production of and the discriminatory prices charged for such unregulated natural gas have become an intolerable burden on interstate commerce;

(13) the increasingly higher and discriminatory prices of natural gas and the scarcity of natural gas are causing a grave threat to the safety, health, education, economy, and welfare of the Nation and its citizens, and the Congress finds that said threat results from the lack of adequate regulation and Federal control over the operation of the natural gas industry;

(14) there being a finite quantity of natural gas, now and in the future, which can be produced and distributed to supply the Nation and all of its citizens, the Congress declares that it shall be the policy of the Nation to encourage the conservation of natural gas and its nonwasteful use;

(15) all natural gas in the Nation is an essential national resource, wherever it may be located, and whether or not some part of said natural gas may in fact cross a State line in the course of the production, supplying, and transportation, and of its distribution and sale. Any unregulated portion of said production, supplying, and transportation, and of the distribution and sale of natural gas to others than ultimate consumers by local distributors in areas where proper regulation is provided under the authority of State or United States territorial authority, is declared to have an adverse economic effect on interstate commerce;

(16) the safety, health, education, economy, and welfare of the people of the Nation require that its essential natural resource, natural gas, be subject to Federal regulation to assure the proper pricing, use, and conservation of said natural gas, no matter where in the Nation the production, supplying, or transportation, or the distribution or sale of said natural gas may take

place, except in areas where sales are made to ultimate consumers by local distributors under proper regulation of State or United States territorial authority, due allowance being made for the legitimate differences in the cost of the transportation of natural gas from the wellhead to the ultimate users in the various parts of the Nation;

(17) the necessity for the Federal regulation of the essential natural resource of natural gas for the general welfare of the Nation having been established, and the Congress having as its purpose the proper use, price and conservation of said essential natural resource, wherever located, the Congress declares that it shall be the policy of the Nation to establish proper Federal regulation of the production, supplying and transportation, and of the distribution and sale of all natural gas, wherever located, in all the States, the District of Columbia, and in any organized territory of the United States, except in areas where sales are made to ultimate consumers by local distributors and proper regulation thereof is provided under authority of States and United States territorial governments; and

(18) to carry out the aforesaid purpose of the Congress, title 15, United States Code, section 717 et seq., the Natural Gas Act, shall be and the same hereby is amended in the following respects:

COVERAGE

SEC. 3. Title 15, United States Code, section 717, is hereby repealed, and the following language shall be substituted in lieu thereof:

"§ 717. Coverage

"It is declared that the business of producing, supplying and transporting, and of distributing and selling natural gas to others than ultimate consumers in areas herein specified are businesses concerning an essential natural resource of the Nation, which said businesses are affected with a public interest and which affect interstate commerce, no matter where said natural gas may be located in the Nation, and that Federal regulation in matters relating to such production, supplying and transportation, and to the distribution and sale of said natural gas, wherever located in the fifty States, the District of Columbia, or any organized territory of the United States, is necessary in the public interest, except sales to ultimate consumers by local distributors in areas where proper regulation thereof is provided under authority of States or United States territorial governments.

"The provisions of this chapter shall apply to the production, supplying and transportation, and to the distribution and sale of natural gas in interstate commerce, as herein defined, and to natural gas companies engaged

in such production, supplying and transportation, and in the distribution and sale of natural gas: *Provided, however,* That the provisions of this chapter shall not apply to the sale of natural gas by local distributors to ultimate consumers, where regulation thereof is specifically reserved to and effectively enforced by the individual States and territories of the United States Government; but in any State or area which does not have a commission, political subdivision, or other agency of said State or territory authorized and charged with the duty to regulate the transportation, production, supplying, distribution, selling and the fixing of prices and rates of such natural gas, the duty so to regulate and the responsibility and authority so to do are hereby vested in the Federal Power Commission; but such responsibility shall revert to any such State or territorial commission, political subdivision or other agency which may later be created by any such State or United States territory for that purpose.".

DEFINITIONS

SEC. 4. Title 15, United States Code, section 717a, is hereby amended in the following respects:

(1) Subsection (5) thereof shall be amended to read as follows:

"(5) 'Natural gas' means either natural gas, unmixed, or any mixture of natural and artificial gas, or

natural gas in liquid form, either mixed or unmixed, or natural gas in any form or mixture.".

"(2) Subsection (6) thereof shall be amended to read as follows:

"(6) 'Natural gas company' means a person engaged in the production, distribution, supplying, transportation or sale of natural gas.".

(3) Subsection (7) thereof shall be amended to read as follows:

"(7) 'Interstate commerce' means commerce between any point in a State and any point outside thereof, or between points within the same State but through any place outside thereof, and shall specifically include any commerce affecting interstate commerce, and shall specifically include the exploration for, drilling of, production, distribution, supplying, transportation or sale of natural gas, regardless of location, except that the sale and distribution of natural gas to ultimate consumers by local distributors in areas where proper regulation is provided under the authority of a State or territorial government shall not be included.".

(4) There shall be added at the end of said section 717a the following new subsections, which shall read as follows:

"(10) 'Local distributor' means any person who

purchases or receives natural gas from any natural gas well, producer, or natural gas pipeline, whether crossing State lines or not, or from any other source, for the purpose of selling, distributing, supplying or redistributing natural gas to ultimate consumers in areas where proper regulation thereof is provided under authority of State or United States territorial authority, but specifically excluding owners and operators of natural gas wells, natural gas producers, all natural gas pipelines, natural gas pipeline companies, whether engaged in transporting natural gas across State lines or not, and all others made subject under the provisions of this Act to regulation by the Federal Power Commission.

"(11) 'Ultimate consumer' means a person who purchases natural gas from a local distributor only for the use of said consumer and not for further production, distribution, supplying, transporting or sale.

"(12) Wherever in this chapter the words either 'transporting' or 'transportation', and the words either 'selling' or 'sale' may be used, said words shall be read to include the words 'production', 'supplying', and 'distribution'.".

MISCELLANEOUS PROVISIONS

SEC. 5. Title 15, United States Code, section 717t, is hereby amended by deleting the period at the end thereof

and by substituting in lieu of said period a comma, which shall be followed by the following language: "unless otherwise specifically set forth herein.".

SEC. 6. Title 15, United States Code, section 717 et seq., is hereby amended by inserting the following language immediately following section 717i thereof, and by relettering accordingly those sections which follow after the inserted language:

"§ 717j. Disclosure

"All natural gas companies shall be required to furnish monthly reports to the Commission of the reserves of natural gas currently available to said companies and of the reserves of natural gas reasonably anticipated to be available to said companies during the succeeding six-month and twelve-month periods, and said monthly reports shall also include the statements of said companies of the demand for natural gas which the said companies experience at the time of said monthly reports and of the demand for natural gas which the said companies anticipate they will experience during the succeeding six-month and twelve-month periods. A copy of each said monthly report to the Commission shall be forwarded by each of said natural gas companies to the President.

"The Commission shall be required to maintain such

monthly reports at all times and to submit monthly summary reports thereof to the President.

"Failure by any person in good faith to furnish the information required by this section shall be punishable by a fine not to exceed $250,000 or by imprisonment for a term not to exceed three years, or both.

"§ 717k. Withholding

"Whenever a demand for the furnishing of natural gas shall exist on the part of the consumers of natural gas, it shall be unlawful for any natural gas company arbitrarily to withhold its available supplies of natural gas from the market or to refuse promptly to sell natural gas, except upon the express authorization of the Commission, and such authorization shall be forthcoming only where the Commission may, after notice and hearing and for good cause shown, find such authority to be in the public interest.

"Any person who shall fail to comply with the provisions of this section shall be punishable by a fine not to exceed $500,000 or by imprisonment for a term not to exceed five years, or both.

"In the event he shall determine that such natural gas has been or is being withheld by any natural gas company, or that any natural gas company has refused to sell any part of its available supply of natural gas, the President is hereby authorized upon ten days notice to

seize such withheld or unsold natural gas and to order its distribution as he shall determine in the public interest and for the general welfare of the Nation: *Provided, however*, That prices for such seized natural gas shall be such prices as are established by the Commission.

"If there be any dispute between the President and the parties from whom natural gas may be seized respecting the compensation for such seizure, said dispute shall be without delay to such seizure.

"§ 717l. Reallocation

"Whenever the Commission shall determine that there is a shortage or insufficient reserves of natural gas to furnish the immediate needs of the customers and users of natural gas in any or all parts of the Nation, the President shall be authorized upon ten days notice to seize any reserves of natural gas and to reallocate said reserves as he deems necessary for the welfare of the Nation, subject to the procedures and in the manner prescribed in the Emergency Natural Gas Act of 1977: *Provided, however*, That prices for such seized natural gas shall be the same as prices established by the Commission.

"If there be any dispute between the President and the parties from whom natural gas may be seized with respect to the compensation for such seizure, said dispute shall be without delay to such seizure.

"§ 717m. Use priorities

"Notwithstanding any other provision of this chapter, the Commission shall establish priorities for the use of natural gas, with first and highest priority for such use being accorded to the essential uses of heating and cooking and the operation of essential appliances for residential consumers and small business consumers and such other uses vitally essential to public health, education and other purposes as shall be determined by the Commission or the President; and the Commission is hereby empowered and directed to establish other and lower priorities for the use of said natural gas. The Commission shall require the furnishing of natural gas on the basis of said use priorities.

"The said use priorities established by the Commission shall become effective upon the approval of the President and if not so approved, the President shall have the power to reorder such priorities.

"§ 717n. Rate schedules

"Notwithstanding any other provision of this chapter, the Commission, in establishing prices and rates for the production, supplying and transportation, and for the distribution and sale to others than ultimate consumers of natural gas in areas hereinabove defined, shall accord first and highest priority to the welfare of the residential and small business users and such other consumers of natural gas as

hereinabove provided and no person shall be permitted by the Commission or any regulatory authority to produce, transport, or supply natural gas which will be ultimately consumed by other than the highest priority users of natural gas at a sale price to such other users which shall be less than the retail sale price to such highest priority users of natural gas; it being the intent of Congress to promote the conservation and nonwasteful use of natural gas, and through graduated price and rate schedules to be established by proper regulatory authorities, to eliminate any economic incentive for those consumers and users of natural gas classified as having a lower use priority rating to convert to or to use natural gas as a fuel in cases where other types of fuel in more plentiful supply will serve the purposes of said lower priority users and consumers of natural gas.

"§ 717o. Enforcement

"The Commission, the President, or any person or persons adversely affected by the failure of any natural gas company to comply with sections hereof may enforce the provisions of this Act by mandatory court order, injunctive relief, or other appropriate relief.

"§ 717p. Certificate processing

"Notwithstanding any other provision of this chapter, the Commission shall be required to complete its processing of any application for a certificate of convenience and

necessity filed by a natural gas company within a period of six months, unless the President shall, for good cause shown, permit said Commission a specified additional period of time within which to complete said processing. In the event the Commission shall fail to complete said processing within a period of six months from the date of an application for a certificate of convenience and necessity filed by a natural gas company, without the permission of the President for a specified additional period of time for such completion, then said certificate as applied for shall be considered approved and valid.

"§ 717q. Exporation incentive

"In order to encourage the exploration and drilling for reserves of natural gas, deemed necessary to increase existing reserves, and it being the specific intent of Congrss that such necessary exploration costs have as little impact as possible on the already economically burdened consumers of said natural gas in the prices and rates they must pay for same, the President is hereby authorized within his sole discretion to enter into an agreement with any natural gas company or other person for the Federal Government to reimburse said person in an amount not to exceed one-half of any net losses which may be suffered by said company or person in the exploration and drilling for such natural gas: *Provided—*

"(1) the site of such exploration and/or drilling shall have received certification, prior to the commencement of any such drilling or exploration, by such competent Federal geologists as shall be appointed by the President, or by the Commission with the approval of the President, for this purpose, as being a site reasonably likely to yield economically sufficient quantities of natural gas to justify such exploration and/or drilling;

"(2) such exploration and/or drilling shall result after good faith efforts, in a failure to produce sufficient natural gas or oil or other petroleum products or minerals to make such exploration and/or drilling a profitable venture; and

"(3) any such net loss claimed to have been incurred by any such natural gas company or person shall be subject to audit and other verification by the General Accounting Office or such other Federal auditors as may be designated by the President before such reimbursement shall be made.".

SEC. 7. This Act shall take effect ninety days after passage hereof, except that portion of section 6 hereof representing the new language of title 15, United States Code, section 717q, entitled "**Exploration incentive**", which shall take effect immediately from and after passage hereof.

[H.R. 3664, 95th Cong., 1st sess., introduced by Mr. Kemp (for himself, Mr. Moorhead of Pennsylvania, Mr. Ashley, Mr. Brown of Ohio, Mr. Dan Daniel, Mr. Dent, Mr. Derwinski, Mr. Devine, Mr. Edwards of Oklahoma, Mr. Flippo, Mr. Guyer, Mr. Harsha, Mr. Hyde, Mr. Kindness, Mr. Mollohan, Mr. Moorhead of California, Mr. Murtha, Mr. Neal, Mr. Price, Mr. Quillen, Mr. Regula, Mr. Rudd, Mr. Symms, Mr. Vander Jagt, and Mr. Walsh) on February 17, 1977;
H.R. 2447, 95th Cong., 1st sess., introduced by Mr. Kemp (for himself, Mr. Edwards of Oklahoma, and Mr. Moorhead of California) on January 26, 1977;
H.R. 3665, 95th Cong., 1st sess., introduced by Mr. Kemp (for himself, Mr. Moorhead of Pennsylvania, Mr. Duncan of Tennessee, Mr. Lott, Mr. Madigan, Mr. Murphy of Pennsylvania, Mr. Perkins, Mr. Preyer, and Mr. Yatron) on February 17, 1977;
H.R. 3911, 95th Cong., 1st sess., introduced by Mr. Kemp (for himself, Mr. Rahall, Mr. Stockman, Mr. Walker, and Mr. Whitehurst) on February 23, 1977;
H.R. 5889, 95th Cong., 1st sess., introduced by Mr. Kemp (for himself, Mr. Moorhead of Pennsylvania, Mr. Cederberg, Mr. Cochran of Mississippi, Mr. Collins of Texas, Mr. Dornan, Mr. Forsythe, Mr. Lederer, Mr. Lent, Mr. Montgomery, Mr. Murphy of Pennsylvania, Mr. John T. Myers, Mr. Pattison of New York, Mr. Perkins, Mr. Pursell, Mr. Sebelius, Mr. Walgren, Mr. Charles Wilson of Texas, and Mr. Young of Alaska) on March 31, 1977; and
H.R. 6078, 95th Cong., 1st sess., introduced by Mr. Kemp (for himself, Mr. Moorhead of Pennsylvania, Mr. Coughlin, Mr. Hall, and Mr. Hamilton) on April 5, 1977,
are identical or similar as follows:]

A BILL

To exempt sales by small producers of certain natural gas from regulation of the Federal Power Commission and from the requirement of certificates of public convenience and necessity of section 7 (c) of the Natural Gas Act.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That notwithstanding any provision of the Natural Gas Act or any other provision of Federal law or any contractural price limitation applicable thereto on the date of enactment of this Act, sales of any natural gas (except synthetic or liquified natural gas) by small producers shall be exempt

from regulation of the Federal Power Commission and may be made without any application for a certificate of public convenience and necessity under section 7 (c) of the Natural Gas Act (15 U.S.C. 717f (c)); and any such sale shall be made at a price not less than that which adequately compensates the seller for current costs, including an adequate return on investment, as determined by the seller and the purchaser.

SEC. 2. For purposes of this Act—

(a) "small producer" shall mean an independent producer of natural gas—

(1) who is not affiliated with a natural gas pipeline company or a producer who is not included within this definition;

(2) whose total sales of natural gas on a nationwide basis, together with such sales of affiliated producers, are not in excess of 10 million Mcf at 14.05 P.S.I.A. during any calendar year; and

(3) whose average production per well for all wells for such calendar year is not in excess of 100 Mcf per day.

(b) "affiliated producers" are persons who, directly or indirectly, control or are controlled by, or are under common control with, a small producer.

[Report of FEA on 8 separate bills follows:]

FEDERAL ENERGY ADMINISTRATION,
Washington, D.C., April 19, 1977.

HONORABLE HARLEY O. STAGGERS
Chairman, Committee on Interstate and Foreign Commerce,
House of Representatives, Washington, D.C.

DEAR MR. CHAIRMAN: This is in response to your requests of February 25, 1977, and March 7, 1977 for views of the Federal Energy Administration on eight separate bills relating to the issue of deregulation of the wellhead price of natural gas, and other natural gas issues.

H.R. 2447 would exempt sales by small producers of certain natural gas from regulation of the Federal Power Commission and from the requirement for certificates of public convenience and necessity of section 7(c) of the Natural Gas Act.

H.R. 2717 would amend sections 1,4,5 and 7 of the Natural Gas Act so that it would not apply to new natural gas except in certain cases where the buyer and seller are affiliated.

H.R. 2818 would exempt from regulation by the Federal Power Commission all production of natural gas from wells commencing production on or after January 1, 1977 and "all new dedications to the interstate market."

H.R. 3136 would deregulate sales of onshore natural gas delivered in interstate commerce for the first time on or after January 1, 1977, provided that such gas was not previously sold or delivered in intrastate commerce. Provisions are made for deregulation, in certain cases, of sales from new wells in previously discovered reservoirs.

H.R. 687 would provide a mechanism for establishing, by rule, a national ceiling price applicable to sales of new natural gas in *interstate* and *intrastate* commerce (pursuant to a contract entered into after the effective date of the ceiling price rule) for producers whose aggregate marketed production of gas in the preceding calendar year does not exceed 100 million Mcf.

H.R. 1460 would amend the Natural Gas Act so that it would not apply to producers or gatherers and sellers of gas who are not affilitated with pipelines or distributors. The bill would also prohibit the FPC from denying that portion of pipeline rates demanded or received in connection with purchase of gas from a producer or gatherer and seller.

H.R. 1562 would exempt from the Natural Gas Act sales of new natural gas by a producer. "New" natural gas is, generally, gas sold or delivered in interstate commerce for the first time after January 1, 1977. Pipeline certificates would not be conditioned upon the price of new natural gas.

H.R. 2088 is substantially similar to H.R. 3136, referred to above.

FEA supports the concept of assuring adequate supplies of natural gas and will consider proposals such as those contained in these bills in determining policy.

As you know, on April 20 the President will submit his national energy program to the Congress. In view of this, it would be premature to comment on specific provisions of these bills until the Administration has the opportunity to submit to the Congress its views on a comprehensive energy policy addressing all fuels and related energy matters.

Nonetheless, I appreciate having the opportunity to review legislation on these important issues. If I can be of further assistance, please contact me.

Sincerely,

JOHN F. O'LEARY,
Administrator.

[The text of title I, part D, of H.R. 6831 appears in part 1 of these hearings.]

Mr. DINGELL. Dr. Schlesinger, we are well aware of the fact that you appear here by extraordinary circumstances today, that it is not the practice of the White House staff members to appear before congressional committees, but that you appear here in your particular capacity as special energy adviser to the President and because you will be, as we well understand and hope, the Secretary of the Department of Energy.

For that reason your particular interests and concerns compel you to be here and we thank you and we will treat you with particular respect in light of that circumstance.

STATEMENT OF HON. JAMES R. SCHLESINGER, ASSISTANT TO THE PRESIDENT; ACCOMPANIED BY HON. JOHN F. O'LEARY, ADMINISTRATOR, FEDERAL ENERGY ADMINISTRATION, LESLIE J. GOLDMAN, FRED HITZ, AND PETER LUEDTKE, FEA STAFF

Mr. SCHLESINGER. Thank you, Mr. Chairman.

Mr. DINGELL. Doctor, if you would identify those who are present with you, we will recognize you for your statement.

Mr. SCHLESINGER. To my left is John O'Leary, the Administrator of FEA; to my right is Mr. Les Goldman, of my staff, Mr. Peter Luedtke of FEA, and Mr. Fred Hitz of my staff.

Mr. DINGELL. Gentlemen, we are happy to welcome you.

Doctor, you may consider yourself recognized for your statement.

Mr. SCHLESINGER. Thank you, Mr. Chairman.

Mr. Chairman, I can summarize or read the statement.

Mr. DINGELL. I leave that choice to you.

Mr. SCHLESINGER. Thank you, Mr. Chairman.

Mr. Chairman and members of the committee, I appreciate very much this early opportunity to discuss with you the administration's proposals for changes in the regulation of natural gas. Working together, it may now be possible to finally resolve one of the most vexing and controversial energy issues—the question of natural gas pricing.

When this administration urged passage of the Emergency Natural Gas Act, it was indicated that a long-term natural gas program would be submitted to the Congress. As that longer range program developed, an effort was made to relate it to policies dealing with other fuels. There are many potential interrelationships. As long as every additional barrel of oil the Nation burns is imported, initiatives directed at establishing industrial gas prices at higher levels than industrial oil prices would result in driving up the use of oil and consequently our level of imports.

It was therefore necessary to develop our natural gas policy keeping a number of important objectives and limitations in mind. First, we needed to move toward bringing supply and demand in the natural gas market back into balance. Second, the natural gas policy had to be one that would not reduce the use of natural gas at the expense of driving up imports. Finally, the natural gas policy had to protect consumers from higher natural gas prices while insuring the availability of adequate supplies and avoiding unnecessary producer profits from known reserves. The policies we are proposing are designed to achieve these objectives through the natural gas pricing provisions before this subcommittee, the new oil pricing regulations under development, and the oil and gas conservation taxes that are part of the National Energy Act.

Our analysis started with the fact that the natural gas regulatory framework has not undergone major revision since enactment of the Natural Gas Act of 1938—almost 40 years ago. Drafters of the act never contemplated the dramatic increase in demand for natural gas which resulted in part from the sudden quadrupling of the world price of oil in 1973 and 1974 and from the growing environmental pressures of recent years.

As a result of the widening gap between natural gas and oil prices and a growing awareness of its premium nature, natural gas has become the Nation's most underpriced and oversold fuel. The object of the National Energy Plan's natural gas policy is to provide appropriate production incentives, remove distortions in the distribution of gas, and, at the same time, protect consumers from unwarranted price increases.

During the 1960's, gas consumption grew by 5.7 percent annually. The average interstate price for gas during this period was approximately 17 cents per Mcf, compared to $2.39 per Mcf for the highest intrastate sales in the first quarter of this year. As a national pipeline network developed, the advantages of low-cost gas for residential and industrial use became increasingly apparent. Gas is a clean fuel, free from ash and sulfur. Its high efficiency, about 75 percent, compares to 60 percent for oil and 50 percent for coal. During the last 15 years commercial and residential consumption of natural gas increased 85 percent.

As interstate gas prices remained controlled based on historic costs that had little relation to the investment realities of the post-embargo world, demand for natural gas continued to rise. As early as 1967, annual consumption surpassed the level of new reserve additions. Since then, the level of proven natural gas reserves has dropped from 293 trillion cubic feet to 216 trillion cubic feet today. By 1976, gas provided only 27 percent of the Nation's energy consumption—the equivalent of 10 million barrels per day or 1.2 million barrels per day less than in 1973. Ultimately, any such difference is made up necessarily by increased oil imports.

At the same time, the volume of new gas flowing into the interstate market has steadily dwindled as producers increasingly committed their new reserves to the higher priced, unregulated intrastate market. Last year, the interstate market received only 19 percent of all new gas commitments. The new interstate commitments were largely from reserves in the offshore Federal domain. Commitments of gas to the interstate market from onshore reserves were minimal. This distinction between intrastate and interstate sales has increasingly given intrastate users first claim to natural gas supplies. Indeed, it has pre-empted the interstate market from receiving any meaningful new supplies.

Much of this premium fuel flowing to intrastate markets is being used for low priority purposes. Today, trillions of cubic feet of natural gas per year are being burned in industrial and utility boilers.

As long as gas was cheap, surplus fuel, the distinction between the unregulated intrastate and the regulated interstate markets made no practical difference. With growing shortages and the emergence of natural gas as the Nation's premium fuel, the need to remove the artificial distinction between these markets has become essential.

Bringing balance back to a badly distorted market through adjustment of demand, increasing supply, and creating a single national market for new natural gas are the basic objectives of the National Energy Plan's natural gas policy.

A pricing policy which evolved at a time when gas was a surplus byproduct of oil production clearly is no longer appropriate in a

world where gas is a premium fuel in short supply. But a policy which recognizes that prices must reflect the cost and the degree of risk associated with finding replacement supplies, and offers a sufficient incentive for the development of these future supplies, must also recognize that in the shortage situation we now face, unchecked natural gas prices would likely rise far above the level needed to increase production. Such price increases in turn would result in potentially massive profits for producers causing reductions in real income to consumers and inflationary pressures on the economy.

Our criteria for natural gas legislation thus required a program that would:

——Provide appropriate incentives for natural gas production through stability, predictability and assurance of reasonable prices.

——Protect the economy from rapidly increasing prices far in excess of needed production incentives.

——End the artificial inter-intrastate distinction.

——Encourage and stimulate conversions from wasteful boiler fuel uses of natural gas to coal and other abundant resources.

I believe the natural gas proposals in the National Energy Plan meet these objectives.

The proposed natural gas legislation places production incentives where they belong, on the development of new gas supplies. To identify new supplies of natural gas, the legislation seeks to propose a tight, automatic and easily administrable definition of new natural gas. Such new gas is taken out from under the time-consuming and complicated FPC cost-based regulation and made subject to a new commodity value pricing approach that limits the price of newly discovered natural gas to the Btu equivalent of the average refiner acquisition price of all domestic crude oil.

This protects the economy from the potential multibillion dollar effects on inflation and recession of unfair natural gas prices, unrelated to any economic contributions of producers, by establishing an outside boundary for the price of new natural gas at a level experts have acknowledged encourages its production. Many studies indicate that in a free market natural gas prices would rise to the Btu equivalent of oil.

Producers have repeatedly sought predictability, stability, and adequate incentives. This bill provides them with what they say they need without running the risk of harmful price gyrations in an already badly distorted market.

The removal of all price restraints on new gas in a continuing unbalanced market could mean an additional shift of as much as $20 billion from consumers to producers. Such a massive shift in wealth—over one percent of our gross national product—would not substantially increase natural gas production.

The Btu related price provides the kind of price incentive that will result in increased supplies, while establishing a buffer against the consequences of adding the pent-up demand of some 46 consuming States to the already high demand in the producing States where in some cases unregulated prices have already reached the Btu equivalent of oil.

The Btu equivalent of the average price of all domestic oil will be about $1.75 per Mcf during the first quarter of next year. It is a price midway between the higher range of unregulated intrastate gas, approximately $2.25 per Mcf, and the current ceiling for new interstate gas of $1.45 per Mcf. It is above the vast majority of existing intrastate contracts. It will rise over time to equivalency with new oil as old domestic oil fields continue to decline. It is a price that will produce an additional 1.1 trillion cubic feet of natural gas by 1985—a 7 percent increase in production. It is a price beyond which little or no measurable increases in supply occur.

To end the inefficiencies and inequities associated with the two-market system of interstate and intrastate sales, the legislation also provides the same insurance against runaway prices for new natural gas sold in the intrastate market. Existing intrastate contracts would not be affected. Neither would regulation necessarily be extended to intrastate pipelines. Contracts for new gas sold in the intrastate market, as well as expiring intrastate contracts, would be subject to the Btu equivalent price. All consumers, and particularly interstate consumers, would be protected by the provision that prevents contractual clauses allowing increases in the price of old flowing gas, based on higher allowable ceiling prices for new gas, from being triggered. These so-called most-favored-nation clauses would be rendered inoperative by the proposed legislation.

By eliminating the distinction between the two markets for new gas production, the bill insured that anxious intrastate buyers, reluctant to convert their facilities from gas to coal, will not create a yet higher priced market, continuing the drain on interstate supplies. By allowing gas available upon expiration of existing intrastate contracts to go to the Btu equivalent, interstate pipelines will have an opportunity to secure this gas. This new gas pricing ceiling will also protect producing States from bidding wars started by hungry interstate pipelines that could draw away the producing States' gas. Thus, the bill attempts to strike a balance between the legitimate needs of producers, on the one hand, and consumers, on the other—consumers in San Antonio, Texas, as well as Buffalo, New York.

All existing interstate vintages are granted sanctity of contract and allowed, if the contract permits, to escalate with the general inflation rate. A new standard designed to maintain production from old fields is applied to the expiration of existing interstate contracts, but in no case can such rollover contracts exceed the current $1.45 per Mcf gas price ceiling.

In recognition of the difficulties of producing high-cost gas, such as gas from deep offshore drilling, geopressurized zones, or tight formations, special authority for incentive prices above the Btu equivalent price is authorized.

On the consumption side, the legislation's incremental pricing provision requires the higher cost of new gas to be paid by boiler fuel consumers of natural gas, adding to their incentives to convert, while protecting the homeowner, who finds it far more difficult to convert, from the immediate effects of higher prices. Today's home consumer is paying approximately $1.75 per Mcf, while the industrial consumer pays .90 per Mcf. In 1985 this program will reverse

that ordering, with the average homeowner paying approximately $2.40 per Mcf and the average industrial user $2.90 per Mcf. This pricing scheme not only protects the homeowner, but encourages industrial conservation and investment in more fuel efficient equipment.

Industrial and utility boiler fuel users of natural gas will also be subject to a special phased-in use tax that will raise the cost of natural gas to the Btu equivalent of the pre-tax price of distillate—or about $3.30 per Mcf—by 1985 for industries and 1988 for utilities. The tax is coordinated and slightly below a similar tax on oil so as to prevent gas to oil switches that could increase imports. It is estimated these taxes will encourage the switching of approximately 3.5 trillion cubic feet of gas per year to 160 million tons of coal.

The bill also extends FPC authority to SNG facilities, so investors building such facilities can receive a reasonable rate of return, and extends the allocation authority of the Emergency Natural Gas Act for three more years. In anticipation of growing shortages over the next several winters, it also extends the President's authority to allocate intrastate supplies.

In summary, the Federal Power Commission's cost-based regulation of interstate natural gas prices has had a distorting effect on supplies and prices. As a result, natural gas has been diverted into the unregulated intrastate market where much of it has been used uneconomically.

This administration is committed to revising this now obsolescent regulatory approach, ending the split market, stopping the wasteful use of such a previous resource, and bringing natural gas supply and demand back into balance. Then, perhaps, we can look forward to market pricing of natural gas.

Until then, we reject the proposition that unconstrained prices in an alleged free market—where prices are set by foreign producers and supplies are subject to the pressures of unlimited demand—is the appropriate answer to the current problem.

Beyond the point at which price increases produce necessary incentives and resources, they produce windfall profits, inflationary pressures and perhaps even recession—not appreciably more gas.

By eliminating complicated and time-consuming cost-based regulation for new gas, establishing incentive prices that emphasize the development of harder to find new supplies, eliminating the split market, and encouraging the conversion from natural gas to coal, we are not following a single ideology or interest—but rather calling on all parties in this debate to compromise in the interests of a balanced, reasonable energy policy that can break the 24-year-old deadlock between natural gas prducers and consumers.

Consumers will be given needed protection, producers will be given adequate and certain incentives, and the market for our Nation's premium fuel will begin to move back into balance. As a national market for new gas is created that recognizes the relationship of natural gas to other fuels, it will be possible to shift to higher priority uses as we simultaneously encourage conservation and reduce imports.

All this can happen if the Nation just faces up to the overwhelming need to reform a natural gas policy that, regrettably, now belongs to another era.

Mr. DINGELL. Doctor, the committee thanks you for a most helpful statement.

Mr. O'Leary, do you have any comments at this particular time?

Mr. O'LEARY. No, I have none, Mr. Chairman.

Mr. DINGELL. The Chair will recognize my colleagues for questions.

First, however, I would like to ask this question, Dr. Schlesinger. It has long been my belief that natural gas deregulation would result in demand-driven gas prices well in excess of those necessary to encourage development of natural gas resources. This is inherent in the structuring of the legislation that the administration has presented to the committee today.

These price increases could, in my view, spell economic disaster through inflation and recession, as you have indicated in your statement.

You indicate in your statement that deregulation would cost consumers $20 billion. Can you give me several comments with regard to that statement. First, what would be the economic impact of deregulation upon gross national product, inflation and unemployment?

Mr. SCHLESINGER. That, of course, depends upon fiscal and monetary policy, Mr. Chairman, that cannot be described in the abstract. I presume that such policies would attempt to alleviate the unemployment and shrinkage effects on the GNP that would result from such a substantial increase in gas prices.

Mr. DINGELL. That is a shift of about one and a half percent, of gross national product from the consuming portion of the public to producers; am I correct?

Mr. SCHLESINGER. To the producers.

Mr. DINGELL. That is right. So its impact would be large and would require substantial correcting measures in other areas of government activity?

Mr. SCHLESINGER. Mr. Chairman, may I say that the distortion in this market is more keenly felt by almost all observers since last winter's emergency. That might have driven prices in a free market to five or six dollars per Mcf.

Mr. DINGELL. I gather from my reading of history that the level of shift of earnings from the consuming portion of the American economy into OPEC during the oil embargo was approximately $20 billion. Am I right?

Mr. SCHLESINGER. Probably in that range, Mr. Chairman.

Mr. DINGELL. And the consequences of that came very close to economic disaster. It moved this Nation to one of the most intensive and extensive depressions which we have known since 1929. Am I correct on that?

Mr. SCHLESINGER. Yes, sir. That particular episode was complicated by the requirements of foreign exchange and for a period the substantially reduced flow of oil.

Mr. DINGELL. Would I be fair in inferring that the economic impact of the shift of this level to the economy would be very substantial in terms of employment, GNP, and other things?

Mr. SCHLESINGER. It could be very substantial, Mr. Chairman.

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Mr. DINGELL. Then let me ask this question. Were we to have deregulation occur under these circumstances, would we not be prudent to apply the same kind of tax and rebate structure that the administration and you, Doctor, have suggested to the Congress in connection with oil pricing? Would we best preserve our national interests by having a tax and rebate system to minimize the impact upon the economy?

Mr. SCHLESINGER. I think there is not only the economic impact but the equity considerations, Mr. Chairman. If one contemplates sudden, immediate deregulation, I think one should consider the resulting massive shift of wealth toward the producers and take offsetting actions. That would be up to the Congress.

Mr. DINGELL. Doctor, can you advise us whether there have been any econometric studies on either of the points I have just discussed which have taken place inside the administration?

Mr. SCHLESINGER. I believe that there have been, Mr. Chairman, and we shall insert the results that we have in the record.

Mr. DINGELL. It would be appreciated.

[The following material was received for the record:]

As the attached chart indicates, the effect of immediate decontrol would add to gas producer revenues between now and 1985 approximately 121 billion dollars. The 10 billion dollars in just the first three years could add as much as ¼% to the inflation index.

GAS DECONTROL MAXIMUM CASE

N.A. Gas

Quantities	1978	1979	1980	1981	1982	1983	1984	1985	1978-1985
Existing Interstate	6.5	5.5	4.5	3.5	2.4	1.7	.9	--	
Existing Intrastate	4.6	3.9	3.3	2.5	1.7	1.2	.5	--	
Renegotiated Interstate	.9	1.2	1.5	1.9	2.4	2.7	3.1	3.5	
Renegotiated Intrastate	.7	.9	1.1	1.4	1.8	2.0	2.3	2.6	
Subtotal	1.6	2.1	2.6	3.3	4.2	4.7	5.4	6.1	
Prices									
Existing Interstate	.52	.53	.54	.55	.56	.57	.58	.59	
Existing Intrastate	.62	.63	.64	.65	.67	.68	.69	.70	
Renegotiated	2.35	2.37	2.39	2.41	2.43	2.46	2.48	2.50	
Revenues									
Existing Interstate	3.380	2.915	2.430	1.925	1.344	0.969	.522	--	
Existing Intrastate	2.852	2.457	2.112	1.625	1.139	0.816	.345	--	
Renegotiated	3.760	4.977	6.214	7.953	10.206	11.562	13.392	15.250	
Subtotal	9.992	10.349	10.756	11.503	12.689	13.347	14.259	15.250	
Base Case Existing	7.134	6.575	6.056	5.505	5.003	4.684	4.252	3.885	
Change: N.A.	2.858	3.774	4.700	5.998	7.656	8.663	10.007	11.365	
Change: A.D.	.356	.716	.905	1.086	1.276	1.479	1.666	1.866	
Change: High Case	2.027	3.331	4.858	6.452	7.915	9.591	10.774	11.885	
Total Change	5.241	7.821	10.463	13.536	16.847	19.733	22.447	25.116	121.204

	1978	1979	1980	1981	1982	1983	1984	1985	1978-1985
A-D Gas									
Quantities									
Existing Interstate	1.1	.9	.7	.6	.4	.2	.1	--	
Existing Interstate	.8	.6	.5	.3	.3	.2	.1	--	
Renegotiated Interstate	.1	.2	.3	.3	.4	.5	.5	.6	
Renegotiated Intrastate	.1	.2	.2	.2	.3	.3	.4	.4	
Subtotal	.2	.4	.5	.6	.7	.8	.9	1.0	
Revenues									
Existing Interstate	.572	.477	.378	.330	.224	.114	.058	--	
Existing Intrastate	.496	.378	.320	.195	.201	.136	.069	--	
	1.538	1.803	1.893	1.971	2.126	2.218	2.359	2.500	
Base Case	1.182	1.807	.988	.885	.850	.739	.693	.634	
Change:A-D	.356	.716	.905	1.086	1.276	1.479	1.666	1.866	

Mr. DINGELL. I think it would be useful for purposes of the record that we have the assumptions that went into the analysis as well as the conclusion itself.

Doctor, I want to thank you for your kindness in being here with us. The members have a large number of questions which they wish to ask. The Chair will recognize first the gentleman from Ohio, Mr. Brown.

Mr. BROWN. Thank you very much, Mr. Chairman. Dr. Schlesinger, I am fascinated by the difference in administration strategy with reference to oil prices and gas prices. I gather through taxes you want to get oil prices high so as to get people to conserve oil and shift to coal and other fuels, but in your colloquy with the chairman you have just suggested you fear the idea of higher prices for natural gas because that would cause an undue shift from natural gas to other fuels such as coal.

I find that to be something of a dichotomy. What was the shortfall of natural gas this past winter?

Mr. SCHLESINGER. Something on the order of 7 trillion cubic feet on an annual basis.

Mr. BROWN. I think the Chairman of the Federal Power Commission estimated somewhere between 2.5 and 3.1 on an annualized basis.

Mr. SCHLESINGER. For the winter season, yes, sir.

Mr. BROWN. On page 11 you indicate that your tax on natural gas usages will save 3.5 trillion cubic feet per year. When will this savings likely occur? Is that promptly or by 1985 or 1988?

Mr. SCHLESINGER. We would expect to squeeze down demand in that manner. The impact of the National Energy Plan between now and 1985 on the use of oil, natural gas and coal is indicated on this chart. It would result in a reduction of something on the order of 4 million barrels of oil equivalent per day and an increased use of coal to the amount of 2.4 million barrels of oil equivalent per day. The difference would be made up by conservation.

Mr. BROWN. I assume the figure of 3.5 by 1985 is from what you have just indicated there?

Mr. SCHLESINGER. That is just gas.

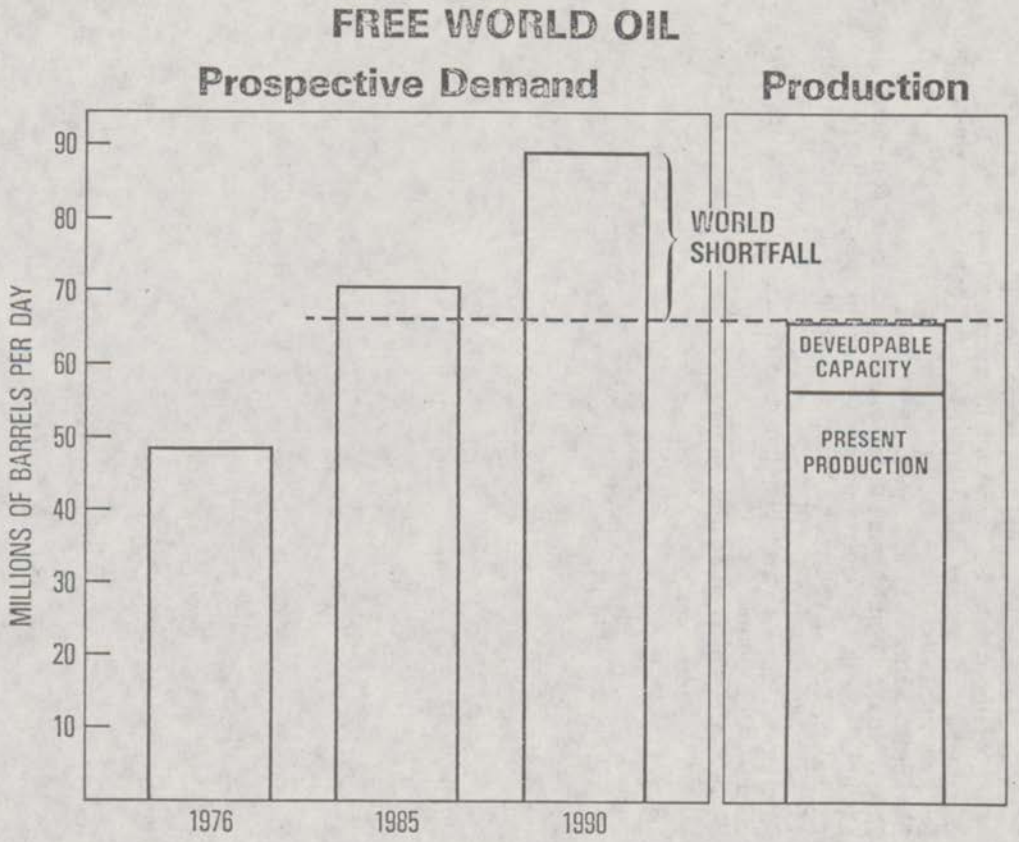
Mr. DINGELL. Would you yield to me to make a comment.

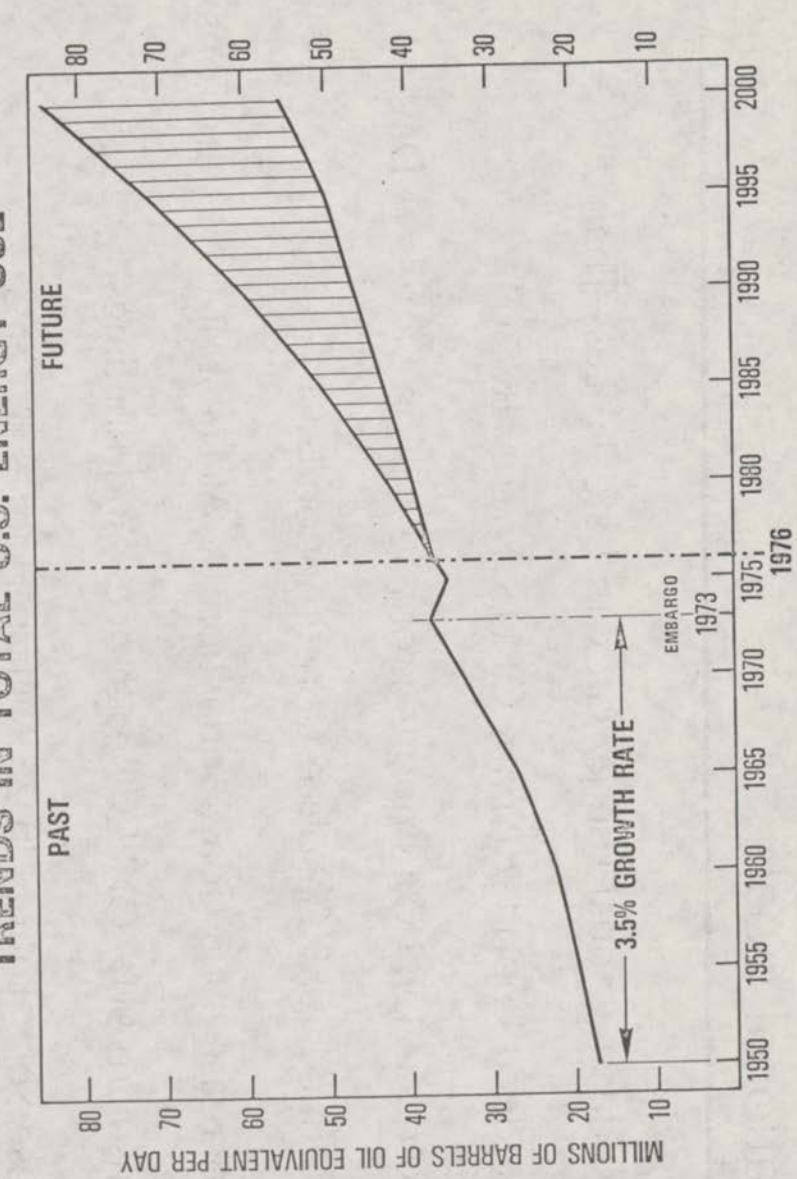
Doctor, I think the charts which you are displaying to us are of great value. Would you make them available to us for the record?

Mr. SCHLESINGER. We will.

Mr. DINGELL. Without objection, the charts will appear in the record at this point.

[The charts referred to follow:]


FREE WORLD OIL
Prospective Demand
Production
MILLIONS OF BARRELS PER DAY
90
80
70
60
50
40
30
20
10
WORLD SHORTFALL
DEVELOPABLE CAPACITY
PRESENT PRODUCTION
1976
1985
1990


TRENDS IN TOTAL U.S. ENERGY USE
PAST
FUTURE
3.5% GROWTH RATE
EMBARGO
1973
1975; 1976
MILLIONS OF BARRELS OF OIL EQUIVALENT PER DAY
10
20
30
40
50
60
70
80
1950
1955
1960
1965
1970
1975
1980
1985
1990
1995
2000

National Goals

- Reduce Annual Energy Growth Rate To Less Than 2%
- Reduce Imported Share Of U.S. Energy By 50%
- Reduce 1985 Oil Imports From 16 Million Barrels A Day To 6
- Reduce 1985 Gasoline Consumption By 10%
- Increase 1985 Coal Production By At Least 400 Million Tons
- Insulate 90% Of U.S. Residences And Buildings By 1985
- Use Solar Energy In 2.5 Million Homes By 1985

Ten Guiding Principles

- Comprehensiveness
- Healthy Economic Growth
- Conservation
- Energy Invulnerability
- Realistic Pricing
- Equity
- Environmental Protection
- Certainty
- Abundant Fuels
- Renewable Resources

INITIATIVES

INDUCE CONSERVATION

- BUILDINGS
  - RESIDENTIAL AND COMMERCIAL TAX CREDITS
  - SECONDARY MARKET FOR LOANS
  - LOW-INCOME WEATHERIZATION
  - SCHOOLS AND HOSPITALS
  - FEDERAL BUILDINGS
  - UTILITY "TURNKEY" PROGRAMS
- UTILITIES
  - TIME-OF-DAY RATES
  - ELIMINATION OF DECLINING BLOCK RATES
- INDUSTRY
  - TAX CREDITS FOR CONSERVATION INVESTMENTS
  - COGENERATION

INITIATIVES
(continued)

DISCOURAGE USE OF OIL AND NATURAL GAS

- OIL AND NATURAL GAS PRICING
- OIL AND NATURAL GAS TAXES
  - WELL-HEAD TAX FOR OIL
  - NATURAL GAS TAX FOR UTILITIES AND INDUSTRY
- GASOLINE
  - "GAS GUZZLER" TAX
  - STANDBY GAS TAX
  - TRUCK STANDARDS
  - INTERCITY BUS EXCISE TAX REMOVAL
  - BOAT AND GENERAL AVIATION GAS EXCISE TAXES
  - FEDERAL GOVERNMENT AUTOMOBILES
  - FEDERAL GOVERNMENT VAN POOLS

INITIATIVES
(continued)

INDUCE SHIFTS TO MORE ABUNDANT FUELS AND RENEWABLE RESOURCES

- COAL CONVERSION
  - INVESTMENT TAX CREDITS
  - TAX REBATES
- SOLAR
  - TAX CREDIT FOR SOLAR EQUIPMENT
  - FEDERAL BUILDING PROGRAM
- GEOTHERMAL TAX INCENTIVES
- NON-NUCLEAR RD&D PROGRAM

PRODUCTION

- CERTAINTY OF POLICY
- NUCLEAR POLICY
- INCENTIVES FOR OIL AND GAS EXPLORATION
  - PRICING
  - ALASKA OIL
  - TAX TREATMENT OF INTANGIBLE DRILLING COSTS
- COAL RD&D PROGRAM

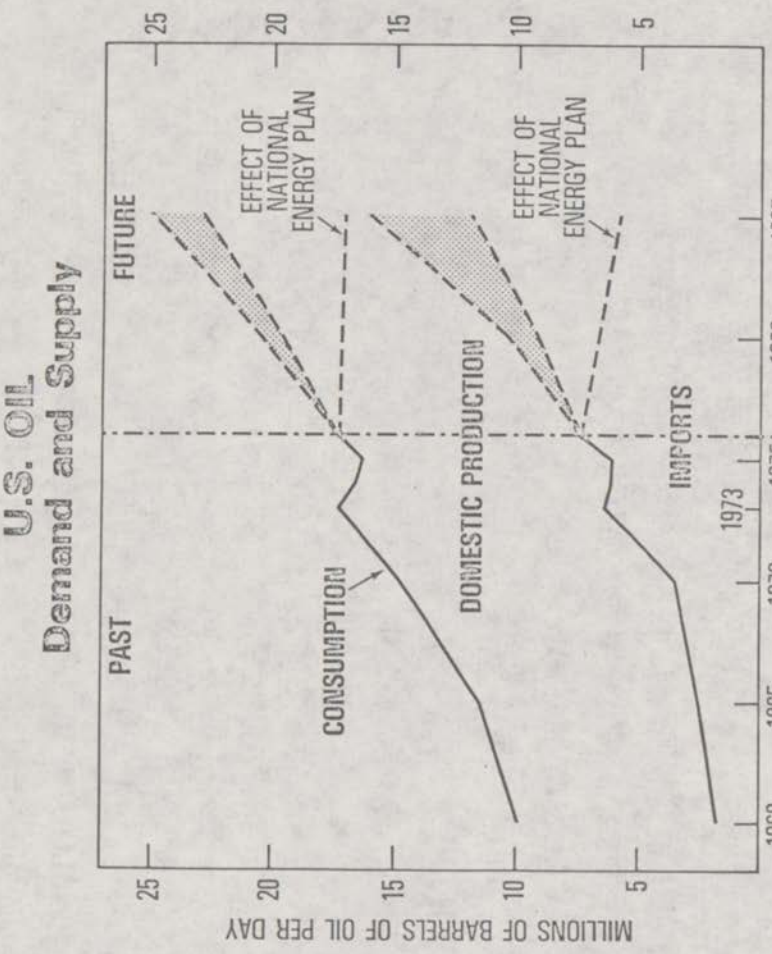
INITIATIVES
(continued)

SUPPLY-INTERRUPTION PROTECTION

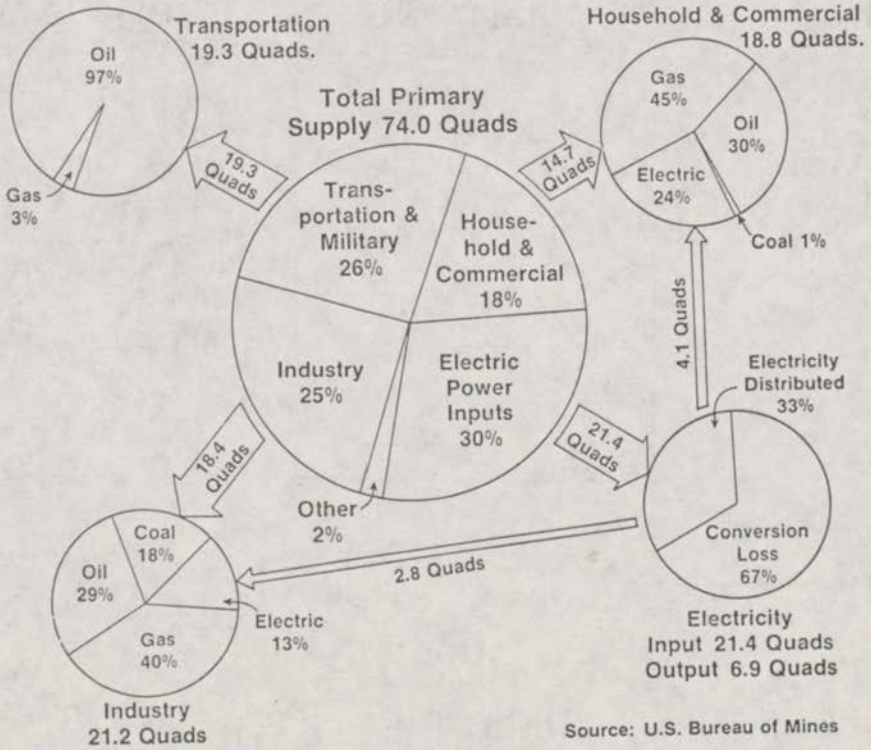
- STRATEGIC PETROLEUM RESERVE
- CONTINGENCY PLANS
- EMERGENCY MANAGEMENT INFORMATION SYSTEM

EQUITY

- TAX REBATES
  - WELL-HEAD TAX REBATE
  - REBATE FOR HOME HEATING OIL
  - STANDBY GAS TAX REBATE
- PROTECTING HOMEOWNERS BY SEGMENTING NATURAL GAS MARKET
- EMERGENCY ASSISTANCE FOR THE POOR
- LOCAL IMPACT ASSISTANCE
- IMPROVED INFORMATION


U.S. OIL
Demand and Supply
PAST
FUTURE
CONSUMPTION
DOMESTIC PRODUCTION
IMPORTS
EFFECT OF NATIONAL ENERGY PLAN
EFFECT OF NATIONAL ENERGY PLAN
MILLIONS OF BARRELS OF OIL PER DAY
25
20
15
10
5
1960
1965
1970
1973
1975
1976
1980
1985

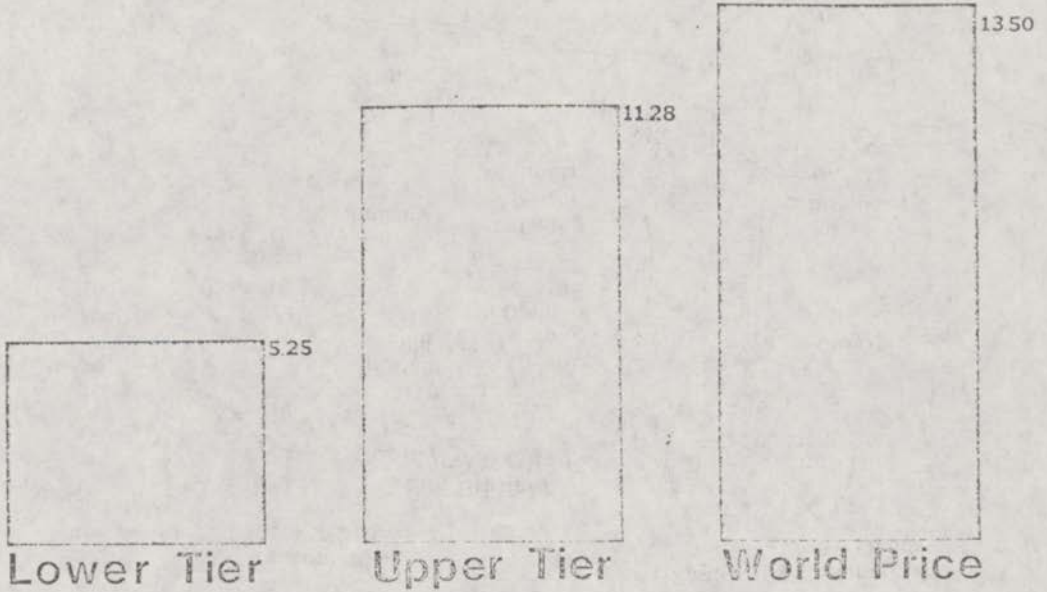
Distribution of Energy by Sector 1976



Source: U.S. Bureau of Mines

U. S. Oil Pricing

Present

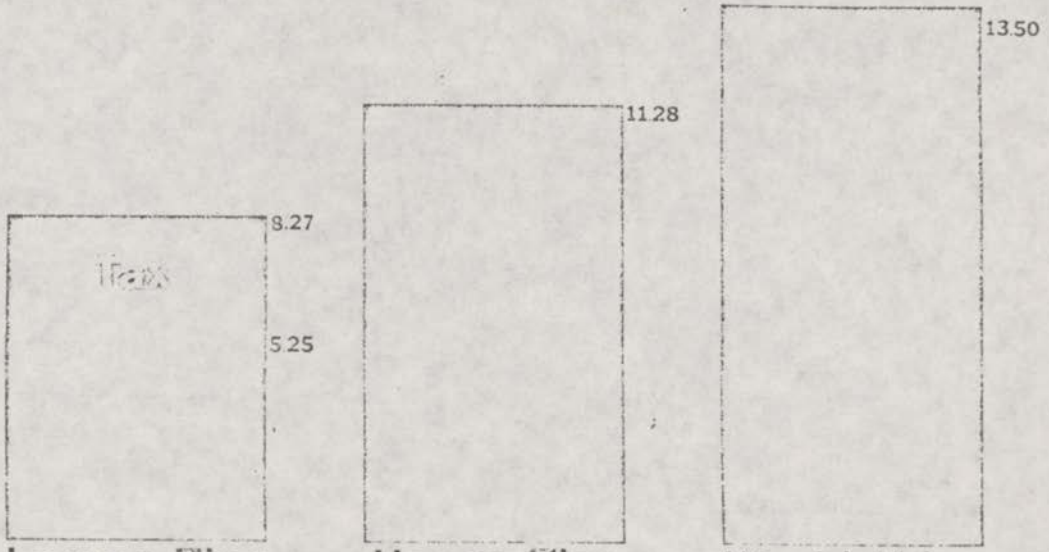


Assumes Constant Dollars

82-911 O - 77 - 7

U. S. Oil Pricing

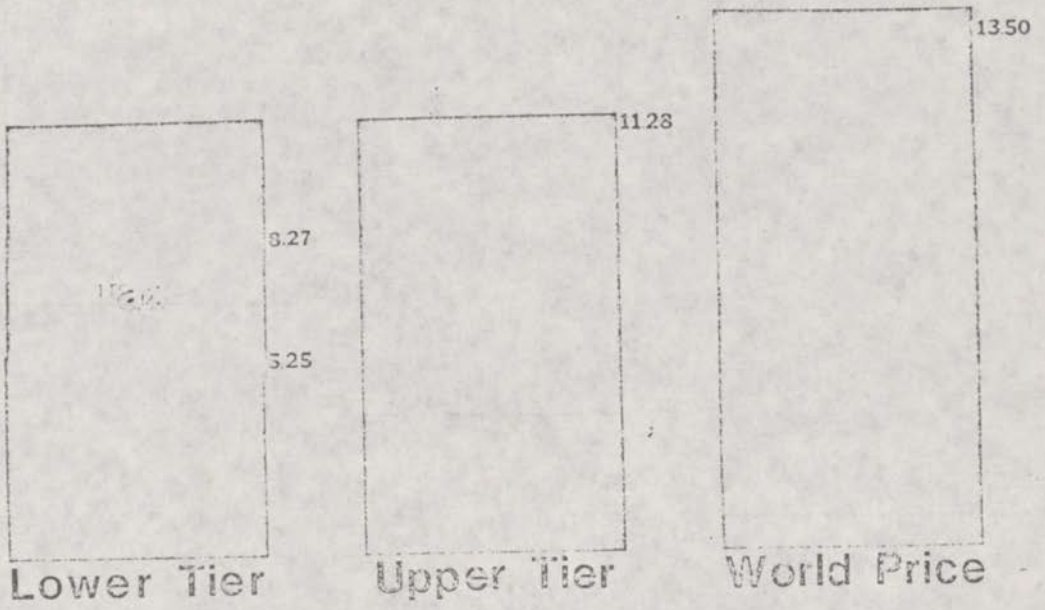
Jan. 1, 1978



Assumes Constant Dollars

U. S. Oil Pricing

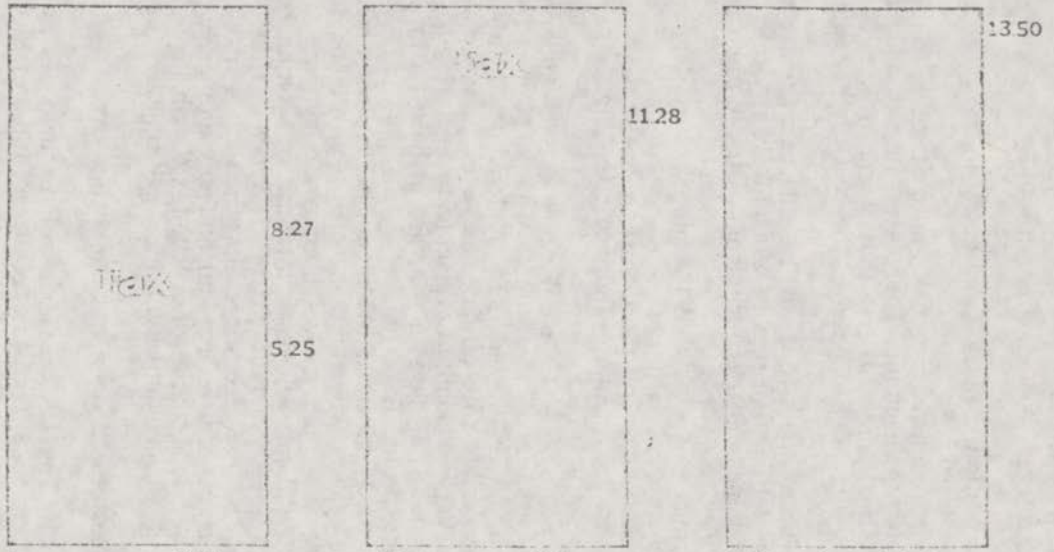
Jan. 1, 1979



Assumes Constant Dollars

U. S. Oil Pricing

Jan. 1, 1980



Assumes Constant Dollars

Mr. BROWN. What would be your estimate of the impact on consumption in 1978-79, Dr. Schlesinger? The impact of the tax that you have proposed.

Mr. SCHLESINGER. On the consumption of gas?

Mr. BROWN. Yes.

Mr. SCHLESINGER. We can supply those figures for the record, Mr. Brown.

[The information requested had not been received at the time the record was closed.]

Mr. BROWN. We have a problem here. It seems to me it is similar to the problem in gasoline. There are going to be some industries: Glass, fertilizer, some others, that won't be able to switch and presumably will have to pass on the cost of this additional tax in their products.

There will be others that will be able to switch. I would assume that that switch is what we are after, and yet, again, it seems to be a matter of some concern to Chairman Dingell and to you that that switch will be too abrupt.

I am curious to know what the objective is. It is to switch from natural gas to coal, is it not?

Mr. SCHLESINGER. The more abrupt, the better.

Mr. BROWN. Then the question is, do the higher prices encourage that switch or not?

Mr. SCHLESINGER. Yes, sir. We have increased over a period of years the pressures on the industrial users to make that switch to coal from both oil and gas, and we trust that they will move as rapidly as possible to coal. They have made investments in their plants and we are using the pricing to encourage that switch.

Mr. BROWN. And taxes in the case of both natural gas and oil?

Mr. SCHLESINGER. Exactly.

Mr. BROWN. It occurs to me since the chairman mentioned a tax and rebate system we might also use a profit and tax system. In other words, if a company which made money from higher prices of its products did not reinvest that fund in seeking new sources of energy, the government might tax it away at that point, but that would have the impact of increasing the search or the production of additional sources of energy, oil and gas and perhaps others.

But I am curious to know how the tax that brings the money into the Federal Government will increase the additional supply of energy.

Mr. SCHLESINGER. I am not sure what tax you are referring to now.

Mr.BROWN. The tax on the use of natural gas by industry.

Mr. SCHLESINGER. That tax creates a fund which the company in question can draw upon to make the conversion to coal.

The purpose of that tax is to raise the price of natural gas to the point that it pays to switch to coal. It does not increase the supply of gas. The $1.75 price is an adequate incentive given the addition of stability and predictability in this market to elicit new supplies of gas.

Mr. BROWN. Couldn't we do both with automatically higher prices you suggest would occur in a market situation and then use that income to produce additional natural gas rather than just simply

return revenues to the government, which would be used at the discretion of the government presumably?

Mr. DINGELL. The time of the gentleman has expired. The Chair will permit the witness to respond to the question.

Mr. SCHLESINGER. There are two aspects to that, Congressman Brown. The first is the degree of responsiveness of supply to those higher prices. The $1.75 price represents a price that has been typical, not in the interstate market but in most of the intrastate markets in the middle of last year. It is a very substantial price on which all producers concede they can make good money. So that that is an adequate incentive price.

On the other side of the problem, what has been restricting the growth of new supplies in large measure has been the lack of availability of equipment and of trained manpower. We have had bidding up by the producers, because of existing incentives, of the prices of trained manpower and equipment and the bidding up of leases. Merely augmenting the flow of funds to the producers, given the restriction on the availability of equipment, trained manpower, and available leases, will just lead to further inflationary pressures in the short run.

Mr. BROWN. I wonder if we might ask for insertion at this point in the record of information backstopping the middle paragraph on page 8, which speaks to the area that the Secretary has just addressed.

Mr. DINGELL. I think that is appropriate. Without objection, so ordered.

[The following material was received for the record:]

In 1976, the initial rates for new and renegotiated intrastate natural gas contracts, as reported by jurisdictional producers, averaged less than $1.75 per Mcf; on a volume weighted basis. The total annual volume of these 1976 contracts is approximately 700 Bcf. (The attached table presents volume weighted prices for 1976, by quarter and by producing region.) Prices for new contracts have escalated rapidly in the five years prior to 1976, moving through a six-fold increase from a base of under $.25 per Mcf in 1971. The prices for the reported contracts executed in the past year do not, in themselves, average over $1.75 per Mcf and account for only about ten percent of total intrastate volumes. It is important to note that the vast majority of *existing* intrastate contracts are well below $1.75 per Mcf.

The projected 1.1 Tcf of additional gas by 1985 is based on the Btu related price which will be about $1.75 for new gas early next year. The base case for measuring the 1.1 Tcf of additional supply is continued FPC cost-based regulation at today's pricing levels. Both base case production and projected production under the energy plan of more associated gas is indicated on the attached tables.

GAS PRODUCTION: ENERGY PLAN (TCF)

GAS BUSINESS	1978	1979	1980	1981	1982	1983	1984	1985	19
NON-ASSOCIATED GAS									
Newly Discovered	.2	.2	.3	.7	1.5	2.3	2.7	3.2	
Other									
Interstate Rollovers	1.0	1.5	2.1	2.6	2.9	3.0	3.2	3.3	
Intrastate Rollovers	.7	1.2	1.5	1.9	2.1	2.2	2.4	2.4	
Existing Interstate	7.4	6.7	6.0	5.4	4.8	4.4	4.0	3.5	
Existing Intrastate	5.3	4.8	4.4	3.9	3.5	3.2	2.8	2.6	
Total	14.6	14.4	14.3	14.5	14.8	15.1	15.1	15.0	
NATURAL GAS LIQUIDS									
Newly Discovered									
Other									
New									
Old									
Tertiary									
Skipper									
Total	1.102	1.052	1.026	1.004	1.003	1.001	1.000	.975	

GAS PRODUCTION : BASE CASE (TCF)

GAS BUSINESS	1978	1979	1980	1981	1982	1983	1984	1985	1986
NON-ASSOCIATED GAS									
Newly Discovered	.2	.2	.2	.5	1.1	1.6	1.9	2.2	
Other									
Interstate Pollvers	1.0	1.5	2.1	2.6	2.9	3.0	3.2	3.3	
Intrastate Pollovers	.7	1.1	1.3	1.7	2.0	2.1	2.3	2.3	
Existing Interstate	7.4	6.7	6.0	5.4	4.8	4.4	4.0	3.5	
Existing Intrastate	5.3	4.8	4.4	3.9	3.5	3.2	2.8	2.6	
Total	14.6	14.3	14.0	14.1	14.3	14.3	14.2	13.9	
NATURAL GAS LIQUIDS									
Newly Discovered									
Other									
New									
Old									
Tertiary									
Shipper									
Total	1.019	1.013	1.026	.973	.967	.954	.931	.897	

REPORTED INTRASTATE NEW NATURAL GAS PRICES: 1976
Initial Rates For Contracts Executed During Period, By Quarter

- $ Per Mcf -

New Contracts

1976	Q1	Q2	Q3	Q4	1976
Permian	1.38	1.35	1.38	1.96	1.55
Texas-Gulf	1.90	1.98	1.83	1.98	1.96
Hugoton	1.46	1.61	1.51	1.65	1.58
South Louisiana	1.44	1.50	1.48	1.56	1.51
Other Southwest	1.56	1.16	1.47	1.71	1.44
Total U.S.	1.54	1.59	1.43	1.80	1.62

Renegotiations

1976	Q1	Q2	Q3	Q4	1976
Permian	1.63	1.45	1.90	1.77	1.70
Texas-Gulf	2.00	2.00	1.73	1.97	1.97
Hugoton	1.49	1.56	1.68	1.61	1.59
South Louisiana	1.50	1.46	1.58	1.50	1.54
Other Southwest	.80	.79	.79	1.77	1.25
Total U.S.	1.78	1.66	1.63	1.66	1.69

Initial Rates for All Contracts Executed During Period

1976	Q1	Q2	Q3	Q4	1976
Permian	1.60	1.43	1.75	1.83	1.67
Texas-Gulf	1.99	1.99	1.75	1.98	1.97
Hugoton	1.47	1.59	1.60	1.64	1.58
South Louisiana	1.44	1.48	1.57	1.53	1.52
Other Southwest	1.44	0.88	1.10	1.77	1.31
Total U.S.	1.71	1.63	1.58	1.73	1.67

GAS PRODUCTION UNDER ALTERNATIVE PRICES

(TCF)

	1978	1979	1980	1981	1982	1983	1984	1985
Base Case	16.9	16.6	16.3	16.3	16.4	16.3	16.2	15.9
Program	16.9	16.7	16.6	16.7	16.9	17.1	17.1	17.0
Decontrol	16.9	16.7	16.6	16.7	16.9	17.1	17.2	17.2

CHANGES IN GAS PRODUCTION UNDER ALTERNATIVE PRICES

(TCF)

	1978	1979	1980	1981	1982	1983	1984	1985
Base Case	--	--	--	--	--	--	--	--
Program	--	.1	.3	.4	.5	.8	.9	1.1
Decontrol	--	--	--	--	--	--	.1	.2

ALTERNATIVE GAS PRICES

($/MCF, 1975 DOLLARS)

	1978	1979	1980	1981	1982	1983	1984	1985
Base Case	1.52	1.52	1.53	1.53	1.53	1.54	1.54	1.55
Program	1.68	1.72	1.76	1.80	1.83	1.87	1.91	1.95
Decontrol	2.26	2.26	2.26	2.26	2.26	2.26	2.26	2.26

The Chair recognizes the gentleman from Texas, Mr. Krueger.

Mr. KRUEGER. Thank you, Mr. Chairman.

We are very pleased to have you here today, Mr. Schlesinger and Mr. O'Leary.

I would like first to pick up with some of the figures that we have had tossed out. It seems to me frankly that they are difficult to sustain. Last year the total amount received by producers of natural gas sold into the interstate market was about $5 billion. That is an average of about 50 cents per Mcf for about 10 trillion cubic feet. On page 7 you indicate removal of price restraints on new gas, even though we would expect to be only about 7 percent of the total production, would lead to a shift of wealth of as much as $20 billion. How, if you get $5 billion for 10 trillion cubic feet, and we expect only about 7 percent of the gas being new gas to be sold without price restraints, could result in a figure of $20 billion is to me incomprehensible.

Mr. SCHLESINGER. The numbers are based on, first, what you have just mentioned, that the average price of gas has been very low, on the average of 50 cents per Mcf. To achieve this kind of increase, the price of gas would go to something like $2.50 per Mcf in the unregulated market. The assumption here is that the rules would be drawn in such a way as to permit a rollover of old gas to new gas at the higher prices.

Mr. KRUEGER. If that assumption were not made that all expiring contracts would suddenly expire, then the figure of $20 billion would obviously be far too high?

Mr. SCHLESINGER. Yes.

Mr. KRUEGER. Am I correct that the proposed budget of the new Department of Energy is about $10 billion?

Mr. SCHLESINGER. I believe that is correct.

Mr. KRUEGER. So we are proposing a budget for a new Department of Energy of about $10 billion, although about 17 percent of last year's energy for the Nation was provided by natural gas in the interstate market. In other words, the department budget of the new Department of Energy is going to be about twice as high as all of the proceeds to producers of natural gas received from funds in the market last year?

Mr. SCHLESINGER. What was the lower number you used?

Mr. KRUEGER. $5 billion as proceeds and $10 billion for the new Department of Energy. I am just trying to get a sense of relationship. What we are suggesting, it seems to me, is that Washington and the Department of Energy will get twice as much as the people spent last year for all of the gas in the interstate market, which is about 17 percent of the Nation's energy.

I would like now to look at the actual bill which we have been presented because on page 55 of the National Energy Act we have some of the many definitions of terms, and as Mr. Brown indicated, there are many definitions of terms in the new bill.

The last sentence at the bottom of page 55 says, "The President shall have the authority to define by rule the terms used in this part in a manner consistent with the purposes of this part."

As I understand that language, what it means is after having many pages of definitions of Btu-related price, surface measurement, et cetera, we are told the President shall have the authority to define by rule the terms used in this part in a manner consistent with the purposes of this part.

I realize we are dealing today with members of the executive branch and that the Executive obviously would have responsibility for carrying this out, but is this not an extraordinary degree of responsibility to give to the executive branch, that is, the responsibility of defining the very terms by the Executive after previously we have already had them defined by statute?

Mr. SCHLESINGER. That, of course, is the judgment of Congress. That is the standard phrase that is employed in such legislation, as you will recognize. The terms on those pages that you are looking at, Mr. Krueger, have a very high degree of specificity—the 2½-mile definition, for example. I believe that it has been the desire on the part of many to provide some flexibility in order to adjust that definition properly to capture new oil and gas.

Mr. KRUEGER. You mention the 2½-mile definition. I have heard and I would like to ask for clarification the way in which it was decided 2½ miles should be the appropriate distance for the definition of a new well, that is, one which would be built beyond 2½ miles from any existing well, was decided as a compromise between zero and five miles, the initial distance suggested within the administration.

Could you verify that or clarify it?

Mr. SCHLESINGER. I cannot, of course, verify it.

Mr. KRUEGER. You could, could you not?

Mr. SCHLESINGER. The definition was chosen to exceed the normal step-out of the industry. We wanted to have a tight definition which could be automatically applied. The judgment of the FEA was that 2½ miles would be a sufficiently tight definition, and that is where the number came from.

Mr. KRUEGER. It is my understanding last year 900 percent of all wells which were called new gas wells would have been within 2½ miles, so you are restricting the definition of new gas if we follow the same practices in the future as we have in the past to 10 percent of the quantity of new gas that we have; is that correct?

Mr. DINGELL. The time of the gentleman has expired, but the Chair will permit the witness to respond.

Mr. SCHLESINGER. It depends on the area of the country, of course. In Texas and Louisiana and similar producing areas the radius around such a well would preclude such an applicability of the definition of new oil or gas. That is why we have stated repeatedly that we are seeking the most precise definition that we can find to properly define new oil and gas. We are open to suggestions.

Mr. KRUEGER. We might have some. Thank you.

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes the gentleman from Louisiana, Mr. Moore.

Mr. MOORE. Thank you, Mr. Chairman.

Dr. Schlesinger, you keep mentioning that you have a study showing the $1.75 proposed figure would be an adequate production incentive. We have not seen those studies. Could you tell us the date of them and who did them and whether they will be made available to this committee or not?

Mr. SCHLESINGER. We will make available to the committee the judgments on which we have reached that conclusion. I should point out that until the last quarter, in fact until last December, according to the data available to the FEA, the price of new natural gas contracts in Louisiana did not reach $1.75, so that that price is below the suggested price, save for the period of last winter's natural gas crisis.

Mr. MOORE. I would like to ask the record be kept open to receive these studies and the former studies done by the FEA on this subject.

Mr. DINGELL. The subcommittee has heard the unanimous consent request of the gentleman from Louisiana. Is there objection?

The Chair hears none. Without objection, it is so ordered.

[The following information was received for the record:]

The chart supplied with the answer to Mr. Brown on page—also addresses this question. The computer runs for a deregulation scenario when compared to those for the National Energy Plan, did not significantly increase supply. The Plan would stimulate 1.1 Tcf of additional supply, compared to the base case. Deregulation does not stimulate any significant additional production.

Mr. MOORE. Dr. Schlesinger, on page 8 of your testimony, in talking about these studies, there is an indication that you feel the $1.75 price based on these studies will produce 1.1 trillion cubic feet of new natural gas. I assume this is different from the report of

Project Independence made in January 1977 and April 14 report, showing it would only produce about 3.5 trillion cubic feet?

Mr. SCHLESINGER. I am not sure of the reports to which you refer, but we will be happy to provide for the record those reports along with the information that we are ready to supply, and to analyze any discrepancy between the two, if, indeed, there is a discrepancy.

[The following material was received for the record:]

TECHNICAL ERRORS

1. All gas quantities in the earlier NEO were overstated by 6-8%.
2. The decontrol supply curves assume unrealistic price trajectories under decontrol. Specifically, if the market price under decontrol was $2.50 quantity in 1985 and $1.50 in 1975, the $2.50 quantity in 1985 represented the amount produced if producers believed that the $1.50-$2.50 rate of price increase over 10 years continued indefinitely into the future at this rate.
3. The "Reference' scenario assumed the interstate price declined in real terms. This understated the reference production.

CHANGED CIRCUMSTANCES UNDER THE PLAN

1. Without coal conversion and conservation, the NEO decontrol scenario forecasted high gas demand. High gas demand produced high market prices, and high quantities, when the interstate market gained access to intrastate gas under control. The program cuts demand, prices, and the increased quantity available from decontrol.
2. The Base Case regulatory behavior was assumed to result in at least a constant dollar increase in the price of new and flowing gas.

Mr. MOORE. Even if we accept the reports of these studies, we have not yet seen the 1.1 trillion cubic feet, that is a long way away from the actual shortage, the estimate of 1.1 trillion. I believe the Federal Energy Administration also issued a study in January 1977 to show if we had a stair step deregulation, by that same time you would have 26 new trillion cubic feet of gas, or exactly 4 trillion cubic feet more, and I am wondering if we are trying to provide more gas for the American people why we go with your figure of 1.1 as opposed to the stair step deregulation similar to the Krueger-Brown bill producing 4 trillion cubic feet, more than the shortfall we had this year.

Mr. SCHLESINGER. I would have to take a look at that study, Congressman. The FEA studies indicate that above this price the supply response will be relatively small. The problem that we face, as you have indicated in your question, is that we have a major shortfall in the availability of gas. The purpose of this legislation is to move industry from gas as well as oil to coal, so that we can deal better with a shortage of fluid hydrocarbons that will be continuing in this country.

Mr. MOORE. I would like you to take a look at the Project Independence Evaluation report of January 1977, because I dispute the point a price above $1.75 will not produce more natural gas. There have been four separate econometric models run on that. According to the information I have, the American Gas Association, Institutes of Gas Technology, Federal Energy Administration, and Standard Research Institute, all showing with the deregulation plan we are proposing, you would produce a minimum of 20. In the case of FEA 20.6 trillion cubic feet of gas, or anywhere from 3½ to 4 trillion cubic feet, or as high as 10 trillion cubic feet more than we

are currently producing. So I think we need to have a better reading on this subject.

Mr. SCHLESINGER. I think so.

Mr. MOORE. I would like to move to the Btu equivalency proposition. Why didn't your plan give us a Btu equivalency of new oil instead of the average price of oil?

Mr. SCHLESINGER. The figure chosen represents the Btu equivalent of the price of oil that is being currently used in the United States, and was regarded as adequate to that purpose. As I have indicated earlier, it represents a figure that is higher than the price that existed in the Louisiana intrastate market until last December, and higher than the price that existed in the Texas intrastate market until roughly 18 months earlier.

It is a substantial price, and it reflects the present composition of the barrel of oil in the United States.

Mr. MOORE. It does not reflect a comparable barrel of oil on the world market, and doesn't reflect the comparable new barrel of oil under our then proposed regulations to free up the price of new discovered oil. Therefore, it's really an artificial figure, is it not, and not a true Btu equivalency of what the going price of new oil is?

Mr. SCHLESINGER. It is a true Btu equivalent of the price of a barrel of oil as used in the United States, reflecting the degree of imports into the United States.

Mr. MOORE. Didn't the administration consider a different figure than $1.75? Did it not consider a Btu equivalency of new oil?

Mr. SCHLESINGER. It considered a whole range of figures.

Mr. MOORE. Would you answer as candidly as you can be with us, was this really an economic decision or was it a political decision not to go to the equivalency of new oil?

Could you get support of certain Senators to pass your plan if you had used the equivalency of new oil?

Mr. SCHLESINGER. It was a judgmental decision.

Mr. MOORE. Then I take it we have no econometric models to show we really would have injured the economy and there are really problems if we go to a higher Btu equivalency.

Mr. SCHLESINGER. Yes, indeed we have that.

Mr. MOORE. After the fact.

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes the gentleman from Virginia, Mr. Satterfield.

Mr. SATTERFIELD. Thank you, Mr. Chairman.

Mr. Schlesinger, I welcome you here this morning. I enjoyed your statement very much. I think it will be informative to us.

I would like to direct my question to the switch to coal, which, I think, based on your statement, is the essential ingredient of the four points you feel must be accomplished.

I am a little disturbed that nowhere in any of the statements with respect to the energy plan has there been significant attention paid to other legislation that might have a depressing effect on the plan, and I am referring specifically now to the stripmining bill and to the Clean Air Act and the limitations that it might impose upon this key feature of your plan.

I would like to know whether any consideration was given to the situation that very well might develop where under this legislation we say to certain new sources that you cannot burn gas and oil, and to certain sources now in existance that by a certain time in the future you must switch to something other than gas and oil.

EPA, under the Clean Air Act amendments, which are now moving through Congress, says to the sources that because of our regulations and particularly the requirement of preventing significant deterioration, you cannot burn coal. What happens in that instance?

Mr. SCHLESINGER. There was continuous and painstaking attention paid to that problem, Mr. Satterfield.

Mr. SATTERFIELD. I can assure you that was also true of our committee, but no solution has yet been found.

Mr. SCHLESINGER. You have correctly identified a dilemma that we face, that we wish to balance the use of coal against the desire to keep air clean, and once again that is a judgmental matter.

What this does is permit a major shift to coal amounting to something on the order of 4 billion barrels a day of oil and gas equivalent.

Mr. SATTERFIELD. I wanted to come back to those figures, because I wonder whether or not they take into consideration the disincentive features of the Clean Air Act, for example.

Instead of the mandatory changes from gas and oil let's go to the incentive aspects as represented by the tax on the industrial use of natural gas which would, as I understand it, bring the price of natural gas up to distillate equivalency at a certain time.

Under the Clean Air Act amendments we are about to adopt, there are certain areas which are protected against significant air quality deterioration in which, if one violates the standard, one would be subject to a $25,000 a day fine or penalty. It seems to me that any source confronted with that prospect would have a very easy election to pay the tax that is supposed to be an incentive under this program rather than pay an amount of $25,000 a day to switch and be in violation.

Was any consideration given to that in arriving at projections of increased use of coal?

Mr. SCHLESINGER. In general, not to those specific numbers.

Mr. SATTERFIELD. It seems to me that with the new clean air legislation you have something that is going to be very important to this key element of the plan, which will be an absolute disincentive to the very carefully drawn incentives which are woven into it.

Mr. SCHLESINGER. We believe that those disincentives would not be offsetting.

Mr. SATTERFIELD. $25,000 a day.

Mr. SCHLESINGER. We certainly assume those who shift to coal will seek to avoid being in violation of the law.

Mr. SATTERFIELD. The only way they could avoid being in violation would be to go out of business.

Mr. SCHLESINGER. In some cases that might be true.

Mr. SATTERFIELD. The second aspect of the plan that bothers me a little bit is the rationale that by bringing the price of natural gas over a period of time up to the equivalent of distillates, you make the use of gas less attractive.

It would seem to me if gas were being sold at the equivalent to the cost of distillate fuel, gas would still be the most attractive of the two.

Mr. SCHLESINGER. That is a judgment that you can consider here in the Congress. That increase in price was regarded as appropriate to induce industries to begin to make the shift, particularly in view of the uncertainty of supply to some industries with regard to natural gas.

Mr. SATTERFIELD. I realize you have built an incentive in, and I think it's a good one. The tax could be offset against energy savings investments within a certain period of time, but I am curious to know what would happen to the balance of revenues raised by the taxes that were not so offset if the person making that investment elected not to do so.

Mr. SCHLESINGER. That would go into the general fund of the Treasury.

Mr. SATTERFIELD. That is not involved in the rebate program?

Mr. SCHLESINGER. No, sir.

Mr. SATTERFIELD. Thank you very much.

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes the gentleman from Indiana, Mr. Sharp.

Mr. SHARP. Thank you, Mr. Chairman.

Under the new gas pricing formula Btu equivalency, can you tell us what you expect the price to be by 1980, for example? It clearly rises each year.

Mr. SCHLESINGER. That depends upon the presumed rate of inflation, but it would be around $2 or $2.25, I think; $2.14.

Mr. SHARP. You expect it to be $2.14 because of the rise in inflation which goes to old oil?

Mr. SCHLESINGER. Those are illustrative figures, yes, sir.

Mr. SHARP. If inflation continues, the price goes up, but is there anything else in the formula?

Mr. SCHLESINGER. They are both projected in terms of the general price deflator, but there also is an incentive price because of the changing composition of the domestic barrel of oil, and this reflects an assumption about the decline rate for old oil and the like.

Mr. SHARP. I see.

Do you have any estimate for 1985? Obviously it's harder.

Mr. SCHLESINGER. I hesitate to tell you this, Mr. Sharp. The estimate in current dollars is $2.98 per Mcf; in constant dollars it is $1.29.

Mr. SHARP. Let me ask you regarding your definition of new gas where you have already expressed the hope that additional work can be done on it. I share your view that if we can avoid having bureaucracy go out in the oil field and try to determine that, we are probably better off, and we should allow for some error in order to avoid that.

I am wondering can you give us any data as to present formations, how many you think would be potentially falling in that error category? As you know, I think gas appears in the Chairman's State in a pinnacle formation in some cases, in which case you can drill into that same existing formation more than 1,000 feet maybe, at one place every 4 or 5 feet, and at the next place you can go below

1,000, so it probably pays you to sink a well and cause that to become new gas.

If that is a minor portion of the whole, obviously it's worth letting that go back. If, in fact, that is a major percentage of the available gas, suddenly this becomes a new ball game.

Mr. SCHLESINGER. We will supply the geological data for the record. We will also supply the numbers with regard to the new gas.

Mr. SHARP. Thank you.

[The following material was received for the record:]

In response to questions voiced by Congressman Sharp regarding the number of formations and the amount of new gas that might be erroneously qualified for the new gas price, we submit the following:

Producing well data in the United States has not been recorded or stored in a manner that enables us to answer this question definitely on a nationwide basis.

Geological investigations have shown us for rainier areas, like Michigan, the 1,000 foot vertical separation criterion will not afford an opportunity for error on the side of excessive new gas because geologists in Michigan report that the maximum vertical column of gas pay in the pinnacle reef reservoirs is less than 750 feet.

We have identified other sedimentary basins in which the gas column is described as in excess of 1,000 feet, but these are the Piceance, Green River and Unita basins in the western, tight-sands region where, normally, the entire pay section in a reservoir is perforated in order to produce enough gas to make a well economically producible.

There are some large anticlinal or monoclinal reservoirs in which porosity or fracturing have developed gas columns in excess of 1,000 feet; for example, the Hugoton Field in Kansas, Oklahoma, and Texas. We see no opportunity for error in the Hugoton Field because it is a mature, well-developed field.

Our estimate of the amount of gas that would be erroneously classified as new gas is approximately zero.

Should it transpire that a few relatively new and undeveloped reservoirs exist that would permit the erroneous classification of new gas, it is our opinion that the error would be self-limiting in that such reservoirs would soon be fully developed and the opportunity for bogus "new gas" qualification would soon be exhausted.

Mr. SHARP. Getting back to a question Mr. Satterfield raised on the Clean Air Act provisions, one of the concerns, of course is powerplant siting, and it's my understanding that you people have some data or at least in the briefing we just had at an earlier hour from your people, the claim was made that there are more than ample available sites under the significant deterioration provision to meet all of the possible coal fired plant needs.

Can you give us more specific data on that? Naturally you didn't have it with you this morning.

Mr. SCHLESINGER. We will insert that into the record. You are referring to areas of significant deterioration as opposed to the nonattainment area.

Mr. SHARP. I think we need the whole thing together. The point is we are about to make a decision on both issues, but on significant deterioration which some claim can alter that dramatically, and what we would like to know is what universe of choices remain after we have enacted those provisions that the President is supporting?

Mr. SCHLESINGER. We will provide that for the record.

[The following material was received for the record:]

Joint studies by FEA/EPA of the constraints on power plant siting implied by proposed nonsignificant deterioration legislation were released on October 1975 and January 1976 (reports attached). These analyses conclude that less than 10% of the total U.S. land area would be precluded from the siting of typical new coal fired

power plants or plant expansions if scrubbers were used (Supplement Report 3, Page 15, Table 7). Furthermore, *none* of the 74 plants studied would be precluded from siting if scrubbers were used to control sulfur oxide emissions (Supplement Report 3, Page 29, Table 8).

In general, the attached reports indicate that siting of facilities would be limited only to Class I or adjacent areas or in rugged terrain, assuming the use of BACT. There are ample sites available in Class II areas for both industrial and utility operations. Furthermore, the less restrictive Class III increments are available to the States where density industrial development is desired.

AN ANALYSIS OF THE IMPACT
ON THE ELECTRIC UTILITY INDUSTRY
OF ALTERNATIVE APPROACHES TO
SIGNIFICANT DETERIORATION

Supplement Report 3

General Edition

FURTHER ANALYSIS OF
HOUSE DISCUSSION DRAFT
DATED OCTOBER 16, 1975
(H.R. 10498)

SECOND DRAFT

SECOND DRAFT

by

Environmental Protection Agency
Washington, D.C. 20460
and
Federal Energy Administration
Washington, D.C. 20461

23 January 1976

92-911 O - 77 - 8

PREFACE

This Supplement Report has been prepared in two versions: a *Congressional Edition*, and a *General Edition*. The *Congressional Edition* is specifically responsive to the wording contained in the legislative proposal identified in the title. The *General Edition* includes the Congressional material, but also addresses the scenario of Environmental Protection Agency regulations now in effect under the Clean Air Act as documented in the original Report Volumes I and II, i.e. the New Source Performance Standards as one of the bases for analyses of alternative approaches to the prevention of significant deterioration of air quality.

The assistance and support of the U.S. Geological Survey of the Department of Interior, which compiled and printed the maps contained herein, is gratefully acknowledged. Neither the cartographic information, nor the contents of this report, necessarily reflect the view or policies of either the U.S. Geological Survey or the Department of Interior.

Supplement Report 3: *General Edition*

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General Edition

Supplement Report 3

FURTHER ANALYSIS OF HOUSE
DISCUSSION DRAFT DATED OCTOBER 16, 1975
(H.R. 10498)

1. INTRODUCTION

The original report prepared jointly by the Environmental Protection Agency (EPA) and Federal Energy Administration (FEA), An Analysis of the Impact on the Electric Utility Industry of Alternative Approaches to Significant Deterioration, was based on the provisions contained in both the September 8, 1975 discussion draft of the Senate Subcommittee on Environmental Pollution, and the June 16, 1975 discussion draft of the House Subcommittee on Health and the Environment as amended on September 4, 1975. Supplement Report 2, "Analysis of House Discussion Draft Dated October 16, 1975," addressed that proposal for the prevention of significant deterioration of air quality using the same analytic procedures and methodologies described in the original EPA/FEA report. (The October 16, 1975 print was referred to the Committee on Interstate and Foreign Commerce on October 31, 1975 as H.R. 10498, the "Clean Air Act Amendments of 1975.")

The present Supplement Report 3 refines and extends the analysis of H.R. 10498 as described below.

2. MODIFICATIONS TO THE ANALYTIC PROCEDURES AND METHODOLOGY

The basic goals of previous analyses of significant deterioration legislation, i.e., to determine total land area and amount of generating capacity potentially impacted, are unchanged in this analysis. However, modifications have been made to the procedures and methodology to allow treatment of additional detail in relation to power plant size, pollution control standards and available coal quality. These modifications are discussed separately in greater detail in the following subsections.

2.1 Power Plant Size

Previous analyses made no attempt to subcategorize the 74 power plant data base used in the determination of potentially impacted generating capacity. This study subcategorizes the basic 74 power plant data base in order to distinguish

the following: (1) addition of generating capacity to an existing power plant site and (2) creation of generating capacity on new sites with no previous capacity. In the context of the use of this data base as a set of surrogate sites for analytical purposes, the present approach evaluates potential impacts of alternative significant deterioration policies on projected total site capacity as well as on the addition of new capacity to an existing site not previously subject to significant deterioration provisions.

The actual power plant sites and generating capacities contained in the power plant sample data base is given in Appendix A. The 74 power plants contained in the data base given in Appendix A are the same as used in all previous analyses, but this data base has been broken down into three different size categories as given below. Note that in order that an uncommonly large or small plant not unduly bias the statistics, median values have been used in analyses of this report rather than means (averages). The three size categories are:

a. Additions of New Capacity to Existing Sites

Of the sample of 74 plants, 40 plants represent additions to the capacity of existing facilities. The median value of this *capacity addition* is approximately 650 megawatts (MW).

b. New Capacity Regardless of Site History

The previous analyses assumed that the approximate size of all new planned capacity, regardless of whether or not capacity previously existed, was 1000 MW. An analysis of the 74 plant data base shows that the median of all *new planned capacity* is 830 MW.

c. Total Site Capacity

A median *total site capacity* of 1350 MW has been calculated by combining the existing site capacity with the capacity additions to existing sites discussed in part (a) above. This figure, 1350 MW, has been used in this analysis as the best estimate of typical new total site capacity. It is probable, however, that this estimate is conservative since some of the sites are likely to be further developed in future years to more total capacity than is included in this analysis.

2.2 Pollution Control Standards (NSPS Definition of BACT)

Previous analyses have assessed the impact of alternative significant deterioration policies on power plant siting with federal new source performance standards (NSPS) assumed to be the minimum control level for all new plants. However, it is noteworthy that a few states presently have emission standards in effect which are more stringent than NSPS, as indicated in Table 1. This additional control requirement in the nine states indicated in Table 1 is now incorporated in the analysis of the BACT equal to NSPS case (i.e., BACT is defined as equal to NSPS in all but nine states, and is defined as equal to the state requirement in the remaining nine states). There are also some metropolitan areas which have standards stricter than NSPS, but these local standards have not been included in this analysis.

2.3 Available Coal Quality and Sulfur Control (NSPS/FGD Definition of BACT)

The BACT definition of NSPS/FGD used in previous analyses was as follows:

- Western States - burning of 0.7% sulfur coal plus 90% SO_2 effluent scrubbing.
- All Other States - burning of 3.5% sulfur coal plus 90% SO_2 effluent scrubbing.

These definitions have been expanded to allow treatment of a more detailed regional coal quality breakdown and to provide for coal washing that can remove up to 30-40% of the sulfur (pyritic sulfur only) in certain coals. Accordingly, the revised definition of NSPS/FGD control levels divides the country into four (4) basic coal availability regions each having coal with a regional average sulfur content and heat value. In addition, the analysis now provides for coal cleaning of eastern and midwestern coal. The details of coal quality and sulfur control used to define the revised NSPS/FGD case are given in Table 2. The regional breakdown for this analysis is shown in Figure 1.

All other features of the previous analysis are not changed for this analysis. For purposes of reference the provisions for Mandatory and Discretionary Class I areas contained in H.R. 10498 are repeated in Table 3. These are unchanged from the description given in Supplement Report 2. Figure 2 shows the land areas graphically.

Table 1

States With Emission Standards More Stringent Than NSPS
(NSPS = 1.2 lb $SO_2/10^6$ BTU Heat Input)

State	Most Stringent Standard	Value Used for Analysis
Montana*	1.2 lb $SO_2/10^6$ BTU	0.12 lb $SO_2/10^6$ BTU
Wyoming†	0.2	0.2
Utah†Δ	80% Control	0.12
Arizona	0.8 lb $SO_2/10^6$ BTU	0.8
New Mexico	0.34	0.34
South Nevada	~0.21	0.15
New Jersey	~0.3	0.3
Pennsylvania†	0.6	0.6
Maryland∞	1.2	0.6

---

* Value used for analysis is one-tenth NSPS on the basis of emission level expected from the Colstrip plant, which will employ FGD in addition to the use of low-sulfur content coal.

† Standards now in effect are under review for possible revision.

Δ Value used for analysis is one-tenth NSPS on the basis of emission level expected from the Kaiparowits plant, which will employ FGD in addition to the use of low-sulfur coal.

∞ Value used for analysis is one-half NSPS on the basis of emission level expected from Dickerson Unit 4, which will employ FGD.

Table 2

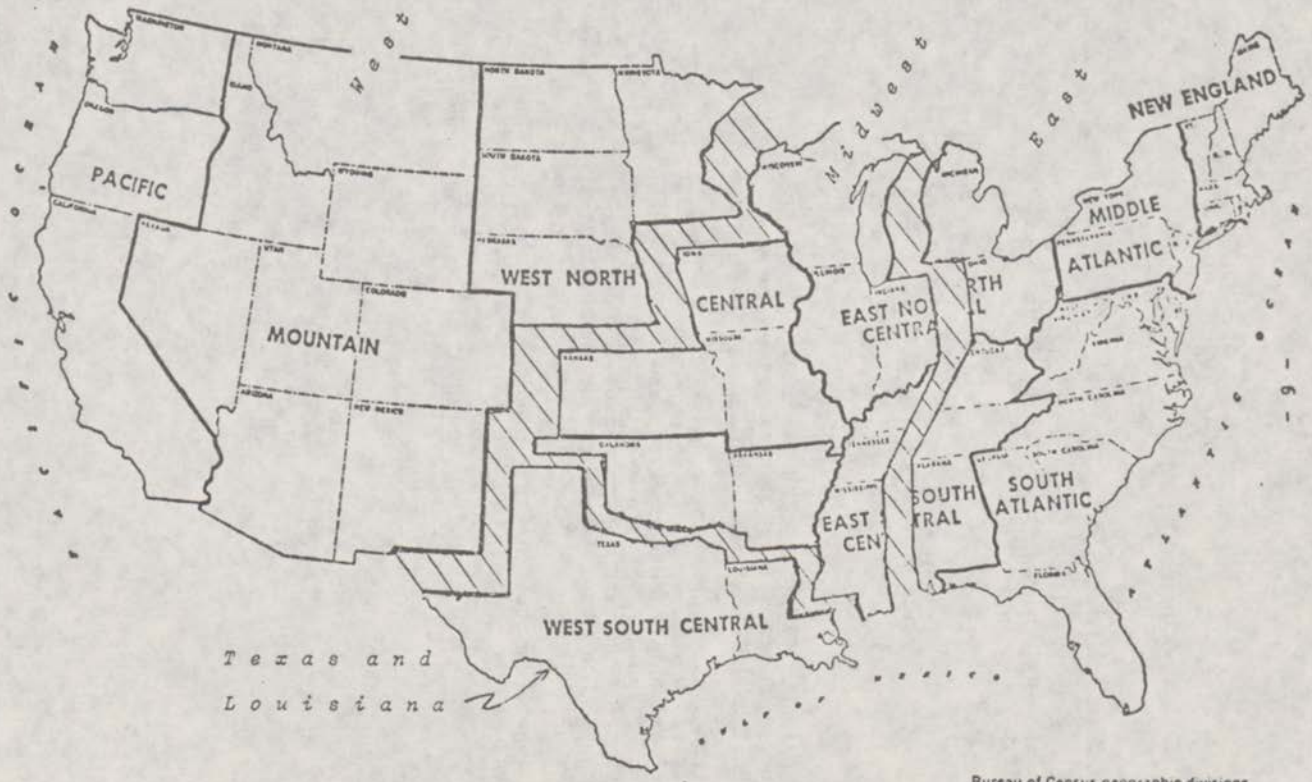
Compilation of Locally Available Coal and Assumptions for Coal Cleaning/FGD

Region*	Intrinsic Average Coal Sulfur Content	Sulfur Content After Cleaning†	Sulfur Content After FGD∞	Net Sulfur Content as Percentage of NSPS
East	5 lb $SO_2/10^6$ BTU	3.2 lb $SO_2/10^6$ BTU	0.32 lb $SO_2/10^6$ BTU	27 %
Midwest (Central)	7	4.6	0.46	38
Texas and Louisiana	2.5	N/A	0.25	21
West	1.2	N/A	0.12	10

* The "East" is bounded on the west by the western borders of Michigan, Ohio, Eastern Kentucky, Eastern Tennessee, and Alabama.
The "West" is bounded on the east by the eastern borders of Minnesota, South Dakota, Nebraska, Colorado, and New Mexico.
Texas and Louisiana are treated separately because of local lignite deposits.
The "Midwest" ("Central") includes the states of Wisconsin, Illinois, Indiana, Western Kentucky, Western Tennessee, Mississippi, Arkansas, Oklahoma, Missouri, Kansas, and Iowa.

† Coal cleaning (washing) is assumed to be effective to the extent of removal of one-third of the total intrinsic sulfur content, national average.

∞ FGD (flue gas desulfurization) is assumed to be effective to the extent of 90% removal of the net sulfur content, subsequent to coal cleaning where applicable.



Bureau of Census geographic divisions as reported in the Edison Electric Institute *Statistical Year Book*.

Figure 1: Regions of Locally Available Coal *(italics)*.

Table 3

MANDATORY AND DISCRETIONARY AREAS

Mandatory Class I Areas	Number of Units
National Parks (in excess of 10,000 acres)	32
National Wilderness Areas (in excess of 10,000 acres)	83
	115

Discretionary Class I Areas (Initial Class I Status, with possible reclassification to Class II at the discretion of the State)	
National Wilderness Areas (between 1,000 and 10,000 acres)	23
National Parks (between 1,000 and 10,000 acres)	1
International Parks (in excess of 1,000 acres)	1
National Preserves (in excess of 10,000 acres)	2
National Monuments (in excess of 10,000 acres)	22
National Recreation Areas (in excess of 10,000 acres)	20
National Primitive Areas (in excess of 10,000 acres)	17
	86

Figure 2: ALL MANDATORY AND DISCRETIONARY CLASS I AREAS AS DEFINED BY H.R. 10498

3. FINDINGS OF THE ANALYSIS

The procedures alluded to above and described in previous reports were used to analyze the following cases:

- Class I Designations: Mandatory only; Mandatory and Discretionary
- Plant Type: additional capacity; new site capacity; total site capacity
- BACT Requirements: NSPS/SIP; coal cleaning and/or FGD

The basic options included in these different cases are summarized in Table 4.

To include all possible combinations of the basic options, twelve different scenarios were separately analyzed. A separate map was prepared showing the land areas affected under each of the twelve different policy options. Shown in Table 5 is a summary of the policy options analyzed and the corresponding map number for each policy option.

For each policy option analyzed, the generating capacity affected by the designation of Class I areas was also calculated using the 74 power plant data base. Shown in Figure 3 is the location of the 74 generating sites in relation to the Mandatory and Discretionary Class I land areas.

Given in separate subsections below are the findings of the analysis in terms of land area and generation capacity affected.

3.1 Land Areas Affected

The percentages of total continental United States land affected by Class I area designations under H.R. 10498 significant deterioration legislation are summarized in Tables 6 and 7. Also shown, for comparison purposes, are the previous results from Supplement Report 2. As can be seen from Tables 6 and 7, the amount of land in the total U.S. affected under the new analysis for *total site capacity* is nearly identical to the amount of land affected as given in Supplement Report 2 for a generic 1000 MW power plant. In terms of new capacity or capacity additions only, the new analysis indicates significantly less total area impacted than reported in Supplement Report 2.

For the case of BACT defined as equal to NSPS in Tables 6 and 7, it can be seen that inclusion of state emission standards

Table 4

POLICY OPTIONS ANALYZED

Generation Capacity	Emission Control Policy	Class I Areas
° Addition of new capacity to existing sites: Median = 650 MWe.		
	° Local coal; BACT = coal cleaning and/or FGD.	° Mandatory Class I areas only.
° All new capacity: Median = 830 MWe.		
	° NSPS with states more stringent.	° Mandatory and Discretionary Class I areas.
° Total site capacity: Median = 1350 MWe.		

TABLE 5

POLICY OPTIONS ANALYZED

Policy Option Analyzed	Figure
Mandatory Class I Areas Only	
Additional capacity to existing sites +	
BACT equal to FGD and/or coal cleaning	4
BACT equal to NSPS or state standards	5
All new capacity +	
BACT equal to FGD and/or coal cleaning	6
BACT equal to NSPS or state standards	7
Total site capacity +	
BACT equal to FGD and/or coal cleaning	8
BACT equal to NSPS or state standards	9
Mandatory and Discretionary Class I Areas	
Additional capacity to existing sites +	
BACT equal to FGD and/or coal cleaning	10
BACT equal to NSPS or state standards	11
All new capacity +	
BACT equal to FGD and/or coal cleaning	12
BACT equal to NSPS or state standards	13
Total site capacity +	
BACT equal to FGD and/or coal cleaning	14
BACT equal to NSPS or state standards	15

Figure 3: ALL MANDATORY AND DISCRETIONARY CLASS I AREAS AS DEFINED BY H.R. 10498, WITH LOCATIONS OF SAMPLE POWER PLANTS

which are stricter than NSPS changes the amount of affected land the most in the west. This is as expected since 6 of the 9 states with standards stricter than NSPS are in the west. For the case of BACT defined as equal to NSPS/FGD in Tables 6 and 7, however, the primary affect of the modifications incorporated in the analysis of this report are in the east and midwest. The results of Supplement Report 2 are unchanged in the west for the NSPS/FGD case, but the inclusion of coal washing and lower sulfur content coal availability in the east and midwest reduces the amount of affected land in these regions. As mentioned above, in terms of total site capacity, the increase in generic site size from the 1000 MW value of Supplement Report 2 to the 1350 MW size of this report, nearly exactly compensates for the reduction in affected area caused by the treatment of state standards, coal washing and lower coal availability in this report.

For the country as a whole, assuming the NSPS case as defined in this report, the new analysis indicates that 32% of the total land area is affected by Mandatory Class I areas if the total site capacity value of 1350 MW is considered, while the amount of land affected drops to 14% if the 650 MW median additions to existing capacity is considered. Considering both Mandatory and Discretionary Class I areas would increase the above figures to 44% and 21%, respectively. With BACT defined as FGD plus coal cleaning in the east and midwest and as FGD plus low sulfur content coal in the west, as much as9% of the land area may be precluded from the location of 1350 MW sites by Mandatory Class I areas in the west (7% and 2% in the east and midwest, respectively) and 14% by Mandatory plus Discretionary Class I areas in the west (13% and 2% in the east and midwest, respectively). In all cases the highest percentage of land is impacted in the west and the lowest percentage in the midwest.

Contained in Figures 4 through 9 are graphical depictions of the data contained in Table 6 which considers Mandatory Class I areas, while Figures 10 through 15 contain the graphical data of Table 7 for Mandatory plus Discretionary Class I areas. Each set of figures contains two maps for each of the three power plant sizes considered (650, 830 and 1350 MW). One of the two maps shows buffer zones corresponding to BACT equal to NSPS except where more stringent state standards apply, while the other map shows buffer zones corresponding to BACT equals to coal cleaing and/or FGD as defined in Table 2 of this report.

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Table 6.

LAND AREAS WHICH MAY BE PRECLUDED FROM THE SITING OF COAL-FIRED POWER PLANTS DUE TO MANDATORY CLASS I AREAS WITH BUFFER ZONES

Region[3]	NSPS CASE[1]				NSPS/FGD CASE[2]			
	Supplement Report 2	Supplement Report 3 Additions 650 MW	All New 830 MW	Total Site 1350 MW	Supplement Report 2	Supplement Report 3 Additions 650 MW	All New 830 MW	Total Site 1350 MW
West	57%	26%	34%	49%	7%	7%	7%	9%
Midwest	9	4	5	16	3	1	1	2
East	27	14	22	40	10	3	4	7
Total U.S.	31%	14%	19%	32%	6%	4%	4%	5%

1. The NSPS case of Supplement Report 2 corresponds to a minimum control level of all power plants equal to to federal new source performance standards (NSPS) which is equivalent to the use of low sulfur (0.7% sulfur) coal. The NSPS definition of BACT implied by Supplement Report 3 is given in Section 2.2.

2. The NSPS/FGD case of Supplement Report 2 corresponds to the use of low sulfur content coal plus a scrubber in the west (i.e., 10% of NSPS) and 3.5% sulfur coal plus a scrubber in other areas (i.e., 50% of NSPS). The NSPS/FGD definition of BACT implied by Supplement Report 3 is given in Section 2.3.

3. The regions are the same as were defined in Supplement Report 2.

Table 7

LAND AREAS WHICH MAY BE PRECLUDED FROM
THE SITING OF COAL-FIRED POWER PLANTS DUE TO MANDATORY
AND DISCRETIONARY CLASS I AREAS WITH BUFFER AREAS

Region[3]	NSPS CASE[1]				NSPS/FGD CASE[2]			
	Supplement Report 2	Supplement Report 3 Additions 650 MW	All New 830 MW	Total Site 1350 MW	Supplement Report 2	Supplement Report 3 Additions 650 MW	All New 830 MW	Total Site 1350 MW
West	69%	35%	43%	57%	12%	11%	11%	14%
Midwest	17	9	11	31	6	1	2	4
East	40	20	31	52	15	5	7	13
Total U.S.	41%	21%	26%	44%	10%	5%	6%	9%

1. The NSPS case of Supplement Report 2 corresponds to a minimum control level of all power plants equal to to federal new source performance standards (NSPS) which is equivalent to the use of low sulfur (0.7% sulfur) coal. The NSPS definition of BACT implied by Supplement Report 3 is given in Section 2.2.

2. The NSPS/FGD case of Supplement Report 2 corresponds to the use of low sulfur content coal plus a scrubber in the west (i.e., 10% of NSPS) and 3.5% sulfur coal plus a scrubber in other areas (i.e., 50% of NSPS). The NSPS/FGD definition of BACT implied by Supplement Report 3 is given in Section 2.3.

3. The regions are the same as were defined in Supplement Report 2.

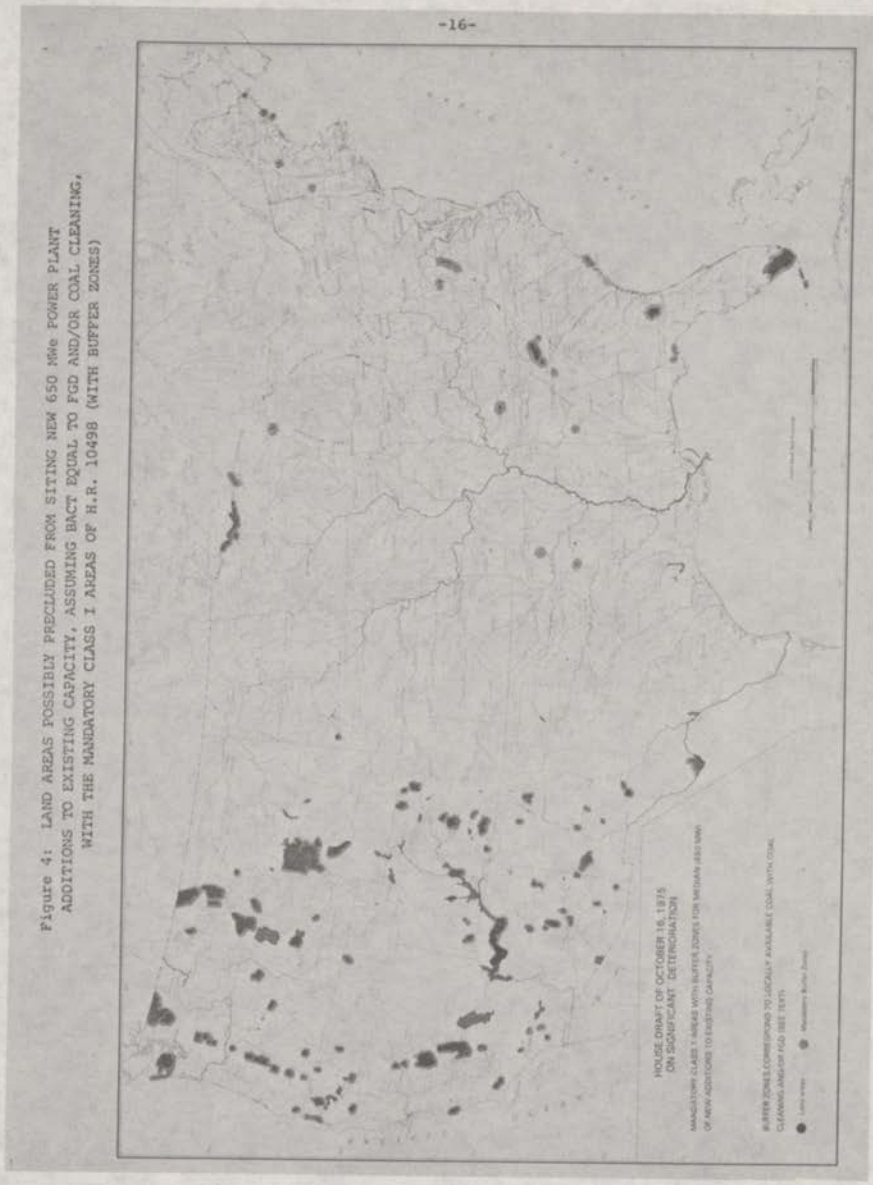

Figure 4: LAND AREAS POSSIBLY PRECLUDED FROM SITING NEW 650 MWe POWER PLANT ADDITIONS TO EXISTING CAPACITY, ASSUMING BACT EQUAL TO FGD AND/OR COAL CLEANING, WITH THE MANDATORY CLASS I AREAS OF H.R. 10498 (WITH BUFFER ZONES)

Figure 5: LAND AREAS POSSIBLY PRECLUDED FROM SITING NEW 650 MWe POWER PLANT ADDITIONS TO EXISTING CAPACITY, ASSUMING BACT EQUAL TO NSPS PLUS STATE STANDARDS, WITH THE MANDATORY CLASS I AREAS OF H.R. 10498 (WITH BUFFER ZONES)

Figure 6: LAND AREAS POSSIBLY PRECLUDED FROM SITING NEW 830 MWe POWER PLANTS, ASSUMING BACT EQUAL TO PGD AND/OR COAL CLEANING, WITH THE MANDATORY CLASS I AREAS OF H.R. 10498 (WITH BUFFER ZONES)

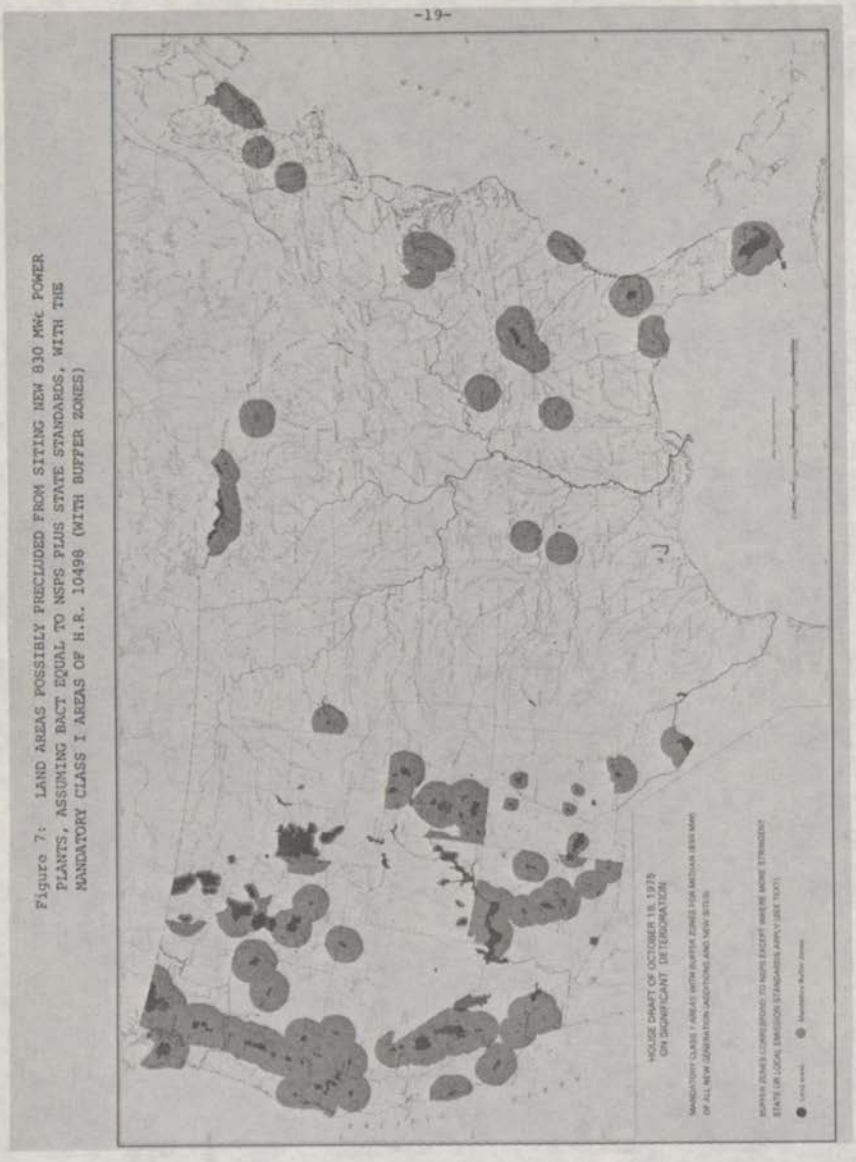

Figure 7: LAND AREAS POSSIBLY PRECLUDED FROM SITING NEW 830 MWe POWER PLANTS, ASSUMING BACT EQUAL TO NSPS PLUS STATE STANDARDS, WITH THE MANDATORY CLASS I AREAS OF H.R. 10498 (WITH BUFFER ZONES)

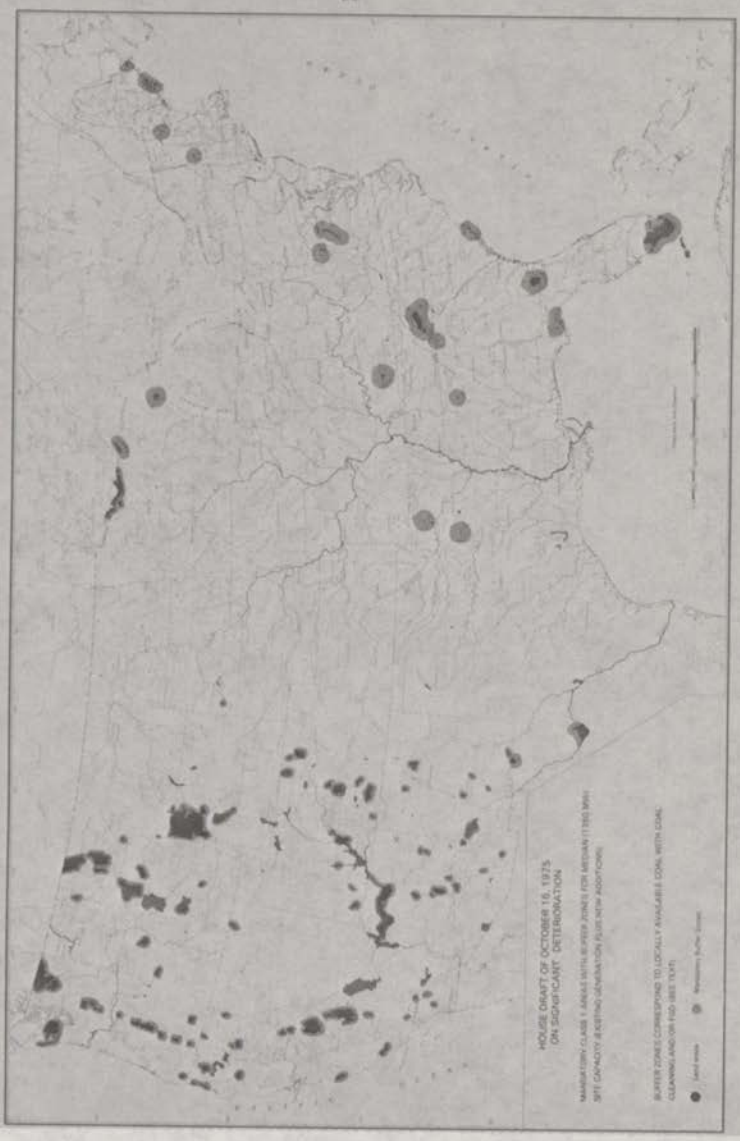

Figure 8: LAND AREAS POSSIBLY PRECLUDED FROM SITING NEW 1350 MWe POWER PLANT SITES, ASSUMING BACT EQUAL TO FGD AND/OR COAL CLEANING, WITH THE MANDATORY CLASS I AREAS OF H.R. 10498 (WITH BUFFER ZONES)

Figure 9: LAND AREAS POSSIBLE PRECLUDED FROM SITING NEW 1350 MWe POWER PLANT SITES, ASSUMING BACT EQUAL TO NSPS PLUS STATE STANDARDS, WITH THE MANDATORY CLASS I AREAS OF H.R. 10498 (WITH BUFFER ZONES)

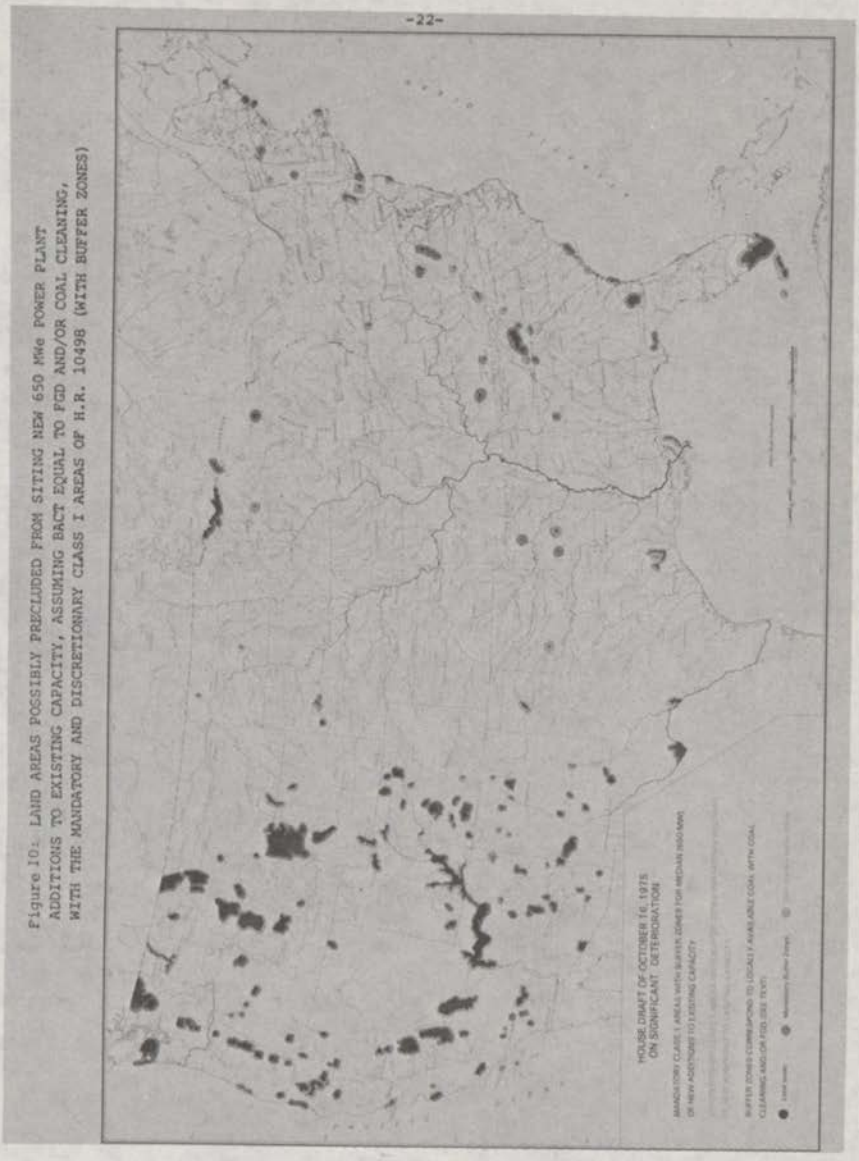

Figure 10. LAND AREAS POSSIBLY PRECLUDED FROM SITING NEW 650 MWe POWER PLANT ADDITIONS TO EXISTING CAPACITY, ASSUMING BACT EQUAL TO FGD AND/OR COAL CLEANING, WITH THE MANDATORY AND DISCRETIONARY CLASS I AREAS OF H.R. 10498 (WITH BUFFER ZONES)

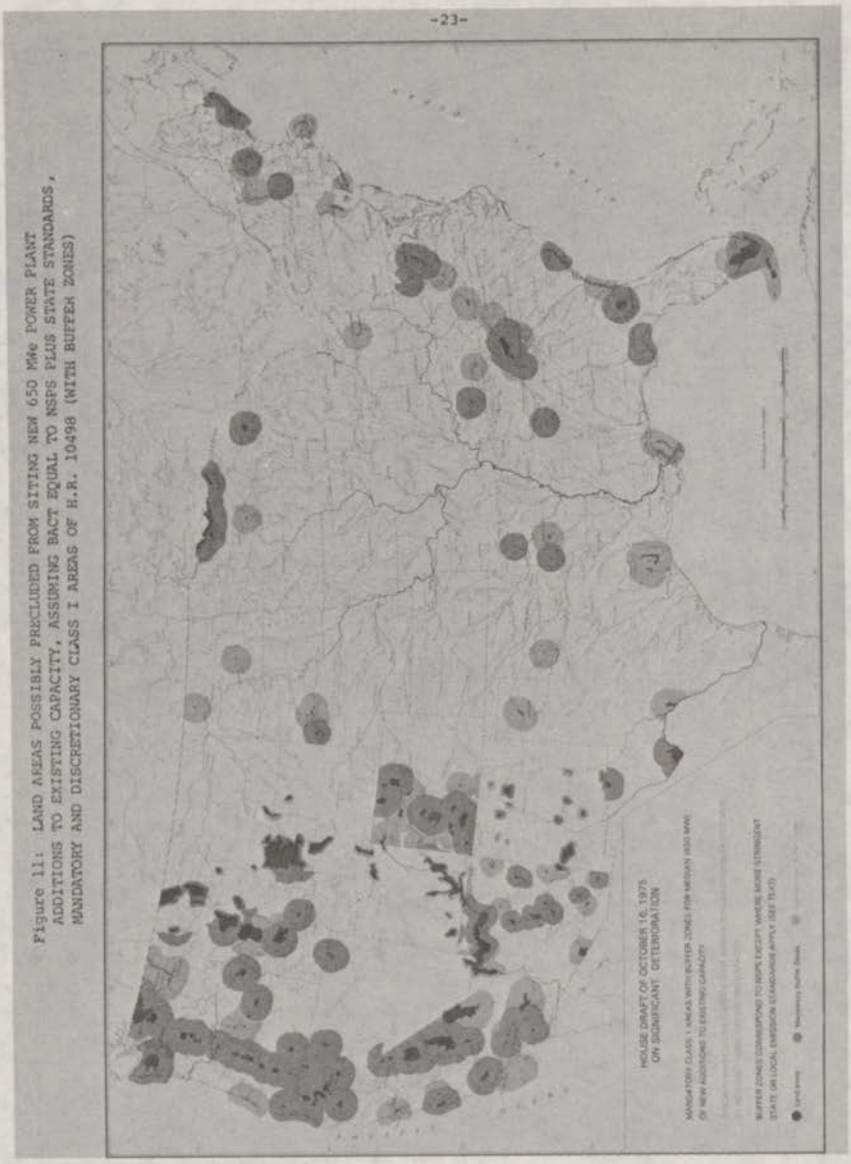

Figure 11: LAND AREAS POSSIBLY PRECLUDED FROM SITING NEW 650 MWe POWER PLANT ADDITIONS TO EXISTING CAPACITY, ASSUMING BACT EQUAL TO NSPS PLUS STATE STANDARDS, MANDATORY AND DISCRETIONARY CLASS I AREAS OF H.R. 10498 (WITH BUFFER ZONES)

Figure 12: LAND AREAS POSSIBLY PRECLUDED FROM SITING NEW 830 MWe POWER PLANTS, ASSUMING BACT EQUAL TO FGD AND/OR COAL CLEANING, WITH THE MANDATORY AND DISCRETIONARY CLASS I AREAS OF H.R. 10498 (WITH BUFFER ZONES)

Figure 13: LAND AREAS PRECLUDED FROM SITING NEW 830 MWe POWER PLANTS ASSUMING BACT EQUAL TO NSPS PLUS STATE STANDARDS, WITH THE MANDATORY AND DISCRETIONARY CLASS I AREAS OF H.R. 10498 (WITH BUFFER ZONES)

Figure 14: LAND AREAS POSSIBLY PRECLUDED FROM SITING NEW 1350 MWe POWER PLANT SITES, ASSUMING BACT EQUAL TO FGD AND/OR COAL CLEANING, WITH THE MANDATORY AND DISCRETIONARY CLASS I AREAS OF H.R. 10498 (WITH BUFFER ZONES)

Figure 15: LAND AREAS POSSIBLY PRECLUDED FROM SITING NEW 1350 MWe POWER PLANT SITES, ASSUMING BACT EQUAL TO NSPS PLUS STATE STANDARDS, WITH THE MANDATORY AND DISCRETIONARY CLASS I AREAS OF H.R. 10498 (WITH BUFFER ZONES)

3.2 Generation Capacity Affected

Section 2.1 referenced the original 74 power plant data which have been the basis in previous analyses for estimating the potential impacts of various significant deterioration options on coal-fired generating capacity actually known to be planned or under construction. For such analytical purposes, these plants are being treated as if all would be subject to the proposed legislation. However, as was noted earlier, no attention was paid to *sites* as opposed to *additions to existing capacity*.

Now, information on previously existing capacity, at those 40 of the 74 locations where the new generation is an addition as opposed to the initiation of a new site, has been added to the data base. The present analysis thus addresses what the impact on *total site capacity* might be over the long term as new sites are identified, initial generation constructed, and additional capacity planned demand increases.

The results of the analysis of generation capacity affected are shown in Table 8, along with the results from Supplement Report 2 for purposes of comparison. As can be seen from Table 8, given BACT equal to NSPS/FGD) the new analysis indicates that none of the planned capacity would be affected, regardless of whether additions to existing capacity or total site capacities are considered. The 74 locations are sufficiently distant from both the Mandatory and the Discretionary Class I areas that, with stringent emission controls as defined in Section 2.3, they are able to surmount the significant deterioration requirements. This is a slight change from the analysis of Supplement Report 2 in which 4% of the generation capacity was affected for the same case.

Given BACT equal to NSPS except where states have more stringent standards, the results of Table 8 indicate that up to 32% of total site generation capacity would be affected by Mandatory plus Discretionary Class I areas, while 17% of the total site generation capacity would be affected by Mandatory Class I areas alone. If only additions to previous sites are considered, Mandatory Class I areas would affect 3% of the total capacity whereas Mandatory plus Discretionary Class I areas would affect 13% of the capacity additions.

The implications of the above are of particular interest from an economic perspective. If one incurs the expense of using coal washing and/or FGD as defined for this analysis then

Table 8

PLANNED CAPACITY WHICH MAY BE AFFECTED BY
MANDATORY OR MANDATORY PLUS DISCRETIONARY CLASS I AREAS

CLASS I DESIGNATION	NSPS CASE[1]				NSPS/FGD CASE[2]			
	Supplement Report 2	Supplement Report 3 Additions to Existing Sites[3]	Supplement Report 3 All New Generation[4]	Supplement Report 3 Total Site Capacities[5]	Supplement Report 2	Supplement Report 3 Additions to Existing Sites[3]	Supplement Report 3 All New Generation[4]	Supplement Report 3 Total Site Capacities[5]
Mandatory Class I Areas Only	18%	3%	11%	17%	4%	0%	0%	0%
Mandatory plus Discretionary Class I Areas	37	13	22	32	4	0	0	0

1. The NSPS case of Supplement Report 2 corresponds to a minimum control level of all power plants equal to to federal new source performance standards (NSPS) which is equivalent to the use of low sulfur (0.7% sulfur) coal. The NSPS definition of BACT implied by Supplement Report 3 is given in Section 2.2.

2. The NSPS/FGD case of Supplement Report 2 corresponds to the use of low sulfur content coal plus a scrubber in the west (i.e., 10% of NSPS) and 3.5% sulfur coal plus a scrubber in other areas (i.e., 50% of NSPS). The NSPS/FGD definition of BACT implied by Supplement Report 3 is given in Section 2.3.

3. This column pertains to the addition of a total of 27,568 MWe new generation to the 40 previously existing sites.

4. This column pertains to all new generation contained in the 74 plant data base (68,546 MWe), regardless of whether additional capacity or a new site.

5. This column includes the sum total of the new generation added to existing sites (noted in footnote 3), plus the previously existing capacity (55,741 MWe).

all the plants in the sample set could be fully built at the designated sites. Alternatively, if plants are built to just meet NSPS plus state standards, the economic penalty arises from the need to provide the affected generation elsewhere, and/or from the need to build smaller scale plants. In neither case are costs attributable to the significant deterioration provisions avoidable. The economic impact of significant deterioration legislation will be addressed in a forthcoming report.

4. SUMMARY AND CONCLUSIONS

This analysis has introduced several refinements not contained in previous evaluations. The distinction has been made between additions of new generation to previously existing capacity as distinct from the potential affects on site development. Also, those states with emission regulations presently more stringent than the federal new source performance standards now in effect have been accounted for. New capacity has been assigned to use coal as regionally available, and maximum pollution control technology has been assessed, i.e., the use of both coal cleaning (washing or beneficiation) and flue gas desulfurization (scrubbers).

The results in brief are that, if total generation site capacity is considered, the results of the previous analysis of Supplement Report 2 are not appreciably changed in the extended analysis of this report. However, if only capacity additions to new or existing sites are considered, then the impact of significant deterioration legislation is appreciably less than previously reported. As was the case in all previous analyses, the more extreme the measures to reduce emissions, the less the siting hardship caused by significant deterioration. Mandatory plus Discretionary Class I areas affect 9% of the U.S. land area with regard to 1350 MWe sites under the NSPS/FGD scenario, but as much as 44% under the NSPS scenario.

Environmental controls such as scrubbers and coal cleaning have attendant energy and economic penalties which must be accounted for in the energy/environment equation. Every megawatt consumed by an emission control device must be generated elsewhere, and has its own environmental impact. Similarly, coal cleaning and flue gas scrubbing both have environmental problems of their own. These matters are discussed in detail in a forthcoming EPA/FEA report.

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Appendix A

DETAILED ANALYSIS OF THE POWER PLANT DATA BASE

A.1 INTRODUCTION

Appendix D of Volume II of the original EPA/FEA report (see Section 2.1) provided a list of the 74 locations where new generation was known to be under construction or planned to come "on-line" between now and 1983. Although the capacities were noted for each location, no distinction was made of additions to existing generation at previously established sites as opposed to the development of entirely new sites. Instead, all 74 data were grouped to obtain a mean (average) new generating capacity of 926 MWe. The difficulty with this is twofold: Firstly, interpretation becomes quite nebulous, as intuitively one would discern that new *sites*, undergoing initial development followed by gradual growth to full capacity, would be much more subject to being affected by significant deterioration provisions than would construction of new unit additions to older generation on existing sites not previously subject to such provisions. Previous analyses were silent on this distinction. Secondly, some concerns have been expressed that the use of the mean (average) capacity rather than the median (explained later) might unduly reflect bias from inclusion of the odd one or two uncommonly large new facilities. This Appendix addresses both these issues.

A.2 DETAILED STATISTICAL ANALYSIS

Table A.1 lists the set of 74 power plants which comprise the basic data base, including information on previously existing capacity. Those sites for which existing capacity is "none" are new, while all others constitute the addition of capacity to previously established generation. Also, this table gives the number of new *units* (i.e. boilers) proposed or under construction, so that unit size statistics may be developed.*

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* The usual usage for the term "power plant" is reference to the total site. For example, the name "Chalk Point" power plant or generating station encompasses all facilities therein located. If one wished to identify one of the two boilers originally constructed, one would cite Chalk Point Unit 1 or Unit 2, while the new boilers would be called Chalk Point Unit 3 or Unit 4. The designation of a "unit" refers to a physically independent electrical generation facility, although units may share a common stack or scrubber installation.

Table A.1

Power Plant Sample Data Base
(including previously existing capacity)

Site Name	Existing Capacity (MWe)	New Capacity (MWe)	Total Capacity (MWe)	Number of New Units	Mean New Unit Size(MWe)
		EASTERN U.S.A.			
Indian River, DE	340	400	740	1	400
Anclote, FL	515	515	1030	1	515
Big Bend, FL	891	796	1687	2	398
Bowen, GA	2547	910	3457	1	910
Central Georgia, GA	none	1792	1792	2	896
Wansley, GA	none	1792	1792	2	896
Dickerson, MD	586	800	1386	1	800
Cayuga, NY	none	850	850	1	850
Roxboro, NC	1813	1060	2873	1	1060
Homer City, PA	1319	650	1969	1	650
Mansfield, PA	none	2475	2475	3	825
Georgetown, SC	none	840	840	3	280
Pleasants, WV	none	1252	1252	2	626
		MIDWESTERN U.S.A.			
Miller, AL	none	2049	2049	3	683
White Bluff, AR	none	1400	1400	2	700
Flint Creek, AR	none	528	528	1	528
Baldwin, IL	1258	600	1858	1	600
Dallman, IL	160	175	335	1	175
Duck Creek, IL	none	800	800	2	400
Edwards, IL	725	500	1225	1	500
Havanna, IL	230	450	680	1	450
Newton, IL	none	1650	1650	3	550
Powerton, IL	1213	840	2053	1	840
Petersburg, IN	733	1030	1763	2	515

Site Name	Existing Capacity (MWe)	New Capacity (MWe)	Total Capacity (MWe)	Number of New Units	Mean New Unit Size(MWe)
George Neal, IA	496	1095	1591	2	548
Muscatine, IA	117	150	267	1	150
La Cygne, KS	893	630	1523	1	630
East Bend, KY	none	1200	1200	2	600
Ghent, KY	557	500	1057	1	500
Mill Creek, KY	677	920	1597	2	460
Big Cajun, LA	230	1080	1310	2	540
Nelson, LA	982	540	1522	1	540
Campbell, MI	650	800	1450	1	800
Presque Isle, MI	345	80	425	1	80
St. Clair, MI	1905	800	2705	1	800
Sherburne County,MN	none	1360	1360	2	680
Jackson County, MS	none	1036	1036	2	518
Morrow, MS	none	400	400	2	200
New Madrid, MO	650	600	1250	1	600
Rush Island, MO	none	1150	1150	2	575
Southwest, MO	none	400	400	2	200
Gentleman, NE	none	1200	1200	2	600
Leland Olds, ND	216	438	654	1	438
Underwood, ND	none	1000	1000	1	1000
Young, ND	235	408	643	1	408
Cardinal, OH	1230	615	1845	1	615
Conesville, OH	1275	750	2025	2	375
Miami Fort, OH	393	640	1033	2	320
Poston, OH	232	750	982	2	375
Northeastern, OK	643	900	1543	2	450
Sooner, OK	none	1030	1030	2	515
Deely, TX	none	836	836	2	418
Fayette, TX	none	1100	1100	2	550
Martin Lake, TX	none	2250	2250	3	750
Monticello, TX	593	1325	1918	2	662
Parish, TX	1255	2640	3895	4	660
Webster, TX	614	520	1134	1	520

Site Name	Existing Capacity (MWe)	New Capacity (MWe)	Total Capacity (MWe)	Number of New Units	Mean New Unit Size (MWe)
Alma, WI	188	350	538	1	350
Manitowoc, WI	69	57	126	1	57
Pleasant Prairie, WI	none	1160	1160	2	580
		WESTERN U.S.A.			
Cholla, AZ	114	850	964	3	283
Coronado, AZ	none	1050	1050	3	350
Comanche, CO	350	340	690	1	340
Craig, CO	none	1070	1070	4	268
Colstrip, MT	none	2060	2060	4	515
Reid Gardner, NV	227	234	461	2	117
San Juan, NM	none	1258	1258	3	419
Boardman, OR	none	500	500	1	500
Emery, UT	none	830	830	2	415
Huntington Canyon, UT	none	830	830	2	415
Kaiparowits, UT	none	3000	3000	4	750
Warner Valley, UT	none	500	500	2	250
Naughton, WY	707	830	1537	2	415
Wyodak, WY	none	330	330	1	330

A.2.1 Mean (Average) Statistics

Of the 74 sites identified in Table A.1, 34 are new, while 40 represent the addition of generation to existing capacity. Tables A.2(a), (b), and (c) present the mean (average) statistics for these data, based on new sites only, previously existing sites only, and all 74 data, respectively. Although these tables show results by region, the number of data are sufficient for meaningful regional interpretation only for Table A.2(c).

The average capacity of a new site is 1205 MWe (Table A.2(a)), while the average capacity addition to an existing site is only 689 MWe (Table A.2(b)). However, the average capacity of existing sites *including the new additions* is 1394 MWe (Table A.2(b)). It is clear that new sites do not initially carry the full capacity ultimately planned for the site based on long term demand growth, site size, cooling water availability, etc. Similarly, it is certain that at least some of the 40 existing sites now adding capacity will grow somewhat larger in the years beyond 1983, i.e. they are not yet being developed to full capacity. Thus the figures contained in Tables A.2(a) and (b) must be regarded as conservative estimates of mean site capacities for coal-fired facilities.

Of the grand total of 68,546 MWe (Table A.2(c)) planned between now and 1983, 40,978 MWe (60%) constitute new sites made up of 75 units of 546 MWe average size (Table A.2(a)). The remaining 27,568 MWe are in the form of capacity additions spread amongst 57 new units averaging 484 MWe each; thus a new unit planned as a capacity addition tends to be about 60 MWe smaller than one intended for a new site.

Looking at Table A.2(c) from a regional perspective, by far most of the new capacity is planned for the Midwest (40,732 MWe), but then most of the previously existing capacity is in the Midwest also. Perhaps most startling is the ratio of new capacity to previously existing for the 74 data: 1.8 for the East, 2.2 for the Midwest, and 9.8 for the West. This must, however, be kept in the perspective of noting that, of the 14 Western sites, only 4 are expansions. It is more noteworthy that the average site capacity as tabulated in Table A.2(c) is much larger in the East (1703 MWe) than in either the Midwest (1266 MWe) or West (1077 MWe).

Table A.2(a)

Mean (Average) Statistics for New Sites Only

Region	Number of New Sites	Total New Capacity (MWe)	Average New Capacity (MWe)	Number of New Units	Average New Unit Size (MWe)
East	6	9,001	1500	13	692
Midwest	18	20,549	1142	37	555
West	10	11,428	1143	25	457
TOTAL U.S.	34	40,978		75	
AVERAGE U.S.			1205		546

Table A.2(b)

Mean (Average) Statistics for Previously Existing Sites Only

Region	Number of Existing Sites	Total Previous Capacity (MWe)	Total New Capacity (MWe)	Grand Total Capacity (MWe)	Average Total Capacity (MWe)	Average New Capacity (MWe)	Number of New Units	Average New Unit Size (MWe)
East	7	8,011	5,131	13,142	1,877	733	8	641
Midwest	29	18,764	20,183	38,947	1,343	696	41	492
West	4	1,398	2,254	3,652	913	564	8	282
TOTAL U.S.	40	28,173	27,568	55,741			57	
AVERAGE U.S.					1,394	689		484

Table A.2(c)

Mean (Average) Statistics for the Entire Data Base

Region	Total Number of Sites	Total Previous Capacity (MWe)	Total New Capacity (MWe)	Grand Total Capacity (MWe)	Average Site Capacity (MWe)	Number of New Units	Average New Unit Size (MWe)
East	13	8,011	14,132	22,143	1,703	21	673
Midwest	47	18,764	40,732	59,496	1,266	78	522
West	14	1,398	13,682	15,080	1,077	33	415
TOTAL U.S.	74	28,173	68,546	96,719		132	
AVERAGE U.S.					1,307		519

A.2.2 Median Statistics

Medians* have been calculated corresponding to the averages (means) noted in Sections A.1 and A.2.1, and are provided in Table A.3. It is interesting that the differences between the means and the medians are usually quite small; only in the "entire data base (existing generation included)" does it succeed 100 MWe. Given the sizes of the data bases available, these differences would lead one to conclude that the odd large facility, or similarly the uncommonly small capacity addition, does not occur to a degree that detracts from the usefulness of the means (averages); i.e., the means are reasonably useful for analysis purposes. Moreover, the median can not be reliably calculated regionally, because of the paucity of data, except for Table A.2(c); for example, in Table A.2(a), "East" has only 6 sites. The median also can not be calculated for generating *units* because, although Table A.1 lists the numbers of units, there is no information on the size of the individual units, and we have no basis for assuming that all units stated for a site (if more than one) are of the same size.

A.2.2.1 Median Statistics for the Entire Data Base:

It was noted above that median values could be calculated regionally for the entire data base, as were the means in Table A.2(c). These results, based on the 34 new sites plus the 40 existing sites, including previous generation, are contained in Table A.4.

On the basis of the median value 37 (or half) of the 74 sites are greater in size than 1180 MWe, when previously existing generation is included. We may similarly determine the number of sites, of the 74 in the sample, which exceed any pre-selected size, as noted below:

49 sites exceed	1000 MWe	
37	1180	(Median)
26	1500	
11	2000	
5	2500	
3	3000	

---

* The median is defined as the middle value of a set of values arranged in order of magnitude.

Table A.3

Median and Mean Statistics Compared

Data Base	Mean (MWe)	Median (MWe)
All new generating capacity (existing generation excluded); 74 statistics:	926[1]	830[†]
New sites only; 34 statistics:	1205[2]	1110
Previously existing sites (new + existing generation); 40 statistics:	1394[3]	1348[∞]
Previously existing sites (new generation only); 40 statistics:	689[3]	645[*]
Entire data base (existing generation included); 74 statistics:	1307[4]	1180

[1] From Section A.1.

[2] From Table A.2(a).

[3] From Table A.2(b).

[4] From Table A.2(c).

[†] This value is the basis for the set of buffer zone maps which corresponds to the original 1000 MWe - equivalent analyses contained in the previous reports. (See Section 2.1.2.)

[∞] This value is the basis for the set of buffer zone maps which corresponds to *sites* as opposed to existing capacity. (See Section 2.1.3.)

[*] This value is the basis for the set of buffer zone maps which corresponds to new additions to existing capacity. (See Section 2.1.1.)

Table A.4

Median and Mean Statistics for the Entire Data Base

Region	Number of Sites [1]	Total Site Capacity Mean (MWe)[1]	Total Site Capacity Median (MWe)
East	13	1703	1687
Midwest	47	1266	1200
West	14	1077	897
TOTAL U.S.:	74		
MEAN U.S.:		1307	
MEDIAN U.S.:			1180[2]

[1] From Table A.2(c).

[2] See also last entry, Table A.3.

It is thus quite clear that large sites, say 2000 MWe or more, are not uncommon, and the significant deterioration provisions would affect these to a proportionally greater extent than indicated in Section 3 of this report.

Volume I: Executive Summary

An Analysis of the Impact on the Electric Utility Industry of Alternative Approaches to Significant Deterioration

by

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PREFACE

This report was prepared jointly by the the Environmental Protection Agency (EPA) and the Federal Energy Administration (FEA). EPA and FEA gratefully acknowledge the assistance and support of the U. S. Geological Survey of the Department of Interior, which compiled and printed the maps contained herein.

Neither the cartographic information, nor the contents of this report, necessarily reflect the views or policies of either the U. S. Geological Survey or the Department of Interior.

This report was prepared in two parts. Volume II, Technical Support Document, is available upon request from the Public Affairs Office of either EPA or FEA. Also available upon request are large (19" x 28") versions of the maps enclosed herein and contained in the Technical Support Document.

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Volume I: EXECUTIVE SUMMARY

I. INTRODUCTION AND CONCLUSIONS

A. Introduction

In 1972, the Sierra Club and other environmental groups filed suit against EPA for failure to promulgate regulations under the Clean Air Act to prevent the significant deterioration of air quality. Both the District Court of the District of Columbia and the U.S. Court of Appeals for the District of Columbia Circuit granted the Sierra Club's motion and required EPA to promulgate significant deterioration regulations. In June 1973, the Supreme Court, by a four-to-four vote, affirmed the judgment of the Court of Appeals.

After extensive public participation and technical and economic analyses, EPA published final regulations in December 1974 [1/], which are based on allowable increments of pollutant concentrations for specific categories of new major industrial sources under an area classification procedure. Subsequently, the Administration, as part of the Energy Independence Act of 1975, requested Congress to consider legislation which would clarify Congressional intent on the prevention of significant deterioration of air quality. The Administration requested that Congress carefully examine the potential effects of a significant deterioration policy, including the consideration of its complete elimination as well as other alternative approaches. In addition, Congress was asked to provide explicit guidance that would allow a balancing of environmental, economic, and energy concerns in any legislative determination of the significant deterioration issue.

In the course of debate on the significant deterioration issue, both the Senate and House subcommittees have proposed plans [2/] which, although similar in many respects to EPA's promulgated regulations, appear to have different impacts, especially on new coal-fired power plants.

This report has been jointly prepared by the Environmental Protection Agency and the Federal Energy Administration. The analysis investigates the possible impacts of the EPA, Senate, and House significant deterioration

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1/ See Significant Deterioration Regulations Published (40 CFR Part 52); 39 FR 42510; December 16, 1974.

2/ Senate discussion draft of September 8, 1975.
House Discussion draft of June 16, 1975, as amended by Congressman Heinz's Amendments on September 4, 1975.

approaches on the electric utility industry. It should be noted that this paper does not address: (1) the impact of alternative significant deterioration proposals on other industrial facilities such as petroleum refineries, synthetic fuel plants, steel mills, and non-ferrous smelters; and (2) the economic/energy costs and benefits that would result from preventing the degradation of air quality up to the national secondary ambient air quality standards.

The analysis is preliminary, but nonetheless, indicative of the range of impacts that could result from alternative significant deterioration approaches.

B. Conclusions

The major conclusions of the study are:

- The aggregate impact of the Senate and House significant deterioration proposals would not prevent the construction of new coal-fired power plants. However, the Congressional proposals would require most new coal-fired plants to either meet emission limitations more stringent than Federal New Source Performance Standards (NSPS), construct taller stacks, build smaller plants and/or relocate at alternative sites.1/2/

- The number of Federal land areas that are designated Class I, as compared to the Class II and III requirements has the greatest impact on (1) the siting and size of new coal-fired power plants,and (2) the level of pollution control required for new coal-fired plants. This results from the fact that new coal-fired plants must be located at a sufficent distance from the Class I area in order to prevent the plant's emissions from violating the Class I increment.

- The impact of the Class I increment is not uniform by geographical area. In addition, the areas impacted by Class I designations may affect the availability of water resources (inland or coastal) that will be needed for power plant cooling.

1/ It was not possible to estimate the aggregate impact of EPA's significant deterioration regulations because the decision to maintain the Class II designation or redesignate to Class I or III is at the discretion of State and local authorities.

2/ Note, however, the Senate proposal independently requires the use of best available control technology (BACT) on a case-by-case basis which in many instances may require a power plant to meet emission limitations more stringent than NSPS.

- A 1000 MW coal-fired power plant meeting NSPS could be built in areas of flat terrain (i.e., surrounding terrain at or below the top of the plant's stack) under the EPA/Senate and House Class II increments.

- In areas of non-flat terrain, a 1000 MW plant meeting NSPS could not comply with the EPA/Senate Class II increment if surrounding terrain within 15 miles is at least 500 feet above the top of the plant's stack. If a plant controls beyond NSPS by the use of low sulfur coal and a scrubber, a plant could comply with the EPA/Senate Class II increment unless the surrounding terrain within 3 miles was at least 500 feet above the top of the plant's stack. It should be noted, however, that a 1000 MW plant located in areas of non-flat terrain would, in certain circumstances, be unable to comply with national ambient air quality standards.

- The House Class II increment is more restrictive than the EPA/Senate Class II increment on the siting and size of new coal-fired power plants because the House 3-hour limit for sulfur dioxide is approximately 50% of the EPA/Senate increment.

- Increasing the allowable stack height from 500 to 1000 feet and/or meeting emission limitations more stringent than NSPS significantly reduces the probability that a plant may be affected by Class II increments in areas of non-flat terrain.

- The ability to redesignate a Class II area to a Class III area (i.e., as in the House and EPA proposals) provides the flexibility to allow the siting of large coal-fired plants in areas of non-flat terrain. However, since the House Class III increment is approximately 50% of the EPA Class III increment, there is less flexibility under the House proposal.

II. ALTERNATIVE SIGNIFICANT DETERIORATION APPROACHES

The general approach to "significant deterioration" taken by EPA and by the Congressional Subcommittees is similar, although numeric limits and coverage vary considerably. In all cases, significant deterioration is prevented by establishing a specified pollution increment in terms of ambient air quality concentrations which may not be exceeded by any major new source of combination of major new sources. In addition, each plan calls for the establishment of area classifications designed to correspond to the overall land use intended for the area, and to reflect the amount of energy or industrial growth desired. These "classes" were established by the EPA regulations as follows:

- Class I - Applies to areas in which practically any air quality deterioration would be considered significant, thus allowing little or no major energy or industrial development.

- Class II- Applies to areas in which deterioration that would normally accompany moderate, well-controlled growth would not be considered significant.

- Class III-Applies to areas in which deterioration would be permitted to allow concentrated or very large scale energy or industrial development, as long as the national secondary ambient air quality standards are not exceeded.

A critical aspect of the EPA regulations is that all regions are initially designated as Class II, subject to redesignation as Class I or Class III by initiative at the State and local level. EPA anticipated that Class I designations would be made to protect existing clean air resources in areas such as national parks and wilderness areas, and the Class III redesignations would occur where State or local policies called for extensive industrial development, requiring incremental air quality increases up to the national ambient air quality standards. To date, no known formal application has been made by communities, States or Federal land managers to reclassify regions to the Class I or Class III designations.

As indicated in Table 1, the Senate numerical limits for Class I and II areas are the same as EPA's. However, the Senate approach has several substantial differences:

TABLE 1: ALLOWABLE AIR QUALITY INCREMENTS UNDER ALTERNATIVE SIGNIFICANT DETERIORATION PROPOSALS
(ug/m^3)

Pollutant Standard	CLASS I EPA Regs.	CLASS I Senate Proposal	CLASS I House Proposal 1/	CLASS II EPA Regs.	CLASS II Senate Proposal	CLASS II House Proposal 1/	CLASS III EPA Regs. 2/	CLASS III Senate Proposal	CLASS III House Proposal
Sulfur Dioxide									
Annual	2	2	1.6	15	15	20	80	No Class III	40
24-hour	5	5	7.3	100	100	91	365		183
3-hour	25	25	26	700	700	325	1300		650
Total Suspended Particulates									
Annual	5	5	7.5	10	10	19	75	No Class III	38
24-hour	10	10	15	30	30	38	150		75

1/ The increments for the House proposal are based on limitations of 2% of NAAQS for Class I, 25% for Class II, and 50% for Class III, except that the limit for total suspended particulates in Class I is 10% of NAAQS. In addition, the House proposal stipulates that the concentration of all pollutants cannot exceed 75% of the national ambient air quality standards in any of the classes.

2/ EPA's Class III allows degradation up to the NAAQS:

	Sulfur Dioxide	TSP
Annual	80 (primary)	75 (primary)
24-hour*	365 (primary)	150* (secondary)
3-hour*	1300 (secondary)	

* The 24-hour and 3-hour standards are not to be exceeded more than once per year. There are no primary 3-hour standards for sulfur dioxide and particulates, nor is there a 24-hour primary standard for particulates.

- The Senate version eliminates Class III designations.
- The Senate requires the designation of some areas of national importance as mandatory Class I and other areas as Class I unless they are redesignated by agreement between the States and the Federal government. (See Table 2).

The House also adopts the EPA approach but contains the following differences:

- The House has more mandatory Class I designations than the Senate (see Table 2).
- The House, like EPA, has a Class III but the allowed increment is half EPA's increment. In addition, a general air quality ceiling of three-fourths of the national ambient air quality standards is imposed.
- The House version includes different numerical limits for the Class I and II increments, but the only significant difference is that the three-hour sulfur dioxide Class II increment is less than half of the EPA and Senate Class II increments (see Table 1).

The other important differences among the proposals are summarized in Table 3. One of these is related to the control technology a new power plant must install regardless of the applicable air quality increment. While EPA's significant deterioration regulations require compliance with New Source Performance Standards (NSPS) or State regulations where they are more stringent than NSPS, the Senate requires the maximum degree of control technology achievable as determined on a case-by-case basis. The Senate proposal may, therefore, require installation of flue gas desulfurization systems (i.e., scrubbers) with low sulfur coal, whereas EPA's significant deterioration regulations do not unless it is required by State law or necessary to meet the applicable air quality increments.

Another important difference is that the House version provides for limitations on the allowable stack height for new power plants.

TABLE 2

CLASS I AREAS UNDER SENATE AND HOUSE APPROACHES
TO SIGNIFICANT DETERIORATION

Land Category	Senate	House
· International Parks (if 1,000+ acres)	Mandatory Class I	Mandatory Class I
· National Parks (if 1,000+ acres)	Mandatory Class I	Mandatory Class I
· National Wilderness Areas (if 1,000+ acres)	Mandatory Class I	Mandatory Class I
· National Wildlife Refuges (if 1,000+ acres)	Mandatory Class I	Mandatory Class I
· National Monuments	Class I; Provision for redesignation as Class II	Mandatory Class I (if 1,000+ acres)
· National Preserves	Class II;Provision for redesignation as Class I	Mandatory Class I (if 1,000+ acres)
· National Recreational Areas	Class I; Provision for redesignation as Class II	Class II; Provision for redesignation as Class I or Class III
· Wild and Scenic Rivers	Class I; Provision for redesignation as Class II	Class II; Provision for redesignation as Class I
· National Lakeshores and Seashores	Class I; Provision for redesignation as Class II	Class II; Provision for redesignation as Class I
· National Forests	Class II;Provision for redesignation as Class I	Class II; Provision for redesignation as Class I
· Military Reservations	Class II;Provision for redesignation as Class I	Class II; Provision for redesignation as Class I or Class III
· Other Federal Lands	Class II;Provision for redesignation as Class I	Class II; Provision for redesignation as Class I or Class III

TABLE 3

SUMMARY OF MAJOR DIFFERENCES OF ALTERNATIVE APPROACHES TO SIGNIFICANT DETERIORATION

Issues	EPA	House	Senate
Sources Covered	18 source categories	Any facility emitting more than 100 tons/yr. of any regulated pollutant	Major emitting facility
Pollutants Covered	TSP and SO_2	All	TSP, SO_2, others to be established later
Control Technology Requirements	Equivalent to NSPS where NSPS exist; and determined on a case-by-case basis where NSPS does not exist	None specified	Maximum degree of emission control possible; determined on a case-by-case basis
Class I Areas	No mandatory (at state and Federal discretion with procedures for full public participation)	Designation of some areas as mandatory Class I and others as either Class I, II or III (see Table 2)	Designation of some areas as mandatory Class I and others as either Class I or Class II (see Table 2)
Class III Areas	Procedures for designation of areas as Class III	Procedures for designation of areas as Class III	No Provision for Class III
Numeric Limitations for Class I,II & III	See Table 1	See Table 1	See Table 1
Maximum Allowed Concentration	National Ambient Air Quality Standards Standards (NAAQS)	Three-fourths of National Ambient Air Quality Standards	National Ambient Air Quality Standards

III. ISSUES EVALUATED

A number of issues have been raised as a result of the recent legislative proposals that have been proposed by the Congress. The issues addressed in this analysis are as follows:

Issue #1: Aggregate Impact of Significant Deterioration Requirements on New Coal-Fired Power Plants

The first critical issue is the potential impact of Class I, II and III significant deterioration requirements on (1) the siting and size of new coal-fired plants and (2) the pollution control technology required for new coal-fired plants. It should be noted that the issue is not whether or not new coal-fired plants can be built, but rather what degree of emission control would be required and what restrictions would be placed on the location and size of new coal-fired plants. Therefore, the public policy issue is: the balancing of the economic, energy and related environmental consequences of alternative significant deterioration proposals against the benefits that would result from preventing the degradation of air quality up to the secondary ambient air quality standards.

Issue #2: Implications of Class I Area Designations

The designation of Class I areas is an issue because of the attendant areas of the country where power plant development may be affected. Class I areas have a significance beyond their geographic limits because the air quality increments that must be met within such areas can be violated, under certain circumstances, by large coal-fired power plants located some distance from a Class I area. The distance may range from less than 10 miles or up to 100 miles depending upon such factors as: plant size; the degree of emission control; neighboring terrain; and meteorological conditions. Therefore, the actual impact of Class I area designations on the siting and size of new power plants would affect an area much larger than the designated Class I area itself.

Issue #3: Impact of Alternative Class II Increments

Alternative Class II increments are an issue because of the resulting impact on plant size, location and required degree of emission control. Of particular importance is the impact of Class II increment on plants sited in areas of non-flat terrain.

Issue #4: Implications of Stack Height Limitations

Allowable stack height is important because a taller stack permits more diffusion of a power plant's emissions. Accordingly, restrictions by the Class II increment on the siting of power plants in areas of non-flat terrain could be minimized by the construction of taller stacks. Thus, for any assumed level of emission control, the use of taller stacks would allow the siting of larger plants. However, it should be noted that the use of tall stacks will result in greater emissions as compared to the use of scrubbers.

Issue #5: Minimum Degree of Emission Control

The last critical issue addressed in this report is the minimum degree of emission control required for new plants (i.e., the definition of best available control technology--BACT). The most restrictive limitation would be to require all plants to meet emission limitations more stringent than Federal New Source Performance Standards (NSPS) through the installation of flue gas desulfurization systems (i.e., scrubbers). The least restrictive limitation would be to require all new plants to meet NSPS or State regulations where they are more stringent than NSPS and allow the plant to choose the most cost-effective means of compliance (i.e., low sulfur coal or scrubbers) with the deterioration increments. It should be noted, however, that under either minimum requirement, new power plants would have to install whatever control technology that was required in order to comply with the applicable air quality increment (i.e., Class I, II, or III). Thus, the determination of the minimum level of emission control is only a relevant issue where more stringent emission controls than necessary to meet the applicable significant deterioration increments would be required.

IV. STUDY METHODOLOGY

The approach taken herein has been to quantitatively assess, under two analytical approaches, the incremental impacts that could result from the application of alternative significant deterioration requirements on the electric utility industry.

A. Cartographic Analysis

In the first approach, cartographic procedures were utilized to identify the potential Class I areas and to graphically depict land areas that may, under various assumptions concerning the level of pollution control, be precluded from the siting of generic 1000 MW power plants. Lands, under the Congressional proposals, that shall or may be designated as Class I have been identified in this report as follows:

- Mandatory Class I: Federal lands legislatively determined to be Class I.
- Discretionary Class I: Federal lands that under the Senate proposal are designated as Class I but may be redesignated as Class II; under the House proposal, lands that are designated Class II but may be redesignated as Class I.
- Possible Class I: Federal lands that under the Senate proposal are designated as Class II but may be redesignated to Class I; under the House proposal, the lands that are designated as Class II but may be redesignated as either Class I or Class III.

The mandatory and discretionary Class I areas as defined by the Senate and House significant deterioration proposals are depicted in Figures 1 and 2.

B. Analysis of Planned Coal Burning Power Plants

In the second approach, a sample of 74 new coal burning power plants representing a total new capacity of 67,000 megawatts was analyzed in order to estimate the expected impact of alternative significant deterioration proposals. The sample of plants was selected from a population of 116,000 megawatts of new coal fired capacity scheduled to be built between 1975 and 1983. The unavailability of data on location, size, and other factors prevented the analysis of a larger sample. However, the coverage and capacity by geographic region is highly significant

Figure 1: ALL MANDATORY AND DISCRETIONARY
CLASS I AREAS AS DEFINED BY SENATE PROPOSAL

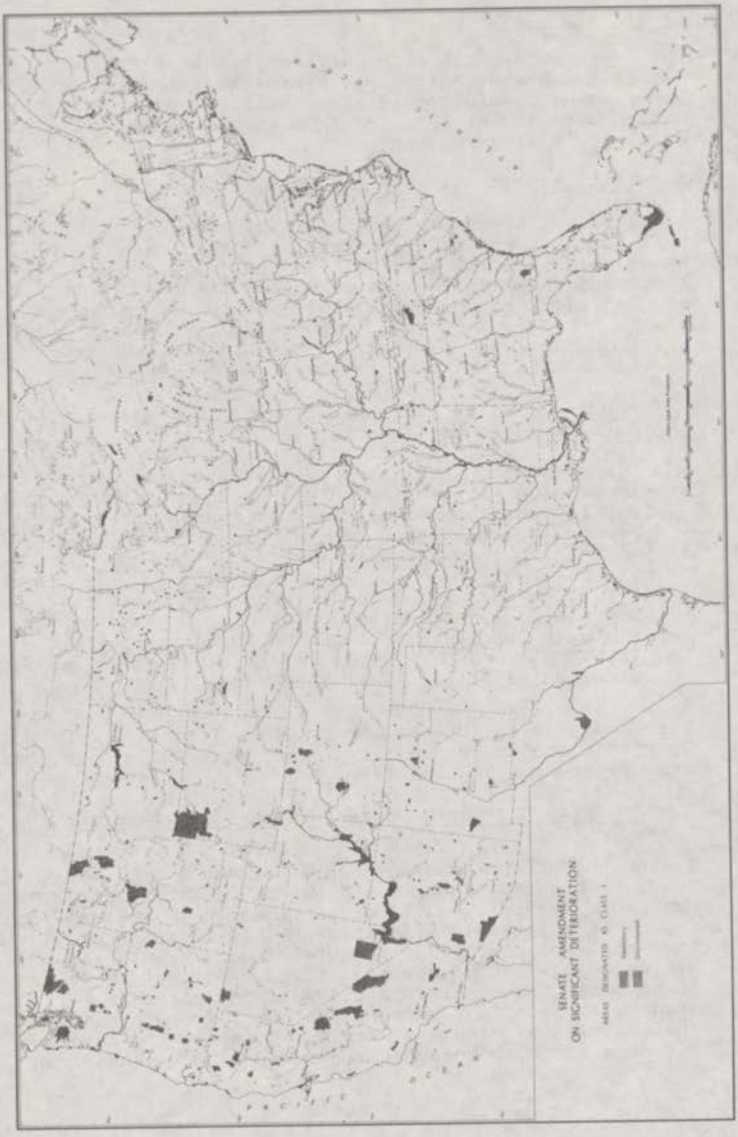

Figure 2: ALL MANDATORY AND DISCRETIONARY
CLASS I AREAS AS DEFINED BY HOUSE PROPOSAL

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in that data represents 74 percent of planned plant capacity in the East, 52 percent in the midcontinent, and 63 percent in the West. In addition, the plants range in size from 80 to 3,000 megawatts. The location of the 74 plants are shown in Figure 3.

While most of the plants that were studied would not be affected by any significant deterioration requirements because most of the plants commenced construction before the effective date of the regulation, it is believed that the results of this analysis are indicative of the likely impact of alternative significant deterioration proposals on the electric utility industry, if the siting decisions remain static. That is, the analysis assumes that there will be no major changes in the geographic distribution and size of new power plants. It is possible that changes in the geographic distribution and size of new power plants would mitigate many of the impacts quantified in this analysis.

It should be noted that the analysis did not address the economic and energy impacts and associated air quality benefits of changes in the geographic distribution of power plants and/or other control measures (i.e., increased stack height, further control of sulfur dioxide emissions, etc.). However, such analyses are appropriate subjects for further study.

In the absence of an economic cost and air quality benefit analysis that would evaluate the implications of alternative significant deterioration requirements, two indicators of impact have been used to quantify the implications. The two indicators are:

- land area that may be affected, and
- projected power plant capacity that may be affected.

For the purpose of the analysis, "affected" land area or "affected" power plant capacity describes the impact of applicable significant deterioration proposals for any particular set of assumptions concerning the degree of emission control, stack height, and plant size. Furthermore, "affected" land or capacity does not mean that power plant development would be precluded but rather that additional emission control measures would be needed before construction would be permitted.

Figure 3: ALL MANDATORY AND DISCRETIONARY CLASS I AREAS AS DEFINED BY SENATE PROPOSAL, WITH LOCATIONS OF SAMPLE POWER PLANTS

c. Scenarios Studied

The impact of alternative significant deterioration proposals is conveyed herein by the examination of two scenarios that show the range of expected impacts on land area and planned capacity. The two scenarios are:

° High Affected Scenario[1/] This scenario conveys the maximum land area and planned power plant capacity that may be affected.[2/] The scenario assumes:

-- All plants as a minimum meet Federal New Source Performance Standards (NSPS)
-- All discretionary Class I areas are designated Class I (none are redesignated Class II) and all possible Class I areas are designated Class II
-- Allowable stack height is 500 feet
-- All plants must meet both the Class I and II increments (i.e., no Class III)

1/ It should be noted that since the Senate proposal requires best available control technology (BACT), to be determined on a case-by-case basis, in many instances new plants will be required to meet emission limitations more stringent than NSPS. Thus, it is not possible to estimate the impact of the Senate proposal under the High Affected Scenario. However, for analytical purposes, the High Affected Scenario contains an estimate of the impact of the Senate mandatory and discretionary Class I areas assuming that BACT is defined as NSPS.

2/ It should be noted that the "possible" Class I areas have not been included in the High Affected Scenario. When mandatory, discretionary and possible Class I areas are designated, 97% of the land area would be affected assuming all plants are required as a minimum to meet NSPS. Only 67% of the land area would be affected if plants are required as a minimum to meet more stringent emission limitations than required by NSPS. The possible Class I areas are not included in the High Affected Scenario because it was considered unlikely that all possible Class I areas would be designared Class I rather than either Class I or III.

- Low Affected Scenario: This scenario conveys the minimum land area and planned power plant capacity that may be affected. The scenario assumes:

  -- All plants as a minimum meet more stringent emission limitations than required by NSPS
  -- All discretionary and possible Class I areas are designated as Class II
  -- Allowable stack height is 1000 feet under the Senate proposal and 500 feet under the House proposal
  -- Some areas may be reclassified as Class III under the House proposal

V. FINDINGS OF THE ANALYSIS

A. Aggregate Impact of the Senate and House Significant Deterioration Requirements on the Electric Utility Industry

The percentage of new coal-fired capacity that may be affected under the High and Low Affected Scenarios is presented in Figure 4. As shown in Figure 4, under the High Affected Scenario, 85% of the capacity may be affected by the House proposal.[1/] Also, under the assumption that Best Available Control Technology (BACT) is defined as Federal New Source Performance Standards (NSPS), 62% of the capacity may be affected by the Senate mandatory and discretionary Class I areas.[2/]

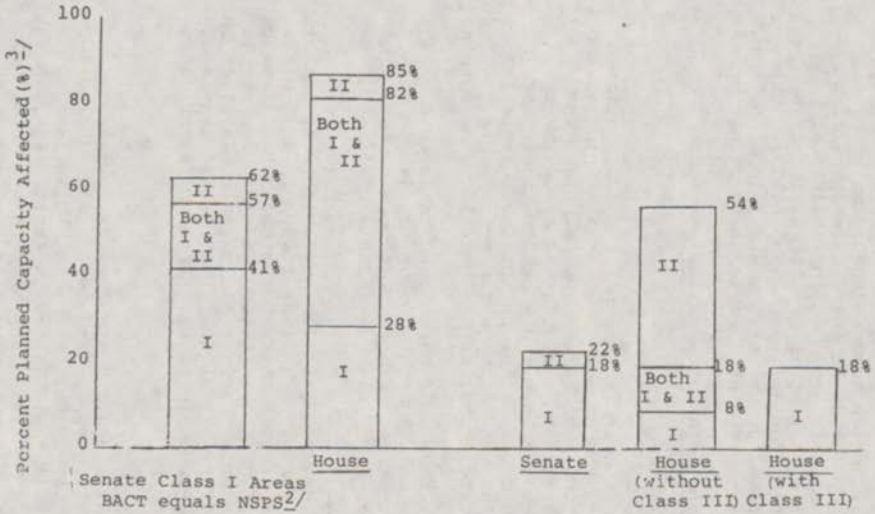
Figure 4 also indicates that if all plants were required at a minimum to meet emission limitations more stringent than NSPS, and if all discretionary and possible Class I areas are designated as Class II (i.e., Low Affected Scenario), the percent of affected capacity under the House proposal would be reduced to 54%. If similar assumptions plus the use of 1000 foot stacks are made for the Senate proposal, 22% of planned capacity would be affected. Finally, if it is further assumed that all Class II areas that restrict plants under the House proposal would be redesignated as Class III, and if background concentrations of sulfur dioxide are assumed to be negligible, the House proposal would only affect 18% of the planned coal-fired capacity.

It can also be concluded from Figure 4 that most of the projected impact under the High Affected Scenario is caused by the designation of Class I areas. For example, 82% of planned capacity under the House proposal would be affected by the mandatory and discretionary Class I provisions.

1/ It is important to note that approximately 16% of the planned capacity under the High Affected Scenario would be constrained by the national ambient air quality standards. However, this capacity would still require additional control in order to comply with the significant deterioration requirements. The cost of the incremental control required can only be properly addressed by an economic analysis.

2/ It should be emphasized that this estimate was made solely for analytical purposes and does not represent the impact of the Senate proposal which defines BACT on a case by case basis and which may in many instances require more stringent control than NSPS.

Figure 4:PLANNED POWER PLANT CAPACITY THAT MAY BE AFFECTED BY THE SENATE AND HOUSE SIGNIFICANT DETERIORATION PROPOSALS[1]



1/It was not possible to quantify the impact of EPA's significant deterioration proposal because the decision to designate Federal lands as Class I areas is at the discretion of State and local governments and/or Federal Land Managers. It should also be noted that affected capacity may be built if additional control measures are employed (i.e., reduced plant size, increased emission control, etc.)

2/This estimate was made solely for analytical purposes and does not represent the impact of the Senate proposal which requires BACT to be determined on a case-by-case basis.

3/I denotes capacity affected only by Class I increments
Both I & II denotes capacity affected by both Class I and Class II increments
II denotes capacity affected only by the Class II increment.

It should be noted that the major impact under the Low Affected Scenario for the House results from the Class II increment (i.e., 46% of a total of 54% of planned capacity). This is caused by the House Class II increment for sulfur dioxide (3-hour increment) which is approximately one-half of the EPA/ Senate Class II increment.

Finally, it should be emphasized that plants which may be affected by the House and Senate significant deterioration proposals could employ additional measures (i.e., relocation at an alternative site, reduced plant size, further control of sulfur dioxide emissions, increased stack height, etc.) in order to comply with the significant deterioration requirements.

B. Implications of Class I Area Designations

1. Land Area Affected

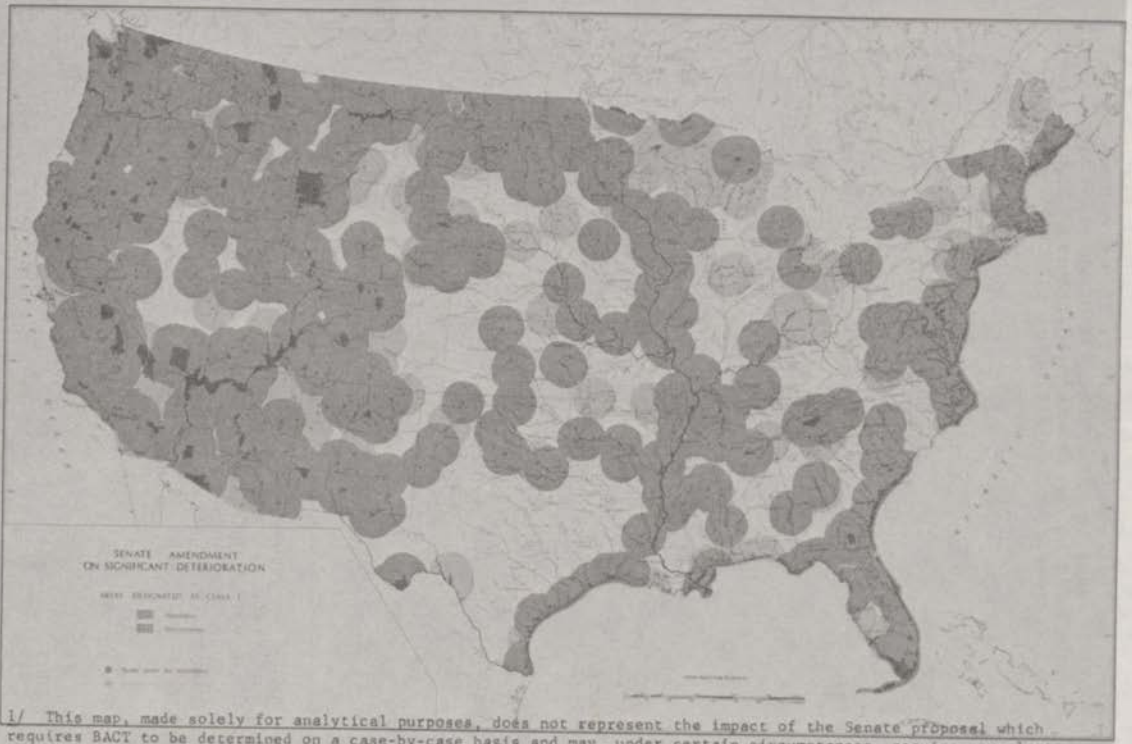
The previous section indicated that the designation of Class I areas has the greatest potential impact on the construction of new coal-fired power plants. The reason why the designation of Class I areas is so important relates to the sizable buffer zones that are necessary in order to insure that pollutants generated by plants located in the vicinity of a Class I area do not violate the Class I air quality increments.

For example, as shown in Figure 5 and in Table 4, 83% of the land area may be precluded by the House mandatory and discretionary Class I areas from the siting of a 1000 MW coal-fired plant meeting NSPS (i.e., High Affected Scenario).1/2/

1/ These estimates assume a 60 mile buffer zone around all mandatory and discretionary Class I areas. This distance was used because accepted meteorological methods indicate that a 1000 MW power plant meeting Federal New Sources Performance Standards (NSPS) could cause a violation in a Class I area as far away as 60 to 100 miles, and is consistent with the preamble to the EPA significant deterioration regulations.

2/ Since there are areas in the country where the sulfur dioxide ambient air quality standard is currently exceeded, the estimates of land area affected provided herein may slightly overstate the likely incremental impact of alternative significant deterioration proposals. However, this overestimate is likely to be minimal for a number of reasons. First, the areas of the country where sulfur dioxide ambient standards are violated are small compared to the estimates of land area affected by the significant deterioration proposals. Secondly, most violations of the sulfure dioxide ambient standard are currently observed in urban areas whereas most new coal-fired power plants are located outside urban areas (see Figure 3 for the location of the 74 coal-fired plants that are planned for the 1975 to 1983 period).

Figure 5: LAND AREAS POSSIBLY PRECLUDED FROM SITING 1000 MW POWER PLANTS, ASSUMING BACT EQUALS NSPS, WITH THE SENATE MANDATORY AND DISCRETIONARY CLASS I AREAS (WITH BUFFER ZONES). 1/



1/ This map, made solely for analytical purposes, does not represent the impact of the Senate proposal which requires BACT to be determined on a case-by-case basis and may, under certain circumstances, require new plants to meet emission limitations more stringent than NSPS.

Also, as indicated in Figure 6, if one assumes that BACT is equal to NSPS, then 75% of the land area may be precluded by the Senate mandatory and discretionary Class I areas from the siting of a 1000 MW power plant. 1/

1/ It should be emphasized that this estimate was made solely for analytical purposes and does not represent the impact of the Senate proposal which requires BACT to be determined on a case-by-case basis and may, under certain circumstances, require new plants to meet emission limitations more stringent than NSPS.

Figure 6: LAND AREAS POSSIBLY PRECLUDED FROM SITING 1000 MW POWER PLANTS, ASSUMING BACT EQUALS NSPS, UNDER THE HOUSE MANDATORY AND DISCRETIONARY CLASS I AREAS (WITH BUFFER ZONES).

Table 4

SUMMARY OF LAND AREA IN WHICH MANDATORY AND DISCRETIONARY REGIONS, WITH BUFFER ZONES, MAY PRECLUDE THE SITING OF A 1000 MW COAL-FIRED PLANT

Percentage of Land Affected

Region[1]	Senate Class I Areas With BACT Equal to NSPS [2][3]	SENATE BACT Equals NSPS/FGD[4]	HOUSE BACT Equals NSPS[2]	HOUSE BACT Equals NSPS/FGD[4]
West	91%	14%	91%	39%
Mid-West	63	24	72	38
East	72	33	85	47
TOTAL U.S.	75%	22%	83%	40%

If control beyond NSPS is assumed, the land area affected by the mandatory and discretionary designations is reduced to 22% and 40% under the Senate and House proposals, respectively (see Figures 7 and 8).

1/ For purposes of this analysis, the Western region is bounded on the east by the eastern boundaries of the states of Montana, Wyoming, Colorado, and New Mexico; and the Eastern region is bounded on the west by the Western boundaries of the states of Pennsylvania, West Virginia, North Carolina, Georgia, and Florida.

2/ NSPS was assumed to be coal with a sulfur content equal to 1.2 pounds sulfur dioxide per million BTU of heat input.

3/ It also should be emphasized that the Senate proposal requires BACT to be determined on a case-by-case basis and in many instances may require new plants to meet more stringent emission limitations than NSPS. Thus, the estimates in Table 4 of the land impacted by the Senate mandatory and discretionary Class I areas assuming all plants meet NSPS were made soley for analytical purposes and do not represent the impact of the Senate proposal.

4/ NSPS/FGD was assumed to be low sulfur coal (NSPS) plus a scrubber in the West and 3.5% sulfur coal plus a scrubber in other areas.

Figure 7: LAND AREAS POSSIBLY PRECLUDED FROM SITING 1000 MW POWER PLANTS, ASSUMING BACT EQUALS NSPS/FGD, WITH THE SENATE MANDATORY AND DISCRETIONARY CLASS I AREAS (WITH BUFFER ZONES).

Figure 8: LAND AREAS POSSIBLY PRECLUDED FROM SITING 1000 MW POWER PLANTS, ASSUMING BACT EQUALS NSPS/FGD, UNDER THE HOUSE MANDATORY AND DISCRETIONARY CLASS I AREAS (WITH BUFFER ZONES).

The impact of designating all discretionary Class I areas as Class II and requiring new plants to meet emission limitations more stringent than NSPS (i.e., Low Affected Scenario) is illustrated in Figures 9 and 10 for the Senate and House proposals respectively. As indicated in Table 5, 16% of the land area under the Senate and 17% of the land area the House proposal may be precluded from the siting of 1000 MW power plants with additional controls.[1/]

Table 5

SUMMARY OF LAND AREA IN WHICH MANDATORY CLASS I REGIONS, WITH BUFFER ZONES, MAY PRECLUDE THE SITING OF A 1000 MW COAL-FIRED PLANT

Percentage of Land Affected

Region	Senate Class I Areas; BACT Equals NSPS[2/]	SENATE BACT Equals NSPS/FGD	HOUSE BACT Equals NSPS	HOUSE BACT Equals NSPS/FGD
West	82%	10%	89%	11%
Mid-West	52	18	54	19
East	57	24	59	24
TOTAL U.S.	65%	16%	68%	17%

If new power plants are as a minimum only required to meet NSPS, the land area affected by the Senate mandatory Class I designation increases to 65%[2/] and the area affected by the House mandatory Class I designation increases to 68% (see Figures 11 and 12).

1/ These estimates assume a 6 mile buffer zone around all Class I areas in the West and a 27 mile buffer zone around Class I areas in the East and mid-West. The buffer zones assume that a 1000 MW plant in the West would use a scrubber in conjunction with low sulfur coal (i.e., control to 10% of NSPS) and plants in all the areas would burn 3.5% coal along with a scrubber (i.e., control to 50% of NSPS). Although this assumption for the East does not take into account the availability of lower sulfur coal or the use of coal washing, the assumption does reflect readily available coal and the assumption of a scrubber achieving 90% removal efficiency with 100% availability.

2/ These estimates were made solely for analytical purposes and do not represent the impact of the Senate proposal.

Figure 9: LAND AREAS POSSIBLY PRECLUDED FROM SITING 1000 MW POWER PLANTS, ASSUMING BACT EQUALS NSPS/FGD, WITH THE SENATE MANDATORY CLASS I AREAS (WITH BUFFER ZONES).

Figure 10: LAND AREAS POSSIBLY PRECLUDED FROM SITING 1000 MW POWER PLANTS, ASSUMING BACT EQUALS NSPS/PGD, UNDER THE HOUSE MANDATORY CLASS I AREAS (WITH BUFFER ZONES).

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Figure 11: LAND AREAS POSSIBLY PRECLUDED FROM SITING 1000 MW POWER PLANTS, ASSUMING BACT EQUALS NSPS, WITH THE SENATE MANDATORY CLASS I AREAS (WITH BUFFER ZONES).

1/ This map, made solely for analytical pusposes, does not repr3sent the impact of the Senate proposal which requires BACT to be determined on a case-by-case basis and may, under certain circumstances, require new plants to meet emission limitations more stringent than NSPS.

Figure 12: LAND AREAS POSSIBLY PRECLUDED FROM SITING 1000 MW POWER PLANTS, ASSUMING BACT EQUALS NSPS, UNDER THE HOUSE MANDATORY CLASS I AREAS (WITH BUFFER ZONES).

It should be noted that the extent of land area affected by the mandatory Class I designations with buffer zones is substantially greater than the land covered by the mandatory Class I areas which is approximately 2% of the continental U.S. land area (see Table 6).

Table 6

LAND AREA COVERED BY THE MANDATORY CLASS I AREAS

	Number of Sites	Area of Land Covered (Million Acres)	% of Continental U.S. Land Area
Senate Version	362	33	1.7%
House Version	414	42	2.2%

Also note in Table 6 that approximately 400 sites are designated as mandatory Class I under the Senate and House proposals. Because of the associated buffer zones, the number of potential Class I designations is the major public policy issue.

It is also important to note that the geographic impacts of mandatory Class I areas on power plant siting is not uniform. For example, under the High Affected Scenario for the House proposal, the impact is mose severe in the West where more than 80% of the land area may be precluded from the siting of a 1000 MW power plant meeting NSPS. On the other hand, the use of low sulfur coal and scrubbers would reduce the affected land area in the West to 10%. By contrast, under the Low Affected Scenario, the impact is most severe in the East where about 25% of the land area may be affected.

Finally, because proximity of a power plant to cooling water is essential for the siting of the facility, an analysis was made of the impact of mandatory and/or discretionary Class I areas on the siting of new plants along the coast or in major water resource regions. As in the preceding analysis, the results varied according to the number of Class I areas included and the degree of pollution control assumed. For example, for the case where all plants meet NSPS as a minimum, mandatory and discretionary Class I areas may preclude about 95% of the coastline from the siting of a 1000 MW power plant. However, if plants are required to meet more stringent emission limitations than NSPS, the percentage of the coastline which may be precluded is roduced to

70% under the Senate proposal and 64% under the House proposal. In addition, if it is assumed that all discretionary Class I areas are redesignated Class II, the percentage of coastline that may be excluded is further reduced to about 50% under both the Senate and House proposals. This number is only reduced to 50% using both the Senate and House mandatory Class I areas because of the significant number of National Wildlife Refuges in these coastal areas, which account for roughly two thirds of the total number of Class I areas specified in the Senate and House proposals.

2. Power Plant Capacity Affected

Since the preceding analysis did not consider the affect of mandatory and discretionary Class I areas on plants larger or smaller than 1000 MW, the impact on a sample of new coal-fired power plants that are planned to be built between 1975 and 1983 was analyzed. In this analysis, a buffer zone was calculated for each power plant in the sample based on the planned plant size and on the degree of pollution control that is assumed. The results using this procedure are presented in Table 7.

Table 7

PLANNED CAPACITY WHICH MAY BE AFFECTED BY MANDATORY AND/OR DISCRETIONARY CLASS I AREAS

Class I Areas	Senate Class I Areas; BACT equals NSPS 1/ 2/	SENATE BACT Equals NSPS/FGD	HOUSE BACT Equals NSPS 2/	HOUSE BACT Equals NSPS/FGD
Mandatory Areas Only	50%	18%	60%	18%
Mandatory and Discretionary Areas	57%	24%	82%	45%

1/ These estimates were made solely for analytical purposes and do not represent the impact of the Senate proposal which requires BACT to be determined on a case-by-case basis and will, therefore, require new plants, in many instances, to meet emission limitations more stringent than NSPS.

2/ It should be noted that if new plants are required as a minimum to meet NSPS, 16% of planned capacity would need to employ additional control measures in order to meet national ambient air quality standards. However, additional control measures would still be needed to meet significant deterioration requirements.

As indicated in Table 7, the percentage of capacity that may be affected by the Class I provisions depends upon the number of areas which are designated Class I and on the degree of pollution control assumed. For example, for the case that all plants are required as a minimum to meet NSPS, the House mandatory and discretionary Class I areas may affect 82% of planned capacity. However, if all new plants are required, as a minimum, to meet emission limitations more stringent than NSPS, the mandatory and discretionary Class I areas may affect only 24% of planned capacity under the Senate proposal and 45% under the House proposal. If it is further assumed that all discretionary Class I areas are redesignated as Class II (i.e., only mandatory Class I areas), the percentage of affected capacity falls to 18% under both the Senate and House proposals.

Finally, it should be emphasized that new coal-fired plants which may be affected by the Class I provisions could employ additional measures (i.e., relocation at an alternative site, reduced plant size, further control of sulfur dioxide emissions, increased stack height, etc.) in order to comply with the House and Senate proposals.

C. Impact of Alternative Class II Increments

1. Size Limitations Imposed by Class II Increments

The actual size of new coal-fired power plants which could be constructed under alternative Class II increments is dependent upon a variety of site specific characteristics. Among these are the size of the plant, the surrounding terrain, meteorological conditions (i.e., prevailing wind directions, inversion layers), the degree of emissions control and the sulfur content of the coal burned. However, for the purposes of this analysis, actual meteorological data from three areas of the U.S. were used to simulate varying meterological conditions around the country. In addition, two different diffusion models were used in order to fully evaluate the effect of terrain on a power plant's size which could meet alternative Class II increments.[1/]

1/ EPA's "CRSTER" model was used to estimate the maximum size plant which could be built for cases where the top of the plant's stack was not higher than the surrounding terrain. EPA's "Valley" model was used to calculate maximum plant size for those cases where the surrounding terrain was at least 500 feet higher than the plant's stack. Detailed explanations of the theory and methodology employed are given in Appendices B and C of Volume II, Technical Support Document.

The results of this analysis indicate that if the surrounding terrain is at or below the top of the plant's stack, both the EPA/Senate and the House Class II increments would allow the siting of a 1000 MW power plant that meets New Source Performance Standards by the use of low sulfur coal.

The analysis also indicates that plants considerably greater than 1000 MW could be built if a scrubber was used in conjunction with low sulfur coal. However, the modeling results show that a 1000 MW power plant burning 3.5% coal and using a 90% efficient (100% reliable) scrubber would not comply with the EPA/Senate and House Class II increments if the surrounding terrain were above the top of the stack. This is due to the decreased plume rise caused by the scrubber, which becomes more significant as nearby terrain approaches the height of the stack.

It should be emphasized, however, that a 1000 MW plant located in such terrain could comply with any of the proposed Class II increments if the stack height were increased by approximately 250 feet, or if coal with a sulfur content of approximately 1.8% was burned in combination with a 90% efficient (100% available) scrubber.

The results of the analysis for the case where the surrounding terrain at or beyond 15 miles is at least 500 feet above the plant's stack indicate that a 1000 MW plant meeting NSPS could meet the EPA/Senate Class II increment but not the House Class II increment.

If the surrounding terrain within 12 miles is at least 500 feet above the plant's stack, then a 1000 MW power plant meeting NSPS would not meet either the EPA/Senate or House Class II increments. However, as in the previous analysis, when control beyond NSPS is assumed, the alternative Class II increments are less restrictive. Specifically, if a scrubber was used with high sulfur coal, a 1000 MW plant could be built under the House Class II increment unless the surrounding terrain within 9 to 12 miles was at least 500 feet higher than the plant's stack. Since the EPA/Senate increment is less restrictive, the dominant terrain feature could be as close as 9 miles. If a scrubber was used with low sulfur coal, a 1000 MW plant could be built under either the EPA/Senate or House Class II increments as long as the terrain within 3 miles was not 500 feet higher than the plant's stack.

Finally, it should be noted that since the House Class II increment for sulfur dioxide is more restrictive than the EPA/Senate Class II increment, larger plants could be built under the EPA/Senate Class II increment. Specifically, depending on local terrain and meteorological conditions, new power plants may be 10% to 100% larger under the EPA/Senate Class II increments than under the House Class II increment.

2. Impact of Class II Increments on Planned Coal-Fired Power Plants

The results of the modeling analysis described in the previous section were used to examine the implications of alternative Class II increments on the sample of 74 new coal-fired power plants. The results of this analysis are presented in Table 8.

TABLE 8

PLANNED CAPACITY WHICH MAY NOT COMPLY WITH ALTERNATIVE CLASS II INCREMENTS[1]

Degree of Pollution Control	EPA	SENATE	HOUSE
-NSPS[2]			
- % of Sample Plants	18%	18% [4]	39%
- % of Sample Capacity	21%	21% [4]	57%
-NSPS/FGD[3]			
- % of Sample Plants	5%	5%	20%
- % of Sample Capacity	10%	10%	47%

1/ Estimates are based on the use of 500 foot stacks

2/ Assumes plants meet NSPS by use of low sulfur coal (1.2 lbs. sulfur dioxide per million BTU heat input).

3/ Assumes plants in the West use a scrubber in conjunction with low sulfur coal (i.e., control to 10% of NSPS), and plants in the East and Mid-west would burn 3.5% coal along with a scrubber (i.e., control to 50% of NSPS). Although this assumption for the East and Mid-west does not take into account the availability of lower sulfur coal or the use of coal washing, the assumption does reflect readily available coal and the assumption of a scrubber achieving 90% removal efficiency with 100% availability.

4/ It should be emphasized that this estimate was made solely for analytical purposes and does not represent the impact of the Senate proposal which requires BACT to be determined on a case-by-case basis and may, under certain circumstances, require new plants to meet emission limitations more stringent than NSPS.

Table 8 indicates that if all plants meet NSPS, about 18% of the plants and 21% of planned capacity may not comply with the EPA/Class II increment. The comparable figures for the House Class II increment are 39% of the plants and 57% of planned capacity. It should be noted that the House Class II increment has more of an impact on new plants because the House's 3-hour increment is only 50% of the EPA/3-hour increment.

Table 8 also indicates that control beyond NSPS will have a greater impact on the number of plants that can comply with the EPA/Class II increment. Specifically, the affected percentage of the sample plants will be reduced to 5% and the percentage of planned capacity to 10%. The comparable figures for the House proposal are 26% of sample plants and 47% of planned capacity. As in the previous example, the differential impact of more stringent pollution control is caused by the House's tighter Class II increment.

It should be noted that the geographic distribution of impacted plants as a result of the Class II increment is not uniform. While the EPA/Class II increment may have a slight impact on eastern and Mid-west plants, assuming New Source Performance Standards are met, approximately 80% of the western plants could be impacted. The House version has a greater impact on the non-western areas possibly impacting one-third of the eastern plantsand one-fourth of those planned for the Mid-west. If plants were required to meet emission limitations more stringent than NSPS, the potential impact under all the proposals on the plants in the East and Mid-west would be negligible. However, even with low sulfur coal and scrubbers, the House or Senate Class II increments may affect the construction of 20% of the planned plants in the West.

3. Limitations Imposed on New Coal-Fired Plants by Class III Increments.

Under the Senate proposal, the plants identified in Table 8 could not comply with significant deterioration regulations unless they employed one or more of the mitigating measures discussed in the previous section. However, under the EPA and House proposals these plants might comply if the area in the vicinity of the plant is redesignated as Class III. The analysis indicates that if all plants met as minimum NSPS, only 16% of planned capacity may not comply with EPA's Class III increment which is equivalent to the national ambient air quality standards. It should be emphasized that

this impact would exist even if there were no significant deterioration requirements. However, the significant deterioration regulations would require these plants to control beyond ambient air quality standards in order to comply with the EPA/Senate Class I or II increments.

It should be noted that an additional 2% (i.e., a total of 18%) of planned capacity would be restricted by the House Class III increment which is 50% of the national ambient air quality standards. It is also important to note, however, that if control beyond NSPS is required, all of the planned capacity could comply with the EPA or the House Class III increments.

D. Implications of Stack Height Requirements

Table 9 illustrates the effectiveness of increasing stack height.

TABLE 9

EFFECTS OF STACK HEIGHT DIFFERENTIALS ON THE NUMBER OF PLANTS WHICH MAY NOT COMPLY WITH ALTERNATIVE CLASS II INCREMENTS[1/]

	ALLOWABLE STACK HEIGHT	
	500' Stack	1000' Stack
EPA/Senate Class II		
- % of Sample Plants	5%	3%
- % Sample Capacity	10%	4%
House Class II		
- % of Sample Plants	26%	14%
- % Sample Capacity	47%	28%

1/ Assumes that BACT requires all plants to meet emission limitations more stringent than NSPS (i.e., 10% of NSPS in the West and 50% of NSPS in the East and Mid-west).

As indicated in the Table 9, increasing the allowable stack height from 500 to 1000 feet will reduce the number of plants affected by the Class II increment. This is because an increase in stack height decreases the possibility of having the plant's plume impact on surrounding terrain.

Specifically, the capacity affected by the EPA/Senate Class II increment is reduced from 10 to 4%. By comparison, the capacity affected by the House Class II increment is reduced from 47 to 28%, which is equivalent to a reduction of 40%. It is worth noting, however, that this potential 40% reduction in affected capacity would not be allowed under the current House proposal due to the proposed stack height limitation of approximately 500 feet.

E. Minimum Level of Emission Control

EPA's regulations require new plants as a minimum to install Best Available Control Technology (BACT) and define BACT as Federal New Source Performance Standards (NSPS) or State requirements where they are more stringent than NSPS. The Senate proposal, however, requires the determination of BACT on a case by case basis which may result in situations where plants are required to meet emission limitations more stringent than NSPS. As was previously discussed, the definition of BACT is only an issue in situations where more emission control may be required than needed to meet the significant deterioration provisions, (i.e., Class I, II, or III increments).

The analysis shows that a definition of BACT as provided in the Senate's proposal[1/] may result in more control than needed to comply with alternative significant deterioration requirements. Specifically, as indicated in Table 10, under the High Affected Scenario, 38% of the planned capacity could comply with the Senate Class I and II requirements by meeting NSPS. Accordingly, the Senate

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1/ This paper assumed that the Senate's definition of BACT would be implemented by the States as follows:

- one-tenth NSPS in the West (i.e., low sulfur coal with a scrubber), and
- one-half NSPS in the East and Midcontinent (i.e., 3.5% sulfur coal with a scrubber).

definition of BACT (i.e., NSPS/FGD) may require 38% of planned capacity to meet more stringent emission limitations than needed to comply with the Senate significant deterioration Class I or Class II increments.

Table 10

PLANNED CAPACITY WHICH MAY BE REQUIRED TO MEET MORE STRINGENT EMISSIONS LIMITATIONS THAN NECESSARY TO MEET THE SENATE AND HOUSE SIGNIFICANT DETERIORATION INCREMENTS

Scenario	Senate Class I Areas; BACT Equals NSPS	SENATE BACT Equals NSPS/FGD	HOUSE BACT Equals NSPS	HOUSE BACT Equals NSPS/FGD
· High Affected Scenario	38%	N/A	15%	N/A
· Low Affected Scenario	N/A	78%	N/A	46-82%

Similarly, Table 10 shows that under the High Affected Scenario, 15% of the planned capacity could comply with the House Class I and II increments by meeting NSPS. Thus, if the House were to adopt the Senate definition of BACT,[1/] 15% of planned cacacity would be required meet more stringent emission limitations than required to comply with the House significant deterioration requirements.

Table 10 also indicates that under the Low Affected Scenario, a maximum of 78% of planned capacity[2/] may be able to comply with the Senate significant deterioration proposal by meeting less stringent emission limitations than required by the Senate definition of BACT (i.e., 10% of NSPS in the West and 50% NSPS in the East and mid-west). Similarly, under the Low Affected Scenario, a maximum of 46 to 82% of planned capacity[1/]

1/ It should be noted that the House proposal,as currently written, does not address the issue of BACT.

2/ An undetermined amount of capacity may have to control exactly to the Senate definition of BACT in order to comply with the Senate or House significant deterioration requirements.

may be able to comply with the House significant deterioration proposals by meeting less stringent emission limitations than would be required if the House adopted the Senate definition of BACT.

Accordingly, as the analysis indicates, the Senate definition of BACT may require a level of emission control that is greater than the level of control necessary to meet significant deterioration requirements. The level of excess emission control depends significantly on the number of Class I areas that may be designated and the allowable stack height. 1/

However, it should be noted that the Senate definition of BACT would result in lower levels of emissions than a definition of BACT which only required new plants as a minimum to meet NSPS. The Senate definition would also allow more flexability for future growth and expansion of other sources in the area surrounding the power plant.

1/ It should be noted that under the High Affected Scenario, allowable stack height for both the Senate and House proposals is 500 feet while under the Low Affected Scenario, allowable stack height for the Senate proposal is 1000 feet.

VI. LIMITATIONS OF THE STUDY

This study was intended to serve as a first effort to estimate the impact of alternative approaches to significant deterioration on the electric utility industry and to identify areas recommended for further detailed analysis. As such, the approach taken herein has certain drawbacks which tend to either overstate or understate the actual impact of alternative significant deterioration policies:

- The analysis is based on a sample of power plants that were planned before the effective date of the significant deterioration requirements. Accordingly, the analysis did not address the feasibility of changing the geographic and size distribution of new power plants based on compliance with alternative significant deterioration requirements.

- The value of preventing the significant deterioration of air quality was not addressed. Although it is difficult to quantify the benefits of preventing air quality from degrading up to the secondary ambient air quality standards, this issue should be addressed in order to fully evaluate the implications of alternative significant deterioration proposals.

- Estimates were not provided of the economic impact of alternative significant deterioration policies on the electric utility industry and on the consumers of electricity. Plants which would be potentially impacted by the significant deterioration regulations could choose between several alternative means of complying with the regulations: relocate at another site with more favorable terrain and meteorological conditions; reduce the planned plant size; reduce sulfur oxide emissions further; and increase the height of the stack. However, due to time limitations it was not possible to quantify the economic impact that would result from the use of these measures. Such an analysis is necessary in order to evaluate the implications of alternative significant deterioration proposals.

- The impact on the generating efficiency of new coal-fired power plants resulting from the possibility of smaller plants, energy penalties associated with scrubber use, alternative site locations and delayed phase-out of old plants has not been assessed. Furthermore, environmental concerns associated with the need to site a greater number of smaller plants, dispose of scrubber by-products and possible resistance to the further designation of Federally protected lands (i.e., potential Class I areas) have not been quantified. Finally, the implications on the development of domestic coal resources and rate of nuclear power plant development needs to be examined.

VII. Recommendations for Further Study

Based on the results of this preliminary assessment of alternative significant deterioration proposals, it appears that additional work would be useful to further refine the analysis. The principal areas of possible future work are summarized below:

1. The economic impact of alternative approaches to significant deterioration on the electric utility industry and on the consumers of electricity should be ascertained. The analysis should include, but not be limited to, an estimation of the cost of the options available to potentially impacted plants;

   - o Alternative siting arrangements
   - o Reduced facility size
   - o Increased sulfur dioxide control
   - o Increased stack height

   Such an analysis should also include an assessment of the benefits that would result from the prevention of significant deterioration of air quality.

2. The analysis should be expanded to include the impact of alternative significant deterioration approaches on other major energy facilities such as:

   - o Petroleum refineries
   - o Synthetic fuel plants (i.e., gasification, liquefaction)
   - o Oil shale facilities

3. The implications of a significant deterioration requirement on national and regional projections for coal and nuclear electric facilities should be explored.

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An Analysis of the Impact on the Electric Utility Industry of Alternative Approaches to Significant Deterioration

Supplement Report 2

General Edition

ANALYSIS OF HOUSE DISCUSSION DRAFT

DATED OCTOBER 16, 1975

by

Environmental Protection Agency

Washington, D.C. 20460

and

Federal Energy Administration

Washington, D.C. 20461

November 1975

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PREFACE

This Supplement Report has been prepared in two versions: a *Congressional Edition*, and a *General Edition*. The *Congressional Edition* is specifically responsive to the wording contained in the legislative proposal identified in the title. The *General Edition* includes the Congressional material, but also addresses the scenario of Environmental Protection Agency regulations now in effect under the Clean Air Act as documented in the original Report Volumes I and II, i.e. the New Source Performance Standards as one of the bases for analyses of alternative approaches to the prevention of significant deterioration of air quality.

The assistance and support of the U.S. Geological Survey of the Department of Interior, which compiled and printed the maps contained herein, is gratefully acknowledged. Neither the cartographic information, nor the contents of this report, necessarily reflect the views or policies of either the U.S. Geological Survey or the Department of Interior.

General Edition

Supplement Report 2

ANALYSIS OF HOUSE DISCUSSION DRAFT
DATED OCTOBER 16, 1975

Introduction

The report prepared jointly by EPA and FEA, An Analysis of the Impact on the Electric Utility Industry of Alternative Approaches to Significant Deterioration, was based on the provisions contained in both the September 8, 1975 discussion draft of the Senate Subcommittee on Environmental Pollution, and the June 16, 1975 discussion draft of the House of Representatives Subcommittee on Health and the Environment as amended on September 4, 1975. The present Supplement Report 2 addresses the House significant deterioration proposal as contained in the House discussion draft of October 16, 1975. The analytic procedures and methodologies described in the original EPA/FEA report remain unchanged.

Provisions of the Rogers/Heinz Amendment

The new amendment restricts Mandatory Class I areas to national parks and wilderness areas exceeding 10,000 acres in size. Wilderness areas, national parks and international parks between 1,000 and 10,000 acres, as well as

national preserves, monuments, recreation areas and primitive areas in excess of 10,000 acres would be Discretionary Class I areas; in the context of the Rogers/Heinz proposal, "Discretionary" would convey Class I Status initially with possible subsequent reclassification to Class II at the discretion of the State. Table 1 indicates the land area categories and number of units included in this analysis.

The Analysis

The results of this analysis are shown in Tables 2, 3, 4, and 5. These Tables are in the same format as Tables 4, 5, 6, and 7, respectively, of the Volume I: Executive Summary report, and show both land areas and power plants which might be affected by the original House proposal as well as those which might be affected by the new Rogers/Heinz amendment. The cartographic information from which these Tables were derived is presented in Figures 1 through 6. These Figures correspond to Figures 2, 3, 12, 6, 10, and 8, respectively, of the Volume I: Executive Summary report.

As can be seen from Tables 2 and 3, the amount of land which may be precluded from the siting of 1,000 MW power plants is significantly reduced under the new amendment. For example, if BACT equals NSPS*, the impact of Mandatory and Discretionary Class I areas in the western United States is reduced from 91% to 69% of the land area, and from 39% to 12% if BACT equals

* Estimates contained herein for the BACT equals NSPS case were made solely for analytical purposes, and do not represent the impact of the House proposal of October 16 which defines BACT such that certain new coal-fired power plants may be required to meet emission limitations more stringent than NSPS.

NSPS/FGD. The impact is even more reduced in the rest of the country. The impacted land area in the East is reduced from 85% to 40% if BACT equals NSPS and from 47% to 15% if BACT equals NSPS/FGD. The comparable reductions for the Mid-West are from 72% to 17% for the NSPS case and from 38% to 6% for the NSPS/FGD case.

Considering Mandatory Class I areas alone, the greatest reductions in the land area which might be affected are in the Mid-West and in the East. In the Mid-West, the land area which might be affected drops from 54% to 9% in the NSPS case, and is only 3% if BACT equals NSPS/FGD. In the East, the land area which might be affected is reduced from 59% to 27% for the NSPS case, and is only 10% if BACT equals NSPS/FGD. The Western United States still has 57% of the land as possibly affected if plants are required as a minimum to meet only NSPS. However, when control beyond NSPS is assumed, the area affected by the new mandatory Class I designation is only 7% in the West.

Table 4 indicates that the actual land area designated Mandatory Class I is reduced to slightly less than half the amount prescribed by the original House proposal, but the number of individual land units identified drops substantially from 414 to 115.

Table 5 provides the amount of actual planned capacity of the sample power plant data base given in Volume I: Executive Summary which might be affected under the Rogers/Heinz amendment. The new House amendment significantly reduces the potential impact on actual power plant siting. Given BACT equal to NSPS, the percentage of planned capacity in the data sample which could be affected by Mandatory Class I areas drops from 60% in the original House proposal to 18% under the new amendment, and with the inclusion of all Mandatory and Discretionary Class I areas the extent of capacity affected is 37% (down from 82% under the original House proposal). Given BACT equal to NSPS/FGD, only 4% of planned capacity is affected by all the Class I areas included in this analysis.

Finally, additional analyses since the release of the original EPA/FEA report now provides the basis for revising somewhat the approach previously used. EPA and FEA have thus initiated a new evaluation of the estimates contained in this report.

Table 1

MANDATORY AND DISCRETIONARY AREAS

Mandatory Class I Areas	Number of Units
National Parks (in excess of 10,000 acres)	32
National Wilderness Areas (in excess of 10,000 acres)	83
	115
Discretionary Class I Areas (Initial Class I Status, with possible reclassification to Class II at the discretion of the State)	
National Wilderness Areas (between 1,000 and 10,000 acres)	23
National Parks (between 1,000 and 10,000 acres)	1
International Parks (in excess of 1,000 acres)	1
National Preserves (in excess of 10,000 acres)	2
National Monuments (in excess of 10,000 acres)	22
National Recreation Areas (in excess of 10,000 acres)	20
National Primitive Areas (in excess of 10,000 acres)	17
	86

Table 2

SUMMARY OF LAND AREA[1] IN WHICH MANDATORY AND DISCRETIONARY REGIONS[1], WITH BUFFER ZONES, MAY PRECLUDE THE SITING OF A 1000 MW COAL-FIRED PLANT

Percentage of Land Affected

Region	HOUSE ORIGINAL PROPOSAL		HOUSE Oct. 16 AMENDMENT	
	BACT Equals NSPS[2]	BACT Equals NSPS/FGD[3]	BACT Equals NSPS[2,4]	BACT Equals NSPS/FGD[3]
West	91%	39%	69%	12%
Mid-West	72	38	17	6
East	85	47	40	15
TOTAL U.S.	83%	40%	41%	10%

[1] Under the Sept. 4 proposal, discretionary areas are initially designated Class II, but at State initiative may be redesignated to Class I. However, under the Oct. 16 proposal, discretionary Class I areas are initially designated as Class I, but may be redesignated to Class II at State initiative.

[2] NSPS is assumed to be coal with a sulfur content equal to 1.2 pounds of sulfur dioxide per million BTU of heat input.

[3] NSPS/FGD is assumed to be low-sulfur content coal (NSPS) plus a scrubber in the West (i.e. 10% of NSPS) and 3.5% sulfur coal plus a scrubber in other areas (i.e. 50% of NSPS).

[4] These estimates, made solely for analytical purposes, do not represent the impact of the House proposal of Oct. 16 which defines BACT such that certain new coal-fired power plants may be required to meet emission limitations more stringent than NSPS.

Table 3

SUMMARY OF LAND AREA IN WHICH MANDATORY CLASS I REGIONS, WITH BUFFER ZONES, MAY PRECLUDE THE SITING OF A 1000 MW COAL-FIRED PLANT

Percentage of Land Affected

Region	HOUSE ORIGINAL PROPOSAL		HOUSE Oct. 16 AMENDMENT	
	BACT Equals NSPS[1]	BACT Equals NSPS/FGD[2]	BACT Equals NSPS[1,3]	BACT Equals NSPS/FGD[2]
West	89%	11%	57%	7%
Mid-West	54	19	9	3
East	59	24	27	10
TOTAL U.S.	68%	17%	31%	6%

[1] NSPS is assumed to be coal with a sulfur content equal to 1.2 pounds of sulfur dioxide per million BTU of heat input.

[2] NSPS/FGD is assumed to be low-sulfur content coal (NSPS) plus a scrubber in the West (i.e. 10% of NSPS) and 3.5% sulfur coal plus a scrubber in other areas (i.e. 50% of NSPS).

[3] These estimates, made solely for analytical purposes, do not represent the impact of the House proposal of Oct. 16 which defines BACT such that certain new coal-fired power plants may be required to meet emission limitations more stringent than NSPS.

Table 4

LAND AREA COVERED BY THE MANDATORY CLASS I AREAS

	Number of Sites	Area of Land Covered (Million Acres)	% of Continental U.S. Land Areas
House Original Proposal	414	42	2.2%
House Oct. 16 Amendment	115	24	1.2%

Table 5

PLANNED CAPACITY WHICH MAY BE AFFECTED BY MANDATORY AND/OR DISCRETIONARY CLASS I AREAS[1]

Class I Areas	HOUSE ORIGINAL PROPOSAL		HOUSE Oct. 16 AMENDMENT	
	BACT Equals NSPS[2]	BACT Equals NSPS/FGD[3]	BACT Equals NSPS[2],[4]	BACT Equals NSPS/FGD[3]
Mandatory Areas Only	60%	18%	18%	4%
Mandatory and Discretionary Areas	82%	45%	37%	4%

[1] Under the Sept. 4 proposal, discretionary areas are initially designated Class II, but at State initiative may be redesignated to Class I. However, under the Oct. 16 proposal, discretionary Class I areas are initially designated as Class I, but may be redesignated to Class II at State initiative.

[2] NSPS is assumed to be coal with a sulfur content equal to 1.2 pounds of sulfur dioxide per million BTU of heat input.

[3] NSPS/FGD is assumed to be low-sulfur content coal (NSPS) plus a scrubber in the West (i.e. 10% of NSPS) and 3.5% sulfur coal plus a scrubber in other areas (i.e. 50% of NSPS).

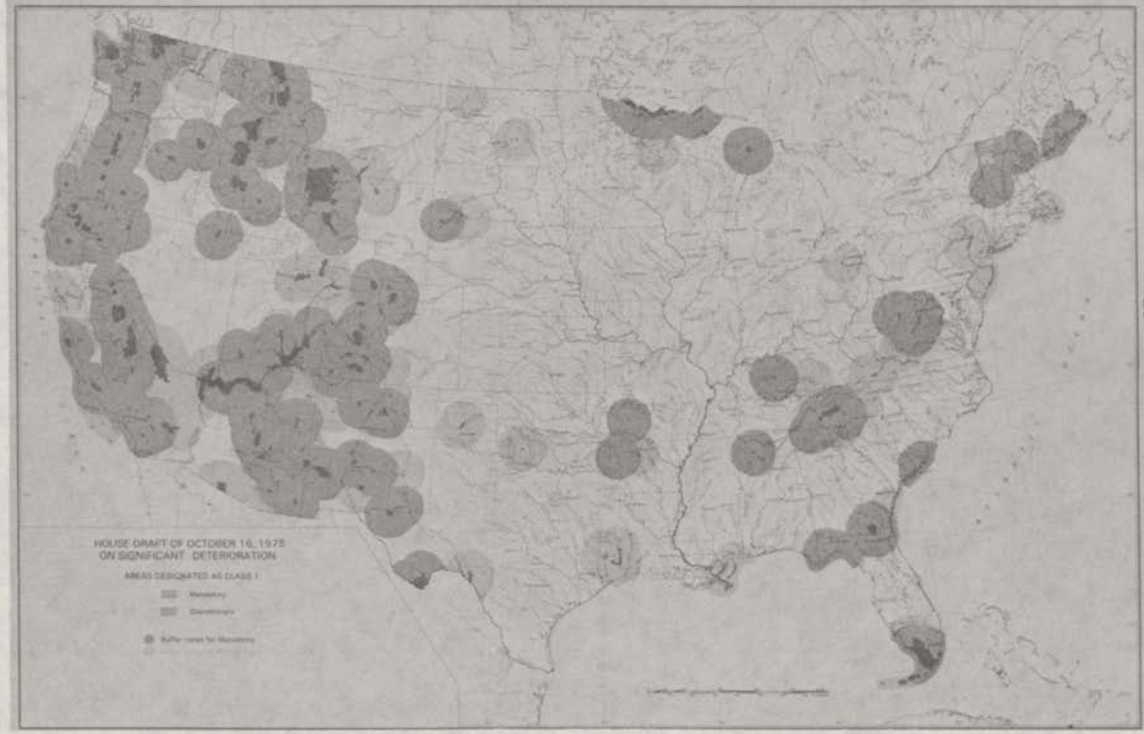
[4] These estimates, made solely for analytical purposes, do not represent the impact of the House proposal of Oct. 16 which defines BACT such that certain new coal-fired power plants may be required to meet emission limitations more stringent than NSPS.

Figure 1: ALL MANDATORY AND DISCRETIONARY CLASS I AREAS AS DEFINED BY HOUSE DISCUSSION DRAFT DATED OCTOBER 16, 1975

Figure 2: ALL MANDATORY AND DISCRETIONARY CLASS I AREAS AS DEFINED BY HOUSE DISCUSSION DRAFT DATED OCTOBER 16, 1975, WITH LOCATIONS OF SAMPLE POWER PLANTS

Figure 3: LAND AREAS POSSIBLY PRECLUDED FROM SITING 1000 MW POWER PLANTS ASSUMING BACT EQUALS NSPS, WITH THE MANDATORY CLASS I AREAS OF THE HOUSE DISCUSSION DRAFT DATED OCTOBER 16, 1975 (WITH BUFFER ZONES)
This map, made solely for analytical purposes, does not represent the impact of the House proposal of October 16 which defines BACT such that certain new coal-fired power plants may be required to meet emission limitations more stringent than NSPS.

Figure 4: LAND AREAS POSSIBLY PRECLUDED FROM SITING 1000 MW POWER PLANTS, ASSUMING BACT EQUALS NSPS, WITH THE MANDATORY AND DISCRETIONARY CLASS I AREAS OF THE HOUSE DISCUSSION DRAFT DATED OCTOBER 16, 1975 (WITH BUFFER ZONES) This map, made solely for analytical purposes, does not represent the impact of the House proposal of October 16 which defines BACT such that certain new coal-fired power plants may be required to meet emission limitations more stringent than NSPS.



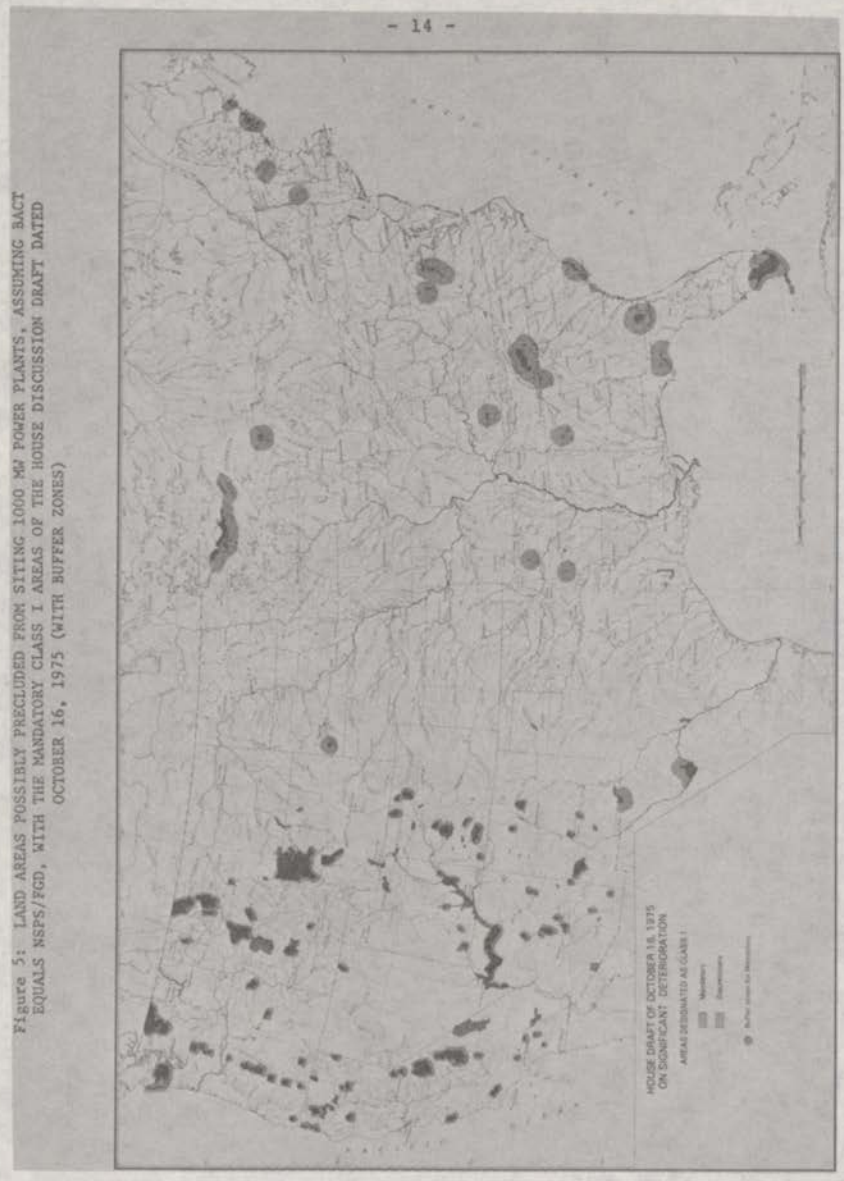


Figure 5: LAND AREAS POSSIBLY PRECLUDED FROM SITING 1000 MW POWER PLANTS, ASSUMING BACT EQUALS NSPS/FGD, WITH THE MANDATORY CLASS I AREAS OF THE HOUSE DISCUSSION DRAFT DATED OCTOBER 16, 1975 (WITH BUFFER ZONES)

Figure 6: LAND AREAS POSSIBLY PRECLUDED FROM SITING 1000 MW POWER PLANTS, ASSUMING BACT EQUALS NSPS/FGD, WITH THE MANDATORY AND DISCRETIONARY CLASS I AREAS OF THE HOUSE DISCUSSION DRAFT DATED OCTOBER 16, 1975 (WITH BUFFER ZONES)

Mr. SHARP. Let me ask you one more question on incremental pricing.

Under the user tax, it goes to the top 2,000 users, as I understand it.

Mr. SCHLESINGER. Yes, sir.

Mr. SHARP. The incremental pricing, does that go to all? I am not sure what universe that is limited to; is that a different universe than the universe of the 2,000?

Mr. SCHLESINGER. Yes, sir.

Mr. SHARP. Broader, more people would be included in that?

Mr. SCHLESINGER. We have sought to avoid the imposition of taxes on small firms, or more precisely, those firms that do not use very large quantities of gas.

Mr. SHARP. That is the user tax, but under the incremental pricing, is that only for those who are using it for boiler fuel purposes, or all industrial sectors?

Mr. SCHLESINGER. The entire industrial sector.

Mr. SHARP. I see.

Thank you, Mr. Chairman.

Mr. DINGELL. The Chair thanks the gentleman.

The time of the gentleman from Indiana has expired.

The Chair recognizes the gentleman from California, Mr. Moorhead, for five minutes.

Mr. MOORHEAD. Thank you.

Dr. Schlesinger, it's good to have you back with us today.

What is your estimate of the total revenue to be raised by the new tax provision of your proposals.

Mr. SCHLESINGER. Which tax provision do you mean?

Mr. MOORHEAD. All of them as a total package.

Mr. SCHLESINGER. It's hard to describe them as a total package. Between now and 1985 the wellhead equalization tax should generate some $72 bilion.

Mr. BROWN. Would you say it again?

Mr. SCHLESINGER. Between now and 1985 the wellhead equalization tax should generate some $72 billion. It would reach a peak of about $14 billion or $15 billion in gross terms. That must be offset against reduced tax from oil and gas firms, so that the net receipts in the peak years will be about $10 billion to $11 billion to the Treasury.

With regard to the gasoline tax, each penny of tax should generate about $1.2 billion, so that if a nickel of that tax is triggered, that would amount to approximately $6 billion.

If the total tax happens to be triggered, that would amount to $60 billion.

Both the wellhead equalization tax, and the gasoline tax would be rebated in their entirety to the public. With regard to the taxes to encourage increased use of coal, I have the net figures here. It would be relatively limited in revenue income for electric utilities and would draw in something on the order of $40 billion for industrial use, because we do not expect industries to make the conversion to coal to the extent that utilities would.

I can supply for the record the annual breakout of those numbers on a gross basis. I have them here on a net basis.

Mr. DINGELL. Without objection, that will be inserted in the record.

[The information requested had not been received at the time the record was closed.]

Mr. MOORHEAD. Dr. Schlesinger, one thing I am concerned about, I think we all understand that the cost of fuels are going to go up, and I don't think it matters which program we are going to adopt. They are going to go up one way or the other, but if we want to increase the available sources of energy that we have and if we want to go into synthetic fuels and if we want to really clean up coal so we can use it in our industries without changing the environment and all of the things that are necessary to do under the present environmental laws, it's going to cost billions and billions of dollars.

It would seem to me that there should be some way to channel this extra cost that is being heaped onto the cost of the energy back into either the new production of gas and oil and discovery and so forth, back to the producer, or into research and development, which the Government could have some control over, so that we won't be dividing scarcity, but we will be encouraging enough energy resources to build our country.

It would seem to me as you slice off any portion of that money that is being added to energy costs, you are taking away from a potentially good result in the end.

I would like your comments on that.

Mr. SCHLESINGER. I think our energy programs will, indeed, be amply funded through the normal budgetary process. We considered the possibiity of the establishment of an energy trust fund or something of that sort for new research. However, I think the heart of this problem, Mr. Moorhead, is the necessity of conveying the need to have prices reflect replacement costs.

That has not been, for a number of reasons, fully appreciated by the entirety of the American citizens. In order to get the acceptance of these higher prices which include a sizable tax component, we must have a credible way of getting that money back to the public. Otherwise, it will not be credible and we will not get those adjustments to reflect replacement cost prices for oil and gas and other fuels.

Mr. MOORHEAD. As these funds are siphoned through the Federal Government, doesn't an awful lot of it get used up in administration costs and building kingdoms within the Federal Government? It's contrary to the basic systems we have had in this country, where it's done through the private enterprise system.

Mr. SCHLESINGER. I think we have ample employment in the Federal Government, and it can be diminished. I don't see this being the source of a building of empires. What we have is a very simple adjustment that will permit a rebate on the income tax to be applied to every citizen in the country.

There will be some other rebates that will be handled in a very simple manner. For example, the direct reduction of fuel oil prices for those who use fuel oil in their homes should not relate to any significant increase in the bureaucracy.

Mr. DINGELL. The time of the gentleman has expired.

The Chair advises there is a vote on the floor at this time on H. Res. 556, which is the rule on the International Development Assistance Act.

That vote commenced at 11:18 a.m. It is the intention of the Chair to sit here and persist, and hope those of my colleagues who go to vote will return punctually and I will go vote when they have done so.

It is the Chairman's intention to recognize the gentleman from Texas, Mr. Collins, who is not here. So we will recogize him later.

The Chair will recognize the gentleman from Tennessee, Mr. Gore. He can use his five minutes and still get over and vote.

Mr. GORE. Thank you, Mr. Chairman.

I wanted to just briefly touch on one point raised by Mr. Moore earlier and that is the question to which you responded that you made a judgmental decision establishing the Btu equivalency at the average domestic price rather than the price of new oil.

If I understand your statement correctly, it's perfectly rational, because you were trying to keep the demand for natural gas higher than the demand for imported oil, which has a much more serious impact on this country. Is that a fair statement of your position?

Mr. SCHLESINGER. That is a partial statement of the position.

It is necessary for us to avoid having natural gas prices so high that we drive industrial users in particular to the use of fuel oil and thus increase demand for oil imports.

Mr. GORE. This Btu equivalency, does it include domestic crude oil transportation costs, and if so, what is the effect of the Alaskan oil going to be on that figure?

Mr. SCHLESINGER. It is at the refinery gate, so it includes transportation costs to the refinery, but not beyond.

Mr. GORE. All right.

Now, on page 8 of your statement you project an addition of 1.1 trillion cubic feet.

Mr. SCHLESINGER. Alaska would be included.

Mr. GORE. It would be included, the transportation cost on the pipeline would be included?

Mr. SCHLESINGER. Alaska is not included, I should correct that. Were it included, of course, it would be included at the refinery gate, and the wellhead price is backed off for Alaska crude oil in proportion to the amount of transportation, which amounts to $6.50 a barrel or thereabouts.

Mr. GORE. It's not going to have an effect of raising up the price under this provision?

Mr. SCHLESINGER. No, sir, it will not.

Mr. GORE. I am glad to hear that. On page 8, as I was saying, you project an additional 1.1 Tcf at a price of $1.75. Do you have any projection on what kind of increased supply would result at the price of $1.50?

Mr. SCHLESINGER. We can provide that for the record.

Mr. GORE. Would it be a comparable figure?

Mr. SCHLESINGER. No, it would be a lesser figure. We are in the range of sensitivity of supply response to price. The problem in the past has been that the FPC pricing has been so low that it has reduced that supply response. We are in the appropriate range at

$1.75. Some might argue $1.85, some might argue $1.65. I think the price you mentioned is probably on the low side.

[The following information was supplied for the record:]

Pursuant to the supply response associated with the answer to the question on page 91, we find no significant supply response between a $1.42 and a $1.50 per Mcf initial gas price.

Mr. GORE. Now, we are talking here about giving a great deal of additional money to the natural gas industry. What assurances can you give the Congress that this money is, indeed, going to be plowed back into the exploration for natural gas, and not used to purchase additional shopping center chains and businesses in other parts of the country.

Mr. SCHLESINGER. We cannot give the Congress assurances that that money will be plowed back into oil and gas production. We can only say that the $1.75 price, with considerable stability in the environment, is an attractive price. The fact that we are going to a single national market as opposed to these fragmented markets, particularly the intrastate markets with a limited absorptive capacity, implies that we are increasing the breadth and depth of the market. This should encourage producers who are looking for stability in the market.

On the oil side, we are going to the international price of oil at the margin. This is a very ample incentive, and we would think that producers would invest their capital. We cannot guarantee that, however.

Mr. GORE. That troubles me a little bit. We may see them going out and trying to buy circuses again, the way we did the last time we approached this question.

You mentioned a moment ago—and correct me if I am wrong—that if we had total deregulation in a free market for natural gas, that during the last shortage the price would have risen to $6 per thousand cubic feet.

Mr. SCHLESINGER. That is speculative. It could have gone to $5 or $5.50. I think that is why the Texas delegation refused to vote for the Emergency Natural Gas Act, because they were fearful of the consequences of rolling in the big interstate market into the limited Texas market, and drawing that gas out.

It could very well have gone to $5 or $5.50. I had one producer from one of the major companies say that deregulation was a nefarious plot designed to embarrass the oil industry.

Mr. GORE. You include throughout your statement figures on supply, different projections on how much natural gas we have, what steps are being taken now to get an independent source of information other than the information simply provided us by the industry.

Mr. SCHLESINGER. There is legislation proposed, including the authorities that will be in the new Department of Energy. There are three provisions in particular in the President's proposals that will assign to the Department of Energy the responsibiity of making thse assessments based upon the existing sources rather than allowing the American Gas Association and American Petroleum Institute to do that for the Government.

Mr. GORE. Thank you, Mr. Chairman.

Mr. DINGELL. The Chair thanks the gentleman. While we are awaiting the return of our colleagues, the Chair will recognize counsel for the purpose of asking questions.

Mr. DEMAREST. Thank you, Mr. Chairman.

Dr. Schlesinger, if I could, I would like to examine the specific legislative language for a moment.

Under section 404, new gas, which under the new gas definition is presumably from genuinely exploratory drilling, is ceiling priced at the Btu related price, approximately $1.75. If we assume that production from acreage is committed under an existing intrastate contract, developmental drilling of that acreage will result in sales of the gas under section 405 at the contract price, which may be greater than the Btu related price.

Doesn't that encourage developmental drilling rather than exploratory driling?

Mr. SCHLESINGER. No; it would not be greater than the Btu equivalent price. The phrase is: "Such maximum lawful price shall be a price equal to the lesser of the contract price or the FPC price." So that would not occur.

Mr. DEMAREST. In other words, under that explanation, paragraph 2 of section 405, would apply to intrastate sales. We are talking here about an intrastate contract, an existing contract, under which developmental drilling is going on. Gas sold under the existing contract would be subject to paragraph 2 of section 405.

Mr. SCHLESINGER. Yes.

Mr. DEMAREST. So you are then going to be applying FPC rates to existing intrastate contracts.

Mr. SCHLESINGER. No.

Mr. O'LEARY. Mr. Demarest, my understanding is that it will not apply to gas now under contract. It will apply to future contracts only in the interstate market, and I think what you are saying is, if you have acreage that is dedicated in the interstate market, this provision is going to encourage developmental drilling at the expense of going over to a new piece of an acreage. I am afraid that is one of the unfortunate aspects of the draft bill. We decided not to interfere with existing contracts.

Mr. DEMAREST. So it does have that effect.

Mr. O'LEARY. Directionally, and I think it's effect will be very marginal, Mr. Demarest.

Mr. DEMAREST. If we could examine the sales of old gas under a new contract, if this gas is produced from an old well which was not interstate natural gas, the producer can receive the Btu related price under section 406(c).

Mr. SCHLESINGER. Yes.

Mr. DEMAREST. If the gas is produced from a new well, the producer can receive $1.45.

If, as is generally recognized to be true, new wells are more costly to drill than old wells, why is the higher price provided for gas from the old well than for gas from the new well?

Mr. SCHLESINGER. Because the point that you are making has considerable local force; the concern we had was rolling back the intrastate prices to $1.45. We sought to avoid that.

Mr. DEMAREST. This legislation looks to a concept of first sale by a producer, and the National Gas Act deals with sale for resale. I assume one of the objectives of the legislation was to remove the existing distinction between interstate and intrastate sales, which has diverted gas away from the interstate market and into the intrastate market.

What happens under this case is the legislation limits a producer in the price he may charge for his first sale. What if producer number one makes a first sale to producer number two? The subsequent sale by this purchaser, for resale, would not be a first sale, and the reseller could charge as much as he wanted.

Each sale and resale could be an intrastate sale and not subject to the Natural Gas Act. The point is that at the end of this daisy chain the FPC will be presented with a sale for resale in interstate commerce. At present, the FPC prevents this kind of daisy chain by limiting what an interstate pipeline may pay for the gas either to the producer of the gas or to a middle man.

If the FPC followed a similar course and prohibited interstate pipelines from making these purchases, the gas would be diverted to intrastate customers who would not be so confined.

Mr. SCHLESINGER. We would not permit the daisy chain to take place. Section 408, part (d) states: "In addition to his authority respecting first sales by a producer of natural gas, the President may, by rule, establish maximum lawful prices applicable to any sales of natural gas by any other person if he determines that such rules are necessary to prevent circumvention of the pricing policies specified in sections 404 through 408."

Mr. DEMAREST. If I might observe, I don't think that cures the problem, because 408(d) is applicable to sales "by any other persons", not sales by a producer, and in the example this would be a producer sale.

Mr. O'LEARY. He is no longer a producer, Mr. Demarest, for the purposes of that section.

Mr. DEMAREST. For purposes of that section you would define him now as not being a producer despite the definition contained in section 402?

Mr. O'LEARY. Yes. Mr. Demarest, if I may, let's think of gathering company now as being the surrogate. The gathering company is the first purchaser but, of course, would be included by this section. That is a very typical case, as you know, in the whole system of supply in the natural gas industry.

Mr. DEMAREST. My concern is that by plugging this potential problem with regulation, we might have a delay during which abuse could occur. I understand there have been daisy chain problems under FEA regulations. What has been the result of that experience?

Mr. O'LEARY. There was a daisy chain problem under FEA regulations. That is still unsolved historically, but there are, to the best of my knowledge, none being pursued now.

Mr. DEMAREST. We had a problem when there was a shortage?

Mr. O'LEARY. We had a start-up problem when our regulatory agency simply didn't understand daisy chain possibilities, but we understand them and now they are being blocked off.

Mr. DEMAREST. Would it be preferable to draft into the legislation language which would address this particular problem?

Mr. SCHLESINGER. Might be; let's review that, Mr. Demarest.

Mr. KRUEGER[presiding]. The Chair will recognize the gentleman from New Jersey, but will first make a 30 second clarification on one point, and that is it is my understanding that in my absence it was referred to a vote by the Texas delegation with regard to the emergency natural gas legislation in February, and it was said the Texas delegation voted against it because it did not include price ceilings.

That is incorrect, and I will state that categorically now for the record.

I personally talked with members of the Texas delegation. We initially voted for the legislation before it contained any intrastate allocation authorities, but once the Senate added in conference language with regard to so-called Hinshaw pipelines that would give the President power to regulate some intrastate gas, the Texas delegation shifted its vote, so lest there be any misunderstanding, I want to clarify that for the record.

At this time I recognize the gentleman from New Jersey for five minutes.

Mr. MAGUIRE. Thank you very much, Mr. Chairman.

Dr. Schlesinger, I want at the outset to indicate that I am very impressed with the thoughtfulness and the comprehensiveness of the proposal that you have put together. I think it's a remarkable piece of work for a very short period of time.

Mr. SCHLESINGER. Thank you.

Mr. MAGUIRE. I also want to say I think natural gas is an extremely valuable source of energy, and that we ought to be much more careful about how we use it in the future.

Against that background though, I do have a question, which is what can you tell us about the cost of producing 1,000 cubic feet of natural gas, onshore or offshore? What do the figures indicate is the cost? It's 15¢ per barrel of oil in the Middle East, for example, and sometimes the costs, I think, are not fully grasped, and I would like whatever you can tell us on that point.

Mr. SCHLESINGER. We shall insert some data in the record.

Of course, these are historic costs in many cases. They reflect different prices from the past. The costs cannot be generalized, because of history and because of different geological formations.

Mr. MAGUIRE. Is there a ballpark figure though on average cost or even the highest costs with respect to current production of natural gas?

Mr. SCHLESINGER. I think we can generate that, but we have to include, quite obviously, the number of dry holes, and the cost of taking risks.

Mr. MAGUIRE. That is always included in any calculation.

Mr. SCHLESINGER. We can supply that for the record.

Mr. MAGUIRE. Let me go over some figures and see if I am making any major errors.

The cost of 1,000 cubic feet of gas in 1968 was 13¢ per Mcf. It was doubled to 26¢ in 1971.

Mr. SCHLESINGER. The price?

Mr. MAGUIRE. Yes, the price. Did I say cost? I beg your pardon, the price.

Let us assume just to round the figures off that we have a base of 25¢ per Mcf five years ago. Let's assume that return on investment was 20 percent, i.e. costs were 20¢ of the 25¢ and profits were 5¢. The price of fuel gas was set at $1.42 in 1976 and you are proposing $1.75 for the future.

Let's round that off to say $1.50, just for fun, for purposes of computation.

Let's further assume that the costs of producing 1,000 cubic feet of natural gas have multiplied in recent years, as I am informed they have by something like 250 percent. The cost then would go from 20¢ per Mcf to 50¢ per Mcf; 50¢ subtracted from $1.50 leaves $1 in apparent profits at that point.

That $1 is a 200 percent return on investment, and it is 2,000 percent greater than the profit that was earned on the 25¢ gas. That is $1 of profits instead of 5¢ of profits.

Those are rather dramatic figures, and unless there is something very wrong with my rough calculations what we are giving the gas producers is a 2,000 percent increase in profits if you look at it over a five year period.

It would be like saying that Chevrolets were going to cost $40,000 and hamburgers were going to cost $4.80, and a haircut was going to cost $24 and a pair of shoes $240 and a six pack of beer $12.80.

What comment do you have on those figures?

Mr. SCHLESINGER. I have a number of comments.

First, in the past, there is no way precisely to describe the cost of producing gas. In the past gas has been a byproduct, by and large, of oil production, and the producers accepted whatever price they could get for the gas. For that reason, for many years they did not take too much offense at FPC regulation. That has changed in recent years, and there has been increasingly an independent quest for gas.

Mr. MAGUIRE. Do we need 200 percent return on investment?

Mr. SCHLESINGER. Let me come to that. If one cannot separate out the costs of gas and oil production, Mr. Maguire, I suspect that the attempt to allocate those costs would simply demonstrate that for those FPC prices there was a substantial loss, and there was a reduction in the incentive to go after new gas.

We believe that the prices that you mentioned, $1.42 or $1.75 for new gas, are in the appropriate incentive range. It is plain, I think, to any fair minded observer that the 13¢ or 26¢ prices are far below the costs of production, and will provide no incentive for gas production, save for those who happen more or less to trip on gas fields in the course of looking for something else.

Mr. MAGUIRE. If I can just conclude with a comment, Mr. Chairman, it may well be that we want to depart to some extent in weighing the whole picture from a strict historical cost basis.

Mr. SCHLESINGER. Yes, sir.

Mr. MAGUIRE. I think it's important, however, that we know what the cost basis is when we make our decision.

Mr. SCHLESINGER. Can we supply for the record some numbers that will deal with the questions of the basis of the substantial

increase in costs, what we perceive the level of risk to be, and what the possible profits will be of the companies?

Mr. MAGUIRE. I would appreciate that.

Thank you.

Mr. KRUEGER. Without objection, so ordered.

[The following information was supplied for the record:]

The table below, indicates the projected changes in profits of oil and gas producers with the Plan and without the Plan:

(1975 Dollars) 1/

	1978	1979	1980	1981	1982	1983	1984	1985	1978-1985
Oil									
With Program	8.1	8.2	8.4	8.6	8.6	8.9	9.3	9.5	69.6
Without Program	8.1	8.3	8.6	8.9	9.1	9.6	10.2	10.7	73.5
Difference	--	-.1	-.2	-.3	-.5	-.7	-.9	-1.2	-3.9
Gas									
With Program	3.2	3.4	3.7	4.1	4.7	5.1	6.2	7.1	37.5
Without Program	3.3	3.5	3.8	4.2	4.8	5.2	5.6	6.0	36.4
Difference	-.1	-.1	-.1	-.1	-.1	-.1	+.6	+1.1	+1.1
Total Difference	-.1	-.2	-.3	-.4	-.6	-.8	-.3	-.1	-2.8

1/ Details may not add up due to rounding

Oil profits are reduced over the entire period under the Plan. Gas profits are decreased through 1983 due to the expensing, for tax purposes, of exploration and development expenditures in advance of the time when the increased gas production stimulated by the Plan actually becomes available for sale.

With respect to the risks and cost of oil and gas exploration, both are factored into the supply estimates with and without the Plan. Unfortunately, costs are disaggregated to the point where a general answer is not immediately available. We will initiate an effort to organize this detailed cost information in a useful format and will respond more fully to your question when it is completed.

Mr. KRUEGER. The gentleman from Texas, Mr. Collins, is recognized for five minutes.

Mr. COLLINS. Thank you, Mr. Chairman.

Dr. Schlesinger, we are certainly glad to have you with us again.

If I could just clarify a point my colleague made here in New Jersey, I checked some, because many times we hear the oil companies criticized by people that haven't had a chance to review their 10 K's, and I took this, the statements of the ten largest oil companies from last year and I found that the consolidated net income was $9.196 billion, and that their capital exploration and drilling was $17.584 billion, which meant they were putting 180 percent of what they made back into drilling and capital.

I also checked to see how much the stockholders were getting out of these businesses, and I think they are a pretty poor investment for stockholders.

I found they have $3.744 billion, whereas the Government in taxes got $25.716 billion. That meant that every time a stockholder got $1, that taxes amounted to $6.87.

I don't know where he got his 200 percent, and I would ask unanimous consent that we provide the time in the record for my colleague to file all of that.

Mr. MAGUIRE. Mr. Collins, it's 250 percent.

Mr. COLLINS. I will be glad to allow time in a unanimous consent for you to file that, because I am quoting what are the official records of the statements they filed with the Securities Exchange Commission.

Let me ask one thing, Dr. Schlesinger. We talked about Btu equivalency, which is really the bottom line. How much energy do you get? What is your figure on the cost Btu equivalency of coal? That is what we are trying to go to.

Mr. SCHLESINGER. The Btu equivalent for coal is $1.10 at the present time.

Mr. COLLINS. $1.10?

Mr. SCHLESINGER. Yes, sir.

Mr. COLLINS. You are talking about compared to gas?

Mr. SCHLESINGER. Yes, sir, per million Btu's.

Mr. COLLINS. I heard it was $2.25.

Mr. SCHLESINGER. No, sir.

Mr. COLLINS. $1.10?

Mr. SCHLESINGER. Yes, sir. Coal is cheap; we would like to persuade people to take advantage of this fact.

Mr. COLLINS. Is that on sweet coal? I don't know what you call coal but we call it sweet oil. Nonsulphur coal?

Mr. SCHLESINGER. We will provide for the record the difference between Western coal, which has a lower Btu content, and its price and the Eastern coal, which has high sulphur content, but which has a much higher Btu value.

[The following information was received for the record:]

In 1985, the delivered price of Eastern high sulfur bituminous coal to utilities in the Middle Atlantic area is estimated to be approximately $1.10 per million Btu's. In the same year, the delivered price of Western low sulfur, sub-bituminous coal to utilities in the North Central area (e.g., Minnesota) is estimated to be about $.60 per million Btu's.

Measured at the mine, these prices would be lower due to the costs required for transportation to these utilities. Compared to the delivered price above, high sulfur Appalachian coal would be priced at about $1.00 per million Btu's at the mine. Low sulfur Western coal from the Northern Great Plains would be priced at about $.50 per million Btu's at the mine.

Mr. COLLINS. Based on that, industry can make the transition, because down in the Southwest where we had an open market on gas we were paying $1 whereas the East was paying 50¢, and we weren't complaining on that.

Of course, I have been wondering about the whole open market situation regarding gas.

Now, did you write this energy bill we have or did President Carter? Is it President Carter's plan or is this the Dr. Schlesinger plan?

Mr. SCHLESINGER. This is President Carter's plan.

Mr. COLLINS. President Carter last October came through the Southwest and he made a statement that he positively believed in deregulation of gas, and that he would work for deregulation of gas with Congress, and in every way he could.

This bill does not provide for deregulation of gas. How did that happen?

Mr. SCHLESINGER. There are two aspects of it, Mr. Collins.

The first is that the President has described this, I think appropriately, as a first step toward deregulation.

We will have to examine the balance of supply and demand in this market to see what additional steps can be taken.

The second point is that, given last winter's crisis, many views changed, including many views of the people from the producing States, who publicly and privately expressed the view that there must be a cap.

As a consequence of that, we recognize increasingly the frightful disproportion between supply and demand in this market, and the consequences. Therefore, to move toward a Btu cap for new gas, and to provide the authority to remove controls from tight or deep formations as in Oklahoma or Devonian shale or geopressurized zones as in Texas, are steps in that direction.

If we can squeeze down the demand so that there is some balance between supply and demand, additional steps may be taken. In the long run I am optimistic about gas supply, but not in the short run.

Mr. COLLINS. Dr. Schlesinger, for five years experts have been saying we would have a gas shortage coming. Do you believe the administration or the leaders of the Administration just anticipated this shortage last winter?

Mr. SCHLESINGER. No, sir. I have been suggesting that a gas shortage was coming on. We faced the fact that we, indeed, in the long run, are going to run out of gas. If we had taken different steps a decade ago or even five years ago much of the pain of the problem might have been averted. We did not take such steps.

If deregulation had occurred last winter it would not have affected the supply of gas through new drilling. The only way it would have affected the supply of gas would be if there had been withholding, and one doesn't know precisely what judgment to make on that possibility.

Mr. COLLINS. Dr. Schlesinger, since that thing came up, many people believe Government intervention has helped aggravate and cause the problem. In 1970 we got activity in intervention in oil; we had 23 percent imports, and now I believe we are around 55 percent. We have gone downhill since then.

Mr. SCHLESINGER. There are two aspects to that, Mr. Collins. First, I think there is no question that the pattern of Federal controls in the past has intensified the shortages and the distortions in the natural gas market. There is no question about that.

With regard to the oil problem, I think that that comes by and large from the disproportion between demands and our growing dependence on overseas supplies. That is not a consequence of Government controls. Government controls flow from the oil problem.

Federal regulation can, indeed, be bad. However, allowing market forces to run free, when the dominant price in an industry is determined by the OPEC nations and when there is a bad disproportion between supply and demand, can also lead to quite unfavorable consequences.

Mr. COLLINS. Thank you.

Mr. KRUEGER. The time of the gentleman has expired.

The Chair now recognizes the gentleman from Texas, Mr. Gammage for five minutes.

Mr. GAMMAGE. Thank you, Mr. Chairman.

Dr. Schlesinger, you alluded a moment ago to the energy crisis of this past winter, and as a consequence of that very early in this Congress we enacted the Emergency Natural Gas Act of 1977.

Repeatedly during the debate on that proposal you stated that the administration did not seek the authority to allocate intrastate gas supplies.

Mr. SCHLESINGER. In that legislation?

Mr. GAMMAGE. In that legislation. When a provision which made inroads on a non-intrastate location policy was included in the conference report of that bill—and I am speaking to the new definition that was included in conference of interstate natural gas to include the Hinshaw gas——

Mr. SCHLESINGER. We opposed that interpretation.

Mr. GAMMAGE. I appreciate that, and as I pointed out a moment ago, it was a new provision that had not been previously approved by either the House or Senate. You had a statement released in response to Senator Bentsen's concern that——

Mr. SCHLESINGER. I think it was Senator Johnston.

Mr. GAMMAGE. At any rate, there was a statement included in the report in the conference committee from you as a response to the fear of some that you intended to allocate intrastate gas. The statement categorically denied you sought such authority or would resort to it. Yet the national energy plan that has been submitted to us by the President inexplicably has included a request for such authority, and it would be nice to know, number one, just where the administration does stand on this question, and how does it square with the statement that I heard made earlier before this subcommittee, and in this session of Congress when we were discussing the Emergency Natural Gas Act, in response to a question relating to

the increase in prices of fuel oil and what have you, particularly fuel oil during this past winter, in areas that still burn a good deal of that, but Mr. O'Leary's response was that had his agency still had authority to regulate pricing and allocation of fuel oil that they could not have met the logistical demands that the industry did meet as far as this past winter's needs were concerned.

How did the position taken in that bill regarding natural gas square with that particular statement, and how does the proposal in the plan square with your previous statements regarding your reluctance to either seek or exercise any allocation authority?

Mr. SCHLESINGER. The emergency natural gas legislation was designed to move quickly through the Congress to deal with an emergency that threatened priority 1 users. It was said very clearly at that time by me and by others that we sought to avoid in any way impacting existing interests in order to get that legislation through quickly to deal with an emergency.

We were pressed at that time to take a position on the longer range natural gas issues. We refrained from doing so, deliberately saying that we wanted to get the emergency legislation through and that we would be back in 90 days' time with long-term proposals for the natural gas market, which we have done.

Those proposals for the natural gas market are included in a comprehensive package that deals with complementary and competing fuels. We cannot deal with the natural gas market alone.

With regard to the allocation authority, as you know the allocation authority in the emergency legislation was there to deal with allocations among interstate pipelines. We are now moving towards a national market. We seek to extend the allocation authority contained in emergency natural gas legislation for 3 more years. We hope that by that time there will be a better balance between supply and demand so that there will be in the long run no pressure to have allocation authority. In the shorter run, we hope for mild winters so that any authority would not have to be used.

Mr. GAMMAGE. I have no further questions.

Mr. DINGELL. The time of the gentleman from Texas has expired. The Chair will recognize my colleagues for another round. The Chair recognizes first the gentleman from Ohio, Mr. Brown.

Mr. BROWN. Mr. Secretary, I want to get back to this question of Btu equivalency and I want to take a hypothetical plant and a hypothetical place like Springfield, Ohio, with which we are both familiar, and ask you how that decision is made by the plant that is going to switch from one type of fuel to another.

It seems to me it is not made on the basis of the way Btu equivalency is determined in this legislation because, in effect, in this legislation what you do is set a Btu equivalency for natural gas as it is ready to be transported to the burner tip from somewhere in Texas, Louisiana, or someplace else, but ready in effect to be burned.

The price of Btu that is compared to in oil is crude oil as it is getting ready to be sent to the refinery where it then is put in some form through refining and then transported to the burner tip someplace, so already we have a dichotomy there of what the two comparisons should be.

The comparison the factory man has to make is that natural gas, if burned in his plant, does not throw particulate matter and noxious fumes into the air. Oil may put some into the air, which may, depending on the location of the plant, have to be cleaned up. So there is additional cost to oil.

Certainly coal, if he uses it—and this is part of the reason for the $1.10 of coal, or coal would have gone up perhaps a little higher if it were an equivalently clean fuel—what I am trying to get at, by setting the $1.75, which in effect is a future price because I think currently we all have to agree it would be $1.60 for natural gas—at least that was the last official price in January—equivalent to $1.60 if you look at the Btu equivalency for crude oil again.

I think we ought to talk about the same numbers. The problem is that you have to add the cleaning mechanisms to your plant stack for coal and so forth. Is the Btu equivalency that you are talking about in the bill really the Btu equivalency we ought to look at, or should we look at the decision process and see the Btu equivalency the factory owner is going to have to make a decision on?

Mr. SCHLESINGER. I think you have to look at both issues, Mr. Brown. The issue at the burner tip, the decision by the factory owner will be based upon the price he pays for gas as opposed to competing fuels. The price that he pays will not be the Btu equivalent; it will not be the Btu equivalent plus transportation. It will be the Btu equivalent plus transportation plus a substantial tax to raise it to the distillate value. That is the comparison the user will make.

On the question of the Btu equivalent price, the argument to the industry for many years—and I share some skepticism with regard to the precision of that argument—has been that in the long run the equilibrium price will be the Btu equivalent. We have accepted that argument to the point of providing that price to the user.

Mr. BROWN. I want to get at what the conservation of that tax is going to be. Your testimony is that the gas user tax will save 3.5 trillion cubic feet in natural gas by encouraging the switching to coal but with all these mechanisms, that is the users tax, the coal conversion boiler fuel prohibition and incremental pricing for saving gas, why then do we have to have a cap on top of all of that that sets that price?

It seems to me that is sort of an artificial mechanism that is unnecessary on top of all of the restraining mechanisms on demand that you have written into the system with taxes that were covered by the government, and so forth.

Could you provide us with some statistics or some argument that justifies those relationships one to another and why we need that $1.75 lid on there?

I am worried about the fact even though you equalize the price between intra and interstate in my district, we still won't get natural gas after this goes into effect because it won't be produced at that price and we will not be any better off or worse off than Texas but we won't be any better off than we were last winter.

Mr. DINGELL. The time of the gentleman has expired but the Chair will permit the witness to reply.

Mr. SCHLESINGER. As I indicated earlier, the production incentives at $1.75 are substantial. Mr. Maguire pointed out that this will be something like a twenty-fold increase in price compared to the FPC regulated price of some years ago.

Mr. BROWN. Those things do not relate really. I understand that kind of economics.

Mr. SCHLESINGER. Wait a second. The fact that a price has increased twenty-fold has something to do with incentive. It may not be closely related to costs as Mr. Maguire suggested, but a twenty-fold increase in price must do something for the incentives of producers, otherwise there is no purpose in increasing the price another 5 percent to go to a different Btu count. If the twenty-fold increase is not going to influence producers, neither will a 5 percent increase.

Mr. DINGELL. The Chair recognizes the gentleman from Texas, Mr. Krueger, for 5 minutes.

Mr. KRUEGER. Thank you, Mr. Chairman.

Mr. Schlesinger, I concur with what you mentioned earlier where the observation that initially people did not go into a search for gas as such, rather gas was a product found in the search for oil. I can easily envision, I suppose, that perhaps with due diligence by ERDA and othes we might some day find, for example, manure from cattle would prove to be more valuable than beef. If one looked at that possibility, one would say, "But at one point I could buy manure for 4 cents a pound and now you want $2 a pound for it."

The fact is there have been times in our experience in which manure was an unrelative byproduct. The same thing happened with natural gas. There are many times in our Nation's experience when it was an unwanted byproduct and therefore there really were very few searching costs for that gas because nobody was searching for it.

I concur with that statement, and therefor, it becomes difficult to use simple correlations.

Mr. SCHLESINGER. May I just point out at this juncture that gas is presently being flared in Saudi Arabia and in Mexico; it has essentially no value in such places.

Mr. KRUEGER. It is being flared because there are no distribution systems to get it to consumers.

It is part of that very concern about the availability of distribution systems that causes me to want to look again at the price that has been set for gas and particularly to the 2½-mile limit for the definition of new gas.

New gas would get a particular top price in your proposal only if it was drilled more than 2½ miles from an existing well.

As I mentioned earlier, since 90 percent of past production of new gas was from wells less than 2½ miles, it seems to me that this proposal would, among other things, say: Let's no longer look in Louisiana, Oklahoma and Texas, the main proven sources of these hydrocarbons, but instead let's look where we have never found. And indeed, I would agree we must look where we have never found, but when we look and find where we have never found, we then have the problem that we do not have gathering systems in place.

There is, of course, an immense investment already in existence in those gathering systems. It seems to me that while the 2½-mile decision like the $1.75 may have been judgmental, there are economic and geologic problems with an arbitrary figure such as 2½ miles. I wonder if you might comment on that.

Mr. SCHLESINGER. I agree with the gist of your comments. Indeed, we have sought to put the priority on frontier areas. I think that priority is one that is widely shared, but we would also seek to provide appropriate augmented incentives in the older production areas if we were able to get a very precise definition.

We have tried to get a definition that will not require us substantially to expand the bureaucracies of the Department of Energy and add to its budget.

If, however, there is no alternative, we may have to examine the geologic contribution of a particular area in order to determine whether or not there is gas.

Mr. O'LEARY. May I amplify, Mr. Chairman?

Mr. KRUEGER. Yes.

Mr. O'LEARY. There appears to me to be ample evidence that the current price for gas and for oil is bringing out an awful lot of investment in the areas you are concerned with. What we are attempting is to shift some of that investment or to gain new investment, into these frontier areas. You cannot ignore the fact that right now the economy is overheated.

Mr. KRUEGER. It is my understanding that the Joint Associates Survey from which the Federal Power Commission takes its drilling costs estimates, has recently indicated that current drilling costs for natural gas are higher than $1.75. If that is correct, why is the present price not $1.75 but rather $1.74 if we compare it to Btu equivalency?

Mr. SCHLESINGER. Let us look at that, Mr. Krueger, and provide that for the record.

I will augment that until you go to your second question.

[The following information was received for the record:]

The $1.75/Mcf referred to is the maximum price at which new discoveries of natural gas will be permitted to be sold either on the inter or intrastate market after January 1978. This price is also estimated to increase to about $3.25/Mcf by 1985 under the Energy Plan. For comparison purposes, as of June, 1976, the average intrastate contract price for natural gas was approximately $1.60/Mcf. Only during the emergency period of this last exceptional winter, and then only in the months of January and February did intrastate contracts exceed the 1.75 per Mcf price. Today they are once again below that level. As of early 1976, Opinion 770 from the FPC set a price of $1.42/Mcf plus $.04/Mcf/yr for new interstate contracts. If one were to adjust this price to 1978 according to the procedures set forth in Opinion 770, it is considerably below $1.75. Thus, FPC in its rulings has implied that on a "cost-of-production" basis the $1.42/Mcf schedule is sufficient to supply new interstate gas.

Mr. KRUEGER. No. Let us finish this one. That is fine.

Mr. SCHLESINGER. The escalation of costs in the industry in recent years was subject to impressive sensitivities that have existed in the industry and has led to a bidding up of leases, of equipment, and of trained manpower. We are concerned about that. It reflects the fact that activity in the industry had declined to a very low level by the early 1970's and has gone up substantially.

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The number of drilling rigs in operation, for example, has almost doubled in recent years. I presume somebody must see some return above costs to see that kind of response.

Mr. KRUEGER. Thank you.

Mr. DINGELL. The time of the gentleman has expired. The Chair is going to recognize the gentleman from Louisiana, Mr. Moore, for 5 minutes. The Chair will request that the gentleman from Texas take the Chair.

Mr. MOORE. Earlier you were talking about the Btu equivalency, and I think you made the statement the Btu equivalency was supposed to be the equivalent price for oil we were using in this country.

Mr. SCHLESINGER. Domestic oil.

Mr. MOORE. And that is not a true market price equivalency?

Mr. SCHLESINGER. I am glad you raised that question, Mr. Moore, because there has rarely in our history been a free market for petroleum, and there certainly is not such a free market today. The prices of oil internationally and thus derivatively in the United States, given the free run of the price mechanism, will be the prices set by the cartel, and they are administered prices.

If the prices are going to be administered, they might as well be administered by the United States Government. I should augment that by saying, looking back at the history of this industry, it is only in rare periods that market forces have been the dominant ones.

Since the 1930's the Texas Railroad Commission has been the ultimate decider of price by restricting supply under the rubric of conservation, but actually for the purpose of basically maintaining prices.

Once Texas ceased to be the dominant influence in oil production, those decision powers were taken over by the international oil companies. There was a decline in price in the United States, but ultimately the powers of the international companies were taken over by OPEC. Thus, to refer to market prices in this industry now is particularly inappropriate.

Mr. MOORE. Dr. Schlesinger, by the fact we continue to regulate price and are willing to pay Arabs more for oil than Americans, aren't we increasing our dependence upon foreign oil?

Mr. SCHLESINGER. That is why we would like to get prices of oil up $13.50, so we can get rid of the entitlements program and can have the conservation effects. Within that framework we are providing a $13.50 price for new exploration, which is where the industry always said the emphasis should be. There is no need to provide incentive profits on existing fields, and that is why we have the wellhead tax.

Mr. MOORE. That is the determination by our government as to what the market price would be.

Mr. SCHLESINGER. There is no market price out there. There is a price, a world price, that is determined by the votes of the OPEC members as reflected by dissident OPEC members. But to suggest that this market has anything to do with price—in fact, if you go back to the days of the Standard Oil trust, the basic problem has been that in most periods of time the flow of oil has been so great there had to be some way of restricting supply in order to avoid something called ruinous competition.

That method of restriction is now provided by a cartel. It had been provided by the Texas Railroad Commission by a variety of decisions. Market forces only influence this industry in fairly rare periods.

Mr. MOORE. I think that is an oversimplification that I would disagree with, although I fully agree with the impact of the OPEC countries. If we are really concerned about an equal Btu proposition, why not let the natural gas have an equivalency of the new oil you are designed to produce? Why put it on an equivalency of an average, which I submit is a political determination and not an economic one or one based upon any desire to increase production?

Mr. SCHLESINGER. It is not based on any desire to increase price; I think that is correct.

Mr. MOORE. I meant production.

Mr. SCHLESINGER. I think it is generally agreed we are in the range of sensitivity. Most producers to whom I have talked privately say, "By golly, we are going to make a lot of money at $1.75." Publicly they urge that free market forces take over, but as you point out, gas prices are going to be derivative of oil prices and that means derivative ultimately of the prices set by the cartel.

With regard to the choice of fuel, we are tempted to get the price for industrial users of natural gas over the Btu equivalent in order to encourage the switch to coal.

Mr. MOORE. Let me ask you this question. Why do we need a cap? I have understood your testimony to be the desire is to reduce the demand for natural gas by many of the things, new tax, the coal conversion, prohibition against boiler fuel, et cetera. Isn't this overkill?

Under the use tax you testified that would save or reduce demand by 3.5 trillion cubic feet, which was less than our shortfall this year. So why aren't we going in for overkill with the caps to begin with?

Mr. SCHLESINGER. The market is certainly out of balance, partly as a result of inappropriate concepts of regulation for many years, but it is indeed sadly out of balance.

The reason we need a cap is the reason conveyed to me privately by many producers in the producing regions. Those companies are publicly calling for a free market but privately say, "If we don't have some kind of cap we are either going to be terribly embarrassed by the run-up in price or we are going to have that big interstate market come into our little intrastate market. Because of the control on old gas, they are going to be able to outbid us and we will be in trouble."

I think the acting chairman gave quite a convincing speech to the Texas Legislature on this subject.

Mr. KRUEGER [presiding]. The acting chairman spoke specifically to the question of redetermination clauses on exactly that point. I would be glad to send our distinguished guest a copy of that speech.

Mr. SCHLESINGER. I like that speech, Mr. Chairman.

Mr. KRUEGER. At this time the Chair recognizes the gentleman from Virginia.

Mr. SCHLESINGER. May I?

Mr. KRUEGER. Yes.

Mr. SCHLESINGER. I think the essential point has been made by those from Texas and Louisiana and other States about the vulnerability, given that great dependence that has been generated on gas, of suddenly rolling in this vast interstate market without a limitation on demand in price. I endorse it.

Mr. KRUEGER. I concur in the need to address the problem.

The gentleman from Virginia is recognized for five minutes.

Mr. SATTERFIELD. I would like to return to a line of questioning I was pursuing earlier. I was intrigued by the statement that the comparative Btu equivalence for coal to gas is $1.10. Forgetting for the moment the incentive to the producer—and I think we have explored that—what about the incentive to conserve and thus switch to coal?

If the comparative Btu equivalent is $1.10, I wonder whether your investigation has given some indication of why there is not already an incentive and why a movement in that direction has not already occurred?

Mr. SCHLESINGER. In many cases the price of gas is very low. What we are attempting to do through a system of taxes is to raise substantially the price of oil and gas to encourage that shift.

Indeed, there are problems with coal. It is difficult to move and it is inconvenient in many respects compared to oil and gas. It is dirty. The relative cheapness of coal to this point has not been sufficient to induce the movement to coal. That is why we want to augment the incentives.

Mr. SATTERFIELD. Is there some indication one of the factors is uncertainty about making that move?

Mr. SCHLESINGER. I am sorry?

Mr. SATTERFIELD. I said, did you uncover any evidence to indicate that uncertainty might be a major factor?

Mr. SCHLESINGER. Absolutely. The underlying premise of this plan and of all discussions, I hope, within both the executive branch and the legislative branch is that we must bring predictability and stability to our policies. That is what the industry requires—that they not face a continuous question mark regarding government policy.

Mr. SATTERFIELD. I agree. However, your chart has indicated what will happen with respect to coal and gas as a result of the incentives built into this measure. I am interested to know what factors were considered in making that prediction.

Mr. SCHLESINGER. We will outline the assumptions in the model in the report, Mr. Satterfield.

Mr. SATTERFIELD. That would be very helpful. I would be particularly interested in knowing whether one of the factors cranked into that model was an estimate of the cost of best available technology for purposes of cleaning up the air.

Mr. SCHLESINGER. Yes, sir, that was included for future commitment to coal.

Mr. SATTERFIELD. Might I inquire whether or not that projection was based on the Clean Air Act of 1970 or was there any factoring for changes which may be made by this Congress?

Mr. SCHLESINGER. We estimated it on the basis of the best available control technology that will add about 50 cents per million Btu's to the cost of using coal.

Mr. SATTERFIELD. I realize what technology it might have been based upon but I wondered whether or not you factored in the broad scope that new clean air amendments might encompass and additional demands such amendments might make on industries over and above those required by the 1970 act.

Mr. SCHLESINGER. No, sir. We proceeded to the point that I mentioned but did not go further.

Mr. SATTERFIELD. Thank you very much.

Mr. DINGELL. The Chair thanks the gentleman.

The time of the gentleman has expired. The Chair recognizes the gentleman from Indiana, Mr. Sharp.

Mr. SHARP. I just wanted to ask, Mr. Chairman, if Mr. Schlesinger would give us a little rundown on where we stand what you expect from the exotic formation, Devonian shale, et cetera. What is happening there now and what will happen under the program in terms of pricing and any government policies?

Mr. SCHLESINGER. The costs of production from such nonconventional sources of gas are obviously substantially higher than they are for what we will call conventional gas sources.

The legislation provides the authority to the Department of Energy to remove any restrictions regarding price for such formations. In general, in the case of the deep deposits in Oklahoma, something on the order of 15,000 feet below would be removed from such controls. We are very hopeful that we will be able to develop the technology to draw gas from the geopressurized zones in the Gulf Coast. If so, we will solve our gas problem for another generation.

We are conducting experiments with horizontal drilling for Devonian shale. If we can achieve that, we will be able to collect enough gas to make that method of producing gas productive.

We are also looking to capturing methane from coal mines and we are looking again at the formations in the West to see if they can be productively worked.

In general I cannot give you probability estimates of success but I think that from the array of possibilities, one or more than one of them is likely to work and we will be able to have a far more optimistic projection with regard to supply of gas two years from now than we presently have.

Mr. SHARP. What do you expect to happen between now and then?

Mr. O'LEARY. There is a lot of research going forward in these areas. There really is no problem with the resource. There is an awful lot of natural gas and methane around.

Mr. BROWN. Could you estimate what an awful lot is?

Mr. O'LEARY. I would say if we have 200 trillion in reserves now, or 230 trillion, we have 10 times that much in these resources that we are talking about, maybe 20 times that much.

Mr. BROWN. Is that in conflict with the CIA report?

Mr. O'LEARY. Not at all. The distinction is between economic resources and noneconomic resources.

Mr. BROWN. The CIA report did not take into account economics?

Mr. O'LEARY. It did not touch upon the problem we are talking about now.

The problem, Mr. Sharp, is that geopressurized reserves carry with each Mcf of gas the requirement to get rid of 5 tons of water. That brings a whole host of problems we simply do not know how to deal with. They are soluable with money but it may mean that by the time you have done that you are not interested in exploiting that resource; there is a better alternative somewhere else.

Mr. KRUEGER. Would the gentleman yield?

It is also highly corrosive salt water and very high temperature, which may be useful.

Mr. O'LEARY. It may be useful.

Mr. SHARP. But essentially it won't be drinking water for California.

Thank you, Mr. Chairman.

Mr. MOORE. If the gentleman would yield.

Mr. SHARP. Yes.

Mr. MOORE. I would like to pursue a moment these reserves. The figures we have from USGS and others show it may well be another 800 trillion cubic feet of reserves in addition to what we are calling the provable reserves. Is that not correct?

Mr. SCHLESINGER. That is a figure. It is high into the range, it is 800 trillion cubic feet.

Mr. MOORE. The range goes from 752 to 1,085. I am taking an average, so I think it is in the middle of the range, not the high end. That is in addition to the other things we are just talking about.

Mr. SCHLESINGER. The speculation differs.

Mr. O'LEARY. Just two years ago, Mr. Moore, these numbers were twice as high.

Mr. MOORE. Isn't that amount 40 years' supply?

Mr. SCHLESINGER. Yes.

Mr. DINGELL. The time of the gentleman from Indiana has expired.

The Chair is concerned with something that is important and yet is not in the record. Let us address ourselves to the question of coal. Where in the bill before us, H.R. 6831, is there anything aside from price increases which would encourage coal production?

Mr. SCHLESINGER. Encourage coal production.

Mr. DINGELL. Yes.

Mr. SCHLESINGER. Sir, to this point coal has not been supply limited; it has been demand limited.

Mr. DINGELL. But to give a direct response to the question, the legislation provides nothing for the increased production of coal; is that correct?

Mr. SCHLESINGER. The problem is increasing demand rather than production.

Mr. DINGELL. It actually has been consumption constrained, is that what you are saying? Given the consequence of the bill, there is going to be a massive shift to coal, is there not?

Mr. SCHLESINGER. We hope there is a substantial move.

Mr. DINGELL. The President has indicated a level of 400 million tons, which is pretty close to half of present consumption, which runs about 600 million tons. If natural gas prices increase by a dollar, coal prices would increase by about $24 on a Btu equivalency basis. Is that a fair statement of the relationship on a Btu basis?

Mr. SCHLESINGER. Yes, I think that is right.

Mr. DINGELL. I will leave the record open in case you find my arithmetic is incorrect, because it is horseback and I want to be fair with you.

If my estimates are correct and we do not bring more coal on line quickly to take up the demand, it is not inconceivable then that for every dollar increase in natural gas prices, we will have a massive increase in coal prices of $24 a ton and a massive increase in extractions of currency from the rest of the economy. Am I correct in that?

Mr. SCHLESINGER. You are absolutely right, Mr. Chairman.

Mr. DINGELL. I get a horseback estimate then that we might be pulling from the economy as much as perhaps $30 billion. Am I correct or incorrect in that assumption?

Mr. SCHLESINGER. Your logic is correct, Mr. Chairman. It points to the fact that we must very carefully watch the movement of coal prices in the first place; and secondly, to see to it that supply expands. But we presently have the tools to generate that increase in supply, including due diligence requirements, from those who presently hold leases of coal.

Mr. DINGELL. The thing that troubles me is here we have no real incentives being brought to bear to increase coal production, nothing in the legislation to protect against the potential for massive coal price increases, enormous price increases possible in the natural gas area, with a potential impact as high as $20 billion to the economy if we deregulate natural gas.

I would assume the potential for coal price increases might conceivably be very high with unregulated oil becoming more common both from without the economy and from within the economy. We face a potential enormous increase in terms of economic impact and extractions from the economy into the energy-producing industry without any real incentive towards coal production to pick up the slack.

What do your econometric models tell us about these concerns of mine?

Mr. SCHLESINGER. The point that I was making, Mr. Chairman, is that we presently have the tools to encourage coal supply. It is a competitive industry. The extent it begins to become less competitive we have action to be taken in the antitrust laws. We have, in addition, a major lack in Eastern coal production and we have due diligence requirements that we can impose upon those who have leases on Federal lands. However, we entirely agree that we must watch this problem with great care to see that what you have logically projected as a possibility does not occur.

Mr. DINGELL. Let us look: We have a number of problems that exist. The difficulty and time with regard to opening new coal mining; environmental constraints such as the Clean Air Act which will impinge significantly on what coal can be burned where, and whether, in fact, it might be burned.

In addition to this we have transportation constraints. Can you give us any judgment as to whether there is the transportation capacity to move coal to market?

Mr. SCHLESINGER. Once again, there are spots in the national transportation system that are worrisome, and we shall be looking at them very carefully, Mr. Chairman.

Mr. DINGELL. There also are investment constraints in the consuming industry, which is a very troublesome matter.

It takes a substantial amount of money and time and equipment to shift our boiler industry from gas to coal, or oil to coal.

In terms of the constraints which we face, how is this going to affect the shift from oil and gas to coal?

Mr. SCHLESINGER. The incentives in the form of the rising schedule of taxes have been spaced in such a way as to spread out the period of the shift from oil and gas to coal.

Our judgment is that industrial capacity will permit the avoidance of major price increases, but once again, Mr. Chairman, that is something that will have to be carefully watched.

Mr. DINGELL. My time has expired, but I express prayerful concern that these questions will be addressed.

Mr. SCHLESINGER. Yes, sir.

Mr. DINGELL. The record does not indicate yet that they have been, and we will probably have additional questions for you on these points.

The time of the Chair has expired.

The Chair recognizes the gentleman from Tennessee, Mr. Gore.

Mr. GORE. Thank you, Mr. Chairman.

Dr. Schlesinger, I find myself in disagreement with a number of provisions in the administration's program. I must say, however, watching you respond to the varied prospectives represented on this subcommittee, I believe you are a good argument for a new energy department.

I think you have demonstrated a fantastic grasp of this problem, and I have confidence in your efforts.

Mr. SCHLESINGER. Thank you.

Mr. GORE. A point you made a moment ago is worth underscoring, and that is that we do not have a free market for energy. Our oil prices are set by the cartel in the Middle East.

We now have evidence that our uranium prices have been set by a cartel in which American companies have participated.

If consumers of natural gas in my home town don't like the price of natural gas that they are being charged, they don't have the option of going to another supplier and saying will you give me a lower price? By nature, the distribution system of natural gas makes it a noncompetitive industry. So I think that you are quite correct in starting from that assumption, that there is no free market for energy, and that we cannot rely on market forces to establish with a invisible hand, the best and most efficient price for energy.

We are basically talking about giving more money to the energy companies, in order to encourage them to give us a greater supply.

The question in my mind is how much encouragement do they need? The present price gives a tremendous incentive to go out and discover and bring on line new sources of natural gas, new sources of oil, new oil wells, new gas wells.

I was interested in the colloquy concerning the 2½ mile figure. It was stated that 90 percent of all gas discovered in the past has been within a 2½ mile radius of the existing wells.

With the present price, it seems to me that they have the incentive to look for the gas, and the historical evidence seems to back this up. We are talking about giving them more encouragement over and above what they need.

What is there in this energy program to take care of another problem that is of concern to me, and that is all of the allegations about withholding during the past several years.

Is there anything in this program to reassure the American people that this problem is going to be taken care of?

Mr. SCHLESINGER. Yes, sir. There are three things that I should mention.

First, not within this program, the Secretary of the Interior is conducting a substantial investigation regarding the allegation of withholding from Federal leases in the Gulf Coast area and elsewhere.

Secondly, as mentioned earlier, we have provided for the Department of Energy the authorities to collect information previously provided from private sources to the Government, and requirements on the part of the energy companies that they break down their sources of income by level of production or domestic or overseas operation. We will have much more ample information.

Thirdly, we have provided a set of incentives that will substantially reduce—I hope eliminate—the inclination or motivation to withhold. I am not suggesting now the extent to which there has been withholding in the past. We do not know that, but this will weaken the motivation to withhold. If I take the Texas market, for example, the producers in the intrastate market have been shortening their contracts in recent years. They have not been going for 20 year supplies, because they expected deregulation and subsequent substantial price increases.

The way it has worked out has been a disadvantage from their standpoint. They would have been better to be on long term contracts above $1.75 per Mcf. I think it underscores the point that the prospects of a bonanza are not the reasons to withhold production from the market.

Mr. GORE. I agree with you that the expectation of higher prices in the future is one of the elements that has not been given enough attention.

What is the status of the interim withholding investigation? We were promised action within 60 days, and I am not aware of any action that has been taken. I am wondering what progress is being made. This is in the jurisdiction of the Interior Department?

Mr. SCHLESINGER. That is right. There has been a preliminary report.

Secretary Andrus indicated it would require far more extensive work, and you could not expect a response until September, I believe.

Mr. GORE. I wanted to ask you one further question in the area of natural gas supply.

I am sure you agree with me that the existence of a million miles of natural gas pipelines is a tremendous national asset, and if we can find additional supplies we need to do so. In that regard, why

doesn't the administration's program include bolder initiatives in the field of gasification?

Mr. SCHLESINGER. Boldness lies in the eye of the beholder, I suppose. We have not endorsed the proposal previously presented to the Congress that we subsidize the commercial deployment of coal gasification plants. We are eager to find appropriate projects and new techologies which will enjoy Federal support. The commercial utilization of these facilities should be up to the private sector.

In some cases that can be done. We are examining very closely what the institutional bottlenecks are to see if we can bring about the commercial use of these facilities. They have great advantages in terms of fuel economy.

Mr. GORE. Thank you, Mr. Chairman.

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes the gentleman from New Jersey, Mr. Maguire.

Mr. MAGUIRE. Thank you, Mr. Chairman.

Dr. Schlesinger, to be more precise about the information that I sought in my earlier colloquy, I would like to say what I am asking for is data, and the sources of that data for the following three things:

Historical costs of production; current costs of production, and projected future costs of production with supporting argumentation for that.

Generally, as I indicated, I would like to know if there is anything wrong with the rough calculations that I made in our earlier colloquy.

Perhaps a Congressman with a pencil is a very dangerous thing.

Mr. BROWN. A Congressman with anything.

Mr. MAGUIRE. I don't yield to the gentleman just now.

I took your figure of $20 billion for the additional cost of deregulation, and I put it together with Congressman Moore's figure.

You might want to note this: I am putting Dr. Schlesinger's figure of $20 billion for the cost of deregulation together with your figure that we would elicit 4 trillion cubic feet additional natural gas and I find that that would mean we would be paying $5 per Mcf for that gas.

Using my earlier cases, even if you assume a 500 percent increase in costs, instead of my earlier 250 percent increase in costs, you then end up with a return on investment of 450 percent, and an increase in profit margin of 4,500 percent. Note that these are precisely correct, but what we need to know is whether the ball game is really going to be played out in this kind of a stratosphere, with respect to the pricing of natural gas.

I would note that in testimony before the Oversight and Investigations Subcommittee, John Galloway, this was last August, indicated that in 1971 when the FPC raised the price from 13¢ to 26¢ per Mcf, it elicited the commitment and promise from the producers—and they pledged this to the American people and to the FPC—that the action to raise the price to 26¢ would make funds available to the producing industry and create a regulatory atmosphere which should provide an incentive for a substantial increase

in exploratory and developmental activities, and make a major contribution to bringing forth the additional sources of gas from the Southern Louisiana area to meet the demands of all consumers supplied by this area.

Mr. MOORE. Would the gentleman now yield?

Mr. MAGUIRE. I will yield in just a moment.

Now, in light of that, and in light of the fact that you are asking us legislatively to sanction Order 770 (a) at $1.42, or now it's $1.44 or what have you, $1.45, thank you, Mr. Chairman. When that is presently in the courts, I think this cost data is extremely important.

I have one additional question: I am conscious of the shortage of time. I will go ahead with that and then yield to the gentleman.

With respect to the impact on the Northeast of the tax on oil and natural gas used in industry and utilities, now, of course, you are doing that to discourage the use and that is a worthy objective, but at the same time, apparently there are going to be exemptions, and I also endorse this, for some Northeast areas where there is clearly a problem moving back to coal in terms of air quality.

Those are both objectives which I endorse. I am just pointing out at this point there seems to be an intersection at cross purposes of those two objectives with respect to some areas in the Northeast, and I wondered whether it would also make sense to have an exemption on the users tax for those markets or industries which you would agree ought to continue to use oil and natural gas for air quality reasons.

One of the underlying principles of your program is we equalize things across the country, and I, therefore, wanted to raise that point.

Mr. SCHLESINGER. We had not contemplated that.

Mr. MAGUIRE. You had not?

Mr. SCHLESINGER. We had not contemplated that.

Mr. MAGUIRE. Would you be inclined to contemplate it?

Mr. SCHLESINGER. No; we could not encourage that.

Mr. MAGUIRE. Why?

Mr. SCHLESINGER. Because an underlying purpose of this program has been to use the price mechanism rather than direct mandating with special waivers, in order to encourage the movement away from particular types of fuels towards other types of fuels.

Those that remain with oil and gas should be subject to the full penalties of the prices that others pay.

Mr. MAGUIRE. Even though there are other objectives which are being met, which are those that you endorse.

Mr. SCHLESINGER. Yes, indeed.

Mr. MAGUIRE. So they are going to pay a penalty then?

Mr. SCHLESINGER. The same for those who use natural gas for process use.

Mr. MAGUIRE. Chemical feed stuff or what have you.

Mr. SCHLESINGER. For process use it seems we are using the price mechanism to determine those who must absolutely use gas in their process. To exempt them because they must absolutely use gas from that competitive process would be to make a monkey of that process.

I am not suggesting that the same is true with regard to the problem you have raised, but the same issue arises to subject all of them to the same set of financial requirements.

Mr. MAGUIRE. Could I just ask you to look at that issue?

Mr. SCHLESINGER. Okay.

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes the gentleman from Michigan, Mr. Stockman.

Mr. STOCKMAN. Dr. Schlesinger, the justification that you and Mr. O'Leary have continually given for maintaining a pretty tight system of controls both on gas and oil has been framed most often in terms of equity. You want to prevent the occurrence of what Mr. O'Leary always calls an arbitrary transfer of the economic rents from consumers to producers.

I have heard you say other things and I have heard people in the administration say other things, and I think there are other factors implicit. Aren't you also saying in a way that you want to maintain the current control system, because you feel that if we released the controls and we allowed prices of conventional fossil fuels to rise to the world level, which would be the effective constraining barriers, there would be a great deal of cash flow generated for producing companies, and that would go into a lot of what you consider to be marginal or unproductive drilling?

Mr. SCHLESINGER. Absolutely.

Mr. STOCKMAN. I have seen that statement hinted at before, and I wonder if that is what you really mean. It means, one, you must believe we can get additional sources of energy, whether it's conservation energy from the residential program or conversion program or whether it's producing energy such as more coal, cheaper for less capital, for less economic costs to the economy, than we can get energy from conventional oil and gas sources at the world level.

Secondly, you seem to imply that you feel that Government or the new energy department or FEA can probably better pinpoint those sources of least cost energy than can the market system.

Isn't that really implicit in what you are arguing, because I don't think it's purely an equity argument at all. You want to manage that cash flow, that flow of resources that are going to have to be directed toward production of new energy, whether you do it by conservation or through traditional means.

Mr. SCHLESINGER. Absolutely not. We seek to avoid that. We seek to use the enterprise system to make these decisions, because I think those decisions will be less competently performed by the Federal Government.

The question of regulation; we have attempted to diminish regulation. One of the purposes in going to the world price is get rid of the entitlements system. We have no affection for regulation. We do recognize the fact that as long as there is no free market and OPEC controls the price, we can never allow the price in the United States to be determined by external requirements. These are not market prices.

We do not believe, however, that certain funds are marginal. We are giving the 1977 world price for oil production, $13.50. It is a higher wellhead price than anybody else in the world receives and

with the exception of the Canadians, double that of anybody else in the world.

The 1977 world price is the most generous price around, and that is the incentive offered for production. Other nations have avoided that. We want those companies to go out and find the oil that they and we believe is there.

Mr. STOCKMAN. Most other countries, consuming countries in Canada and Western Europe, wouldn't produce much anyway, but the $13 price or equivalent of gas really applies to a very limited category of new gas in terms of the definitions under 2½ mile radius, and the 1,000 feet depth, and I think you have indicated that in your own studies the national energy plan in its tables in the back says that without the plan domestic oil production would be 10.4 million barrels a day in 1985 and with the plan it would be 10.6

Either you are absolutely convinced there are no additional fossil sources out there to find or you are implicitly acknowledging that your incentives aren't going to do much. I am wondering if you would respond to that.

Mr. SCHLESINGER. The estimates regarding the availability of oil are those that come from the oil industry. This has been the refrain of the industry for some extended period of time.

There are two possibilities. Either this refrain about the lack of availabiity of supply was designed to elicit substantially higher prices and therefore was just a facade, or else they believed it. I am inclined to believe the latter, that indeed, industry does appreciate a severe decline in the availability of petroleum, but we are not taking any fixed view of this.

We are offering the world price for new finds; we are putting the emphasis where the industry has always said the emphasis should be put, which is on new exploration. That is a $13.50 price. In the North Sea the British Government taxes new finds at $7.50, so the wellhead price is half of what we are offering. The same companies that are objecting to a lack of incentives in this country are scampering into the North Sea for half the price in order to make the finds in deeper water, with 30-foot waves.

I would underscore the fact that we have offered substantial incentives. We want the companies to respond as they have always said, which is if the price is right there is plenty of oil to be found there. So let me suggest that the dispute is not about incentives. The dispute that is being raised marches under the banner of incentives, but it is basically an argument about inventory profits to existing finds, and the desire that many have for a massive shift of income and wealth towards the producers.

Mr. DINGELL. The time of the gentleman from Michigan has expired.

Mr. BROWN. Would the gentleman yield just for a moment?

Mr. DINGELL. The Chair recognizes the gentleman from Ohio for a unanimous consent request.

Mr. BROWN. Mr. Chairman, this document just made a reference to this chart at the back of the National Energy Plan, and there are three charts, IX-1, which is the demand chart, and IX-1 which is the supply chart, two parts, and the balances of fuel, which is IX-2, and I have been sitting here trying to rationalize that with the 3.5 trillion cubic feet savings in gas.

I would like to ask that the record be left open so that that can be rationalized, 3.5 trillion cubic feet savings with the figures in that chart.

Mr. SCHLESINGER. Be delighted.

Mr. DINGELL. Without objection, it is so ordered, and without objection, the three charts referred to will appear in the record.

[The charts referred to follow:]

Figure IX–1

Fuel Balances by Sector

[Millions of barrels of oil equivalent per day]

	1976	1985 without Plan	1985 with Plan	1985 Plan plus additional conservation
Demand	37.0	48.3	46.4	45.2
Residential and commercial:				
Oil	3.5	3.2	2.7	----------
Natural gas	3.9	3.8	4.1	----------
Electricity	6.3	9.1	8.4	----------
Coal	.1	(1)	(1)	----------
Total [2]	13.8	16.1	15.2	----------
Industry:				
Oil	3.2	7.0	4.0	----------
Natural gas	4.4	4.5	4.5	----------
Electricity	4.2	7.2	7.1	----------
Coal	1.9	2.7	5.0	----------
Total [2]	13.7	21.4	20.6	----------
Transportation:				
Oil	9.2	10.6	10.2	----------
Natural gas	.3	.2	.3	----------
Total [2]	9.5	10.8	10.5	----------
Electricity: [3]				
Oil	1.6	2.0	1.3	----------
Natural gas	1.5	.9	.5	----------
Coal	4.9	8.2	8.3	----------
Nuclear	1.0	3.6	3.8	----------
Other	1.5	1.6	1.6	----------
Total [2]	10.5	16.3	15.5	----------

See footnotes at end of table.

Figure IX–1—Continued

Fuel Balances by Sector

[Millions of barrels of oil equivalent per day]

	1976	1985 without Plan	1985 with Plan	1985 Plan plus additional conservation
Supply	37.0	48.5	46.4	45.2
Domestic:				
Crude oil [4]	9.7	10.4	10.6	----
Natural gas	9.5	8.2	8.8	----
Coal	7.9	12.2	14.5	----
Nuclear	1.0	3.7	3.8	----
Other	1.5	1.7	1.7	----
Refinery gain	.4	.9	.6	----
Total [2]	30.0	37.1	40.0	----
Imports/exports (−):				
Oil	7.3	11.5	7.0	5.8
Natural gas	.5	1.2	.6	----
Coal	−.8	−1.2	−1.2	----
Total [2]	7.0	11.5	6.4	5.2

[1] Less than 0.05 million barrels of oil equivalent per day.
[2] Detail may not add due to rounding.
[3] Included in previous sectoral totals.
[4] Includes natural gas liquids.

Figure IX–2

Balances by Fuel [1]

[Millions of barrels of oil equivalent per day]

	1976	1985 without Plan	1985 with Plan	1985 Plan plus additional conservation
Oil:				
Consumption	17.4	22.8 [2]	18.2	17.0
Domestic supply [3]	9.7	10.4	10.6	10.6
Refinery gain	.4	.9	.6	.6
Imports	7.3	11.5	7.0	5.8
Natural gas:				
Consumption	10.0	9.4	9.4	----
Domestic supply	9.5	8.2	8.8	----
Imports	.5	1.2	.6	----
Coal:				
Consumption	6.8	10.9	13.3	----
Domestic supply	7.9	12.2	14.5	----
Exports	.8	1.2	1.2	----

[1] Detail may not add up to total due to rounding.
[2] Assuming compliance with automobile efficiency standards under current law, and reduced driving as a result of higher gasoline prices. Without these assumptions, consumption would be 25 million barrels per day.
[3] Includes natural gas liquids.

Mr. MOORE. Mr. Chairman, I wonder if I might get you to yield for a unanimous consent request.

Mr. DINGELL. The gentleman will state it.

Mr. MOORE. I am not quite sure how to handle this. The gentleman from New Jersey made some calculations and figures a moment ago and didn't have time to yield to me for reply, and I would like unanimous consent for him to yield to me for one minute to reply.

Mr. DINGELL. If the gentleman wishes to make a reply for purposes of the record, the Chair will see that it is inserted and without objection so ordered. I am sure the gentleman is aware of the time constraints of the committee and will see to it that it is promptly submitted to the committee.

[The following statement was received for the record:]

ADDITION TO THE RECORD OF THE HEARINGS OF THE ENERGY AND POWER SUBCOMMITTEE BY HON. W. HENSON MOORE (R-LA.)

In response to a unanimous consent request granted by the Chairman, I would like to offer this rebuttal to hasty computations made by the gentleman from New Jersey, Mr. Maguire, during the Committee hearings of the Energy and Power Subcommittee in the morning session on Thursday, May 12, 1977. Mr. Maguire commented that using 4 trillion cubic feet of new natural gas produced by deregulation would cost in the neighborhood of $5 per thousand cubic feet. I do not accept his computations and believe he is in gross error.

The figure of 4 trillion cubic feet of new natural gas is a very conservative one as an earlier report from the Federal Energy Administration dated December 13, 1975, showed that figure was more like 9 trillion cubic feet of new natural gas and a study by the Stanford Research Institute shows more like 10 trillion cubic feet of new natural gas. Both of these reports are part of this record. That alone would bring the gentleman from New Jersey's computations to down well less than half of his $5 figure.

In addition, his computations completely ignore the increased cost of production. Figures prepared by the Joint Association Survey of the U.S. Oil and Gas Producing Industry, which have been accepted by the Federal Power Commission in their rate regulation model computations show that the cost of an offshore gas well increased 72% in one year (from 1974 to 1975) and that the average cost per foot of drilling had gone up 30%. This same model would call for a price of $2.58/mcf today based on these increased costs. Therefore, we must realize that the cost of drilling a gas well is escalating very quickly which will, of course, cause the ultimate value of natural gas to go up. In addition, it must also be noted that new discoveries of natural gas are very often at far deeper depths than previously discovered or produced from and, of course, it costs disproportionately more to drill for natural gas the deeper you go.

Therefore, I submit this information to show that the gentleman from New Jersey's computations should not be accepted.

Mr. DINGELL. The Chair now recognizes the gentleman from Texas, Mr. Gammage, for five minutes.

Mr. GAMMAGE. Thank you, Mr. Chairman.

Dr. Schlesinger, as I understand it, the President's energy plan imposes a coal tax relating to tonnage; is that correct?

Mr. SCHLESINGER. No, sir. It's not in the energy plan. There is a requirement in the stripmining legislation, which incidentally originated in the Congress, that a fee be paid for stripmining to restore the land.

Mr. GAMMAGE. Based on tonnage.

Mr. SCHLESINGER. I think so; yes, sir.

Mr. GAMMAGE. This is one of the problems I am having with the whole program, because we deal with the Clean Air Act. We deal with various aspects of the energy production and consumption and the right hand never seems to know what the left hand is doing.

The stripmining legislation and the Clear Air Act itself I think would throw some substantial monkey wrenches into the many phases of the President's proposal here, particularly as far as coal convervsion is concerned, and that is what I am getting out of the stripmining bill or wherever it comes in from, and I would like your response to this.

Texas has vast reserves of lignite, and yet the proposed tax has been discussed across the board, which is one based on tonnage rather than Btu output. Lignite, of course, has a much lower Btu output than other forms of coal, and yet it's right there at home.

Could you give me a response or do you not think it would be more rational and more reasonable if we are going to impose any type of tax it be based on Btu output rather than tonnage, so it would encourage the use of local coal in areas where it can be found, particularly in areas of high lignite concentration and discourage the import, and the transportation for purposes of the economics and convenience, both to encourage the use of local coal in local areas.

Mr. SCHLESINGER. I believe that the tax in question would have very little effect on the prices. We will examine that and give you a response.

[The following material was received for the record:]

A Btu basis for a tax would be more equitable to the coal consumers, but it would require an insurmountable administrative effort. It would require an analysis of all coal produced and a sampling of every carload shipped. Coal is very heterogeneous, and Btu content varies widely between seams and within seams of coal.

Both the Senate and House versions of surface mining legislation impose a reclamation fee of 35 cents per ton for surface mined coal and 15 cents per ton for underground mined coal limited, however, to 10 percent of the value of the coal as determined by the Secretary of the Interior. The value would certainly reflect the Btu content of the coal. While the Senate version of the legislation would not impose a reclamation fee for lignite production, the House version would limit the fee to 35 cents per ton on lignite limited to 5% of the value of the coal at the mine.

Mr. GAMMAGE. My response to the whole spectrum is that I hope someone is going to exercise some coordinating authority. I don't know whether Congress can, will, or should, but leadership has to come from some direction.

Mr. SCHLESINGER. I think there is a very high degree of coordination here. The problem you allude to is the balancing between environmental considerations and energy considerations. That is a difficult problem, and on that problem individuals will differ.

Mr. GAMMAGE. I have a particular problem right at home in an area of high population impaction, increasing rapidly, increasing population where additional utility demands are made on a daily basis, particularly as far as electrical power generation is concerned, and the industry there, the traditional utility industry traditionally uses the natural gas.

There is a lag of 11 years or so for new nuclear generation.

Mr. SCHLESINGER. We hope to cut that.

Mr. GAMMAGE. They are prepared to move immediately to coal. However, it's also a non-attainment area, where a one on one trade-off from deregulation simply will not accommodate the immediate needs because the environmental technology is not available as far as cleaned up coal burning. They can't construct new gas burning

facilities, obviously. They can convert some of their old gas burning facilities to oil, but not coal.

Any new construction in the immediate future—and there is an immediate need—would have to obviously been coal fired. They can't do it. Yet the need is there. The demand is there. The consumers are there, residential and industrial, and we are catch 22; where do we go?

Mr. GORE. Would the gentleman yield?

Mr. GAMMAGE. Absolutely.

Mr. GORE. There will be an amendment offered on the floor when the Clean Air Act is presented with the support of Mr. Rogers to allow the use of local coal if the State authority certifies the use of coal from other States would have an adverse impact.

Mr. GAMMAGE. That speaks to one end of it; if the environmental end of it lets you burn it. Here again, as I pointed out in my earlier question, the industries, the consumers in the producing areas like that feel threatened as far as their ability to continue to exist with existing industry and existing rates of consumption because of the intrastate allocation authority that is included in this proposal.

Mr. SCHLESINGER. I think that that fear is unwarranted. As I indicated earlier, there is no intention save in emergency situations to make use of that allocation authority. We fully recognize that Texas, Louisiana, and some of the other States have become quite dependent on gas and that that must be given very careful consideration in whatever action is taken.

We have attempted to do so. There is legislation in the Texas Legislature that would mandate the cutoff of use of gas as boiler fuel by 1985. We carefully avoided that. We used price measures, gave a longer period of time so as to minimize the difficulties of a State like Texas that has become dependent upon the use of gas. Until recently they were doing a national service to avoid gas being wasted. We are deeply cognizant of those problems.

The notion that gas will be allocated away from those intrastate markets strikes me as inappropriate.

Mr. GAMMAGE. If the authority is requested and included, the fear does not seem to me to be appropriate. They feel like they are between the rock and the hard place down there.

Mr. DINGELL. The Chair will give the witness time to respond. The time of the gentleman has expired.

Mr. SCHLESINGER. As I just indicated, we have been deeply cognizant of the special problems of places that have become disproportionate users of gas. They must be given an extended period of time in the first place, and in the short run one must take into account the requirements of their industries that are so dependent upon gas.

The notion that the allocation authority would be used in some way to be not cognizant of those local requirements is understandable alarm perhaps, but it is unjustified in my judgment.

Mr. DINGELL. The Chair recognizes counsel for purposes of asking questions.

Mr. DEMAREST. Thank you, Mr. Chairman.

Dr. Schlesinger, on page 6 of your testimony you say that a criteria for natural gas legislation was that it would provide appropriate incentives for natural gas production "through stability,

predictability and assurance of reasonable prices." Section 405 of the proposed legislation would guarantee a producer lesser of the contract price or the just and reasonable rate as determined by the Federal Power Commission. Is that correct?

Mr. SCHLESINGER. Yes, sir. For existing contracts.

Mr. DEMAREST. FPC Order 749 guarantees a producer 18 cents an Mcf for gas even if the contract price is less. Does section 405 overrule that order, and if so, why?

Mr. SCHLESINGER. There would be discretion on the part of the President.

Mr. DEMAREST. Where is that discretion found? In section 405 or elsewhere?

Mr. SCHLESINGER. The President would have the authority to overrule the judgment, coming up either from the board of hearings of appeals in the Department of Energy or the FPC under present statutes. We will clarify that for the record.

[The following information was received for the record:]

Section 405 sets the existing contract—old gas price at the lesser of (1) the contract price, or (2) the pre-April 20, 1977, FPC just and reasonable price. The Section 405 price is, through the operation of Section 409, binding on the FPC. To the extent the Section 405 determination will result in a price less than the FPC price, it can be said Section 405 would "overrule" an FPC price. Since the President is directed to establish the lesser price he cannot be said to have discretion. This was done to prevent any windfall from accruing to producers on gas already discovered and dedicated.

Mr. DEMAREST. In view of your definitions of a new well and an old well, what is the status of a well that was begun prior to April 20 but was not capable of producing on or before April 20?

Mr. O'LEARY. It is irrelevant for purposes of sections 404, 5 and 6. We will be glad to explain that to you for the record.

Mr. DEMAREST. It is irrelevant? Why do we have two definitions then? Is only the new well definition operative, in other words?

Mr. GOLDMAN. The old well definition is only applicable for purposes of defining the distances. The new well definition is applicable for other purposes in terms of section 404, 5 and 6. That is why the middle ground that you just described does not fall within the definition of new well or old well. It does not make any difference because it has no relevance in terms of the price-setting system. The well you described wasn't producing anything.

Mr. DEMAREST. If a producer cannot obtain a higher price for an intrastate sale than he can for interstate sale, will he nevertheless continue to prefer intrastate sales rather than interstate sales in order to avoid the regulatory burden that is placed upon those interstate transactions by FPC regulation, including certification requirements of the Natural Gas Act?

In other words, aren't there in fact two impediments: price and regulation?

Mr. SCHLESINGER. That is a possibility.

Mr. DEMAREST. Would an alternative approach be acceptable which would not only take the action you have taken on price but would also, in effect, deregulate the interstate producer from Natural Gas Act requirements of certification, abandonment, reporting requirements, and then subject all producers, both interstate and

intrastate, to a uniform set of rules regarding contract terms, et cetera?

Mr. SCHLESINGER. The first part of that is done in section 412. We will look at the totality and get back to you for the record.

[The following material was received for the record:]

Section 412(a) of the bill specifically recognizes this concern by doing away with the dedication requirement for new natural gas whenever it is mandated. It is this dedication request (owner or purchaser is committed to interstate commerce forever) that has deterred intrastate purchasers from making any interstate commitments. The elimination for new gas of vintaging (staying at one constant price once gas is sold) together with the elimination of the dedication requirements for new gas is expected to create a new national gas market similar to the national oil market. These two new initiatives will allow sellers to move more freely in and out of both the intrastate and interstate new gas markets.

Mr. DINGELL. The Chair will be submitting some additional questions to you, Doctor. I am troubled about the specifics of things like coal mines, methane gas from coal seams. I assume the bill provides the opportunity for deregulation of that, or higher prices for that, but at a time at your convenience I think it would be useful if we had information on that matter that would enable us to have some appreciation of how we could bring that gas on line since it appears to be a very large supply of gas now being wasted through ventilation practices.

Mr. SCHLESINGER. That would be much appreciated.

[The following information was received for the record:]

The President, under section 408 of the proposed National Energy Act, would be empowered to set a special price for any natural gas which he specifies, if he determines that a special price is necessary to provide incentives for the production of gas in categories which involve high costs. This authority would extend to the production of methane from coal seams, wherever costs of production necessitated a special incentive price. The experience with production from this source to date is insufficient to speak to the question of where such special rates would begin to offer meaningful incentives. The Energy Research and Development Administration is conducting a research program which will provide this experience, not only for coal bed methane, but also for gas from geopressurized formations, tight sands, Devonian Shales, and other unconventional sources.

Mr. DINGELL. The gentleman from Michigan, Mr. Stockman, has requested additional time.

Mr. STOCKMAN. I hesitate to go back to some of the points we were debating before because I learned my public policy concepts in economics from reading your books. One thing that I cannot remember from that process of education is the concept of what you call inventory profits and what Mr. O'Leary calls economics rents. I cannot understand what is the difference between the so-called inventory profits that you would see resulting from deregulation in the oil and gas scene today and the $9 a bushel that soybean farmers were getting in 1973. There was a series of shortages, the price ran up, and as a result they were making profits far in excess of the historical average. Those probably were inventory profits too, or economic rents, but the fact is that the cash flow that came from those inventory profits or economic grants went back into expanded soybean acreage production and, with some changes in supply and demand and conditions around the world, equalled out.

I do not see why we are in that much of a different situation, unless you have some pretty hard evidence and some strong reason

for believing there is a very low elasticity of supply for oil and gas and that has to be what is in the computer or you never would have gotten the results you printed in the back of your book.

I have seen a lot of other estimates based on elasticity assumptions which indicate we could get 14 or 15 million more barrels of production by the mid-1980's and an equivalent response for gas. Where do you get your numbers and why are you so sure about them?

Mr. SCHLESINGER. As I indicated before, we are quite agnostic with regard to how much oil can be produced how quickly in the United States. I hope that the number in the report is on the low side. We are giving $13.50 for a new barrel of oil which is a very generous price.

We have been repeatedly told that if the price is right, there is plenty of oil out there. I hope that is correct. Come in and prove it. If it is 14 or 15 million barrels a day, that is great.

There is a problem.

Mr. STOCKMAN. I don't want to debate incentives with you. I agree completely and I think we are kind of missing arguments. But drilling is a function of cash flow and cash flow will be a function of the current price.

I think you can show on the historical record that there has been a historical relationship between the amount of new drilling and the amount of reserve building and cash flow.

Mr. SCHLESINGER. I think you are quite correct that we do have a difference there, Mr. Stockman. There has been an inconsistent relationship between drilling and cash flow. If one examines the performance of the oil companies in recent years, one discovers $4 billion generated in excess cash that was not being put into drilling. These are just the majors. Among the independents there has been a closer relationship. But even that is not as close as was suggested.

Mr. STOCKMAN. I think it is going to depend to some degree on a concept I learned from you and that is opportunity costs. In the late sixties, perhaps early seventies or during the uncertain economic climate of 1975, there may have been better opportunities for investment of funds.

It seems to me if you look at the world economic market, that we are in a good position for energy and particularly for gas and oil because it has a lot of attributes that the market desires. There aren't going to be very many better opportunities to direct cash flows in terms of their return than oil and gas production that is produced if we don't have the overhang of uncertainty resulting from government control.

Now where is that cash flow going to go? It is either going to go into investments outside the energy industry or it is going to go into dividends. I don't think either of those are very likely.

Mr. SCHLESINGER. I agree with you almost entirely, Mr. Stockman. It is a matter of opportunity costs. That is why we are creating opportunities at the margin, aside from the question of inventory profits, to make this as attractive as possible.

If the Congress supports this legislation, we will have a stable environment for industry to make its decisions with attractive prices. Under those circumstances, and the opportunity costs, I

would expect that excess funds that have not been invested will be invested if, indeed, if there are leases available, rather than simply bidding up the leases as has happened in recent years.

There is no purpose in simply bidding up, where various people competing against each other to bid up the price of a limited number of leases, drilling rigs and trained manpower. But if there is the oil out there and we can expand this industry, the price is right. We hope to create a stable climate and that is the purpose. So we are in agreement on that.

Mr. DINGELL. The time of the gentleman from Michigan has expired.

Doctor, we express our thanks to you and to Mr. O'Leary. You have been helpful and generous with your time. The committee is appreciative of your kindness.

Mr. SCHLESINGER. Mr. Chairman, the question of opportunity costs came up. These are some of the indications that we have through 1975. Our data can be improved and will be improved when the Department of Energy comes into position.

But at least the reports are that the company profits for exploration and production are running in excess of 30 percent. That is not a bad rate of return. The cost of not getting into those production opportunities, if indeed they are available, is very high.

Thank you, Mr. Chairman.

Mr. DINGELL. The Chair has done a discourtesy to one of my colleagues, the gentleman from Pennsylvania, Mr. Walgren.

Mr. WALGREN. I want to apologize for not being here to hear your testimony this morning. I have a problem with a hospital in my community whose funds are in great trouble. I knew I could read the testimony and I felt I should take care of what was a higher priority to me and some other people.

In response to reading it, I will try to provide some questions for the record.

Mr. DINGELL. Dr. Schlesinger, the committee thanks you for your participation and assistance today.

The committee will stand adjourned until 2 p.m.

[Whereupon, at 1:14 p.m., the subcommittee adjourned, to reconvene at 2 p.m. the same day.]

AFTER RECESS

[The subcommittee reconvened at 2 p.m., Hon. Richard L. Ottinger presiding.]

Mr. OTTINGER. The subcommittee will come to order.

We are continuing our hearings on H.R. 6831, the National Energy Act. We are limiting ourselves today to title I, part D, dealing with natural gas. We have before us a panel of industry producer witnesses.

Gentlemen, we welcome you here. I wonder if you would introduce yourselves.

STATEMENTS OF A. V. JONES, JR., PRESIDENT, INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA, ACCOMPANIED BY D. K. DAVIS, VICE CHAIRMAN, IPAA NATURAL GAS COMMITTEE; DA-

VID H. FOSTER, EXECUTIVE VICE PRESIDENT, NATURAL GAS SUPPLY COMMITTEE, ACCOMPANIED BY C. M. ALLEN, GENERAL NATURAL GAS GEOLOGIST, PHILLIPS PETROLEUM COMPANY, AND TOM JOHNSON, SENIOR COUNSEL, SHELL OIL COMPANY AND MEMBER, LEGAL SUBCOMMITTEE, NATURAL GAS SUPPLY COMMITTEE; AND ROBERT A. HEFNER III, CHAIRMAN, INDEPENDENT GAS PRODUCERS COMMITTEE

Mr. ALLEN. I am C. M. Allen with Phillips Petroleum Company.

Mr. FOSTER. I am David Foster, executive vice president of the Natural Gas Supply Committee. With me today is Tom Johnson, senior counsel with Shell Oil, and he is a member of the Legal Subcommittee of the Natural Gas Supply Committee.

Mr. JONES. I am A. V. Jones of Albany, Texas, president of the Independent Petroleum Association of America.

Mr. DAVIS. I am D. K. Davis, an independent gas producer from Dallas, Texas and here in conjunction with the Independent Petroleum Association of America.

Mr. OTTINGER. We welcome you gentlemen. I am sorry our supply of committee members is sparse today. We are operating under very difficult time restraints to get the legislation out. I trust we will be joined later in the afternoon by other members of the subcommittee.

Do you gentlemen have a preference as to which order you will speak in?

Mr. FOSTER. The last member of our panel just appeared and I believe he would like to introduce himself.

Mr. HEFNER. I am Robert A. Hefner III, chairman of the Independent Gas Producers Committee.

Mr. FOSTER. With your agreement, Mr. Jones will lead off and I will follow him. Then, Mr. Davis will proceed and Mr. Allen and then Mr. Hefner, if that is agreeable with you.

Mr. OTTINGER. That is most agreeable. You may proceed.

Without objection we will put the full statement of each of you gentlemen into the record.

Because of the number of witnesses and the time involved, if you could summarize your statements, you are welcome to do so.

Mr. Jones, you may proceed.

STATEMENT OF A. V. JONES, JR.

Mr. JONES. My name is A. V. Jones, Jr., and I am a partner in A. V. Jones, Ltd., an independent oil and gas exploration-producing organization at Albany, Texas. I am appearing here as president of the Independent Petroleum Association of America (IPAA), a national organization of more than 4,500 independent oil and natural gas producers who operate in every producing area of the United States. We appreciate the opportunity to comment on H.R. 6831, President Carter's National Energy Act.

President Carter deserves credit for focusing the attention of the people of the country on the seriousness of the energy situation. My industry has been trying to do this for more than 20 years and has not been very successful in doing it, I might add. The problem is

finally ripe for a solution. But having stated the positive feature of the Carter energy plan, I must emphasize that it fails to deal with the fundamental problem we face—the necessity to find and develop new supplies of domestic energy.

The more than 10,000 independent oil and gas producers who drill more than 90 percent of the wells in the United States have an important role to fulfill in providing energy for our citizens. We will be unable to carry out that vital role under the permanent price regulation proposed by the administration.

We find the Carter energy proposal to be poorly conceived, poorly drafted and internally inconsistent. Not only will it not maximize the production of crude oil and natural gas, it will cause less to be produced than would be under existing law. IPAA has in the past and continues to believe decontrol of new natural gas is the keystone to solving our natural gas supply problems. While conservation is an important factor in dealing with the problem, it alone cannot do the job. The Carter proposal is built on the erroneous premise that there is no more oil and natural gas to be found. We do not agree with that premise and neither does the American public. In a recently released Gallup poll, the public by a two-to-one margin said they believed the Carter scheme relied too much on conservation and not enough on increasing production.

The Carter package contains all the elements for economic chaos at home and political nightmares on the international front. Having made significant progress toward convincing the people of the country that there is really an energy crisis, the program makes no effort to actually solve it. It merely suggests that conservation is all that is necessary.

Instead of taking the opportunity to design a program that would finally insure development of domestic petroleum resources, the surest means of guaranteeing energy for the transition period to alternative energy sources, the architects of this plan have chosen to recommend reliance primarily on conservation and coal and to further discourage oil and gas producers from looking for the additional reserves they know they can find and which are so vitally needed.

This program sells the consumer short. It threatens the very existence of his job and the jobs of some 15 million other men and women, already born, who will join the work force between now and 1985. For every Btu of energy not produced here at home, another must be purchased abroad and for every one purchased abroad, another dollar, and ultimately, another job is exported.

This program represents a complete lack of faith in the system which has produced the strongest economy in the history of man. It demonstrates a lack of faith in the ingenuity of American men and women who historically have risen to every challenge with which they have been confronted.

The reasons IPAA members, and nearly every American, for that matter, should oppose the Carter scheme are many. In the interest of time, I shall summarize but a few. They are:

1. It perpetuates price controls indefinitely which will make scarcity and rationing a permanent way of life.

2. It takes a giant step toward a totally regimented economy and eventual nationalization of the natural gas industry.

3. Instead of building on the successes of the intrastate competitive market it extends price controls to that market.

4. It provides for severe price rollbacks and continued price uncertainty which will work to deter supply development.

5. It provides for the defining of new natural gas on an arbitrary, political basis rather than a practical geological basis.

6. It discriminates against users of natural gas and in favor of those using heating oil, much of which is derived from insecure foreign crude.

7. It will feed the fires of inflation, deny jobs to millions of Americans and reduce the standard of living.

8. It takes billions of dollars from consumers which will end up in the U.S. Treasury instead of being available for the development of new gas supplies.

9. It ties new natural gas prices to the poorly conceived composite price of domestic crude oil rather than at its actual replacement cost.

10. It ignores the unprecedented capital requirements of our industry. Chase Manhattan Bank has estimated those requirements to be $265 billion over the next 10 years—four times as much as was needed in the last 10.

The last Congress spent months working on energy policy. While we disagreed with many features of the Energy Policy and Conservation Act of 1975, we agreed with the Congress when it said that there must be a day when price controls on American oil must come to an end. We strongly agreed with the Senate in 1975 when it voted by a margin of two to one to remove price controls from new natural gas. That proposal came within a slim two vote margin of passing the House and surely becoming law.

To us it is incredible that little more than a year later we have moved from that "can do" approach to solving the energy crisis to the negative, doomsday approach to the problem that we have before us today.

Before I conclude this statement, I would direct your attention to two attachments to my statement which were discussed and unanimously adopted by more than 1,000 independents attending the IPPA midyear meeting in Denver earlier this week. I would also ask that we be allowed to submit additional information within the next few days for the record and for use by this committee.

Independent oil and gas producers are not accustomed to pessimism. In fact, the opposite attitude is a way of life for them or they would not be in the business they are in. Thus, we must tell you that IPAA totally rejects the proposals contained in the Carter proposal and urges you to do the same by setting aside consideration of the gas provisions of H.R. 6831 and give prompt attention to reporting out H.R. 2088 which has been sponsored by a number of members of this committee. American producers and consumers deserve better than this and it is the responsibility of you, their elected representatives, to give it to them.

Thank you, very much.

[The attachments to Mr. Jones' statement follow:]

STATEMENT ON NATIONAL ENERGY POLICY BY THE INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

Denver, Colorado, May 10, 1977

The Carter Administration's national energy plan is a massive taxing and regulatory system that would:

(1) Take a giant step toward a totally regimented economy;
(2) Deprive the American people of secure and adequate energy supplies;
(3) Accelerate our dependence on high-cost, remote and unsecure foreign oil;
(4) Make scarcity and rationing a permanent way of life;
(5) Feed the fires of inflation;
(6) Deny jobs to millions of Americans; and
(7) Reduce the standard of living.

The program calls for a massive intervention of government into the life of every citizen of the United States. It abandons the concept of a free market that has served the public and built the strongest economy in the world. It would lead to stagnation, followed by nationalization—first of the energy industries and later of other basic industries.

Price controls would be continued indefinitely on both oil and natural gas which supply three-fourths of all the energy required for economic growth and higher employment. High taxes would be imposed on oil and gas production, gasoline and automobiles. These taxes could accumulate over just the next five years to the staggering total of more than $125 billion and eventually reach about $70 billion per year. Not one penny of this enormous sum would be available to increase vitally needed domestic energy supplies.

Under the Administration's plan, our already intolerable dependence on high-cost, insecure foreign sources of energy would be further aggravated. We would be increasingly at mercy of the OPEC cartel which already is in a position to paralyze our economy and undermine our security.

The glaring and catastrophic weakness of the Administration's energy program is the deliberate decision not to encourage domestic oil and natural gas exploration and development which must be greatly expanded. This decision is based on the assumption that there is little or no potential for finding and producing additional oil and gas in the United States. This is a false assumption. Known and undiscovered domestic supplies are adequate to significantly contribute toward meeting U.S. requirements for decades to come.

There is no practical alternative to supplying substantially more oil and gas. And this can and must come from domestic reserves if this nation is to remain secure and prosperous. The Administration's program ignores the compelling need to accomplish that all-important objective.

We believe reliance on the free market provides the most effective and least costly solution to the nation's worsening energy supply problems. We dedicate ourselves to preserving the American system of private enterprise under which the United States has served the best interests of its citizens and attained the leadership of the Free World.

REPORT OF THE NATURAL GAS COMMITTEE, INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA, 1977 MID-YEAR MEETING

Denver, Colorado, May 8, 1977

The Natural Gas Committee of IPAA reports to the Executive Committee and the membership that it has reviewed the natural gas provisions of President Carter's energy program. We find the proposal to be poorly conceived, counterproductive, and unworkable. Instead of solving the problems related to providing needed natural gas supplies now and in the future, this proposal, if adopted by the Congress, would make the situation worse. As independent producers of natural gas, who drill more than 90 percent of the wells in the nation, it is our obligation to alert the American people to the fact that the proposal will adversely impact them by promoting more severe natural gas shortages, increasing unemployment, and causing additional imports of insecure foreign fuel.

The facts which lead us to this conclusion are:

1. The extension of federal price controls to the intrastate market. Instead of building on successes of the intrastate competitive market in producing new supplies, the proposal is based on the philosophy of continued and expanded price controls.

2. Not only are controls continued and expanded, in many instances there will be severe price rollbacks, further discouraging expanded supply development.
3. Coupled with the price rollbacks is the continuation of price uncertainties which will also work to deter supply development.
4. Contrary to what candidate Carter promised, President Carter's proposal would perpetuate controls indefinitely with no hope of achieving competitive market prices.
5. The definition of new natural gas in the proposal is totally unrealistic and arbitrarily based rather than geologically based.
6. As drafted, the proposal would discriminate against users of natural gas to the benefit of those using heating oil.

The Carter proposal is erroneously based on the premise that there is no more natural gas to be found. That premise is contrary to every reputable study which has been made. Since 23 years of federal controls over the interstate market have brought us the natural gas shortage we face today and in light of the fact that the intrastate competitive market has worked so well to bring on new supplies of natural gas, we totally reject the Carter proposal and call upon him to make good on his campaign promise to the American people to decontrol natural gas prices.

Mr. DINGELL. Thank you, Mr. Jones.

STATEMENT OF DAVID H. FOSTER

Mr. FOSTER. Mr. Chairman, my name is David H. Foster. I am Executive Vice President of the Natural Gas Supply Committee which is an organization of major independent and individual gas producers.

I have submitted for the record a more definitive statement of our position. I will confine my opening remarks to a general commentary on the natural gas provisions of H.R. 6831, an analysis of some of the more obvious flaws in the legislative proposal and our proposal for a more efficacious solution to the problems which the President has laid before us.

Mr. DINGELL. Without objection your full statement will be placed in the record and you will be recognized for the summary.

Mr. FOSTER. Thank you, Mr. Chairman.

Few would disagree with the findings and purposes set forth in section 401 of the bill. We are all painfully aware of the tragic story of 23 years of Federal price tinkering, with its inevitable consequences of artificial stimulation of consumption, disincentives to exploration and dwindling reserves. Clearly, something must be done.

Nevertheless, our examination of H.R. 6831 reveals it to be nothing more than a thinly disguised continuation of what has already failed in the interstate market coupled with an extension of those failures to the only bright spot in the Nation's energy picture—the eminently successful intrastate market for natural gas.

The President has promised incentives for new production, but instead we find a composite of disincentives which go far beyond those existing today under FPC controls.

The President has promised certainty upon which future investment decisions might be based, but instead we find confusion and complexity so pervasive that it has defied our initial legal analysis.

The President has envisaged a gradual movement toward decontrol of wellhead prices but instead we find a crystallization of policy in permanent and total Federal domination of the pricing mechanism.

What is the philosophical rationale for this approach? Strangely enough, it is not found in the findings of section 401, although it has

been often stated by the President and his energy advisors. The potential supplies of natural gas are finite and, therefore, there is little or no price/supply elasticity. Thus, there is no point in permitting prices to go to market clearing levels.

That, of course, is a self-fulfilling prophecy but it is the fallacious foundation of this entire proposal. We disagree with it totally. Natural gas producers are confident that the resource base for natural gas is substantial and will be for many years. We know there is a supply response to market clearing prices because we have experienced it in the intrastate market. We believe that this same kind of response is available for interstate supplies because our own geologists, economists and financing sources tell us so.

Mr. Chairman, this bill gives up on natural gas as a major resource in the Nation's energy warehouse. That is unsound, imprudent and just plain contrary to the best interests of all of us. Producers believe in conservation and demand control. But, at the same time, they want the opportunity to prove once more, as they have so often in the past, that the market pricing mechanism is the best and most efficient way to assure conservative use and maximization of supply.

Let me turn to specific problems in H.R. 6831.

First of all, as the price of new gas will be pegged to the average cost of domestic crude oil at the refinery and the bill contains no crude oil pricing measures, it is totally impossible for the producer to predict what this price will be. An analysis of the various administration pronouncements on this subject not only fails to clear up this uncertainty but actually creates more confusion. We are completely in the dark as to how the much-quoted $1.75/Mcf is derived.

Even assuming, however, that a ceiling of something like $1.75/Mcf is intended and will somehow come about, the pricing structure continues the folly of pricing natural gas, our most desirable fuel, below the cost of available alternatives.

The price of new gas will be less than the price of new oil. If one assumes that new oil will eventually rise to the world crude price as has been promised, new gas will be priced at a substantially lower figure, because of the more heavily weighted impact of the lower and upper tier oil prices in the "Btu related price" of new gas.

The freezing of the current FPC multiple vintage pricing system results in substantially lower prices for gas than for other fuels. This is, of course, because of the inability of the pipelines to roll all prices into a composite price to the consumer. Even for the low priority user, the resulting price will still be below the cost of alternative fuels.

My colleague, Mr. Allen, will address in detail the specific deficiencies in the new gas definition contained in the bill. Let me only comment that it is a typical example of the manner in which the draftsmen of this measure totally ignored the geological, engineering and economic realities of the natural gas industry. If one had set out to fashion a provision calculated to discourage exploration activity and to minimize the already speculative chances of success in wildcat ventures, one could scarcely have done a more thorough job.

Turning to another supposed incentive in the bill, we have all heard much about the special pricing provisions in section 408 which are designed to encourage new frontier drilling.

Each of the FPC ceiling price orders since the first *Permian* case has contained a similar special relief provision. It has been interpreted so restrictively, however, that it is of little value to the producer. Producers have no reason to believe that a less restrictive interpretation would be applied under this bill, particularly in view of the narrowly limited examples of what might qualify. The one factor that will definitely and positively result in new frontier drilling investment and development of necessary new technology is the prospect of market prices.

We are also aware of the publicity given to the provisions of section 406 granting special pricing relief to old gas sold under new contracts. One administration spokesman was quoted as predicting that the so-called roll-over price of $1.45 would bring additional annual revenues of $1 billion to the industry. Obviously, section 406 does not peg a price of $1.45 but permits the President to fix a price of up to $1.45, giving due consideration to the original contract price and the price necessary to maintain production.

The special relief provision and the roll-over contract provision are typical of the much touted but basically illusory incentives in this bill—all of them fraught with uncertainty, vagueness and complete unpredictability.

Mr. Chairman, this is by no means a complete catalog of what is wrong with this bill. There are countless internal inconsistencies and defects which I am sure the most competent staff of your subcommittee will ferret out and attempt to adjust.

However, we respectfully submit that no amount of technical cutting and fitting will make this a measure that will do anything for the supply side of the natural gas equation. Only if this bill is amended to include the clear and certain promise of market prices for new natural gas and an intelligent and realistic definition of new gas will it rise to the dignity of energy policy. In its current form it is surely energy despair.

Mr. Chairman, I would like to comment on one statement that was made this morning by Dr. Schlesinger. He stated for the record that he had conversed with representatives of major oil companies, independent oil companies, and that a clear majority of them did not favor deregulation and they felt $1.75 was an incentive price.

I don't know who he talked to. However, our organization represents producers of about 90 percent of the interstate gas in this country and a slightly smaller percentage of intrastate gas. I have been conversing with those people ever since this energy policy was announced. I have talked with literally hundreds of producers and all the major trade associations representing them.

Let me state for the record, not only our policy on the record but the record is that deregulation is the answer to the natural gas problem.

Thank you.

[Mr. Foster's prepared statement follows:]

TESTIMONY
OF
DAVID H. FOSTER
ON BEHALF OF
NATURAL GAS SUPPLY COMMITTEE

My name is David Foster and I am Executive Vice President of the Natural Gas Supply Committee, an organization of major, independent and individual natural gas producers. We appreciate the opportunity to appear before you today to express our views on natural gas. I would like to state first the position of the Natural Gas Supply Committee on natural gas legislation and then offer some comments on the Administration's proposed energy bill as it relates to natural gas.

We start with the proposition that the present shortage of natural gas in this country results primarily from twenty-three years of federally dictated controls upon the wellhead price of natural gas sold in interstate commerce for resale. These controls persistently kept the price levels at unrealistically low levels. As a result demand for this premium fuel was stimulated without commensurate stimulation of the effort to develop new supplies. Demand for other fuels such as coal was dampened at the same time as consumers shifted to natural gas. This shift was price-motivated and in many cases led to a wasteful consumption of natural gas.

The regulatory approach which failed was premised upon an adaptation of a utility cost of service approach. Though theoretically designed to return cost plus a reasonable rate of return, this approach was never suitable for application

to natural gas producers engaged in a high-risk, capital intensive business. What developed was a procedure in which prices were set after long delays, based upon historical costs bearing little or no relation to the prospective costs which would be incurred in developing new supplies. Lacking the incentives to search for and develop new supplies, many producers left the business, or turned their attention to other investments, or concentrated on development for sales in the unregulated intrastate market. The result was to be expected -- commencing about 1968, production of natural gas exceeded new reserves added; the interstate market began to experience increasing shortages as old supplies dwindled without being replaced; and curtailments of lower priority uses of natural gas became necessary to preserve the supply for human needs customers.

NGSC believes that the solution of a problem caused, in the main, by Federal controls is not to be found in additional Federal controls. On the contrary, removal of Federal controls on the wellhead price of natural gas offers the most effective means of eliciting new supplies of natural gas. Allowing the market forces to operate has a dual salutary effect of providing the incentive to producers to search for and develop new natural gas reserves as well as inducing conservation by consumers of natural gas as the premium value of that commodity becomes apparent through market forces.

The potential of substantial new supplies of natural gas is illustrated by several estimates. The U.S. Geological Survey estimates potential undiscovered supplies ranging from a low of 322 trillion cubic feet to 655 trillion cubic feet (USGS Cir. No. 725). These estimates are conservative in that they assumed the price-cost relationships and technological trends prior to 1974 and make no attempt to analyze what might happen to the estimates under market clearing pricing conditions. On the non-governmental side the Potential Gas Committee under the sponsorship of the Mineral Resources Institute of the Colorado School of Mines utilizes economic criteria which assume the existence of "adequate prices and reasonable governmental policies." Its most recent estimate released on May 2, 1977, showed between 923 and 973 trillion cubic feet of probable, possible and speculative potential reserves.

Without debating which of these (or any of the other) potential figures is correct, there are two points that are clear in any event: first, the total resource base is large enough for prices to have an impact on supply and secondly, the degree of disparity betwen the low and high numbers virtually guarantees that price will be a powerful determinant. If we accept 228 Tcf(AGA - 1975) as proven and USGS's 322 Tcf as

potential, we have about a 25 year supply at current usage. Even the Report by the White House on the Administration's Energy Plan shows that substantial quantities of new natural gas are expected with this period (Special Report, p.12).

The American public seems to be perceiving these facts. The following question was posed by a Louis Harris poll in February, 1977, "Many people in the energy field agree that deregulating oil and natural gas prices would encourage companies to explore for and develop new oil and natural gas supplies in the United States. In the light of this argument, do you favor or oppose the deregulation of the price of oil and natural gas?" By 56% to 24% a majority favor deregulation under these conditions. In the latest survey majorities in every demographic category favor deregulation if it produces more energy supplies.

Our basic policy position continues to be that complete and immediate removal of federal controls on new natural gas is necessary to achieve the maximum effort to increase supply and mitigate demand.

Recognizing the need to encourage the maximum possible recovery of natural gas from presently producing reservoirs and the need to generate capital funds necessary to accomplish the goal of finding new supplies, the controls over the gas

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sold under existing contracts should be phased out as promptly as possible. Upon the expiration of an existing contract, there should be immediate removal of federal controls.

NGSC opposes any extension of federal price controls to the intrastate market which has shown itself to function properly according to traditional market conditions. Thus, in the State of Texas when demand began to exceed supply, the price of natural gas increased; given the stimulus of increased prices, there was a significant increase in the amount of drilling activity. The resultant increase in new supplies was such that demand was satisfied and with the balancing came a leveling off, and even some declines in the prices.

Removal of federal controls of new gas provides for the gradual phasing in of the higher prices that must inevitably accompany the efforts to find and develop the marginal fields, the remote or deep fields, and the offshore fields. Viewed in the context of the total gas supply, the prices obtained for these volumes of gas should account for only a portion of the market. Looking at the average cost of gas to the consumer, even though some increment is added into the mix at higher rates, the overall average will still be considerably lower than the Btu equivalent price of alternate fuels.

NGSC believes that the energy picture of the country will be benefited by the removal of federal controls in the following respects:

1. Consumers of all types will be encouraged to conserve energy supplies in general and natural gas in particular. With natural gas priced at least at the level of alternate energy there would be increased incentives to convert to other, more abundant, fuels. At the present time industrials account for some 45% of the natural gas used. Dependence upon natural gas has been encouraged by the controls which have held natural gas below its commodity value and below the price of alternate fuels. Electric generation accounts for 16% of the natural gas used and again results not from the fact that natural gas has been the only fuel available but from the fact that it has been the cheapest. Recognizing the premium value of natural gas as a clean burning energy source will assure that it is put to higher priority usage and not consumed where a more abundant, though not as desirable, fuel is available.

2. Increased supplies of gas will be elicited. The figures stated above indicate that the potential for discovery of natural gas in the U.S. exceeds what has been previously discovered.

3. The recovery of the maximum amount of natural gas possible from existing discoveries will be enhanced. The

production of natural gas must of necessity be geared to economics as well as the natural reservoir dynamics. Allowing gas under old contracts to be sold free of controls upon expiration of a contract permits the economics to justify rework operations, installation of additional compression equipment and other activities by which the maximum volume can be extracted from a reservoir.

4. The 23 years of price controls have had a depressant effect upon the development of other energy forms. Coal, for instance, simply could not compete against the federally constrained price of natural gas, and consequently development of the vast coal resources of the country was hampered. With natural gas being allowed to take its place in the marketplace of energy alternatives, coal can again become competitive. With coal representing something like one-half of the world's energy resources, it is extremely important that it be developed so that it can occupy a greater portion of the U.S.'s energy uses than the 20% it presently serves.

Implicit in any effort to increase supplies, is the availability of additional leases in the federal domain. The federal government, and state governments as well, should make available leases on publicly owned acreage on an expedited and regular basis, in order to assure that these supplies can be obtained.

The winter of 1977 graphically demonstrated the need for a comprehensive energy policy with the cornerstone of such a policy being remedial natural gas legislation. Such legislation must, at one and the same time, stimulate the maximum development of new supplies while inducing conservation of existing supplies. Maximizing the natural gas portion of the nation's resource base over the next twenty-five to thirty-five years will provide the lead time required for the development of alternate energy sources which will be necessary to assure the quality of life for the nation.

We do not believe that the Administration's proposed energy plan serves this goal.

In that regard we would now propose to turn to Part D of the Administration Energy Bill, H.R. 6831, dealing with Natural Gas Pricing, and the alternate proposal contained in H.R. 2088, which are suggested ways of dealing with natural gas in the context of the broader energy problem.

The first section of the Administration's proposal for Natural Gas Pricing lists "Findings and Purposes", which we believe, correctly state the nature of the problem in the natural gas market, the need for an incentive-based-pricing approach for natural gas, and the economic desirability of moving toward a commodity value price ceiling. Another stated purpose is to "provide for the conservation of natural gas by pricing natural gas . . . at a level which will provide incentives for conversion to other more plentiful fuels and for conservation."

Although the Administration's Energy Program for natural gas has begun correctly by squarely facing the seriousness of the problem, accepting how the problem developed, and correctly stating the purpose of the proposed legislation, we believe that the program proposed to accomplish these purposes is seriously defective. The program is premised upon the fallacy that there are no significant reserves of natural gas yet to be discovered. Apparently because this premise has been accepted, the proposal does not provide incentives, either for increased efforts by producers to explore for new supplies, or for consumers to conserve natural gas by converting to other fuels because of the price which they must pay.

The principle objective of the Administration Plan is to persuade the consumer to switch from oil and gas to coal and other more abundant fuels. Yet the price structure imposed by the Plan perpetuates the present situation, which prices natural gas, the premium fuel, at the lowest price of any form of energy in the United States. This is true for following reasons:

A. The price of "new" gas is less than the the price of "new" oil

The "incentive" price in the Administration Plan for "new" gas is determined by the Btu related price for the average per barrel crude oil acquisition cost of all crude oil produced in the United States. This is a composite of "first tier" oil "second tier" oil and "new" oil, which will be allowed to rise to the world price over a three year period.

After the 3 years have expired, "new" oil will receive a price equivalent to the world price of crude oil. But "new" gas will be priced at a substantially lower figure, because of the more heavily weighted impact of the first and second tier oil prices in the "Btu related price" for new gas. Thus, the impact of the Administration Plan is to continue the price disparity between oil and gas, with a continued incentive to the consumer to burn gas. This is inconsistent with the Administration's announced policy to relate the price of new natural gas with world oil prices.

B. The "freezing" of the current multiple vintage pricing system for gas results in substantially lower prices for gas than for other fuels

We have previously referred to the current multiple vintage price structure imposed by the Federal Power Commission, and now "locked-in" by the Administration Plan. The interstate pipeline companies, of course, are able to buy some gas at each of the vintage prices. These prices are "rolled-in" by the pipeline tariff, so that the consumer pays a composite price which is substantially less than the price for new gas. Thus, when the composite prices of oil and gas are compared, gas is still cheaper than oil. Under Section 414, this price advantage is retained

for the "high priority user", without even the impact resulting from the phasing in of "new" gas, the "low priority user" is required to bear the full impact of any higher prices permitted for "new" gas or "newly contracted" gas. Although the disproportionate impact of the new gas price will increase the price to the low priority user, the resulting price will still be below the cost of alternate fuels by substantial amounts. To the extent that the low priority user exceeds the volume limit of Section 4992, this price advantage will be taken away by the natural gas consumption tax.

But the total effect of this complicated plan still leaves natural gas as the lowest price fuel, even for the low priority, high volume user. For the high priority, low volume user, the price advantage of using natural gas is even greater than it is today, without any change in the law.

All parties concede that natural gas is a premium fuel. The equipment required to burn gas by the consumer is less complicated, cheaper, and cleaner. The advantages to the environment are obvious. Under a completely free market, there is no question that natural gas would command a higher, not a lower, price than other fuels. The effect of the denial of this premium value, and the continuation of a price structure which makes gas the cheapest fuel, is not conducive to conversion to other fuels.

In addition to being too low in terms of price level, the "maximum lawful price" in the Administration's plan is too narrow in scope. By narrowly defining "new" gas in a very restrictive way, this bill eliminates from its "incentive" price a substantial part of the most favorable new gas prospects. This subject will be dealt with more extensively in Mr. Allen's testimony. We would say only that the restriction to production from offshore leases awarded after April 20, 1977, assures that there can be no supply response from the Federal Domain Offshore for at least 3½ to five years.

In addition to the lack of incentive pricing for "new" gas in the Administration's bill, the proposal "freezes", except for the inflation adjustment, all existing FPC prices for "old" gas. This provision removes the power of the FPC to adjust existing ceiling prices, even though those prices are manifestly too low, as recognized in the "findings" (Section 401). The provision contained in the earlier press releases of a minimum price of 32¢ per Mcf has apparently been dropped.

Furthermore, the "locking-in" of the existing multiple vintage pricing system violates one of the cardinal principles announced in the overall energy plan. The idea that energy should be sold at its replacement cost. The national average replacement cost of natural gas, under the most recent FPC decision, is $1.63. The national average replacement cost is now $2.50 per Mcf.

various FPC decisions, which are locked in concrete by Sections 405 and 406, are as follows:

(a)*	Gas produced from wells drilled prior to January 1, 1973, except for (b) and (c)	29.5¢
(b)	Gas produced from wells drilled prior to January 1, 1973, but contracted for or first delivered in interstate commerce or recompleted in a different producing zone, after January 1, 1973	53¢
(c)**	Gas produced from wells drilled prior to January 1, 1973, sold in interstate commerce by a long-term contract, which contract has expired by its terms and rededicated in interstate commerce by a renewal contract dated after January 1, 1973	53¢
(d)	Gas produced from wells commenced between January 1, 1973, and January 1, 1975	94¢
(e)	Gas produced from wells commenced between January 1, 1975, and January 1, 1977	1.45¢
(f)	Gas produced from wells drilled after January 1, 1977	To be established in Docket RM77-13

Additional Note: "Small" producers are allowed to collect ceiling prices, where authorized by contract, equal to 130% of the above prices, except for the $1.45 price.

*Some of the press material indicated that this price would be increased to 32¢ per Mcf, but this does not appear in the bill.

**According to some of the press releases, this price may be allowed to increase under Section 406 to $1.45 per Mcf, or some lesser price to be determined by the President, "considering the price in the prior contract and the price necessary to maintain production of such gas."

In noting that the price is "frozen" at the above levels by the Administration's plan, we are aware of the "Special Pricing Provision", Section 408. Each of the FPC ceiling price orders since the first Permian case has contained a similar "special relief" provision. It has been interpreted so restrictively however, that it is of little value to the producer. Producers have no reason to believe that a less restrictive interpretation would be applied under the new bill.

In order to obtain Special Relief (now called "Special Pricing" in the proposal), the producer has been required to come in and prove, the additional costs which would be incurred by his project, and the amount of additional gas reserves hoped to be obtained by the effort. If the reserves are large enough to justify the administrative burden and delay of the proceeding, yet still small enough to show a higher unit cost, the producer can present his case. The size of the reserves hoped for is at best a nebulous figure prior to undertaking the drilling. If the producer has over-estimated the reserves obtained, the volume of the gas he produces will not be sufficient to return his costs even at the higher price allowed. If he has underestimated the reserves which he obtains, he faces a retroactive price reduction because his excess price is no longer cost justified.

In addition, the type of evidence required or even the type of proceeding to be conducted, is extremely uncertain under the Administration's proposal. The time delays and administrative burden of the proceeding, as well as the uncertainty of result, militate against the use of this approach. While we do not object to this provision, it should not be regarded as any panacea to cure all problems if the fixed ceiling price structure of the bill proves inadequate.

When the pricing structure for gas in the Administration's bill is carefully examined, only price "freezes" or price rollbacks are proposed. We therefore conclude that those responsible for this approach must have decided that there is very little opportunity left in the United States and adjacent offshore areas for finding and developing new gas supplies. We believe this conclusion is basically wrong.

As Mr. Allen will discuss, and as the Potential Gas Supply Committee has indicated in its news release of May 4, 1977, there is a potential in this country for the discovery of additional gas supplies exceeding those already found. But the maximum discovery and development of these potential supplies can not occur unless the American public and their representatives in Congress are prepared to allow prices for such gas to increase to the point that the substantially higher costs of finding and developing these supplies can be met. If these prospective costs could be accurately measured,

and the supply resulting from the expenditures of these costs guaranteed, we have little doubt that in many cases the consumer, and his Congressman would opt for this domestic gas supply, with all of its advantages in increased domestic employment, utilization of existing pipelines, distribution, and consumer investments, balance of payments, etc. in lieu of buying imported oil at inflated prices. Solar energy and other forms of energy will be substantially more expensive in terms of initial capital investments than additional domestic gas supplies. The problem is, that the industry is so large and complex, and deals with such uncertainties, that it is not possible to say how much supply will be obtained for the expenditure of any particular additional amount of the consumer's dollars. What can be said, however, is that if the higher price does not bring forth additional gas supplies, the consumer will never pay it. Therefore, the consumer has everything to gain, and nothing to lose, by a higher price for new gas supplies.

We do not contend that natural gas supplies in the United States are inexhaustible, or that over time, the nation must not shift away from primary reliance as our sources for energy.

The Administration's bill seeks to slow this demand for gas by price increases brought about by imposing taxes on large users of natural gas (Section 4992). While this step may accomplish part of the desired result, it does not encourage the smaller user to make conversions to other fuels as long as he can buy gas at a lower price. The idea that industry must pay these taxes instead of individuals is illusory. The additional costs on industry will merely be added to the price of the products being sold. But by hiding these costs, the gas consumer is again lulled into a false complacency about the need to conserve energy and seek other energy sources, until his gas is physically cut off and he is forcibly required to junk his investment in gas burning equipment and buy equipment which burns another fuel.

To the extent that additional gas supplies can be made available at prices higher than permitted in the Administration bill, but lower than alternate fuel prices, it makes little sense to deny the consumer the opportunity to obtain these domestic gas supplies. Yet this is precisely what the imposition of price ceilings and price rollbacks accomplishes. If the producer were allowed to retain the price differential between the present ceiling prices

and the replacement cost, substantial additional capital would be available for reinvestment in gas exploration and development projects which will go a long way toward "replacing" the gas consumed.

We are aware that some industry critics charge that such sums would not be reinvested in gas exploration. As long as ceiling prices are imposed which will not permit the recovery of the higher costs to obtain such supplies little incentive exists for reinvestment in gas exploration. But if a true incentive price is permitted and the capital is available, then the additional exploration for gas will occur. Producing companies will invest their capital in the business they know best, if such investments are made profitable.

The argument made against the application of these clear economic principles is the emotional charge that producers are withholding gas in the hope of obtaining higher prices. Those who make that charge ignore the fact that it has never been proved, although repeated governmental investigations have taken place. The Department of Interior is currently involved in another investigation which we hope will resolve the issue.

This charge is credible in the minds of the uninformed because of the confusion between gas reserves which have been discovered by the drill bit and are capable of being produced through existing wells, and potential gas supplies believed by experts to exist but which have not yet been discovered. It

is extremely important to distinguish between these two types of "reserves". The distinction is much more than one of definition - it is like the difference between gold in a known vein in a producing mine and the idea that "there's gold in them thar hills". The difference, of course, is the necessity of an entrepreneur with the courage, capital and drive to find this resource and bring it to the surface where it can be made available to the consumer. This is the function performed by the gas producing industry. While the "gamble" in our operations prevents the quantification of risks and costs in a utility-type manner, or with sufficient precision to satisfy the bureaucratic mind, it has served the American public well in the past. What we ask is that the industry not be prematurely "written off" through further oppressive price controls.

Shortages of natural gas resulting from the lack of incentives flowing to the producer will ultimately be reflected in much higher prices for Priority 1 and 2 customers. The wellhead cost of natural gas at present represents less than 30% of the homeowner's monthly bill. The remaining 70% is the transportation charge attributed to pipelines and local gas distributors to defray the high investment in plant facilities to transport gas to users.

If a pipeline is one-half empty the economic impact on the consumer will be immense. In 1975, the interstate pipelines serving the Northeast were 15% empty as a result of regulatory-induced natural gas shortages. The 15% of unused pipeline

capacity cost almost one billion dollars in added overhead of the gas delivered by said pipelines. The greater the degree of shortages, the greater the proportionate increase on the homeowner's bill to recover their fixed costs.

The apparent desire of the proposed Energy Act is to eliminate as users of natural gas, all present users except Priority 1 and 2 customers. This is accomplished by incremental pricing (Sect. 414) of industrial and lower priority users including all costs of SNG and LNG projects. If successful, all lower priority users will have switched to alternate fuels leaving only seasonable priority 1 and 2 customers to be served. In the 1975 - 1976 heating season (November - March), priority 1 and 2 customers utilized about 50 percent of all gas produced. Therefore, these users will carry 100% of the costs of transportation of the gas, if all other priorities cease taking gas, which will increase costs to priority 1 and 2 users by billions of dollars. Homeowners take natural gas on a seasonal basis, therefore without alternate users of natural gas, crude oil activities could be affected. It is certainly forseeable that if pipelines cannot take all natural gas production, crude oil production could be shut down because of the no-flare orders of state and federal regulatory agencies.

After Congress had reached its decisions on the proposed legislation, we hope the gas producing industry can say as did Mark Twain:

> "The reports of my death have been greatly exaggerated."

STATEMENT OF D. K. DAVIS

Mr. DAVIS. Mr. Chairman, I am D. K. Davis, a partner in Natural Gas Finders, Inc. and Vice Chairman of the Independent Petroleum Association of America's Natural Gas Committee.

Certainly no serious energy student can dispute the virtues of conservation, which is the cornerstone of the President's dramatic energy proposal. But a cornerstone is not a foundation, and the basic objectives of the program may never be achieved unless the Congress changes the major thrust of the proposal, and undergirds it with the means to provide increased energy supply between today and 1990.

The President's message is based on a seriously defective premise. It assumes that so little oil and natural gas remain to be discovered within our national boundaries that there is no need to encourage exploration for such resources. Legislation based on this false premise could faster make it a self-fulfilling prophecy which could severely damage our national economy, promote unemployment, and even place our national security in jeopardy.

Professional geologists nationwide agree that vast quantities of natural gas remain to be produced in this country. Over 3 million square miles of basinal area in the United States have been identified as having sediments prospective for oil and gas. This compares with only 50,000 square miles on which oil and gas production has ever existed, less than 2 percent of the prospective area, and most of that is relatively shallow. With the Nation being called on to attack our energy shortages with the "moral equivalent of war," it seems highly inconsistent that we should also be told to turn our back on 98 percent of the prospective environment of oil and gas, and simply lay down under a flag of truce. Americans have not normally responded to the great challenges of the past in this manner.

The people of Texas responded to the challenge of natural gas shortages early in this decade by paying the replacement cost for new natural gas. Producers responded to price incentives by drilling thousands of new wells. In the Fort Worth Basin of Texas, it became profitable to produce known reserves of natural gas and a 600 percent increase in annual drilling activity was achieved from 1972 through 1976. The supply of natural gas in part of the area has increased 3,000 percent and as the demand has been met, the price generally has dropped by 20 percent for new contracts.

Statistics leading to the conclusion that less natural gas can be found are derived from dwindling reserve figures brought about by price controls which curtailed drilling and exploration activity not on the lack of natural gas. Texas and other unregulated markets have provided an example to the Nation which can be repeated over and over, in basin after prospective basin in this country with 15,000 to 40,000 feet of sediments where vast amounts of new natural gas are known or reasonably expected to exist. Prime targets are going begging.

The methane gas in the hot salt waters at 8,000 or 25,000 feet along the Gulf Coast of Texas and Louisiana is one of the most dramatic examples of the tremendous quantities of natural gas yet to be produced but it is only one of many. Competent calculations

indicate that there may be as much as 105,000 trillion cubic feet of gas in this one location. If it lives up to its promise, this one known resource could free the Nation from fuel imports for generations to come. Even if only 10 percent of it can be produced and we more than double our peak demand for natural gas to 50 trillion cubic feet per year, it still represents a 200 year supply.

Prices will gradually rise if controls are discontinued for all future production of natural gas, but they can only rise more sharply if maximum production incentives are denied, and American consumers face continued shortages, vastly higher prices for foreign oil and liquefied natural gas, higher payments for disproportionate shares of under-utilized pipelines, and an increase in the invisible tax of inflation brought about by balance of payment deficits and a reduction in gross national product caused by energy shortages.

For the past two years the concept that "OPEC is setting the price" has been used as an argument against the payment of replacement costs for American energy. In fact, OPEC is being paid the price and our trade deficit, due principally to oil imports, was higher for the first quarter of 1977 than for all of 1976.

Mr. Chairman, this committee might do a great service toward resolving some of the natural gas pricing rhetoric by authorizing an economic study to explore the differences in economic impact to the Nation between (A) consumers paying perhaps $2.25/Mcf for 5 trillion cubic feet of new natural gas to add to their present supply of old gas, keeping that money circulating in our own economy, plus the advantages of that new supply offsetting the present cost of unused pipeline facilities as compared with (B), the cost of sending an equal amount of money out of the country's economy forever to pay for an equal amount of imported oil.

The suspension of controls covering any future natural gas will represent phase-in replacement costs for new energy supplies. It is the fastest way to utilize the huge resource base of our Nation and keep our economy sufficiently healthy to afford the massive sums which will be needed to develop our other opportunities for energy during the coming 25 years.

Thank you.

[Mr. Davis' prepared statement follows:]

STATEMENT OF D. K. DAVIS
VICE CHAIRMAN, NATURAL GAS COMMITTEE
INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

Before the
HOUSE COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
SUBCOMMITTEE ON ENERGY AND POWER

RE: National Energy Act
May 12, 1977

MR. CHAIRMAN:

THE PRESIDENT HAS DRAMATIZED THE SERIOUSNESS OF THE POTENTIAL ENERGY PROBLEM FACING THIS NATION, AND HAS ALERTED THE GENERAL PUBLIC TO THE NEED FOR SPECIFIC GOALS, OBJECTIVES, AND GUIDELINES. NO SERIOUS ENERGY STUDENT CAN DISPUTE THE VIRTUES OF CONSERVATION, WHICH IS THE CORNERSTONE OF THE PROPOSAL. BUT A CORNERSTONE IS NOT A FOUNDATION, AND THE BASIC OBJECTIVES OF THE PROGRAM MAY NEVER BE ACHIEVED UNLESS THE CONGRESS CHANGES THE MAJOR THRUST OF THE PROPOSAL, AND UNDERGIRDS IT WITH THE MEANS TO PROVIDE INCREASED ENERGY SUPPLY BETWEEN TODAY AND 1990.

THE PRESIDENT'S MESSAGE IS BASED ON A SERIOUSLY DEFECTIVE PREMISE. IT ASSUMES THAT SO LITTLE OIL AND NATURAL GAS REMAIN TO BE DISCOVERED WITHIN OUR NATIONAL BOUNDARIES THAT THERE IS NO NEED TO ENCOURAGE EXPLORATION FOR SUCH RESOURCES. LEGISLATION BASED ON THIS FALSE PREMISE COULD MAKE IT A SELF-FULFILLING PROPHECY WHICH COULD SEVERELY DAMAGE OUR NATIONAL ECONOMY, PROMOTE UNEMPLOYMENT, AND EVEN PLACE OUR NATIONAL SECURITY IN JEOPARDY.

PROFESSIONAL GEOLOGISTS NATIONWIDE AGREE THAT VAST QUANTITIES OF NATURAL GAS REMAIN TO BE PRODUCED IN THIS COUNTRY. IN 1967 THE NATIONAL PETROLEUM COUNCIL, AT THE REQUEST OF THE DEPARTMENT OF THE INTERIOR BEGAN A STUDY OF FUTURE PETROLEUM PROVINCES OF THE UNITED STATES. THE RESULTS OF THE COORDINATED STUDY, IN WHICH DOZENS OF THE NATION'S MOST PROMINENT GEOLOGISTS PARTICIPATED, WAS PUBLISHED IN TWO VOLUMES IN 1971. OVER 3,000,000 SQUARE MILES OF BASINAL AREA IN THE UNITED

STATES WERE IDENTIFIED AS HAVING SEDIMENTS PROSPECTIVE FOR OIL AND GAS. THIS COMPARES WITH ONLY 50,000 SQUARE MILES ON WHICH OIL AND GAS PRODUCTION EXISTS, OR HAS EXISTED TO DATE -- LESS THAN 2% OF THE PROSPECTIVE AREA, AND MOST OF THAT IS RELATIVELY SHALLOW. WITH THE NATION BEING CALLED ON TO ATTACK OUR ENERGY SHORTAGES WITH THE "MORAL EQUIVALENT OF WAR," IT SEEMS HIGHLY INCONSISTENT THAT WE SHOULD ALSO BE TOLD TO TURN OUR BACK ON 98% OF THE PROSPECTIVE ENVIRONMENT OF OIL AND GAS, AND SIMPLY LAY DOWN UNDER A FLAG OF TRUCE. AMERICANS HAVE NOT RESPONDED TO THE GREAT CHALLENGES OF THE PAST IN THIS MANNER.

THE PEOPLE OF TEXAS BEGAN TO RESPOND TO THE CHALLENGE OF NATURAL GAS SHORTAGES EARLY IN THIS DECADE BY PAYING THE REPLACEMENT COST FOR NEW NATURAL GAS. PRODUCERS RESPONDED TO PRICE INCENTIVES BY DRILLING THOUSANDS OF NEW WELLS. IN THE FORT WORTH BASIN OF TEXAS, IT BECAME PROFITABLE TO PRODUCE KNOWN RESERVES OF NATURAL GAS AND A 600% INCREASE IN ANNUAL DRILLING ACTIVITY WAS ACHIEVED FROM 1972 TO 1976. THE SUPPLY OF NATURAL GAS IN PART OF THE AREA HAS INCREASED 3,000%, AND AS THE DEMAND HAS BEEN MET, THE PRICE HAS DROPPED FOR NEW CONTRACTS. (EXHIBIT 1) IN THE ENTIRE STATE THE NUMBER OF NEW, PRODUCTIVE GAS WELLS HAS INCREASED 288% SINCE 1970.

STATISTICS LEADING TO THE CONCLUSION THAT LESS NATURAL GAS CAN BE FOUND ARE BASED ON DWINDLING RESERVE FIGURES BROUGHT ABOUT BY PRICE CONTROLS WHICH CURTAILED DRILLING AND EXPLORATION ACTIVITY NOT ON THE LACK OF NATURAL GAS. TEXAS HAS PROVIDED AN EXAMPLE TO THE NATION WHICH CAN BE REPEATED OVER AND OVER, IN BASIN AFTER PROSPECTIVE BASIN IN THIS COUNTRY WITH 15,000 TO 40,000 FEET OF SEDIMENTS. (EXHIBIT 2 WITH DETAIL ATTACHMENTS) WHERE VAST AMOUNTS OF NEW NATURAL GAS ARE KNOWN, OR REASONABLY

EXPECTED, TO EXIST. PRIME TARGETS ARE GOING BEGGING! WHILE CONSUMERS AND JOBHOLDERS ARE DENIED ACCESS TO HUGE SUPPLIES OF AMERICAN ENERGY BASED ON REASONABLE PRICES, THEY ARE BEING FORCED TO PAY MULTIPLES OF AMERICAN REPLACEMENT COSTS FOR FOREIGN FUEL.

THE METHANE GAS IN THE HOT SALT WATERS AT 8,000 TO 25,000 FEET ALONG THE GULF COAST OF TEXAS AND LOUISIANA IS ONE OF THE MOST DRAMATIC EXAMPLES OF THE TREMENDOUS QUANTITIES OF NATURAL GAS YET TO BE PRODUCED BUT IT IS ONLY ONE OF MANY. COMPETENT CALCULATIONS INDICATE THAT THERE MAY BE AS MUCH AS 105,000 TRILLION CUBIC FEET OF GAS IN THIS ONE LOCATION. THIS IS A STUPENDOUS NUMBER WHICH CAN BE TRANSLATED TO MEAN THAT IF ONLY THIS ONE SOURCE OF ENERGY (NO COAL, NO OIL, NO NUCLEAR, NO SOLAR, NO ANYTHING EXCEPT THIS ONE KNOWN SOURCE OF NEW NATURAL GAS) AND IF WE USED ENERGY AT THREE TIMES OUR PRESENT DEMAND, IT COULD STILL PROVIDE ALL OUR ENERGY NEEDS IN THIS COUNTRY FOR 500 YEARS. IT CAN PROBABLY BE PRODUCED FOR $3.00/MCF OR LESS, AND COULD CONTROL THE WORLD PRICE OF ALL ENERGY. WE COULD BECOME A NET EXPORTER OF ENERGY. EVEN IF ONLY 10% OF IT CAN BE PRODUCED AND WE MORE THAN DOUBLE OUR PEAK DEMAND FOR NATURAL GAS TO 50 TRILLION CUBIC FEET PER YEAR, IT STILL REPRESENTS A 200 YEAR SUPPLY. IT'S ONLY ONE EXAMPLE THAT WE HAVEN'T EVEN BEGUN TO DRILL FOR NATURAL GAS IN THIS COUNTRY!

IT DOESN'T TAKE GOVERNMENT LOANS, OR UNIFORMED BUREAUCRATIC DECISIONS ABOUT HOW FAR APART WELLS SHOULD BE TO QUALIFY AS A NEW DISCOVERY, NOR DOES IT TAKE MORE DETAILED AND ALL-ENCOMPASSING CONTROLS TO GET THE JOB DONE. ALL IT TAKES IS THE CONGRESS OF THE UNITED STATES TO TELL THE

PRODUCERS TO GO TO WORK. THE PURSUIT OF COMPLICATED PRICING SCHEMES CAN ONLY RESULT IN MORE DELAY IN GETTING AMERICAN ENERGY INTO THE HANDS OF AMERICAN CONSUMERS. PRICES WILL GRADUALLY RISE IF CONTROLS ARE DISCONTINUED FOR ALL FUTURE PRODUCTION OF NATURAL GAS, BUT THEY CAN ONLY RISE MORE SHARPLY IF MAXIMUM PRODUCTION INCENTIVES ARE DENIED, AND AMERICAN CONSUMERS FACE CONTINUED SHORTAGES, VASTLY HIGHER PRICES FOR FOREIGN OIL AND LIQUIFIED NATURAL GAS, HIGHER PAYMENTS FOR DISPROPORTIONATE SHARES OF UNDER-UTILIZED PIPELINES, AND AN INCREASE IN THE INVISIBLE TAX OF INFLATION BROUGHT ABOUT BY BALANCE OF PAYMENT DEFICITS AND A REDUCTION IN GROSS NATIONAL PRODUCT CAUSED BY ENERGY SHORTAGES.

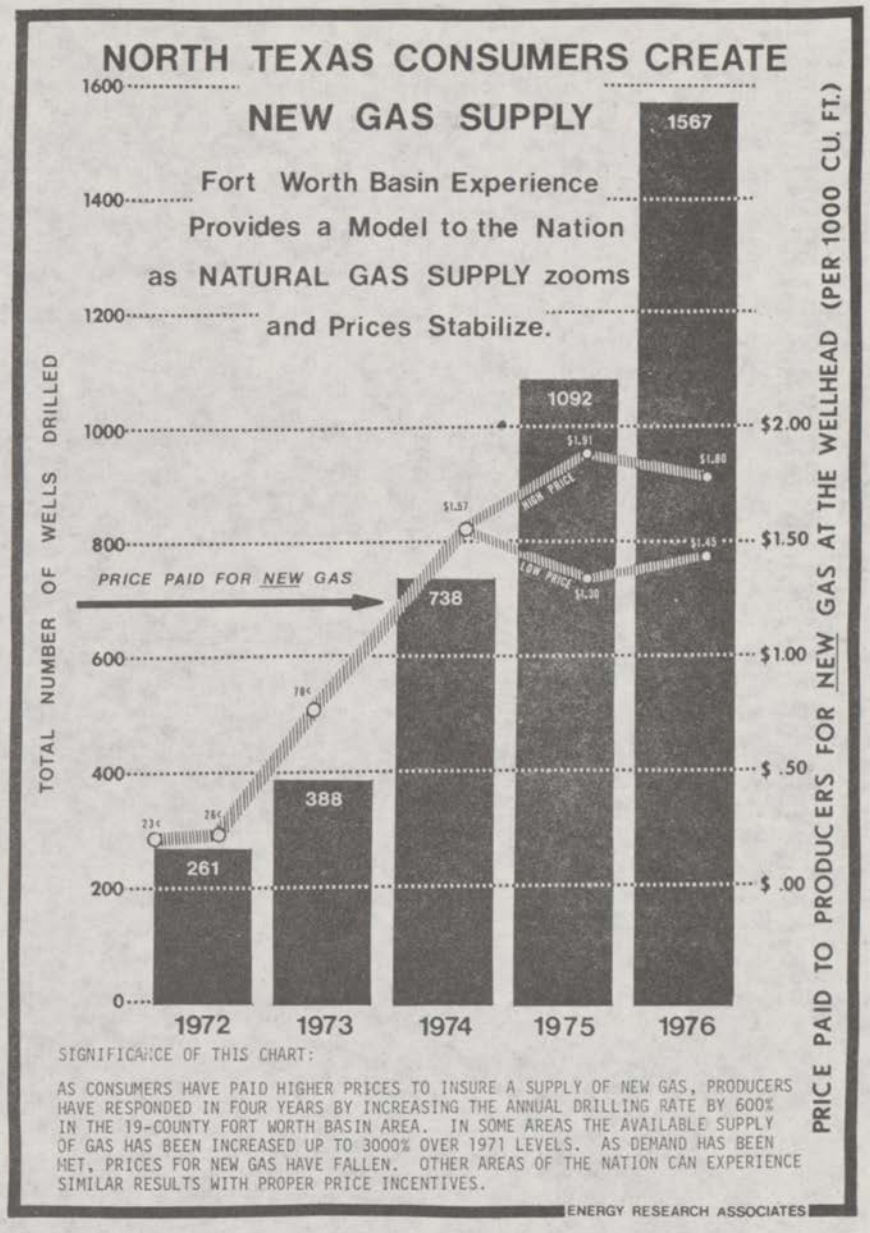
THE FOLLOWING QUOTE IS FROM PAGES 12 AND 13 OF THE CONGRESSIONAL BUDGET OFFICE DOCUMENT, "ENERGY POLICY ALTERNATIVES" PUBLISHED IN JANUARY OF THIS YEAR: "WHILE THERE IS NO DOUBT THAT---PRICE INCREASES WILL RAISE THE HEATING BILLS FOR GAS CUSTOMERS, THE OVERALL EFFECTS ON BOTH EMPLOYMENT AND INFLATION ARE EXPECTED TO BE SMALL---OFFSETTING THE INCREASES IN GAS BILLS WILL BE REDUCTIONS IN THE AMOUNT OF HIGH-PRICED IMPORTED OIL (AND GAS), WHICH WOULD OTHERWISE HAVE BEEN CONSUMED. THESE LATTER EFFECTS WILL MUTE THE INFLATIONARY IMPACT OF THE GAS PRICE INCREASE AND WILL STIMULATE DOMESTIC EMPLOYMENT." THAT IS FOLLOWED BY ANOTHER COMMENT, i.e., "IN A RAPIDLY EXPANDING ECONOMY THERE IS MORE ROOM FOR CHANGES IN THE DOMESTIC PRICE OF ENERGY, THAN IN A WEAK ECONOMY."

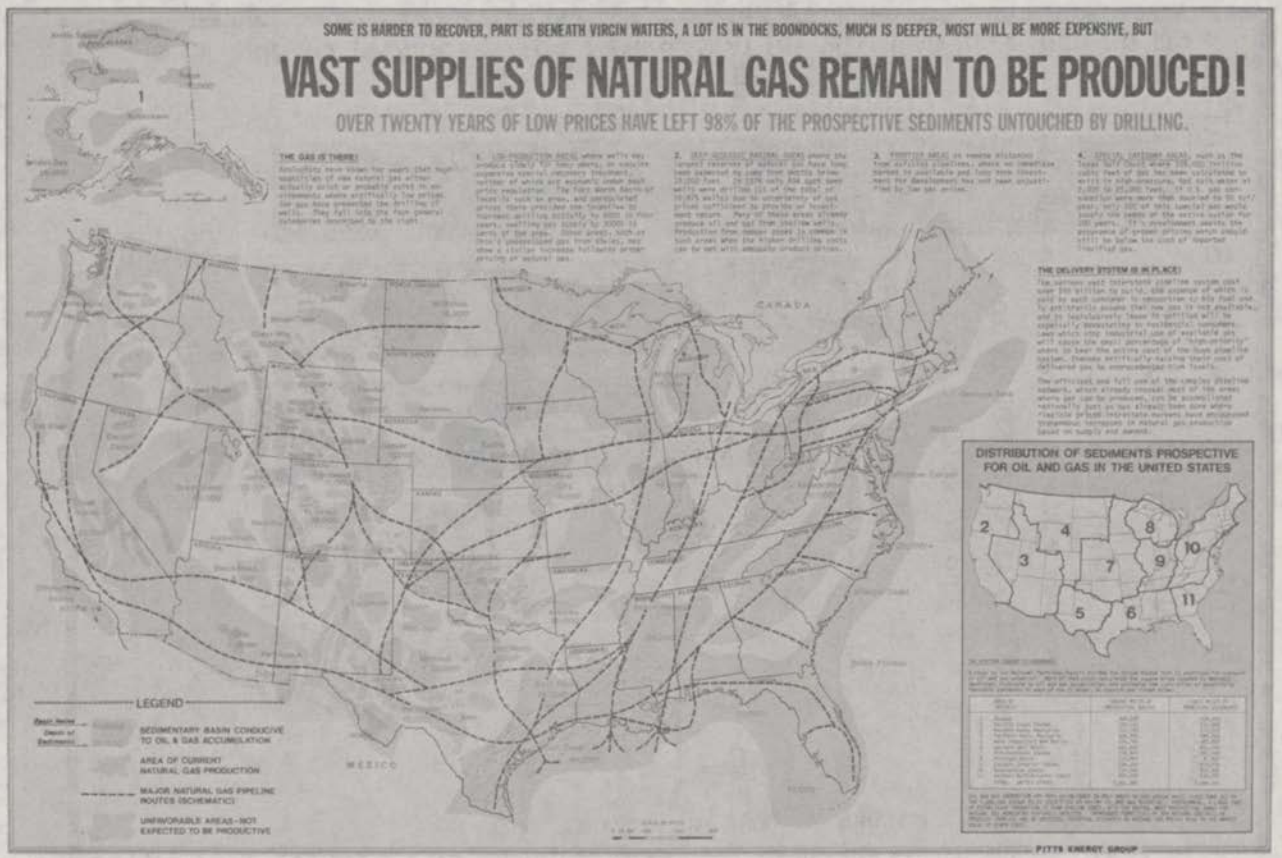
FOR THE PAST TWO YEARS THE CONCEPT THAT "OPEC IS SETTING THE PRICE" HAS BEEN USED AS AN ARGUMENT AGAINST THE PAYMENT OF REPLACEMENT COSTS FOR AMERICAN ENERGY. IN FACT OPEC IS BEING PAID THE PRICE, AND OUR TRADE DEFICIT, DUE PRINCIPALLY TO OIL IMPORTS, WAS HIGHER FOR THE FIRST QUARTER OF 1977, THAN

FOR ALL OF 1976. MR. CHAIRMAN, THIS COMMITTEE MIGHT DO A GREAT SERVICE TOWARD RESOLVING SOME OF THE NATURAL GAS PRICING RHETORIC BY AUTHORIZING AN ECONOMIC STUDY TO EXPLORE THE DIFFERENCES IN ECONOMIC IMPACT TO THE NATION BETWEEN (A) CONSUMERS PAYING PERHAPS $2.25/MCF FOR 5 TRILLION CUBIC FEET OF NEW NATURAL GAS TO ADD TO THEIR PRESENT SUPPLY OF OLD GAS, KEEPING THAT MONEY CIRCULATING IN OUR OWN ECONOMY, PLUS THE ADVANTAGES OF THAT NEW SUPPLY OFFSETTING THE PRESENT COST OF UNUSED PIPELINE FACILITIES, AS COMPARED WITH, (B) THE COST OF SENDING AN EQUAL AMOUNT OF MONEY OUT OF THE COUNTRY'S ECONOMY FOREVER TO PAY FOR AN EQUAL AMOUNT OF IMPORTED OIL.

THE SUSPENSION OF CONTROLS COVERING ANY FUTURE NATURAL GAS, WILL REPRESENT PHASED-IN REPLACEMENT COSTS FOR NEW ENERGY SUPPLIES. IT IS THE FASTEST WAY TO UTILIZE THE HUGE RESOURCE BASE OF OUR NATION, AND KEEP OUR ECONOMY SUFFICIENTLY HEALTHY TO AFFORD THE MASSIVE SUMS WHICH WILL BE NEEDED TO DEVELOP OUR OTHER OPPORTUNITIES FOR ENERGY DURING THE COMING 25 YEARS.

# # #


NORTH TEXAS CONSUMERS CREATE
NEW GAS SUPPLY
Fort Worth Basin Experience
Provides a Model to the Nation
as NATURAL GAS SUPPLY zooms
and Prices Stabilize.
TOTAL NUMBER OF WELLS DRILLED
PRICE PAID TO PRODUCERS FOR NEW GAS AT THE WELLHEAD (PER 1000 CU. FT.)
1600
1400
1200
1000
800
600
400
200
0
$2.00
$1.50
$1.00
$ .50
$ .00
PRICE PAID FOR NEW GAS
261
388
738
1092
1567
23¢
26¢
78¢
$1.57
$1.91
$1.88
$1.45
$1.30
HIGH PRICE
LOW PRICE
1972
1973
1974
1975
1976
SIGNIFICANCE OF THIS CHART:
AS CONSUMERS HAVE PAID HIGHER PRICES TO INSURE A SUPPLY OF NEW GAS, PRODUCERS HAVE RESPONDED IN FOUR YEARS BY INCREASING THE ANNUAL DRILLING RATE BY 600% IN THE 19-COUNTY FORT WORTH BASIN AREA. IN SOME AREAS THE AVAILABLE SUPPLY OF GAS HAS BEEN INCREASED UP TO 3000% OVER 1971 LEVELS. AS DEMAND HAS BEEN MET, PRICES FOR NEW GAS HAVE FALLEN. OTHER AREAS OF THE NATION CAN EXPERIENCE SIMILAR RESULTS WITH PROPER PRICE INCENTIVES.
ENERGY RESEARCH ASSOCIATES


SOME IS HARDER TO RECOVER, PART IS BENEATH VIRGIN WATERS, A LOT IS IN THE BOONDOCKS, MUCH IS DEEPER, MOST WILL BE MORE EXPENSIVE, BUT
VAST SUPPLIES OF NATURAL GAS REMAIN TO BE PRODUCED!
OVER TWENTY YEARS OF LOW PRICES HAVE LEFT 98% OF THE PROSPECTIVE SEDIMENTS UNTOUCHED BY DRILLING.
THE GAS IS THERE!
THE DELIVERY SYSTEM IS IN PLACE!
CANADA
MEXICO
LEGEND
SEDIMENTARY BASIN CONDUCIVE TO OIL & GAS ACCUMULATION
AREA OF CURRENT NATURAL GAS PRODUCTION
MAJOR NATURAL GAS PIPELINE ROUTES (SCHEMATIC)
UNFAVORABLE AREAS - NOT EXPECTED TO BE PRODUCTIVE
DISTRIBUTION OF SEDIMENTS PROSPECTIVE FOR OIL AND GAS IN THE UNITED STATES
2
4
8
10
3
7
9
5
6
11
PITTS ENERGY GROUP

Mr. DINGELL. Thank you.

STATEMENT OF CHARLES M. ALLEN

Mr. ALLEN. My name is C. M. Allen. I am Division Natural Gas Geologist with the Phillips Petroleum Company, North American Exploration and Production Division. I would like to thank the chairman and the members of the committee for this opportunity to make comments on the administration's energy bill.

At the outset, I would like to point out what seems to me to be a basic assumption behind the whole bill. That assumption particularly as it is related to natural gas is that there are no significant quantities remaining to be found in this country.

That is an assumption that I can't accept. I believe there are significant quantities. The potential gas committee has released its estimate of gas remaining to be found in the United States as of December 31, 1976. This estimate is 923 to 973 trillion cubic feet of gas.

I am not going to discuss this estimate in any detail as I understand the director of the Potential Gas Agency is to follow as a witness later this afternoon.

Mr. DINGELL. Mr. Allen, I apologize. We are trying to work, as you know, under great time strictures and the House is in session and there is a vote on the floor.

Let me ask the pleasure of my colleagues. Do you think we ought to adjourn and come back? I do apologize to you. That is not the way I like to proceed. I am sorry about this. I mean you no discourtesy, but we will recess very briefly and return just as quickly as we can.

[Brief recess.]

Mr. DINGELL. The subcommittee will come to order. Gentlemen, the Chair apologizes to all. We had not one vote, as events turned out, but three. We are, in any event, returned.

As I recall, Mr. Allen was testifying when we left. Mr. Allen, we recognize you again.

Mr. ALLEN. Thank you, Mr. Chairman. At pages 2 through 4 of my written statement, I point out some of the reasons that I believe that the level of the new gas ceiling which would be calculated in this bill would reduce the drilling effort for gas, and that is from the standpoint of recent trends. If recent cost and productivity data are cranked into the FPC's formula for costing new gas, I am informed that the calculated average cost that would come out of that formula is about $2.50 per Mcf. That is, of course, 75 cents in excess of the ceiling of $1.75, which Mr. Schlesinger talked about this morning.

I can't see that that would be much of an incentive for new exploration.

At pages 5 through 8 of my written statement, I discuss some of the definitions appearing in section 402 of the administration bill. There, gas which would qualify as new natural gas and receive the higher price is severely restricted by definition. Insofar as offshore gas is concerned, only gas from leases which have not as yet been issued would qualify for the higher price.

This very simply means that there could be no supply response to any higher price in this area for at least 3½-5 years after the first lease sale. Exploration for and development of offshore gas from newly acquired leases requires at least this much time if everything goes well.

Now, insofar as onshore gas is concerned, a more complicated set of definitions applies. I have tried to sort those out on page 6 of my statement, and, stated very briefly, those definitions can be interpreted to mean that no gas produced within a 2½-mile radius of present production can qualify for the higher price. How that is going to be interpreted, I don't know, but that interpretation can be made easily from the language in those definitions, and I point that out at page 6.

Now, that means that gas exploration would be discouraged, not encouraged, in and around present producing structures. The potential gas committee in its estimate comes up with a figure of 215 trillion cubic feet of potential supplies falling into the probable category which is in and around presently producing fields.

I point out in the statement why I think it is important that that supply be looked for. It is one of the most economical supplies the consumer can receive. The pipelines are there; they are installed and very little increment of investment is needed for transportation.

In the written statement I also point out some areas of uncertainty in the definition, and it appears to me that the bill in its present form would create an administrative nightmare both from the standpoint of the administrative agency as well as for the producer.

I thank you for your patience.

[Mr. Allen's prepared statement follows:]

TESTIMONY
OF
C. M. ALLEN
ON BEHALF OF
NATURAL GAS SUPPLY COMMITTEE

My name is C. M. Allen. I am a geologist employed by Phillips Petroleum Company. I am appearing today in behalf of the Natural Gas Supply Committee. I have been working with the Committee for the past several years in a technical capacity and have reviewed the Administration's Energy Bill with a view to its effect upon the operations of natural gas producers.

In my opinion there is one basic assumption underlying the Administration's bill as it affects domestic natural gas policy and it is an assumption which I cannot accept. That assumption is that there is no substantial quantity of natural gas remaining to be found in the United States. I am not alone in my belief that there are substantial quantities of natural gas yet to be discovered as highlighted by the release of the recent estimate of the Potential Gas Committee. I will not discuss that estimate in any detail because it is my understanding that a witness will appear before the Subcommittee later today for the primary purpose of explaining the Potential Gas Committee's work.

I would only like to point out that the Potential Gas Committee has estimated a total potential gas supply of 923 to 973 trillion cubic feet of gas remaining to be found in the United States as of December 31, 1976. To put this figure in

perspective, this is more than four times the present proved reserves and almost two times the total amount of gas produced in the United States throughout the more than 100 year history of the industry. In my opinion, this is a substantial quantity of energy that is sorely needed at this time and efforts to find and produce this gas should be encouraged by governmental policy, not discouraged as I believe the Administration's bill would do.

I would like to point out some of the reasons why, from my viewpoint, the Administration's bill would reduce drilling for natural gas, even below the inadequate levels which result today from FPC cost-based pricing. This is true for the following reasons:

1. The price level for new gas, although discussed in press releases at approximately $1.75 per Mcf, calculates to something less than that using current oil prices.
2. A ceiling price at this level is below the most recent cost estimates for the nationwide, industry-wide average unit cost of gas. In Opinion 770, the Commission estimated this cost at $1.63 (Opinion 770, p. 88). The $1.42 ceiling rate was obtained by "backing out" escalations at one cent per quarter for the first five years of a 15-year depletion period.

> The President's bill now "locks in" the current rate of $1.45, cutting off these future escalations; therefore, this vintage of gas (wells drilled during 1975 - 1976) can never recover its average estimated cost.

Evidence being prepared for the newest FPC proceeding, Docket RM77-13, shows that more recent cost data indicate a continuation of the sharp increases in cost which has been an industry fact of life over the last ten years. Utilizing the same formula followed by the FPC in Opinion 770, the current nationwide, industry-wide average cost is about $2.50 per Mcf, or 75 cents over what has been indicated in news reports as the price of "new" gas under the Administration's proposal.

I would like to digress and discuss some of the reasons the cost of finding, developing, and producing gas is increasing so rapidly. The use of nationwide ceiling prices, and nationwide cost studies by the FPC tends to obscure the fact that all gas projects do not cost the same. On the contrary, the producing industry must analyze thousands of prospects for gas exploration containing many different characteristics of cost, risk, and capital requirements. To the extent that these factors can be correctly evaluated, the producer will drill only those prospects which his studies indicate will obtain sufficient volumes of gas to repay his estimated costs plus a return <u>at the ceiling price</u> permitted by the Commission. Those prospects which are believed to contain lesser volumes, or higher costs so that the expected

revenue will not allow their recovery of costs plus return, are not drilled.

The backlog of gas reserves discovered and developed prior to the advent of FPC regulation has been substantially depleted (see Charts attached as Exhibit I). FPC ceiling prices, in confining exploration to the lowest cost, low-risk supplies have caused the rapid depletion of such prospects. Many of the remaining projects available for exploration are at greater depths, less accessible locations, and the targets are smaller, less productive reservoirs. The result is an increasing cost trend for the gas producing industry which is substantially greater than many other sectors of the American economy. The inability of the FPC ceiling prices to keep pace with these cost trends is largely responsible for today's gas shortage.

Returning to the discussion of the Administration's bill as applied to natural gas, the so-called "incentive" price for new gas is also too low as applied to intrastate gas. Intrastate gas prices today are substantitally higher than the ceiling price calculated in the President's bill. In my Exhibit No. 2, I am attaching the most recent FPC Staff Study showing current intrastate prices for the last quarter of 1976. It is not reasonable to expect an expansion of the drilling effort when prices in a substantial segment of the market are rolled-back below current levels for new gas.

In addition to being too low in terms of price level, the "maximum lawful price" in the Administration's plan is too narrow in scope. By narrowly defining "new" gas in a very

restrictive way, this bill eliminates from its "incentive" price a substantial part of the remaining potential supply.

By restricting the "new" price to gas from offshore leases issued after April 20, 1977, the bill would assure that there could be no supply response in this area for at least 3½ to 5 years after the first lease sale due to the long lead time required to explore and develop new prospects.

There are many opportunities for deep and risky exploration in and around presently producing structures in the offshore area. The more biased critics of the industry would categorize such prospects as having been "withheld" supplies. However, such charges do not make sense when one examines the economics of individual cases. Very simply, we compare the investment required - and that is no small item when considering offshore drilling - with the production and resulting revenues we expect if the drilling is successful. If the ceiling price for gas had been $1.42 per Mcf and the economics had shown a very small or no return, that exploration would not have been done. If prices increase and the economics become favorable then such exploration could be done. Under the Administration bill most of such projects would be foreclosed by freezing present prices on present leases. As to the offshore area, which currently supplies the bulk of new sales of gas being made on the interstate market, the Administration's bill offers no incentives for new exploration and development. Under the bill, production from these new weels would be "locked in" at $1.45 per Mcf.

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There are different restrictions placed on gas qualifying as "new natural gas" for onshore wells under the Administration bill. The first restriction is that the "completion location" must be "2.5 statute miles or more (surface measurement) from the completion location of any old well," or secondly, "the completion location of which is at a depth of 1,000 feet or more in excess of the depth of the completion location of any old well with a completion location that is within 2.5 statute miles (surface measurement) provided that the completion location of any such new well is not in the same producing zone as the completion location of any such old well." This second restriction is further complicated by defining the term "producing zone" to mean "a geological formation having common characteristics that contain crude oil or natural gas, whether or not there is communication between the portions thereof." A literal interpretation of this definition of "producing zone" would seem to foreclose all gas from qualifying within a 2.5 mile radius of any old well. All formations which produce crude oil or gas have at least two common characteristics. They must have porosity and permeability in order to contain and produce oil or gas.

As I pointed out in connection with my earlier discussion of the definition of offshore "new natural gas", there are many opportunities for deep and risky exploration in and around presently producing structures. In some of the more mature producing provinces, if one were to draw a circle with a radius of 2.5 miles around all present wells, he would find very little area remaining.

The recent Potential Gas Committee estimate for the probable category of potential supply is 215 trillion cubic feet -- an amount just about equal to present proved reserves. The probable category is that supply to be developed from the growth of known gas fields and new pools discovered by further exploration associated with existing fields. The Administration bill would foreclose the bulk of this gas from qualifying as "new natural gas" because of its proximity to production.

This restraint on exploration would seem to make little sense from the standpoint of the presently installed pipelines. Gas supplies in the vicinity of these pipelines are one of the most economical sources of additional supply to the consumer. Very small increments of additional investment in transportation facilities are needed.

This restraint makes little sense from the standpoint of the producer as well. Let us look at two simple examples. In the first instance we have a producing gas field onshore at a depth of 6000 feet. Another structure with similar characteristics lies four miles from this field. A well to test this second structure would cost about $170,000. If successful gas from this well would qualify as "new natural gas" under the Administration's bill. The second example is a producing field at a depth of 16,000 feet. An untested prospect lies across a fault and only one-quarter mile from the nearest producing well in that field. An exploratory well to test this prospect would cost about $1,700,000 or about 10 times the well in the first example.

If successful, this gas would not qualify as "new natural gas" but would be limited to some lower price by the Administration's bill. Thus, these types of restrictions in the bill make no sense from a geological or an economic standpoint.

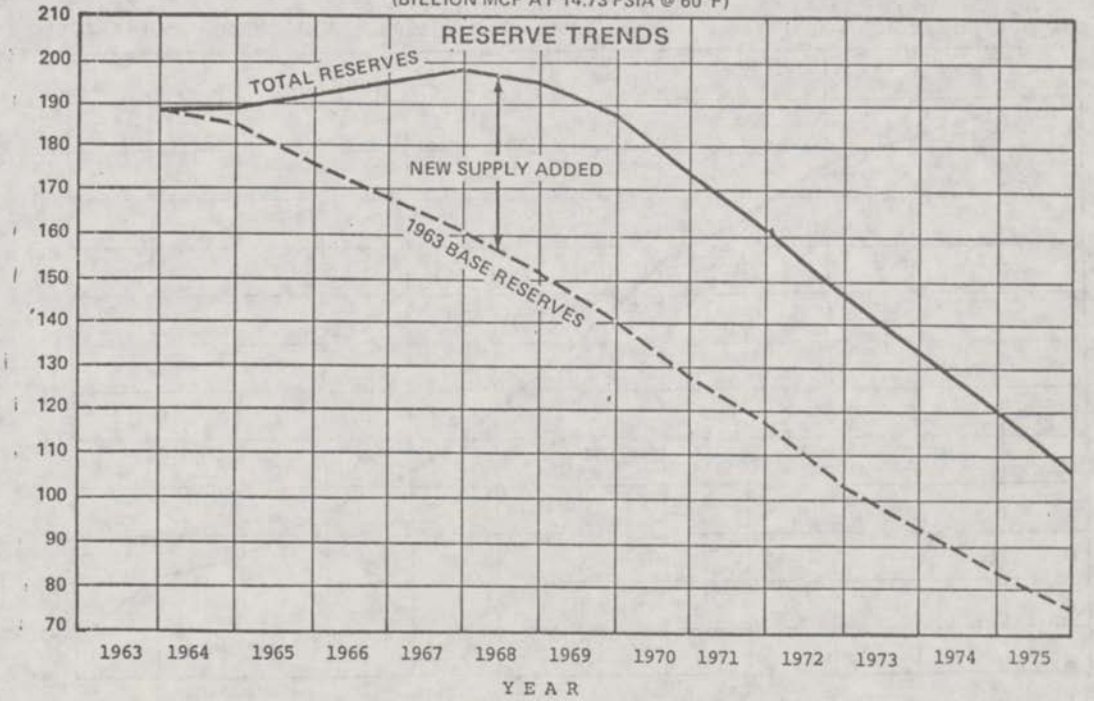
There are many other definitional criteria set out in Section 402(a) that would greatly complicate the administration of this program. The administration of these criteria, both within the regulated companies and within the regulating Agency, would be a total nightmare. A casual reading of Section 402(a)(12) is illustrative:

> "The term 'surface measurement' means the distance at mean sea level between the points at which vertical lines, drawn through the nearest points of any two completion locations, would intersect the surface of the earth at mean sea level."

It is not hard to imagine the chaos and uncertainty that will result in drawing the needed circles and lines required to ascertain the eligibility of a new gas prospect for the new gas price. The net effect is a supply disincentive accompanied by the unwarranted expansion of the federal bureaucracy.

CHART 2 - INTERSTATE PIPELINE COMPANIES CHANGES IN GAS RESERVES DOMESTIC RESERVES AND PRODUCTION TRENDS

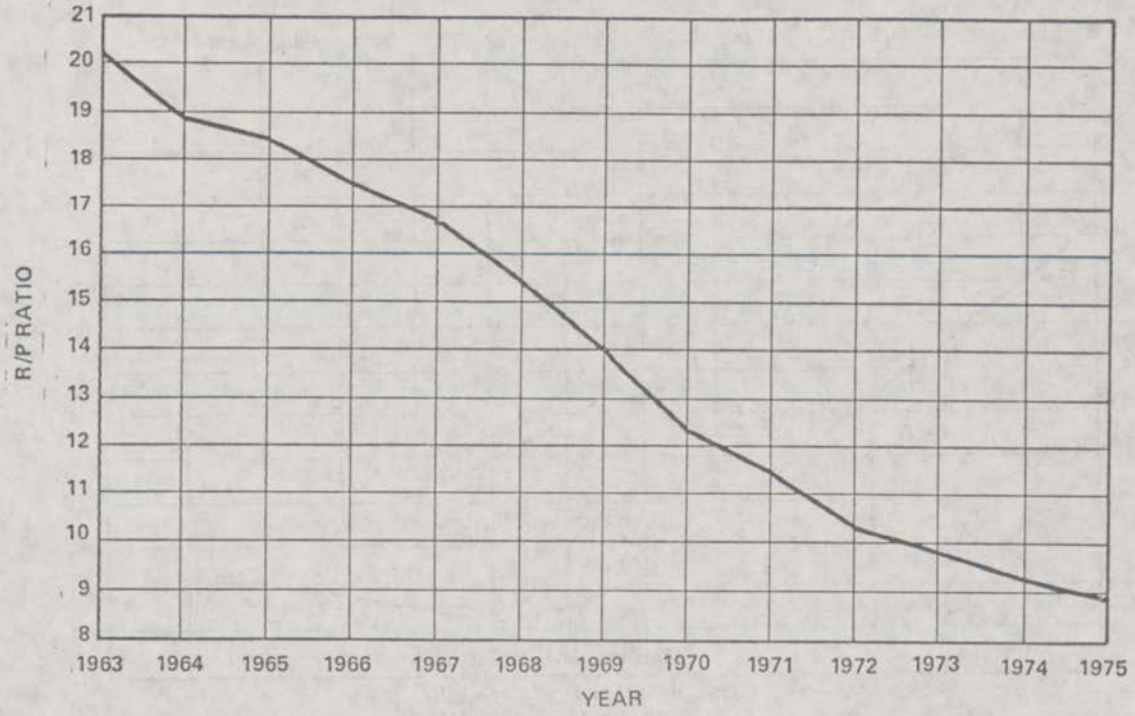
INTERSTATE PIPELINE COMPANIES
(BILLION MCF AT 14.73 PSIA @ 60°F)



THE GAS SUPPLIES OF INTERSTATE NATURAL GAS PIPELINE COMPANIES – 1975
PUBLISHED BY FEDERAL POWER COMMISSION BUREAU OF NATURAL GAS – JAN. 1977

EXHIBIT 1

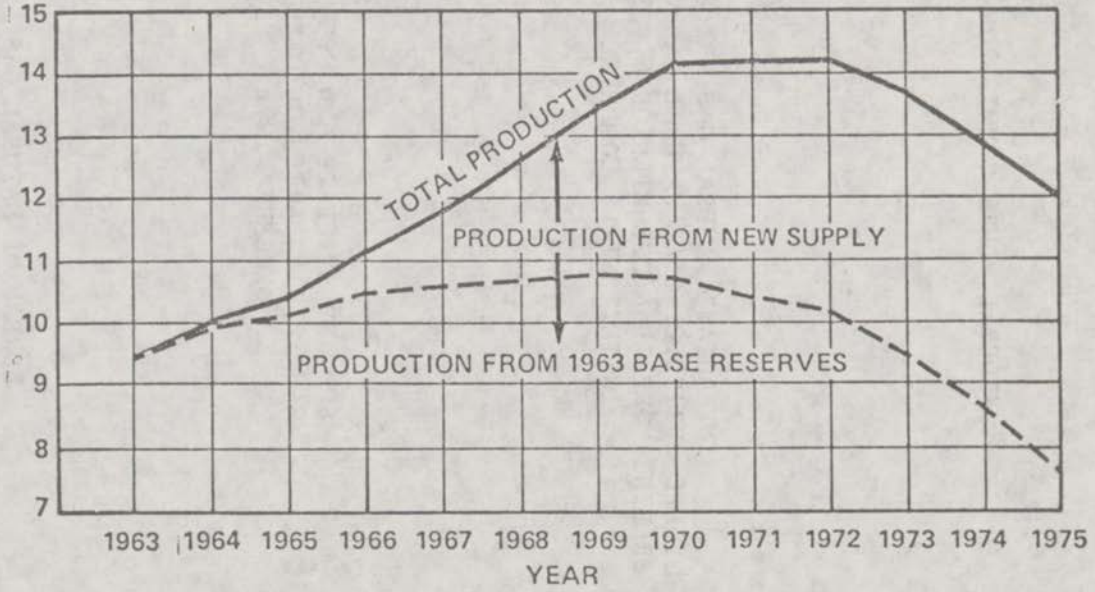
CHART 3 - R/P RATIOS, ALL INTERSTATE NATURAL GAS PIPELINE COMPANIES



THE GAS SUPPLIES OF INTERSTATE NATURAL GAS PIPELINE COMPANIES – 1975

PUBLISHED BY FEDERAL POWER COMMISSION BUREAU OF NATURAL GAS – JAN. 1977

PRODUCTION TRENDS



THE GAS SUPPLIES OF INTERSTATE NATURAL GAS PIPELINE COMPANIES – 1975

PUBLISHED BY FEDERAL POWER COMMISSION BUREAU OF NATURAL GAS – JAN. 1977

EXHIBIT II

FEDERAL POWER COMMISSION

INTRASTATE NATURAL GAS PRICES OF FPC JURISDICTIONAL NATURAL GAS COMPANIES SELLING MORE THAN ONE MILLION MCF PER YEAR IN INTERSTATE COMMERCE

SUMMARY BY STATE AND FPC GAS PRICING AREA, OCTOBER TO DECEMBER 1976

BUREAU OF NATURAL GAS
STAFF REPORT

Washington, D. C.
February, 1977

On January 9, 1975, the Commission issued Order No. 521 for the purpose of establishing a data collection system designed to investigate rates charged by jurisdictional natural gas companies for intrastate sales 1/ of natural gas which were not subject to Commission jurisdiction. Order No. 521 exempts from the filing requirement all jurisdictional producers selling less than 1 million Mcf per year in interstate commerce. 2/ Producers selling in excess of 1 million Mcf but less than 10 million Mcf in interstate commerce report on a quarterly basis, while the larger producers report on a monthly basis. A compilation of the responses to this order as filed by 109 companies on FPC Form No. 45 representing 212 intrastate contracts executed between October 1, 1976 and December 31, 1976, is presented in this report. 3/ The summary represents data from contracts having contract terms of 1 year or longer and was analyzed by state and FPC pricing area. Those contracts lacking volume data and percentage sales were omitted in the computation of the average prices and price ranges.

Summary tables by month, by state, and by pricing area are provided. The summary tables show the monthly weighted average price for new contracts was 180.41/Mcf for the three months period and for renegotiated or amended contracts a three months average of 165.52/Mcf.

Detailed data on monthly prices for each state and pricing area and an analysis of the volumes of gas sold at varying prices is also provided.

1/ Producers who sell gas only to the intrastate market are not subject to FPC jurisdiction and the requirement of Order No. 521.

2/ It is estimated that the producers required to report under the provisions of Order No. 521 sell approximately 90% of the gas produced nationally.

3/ Individual responses were found by the United States Court of Appeals for the Fifth Circuit to contain proprietary information which the Court stated must be protected from public disclosure. Continental Oil Co. v. F.P.C., 519 F2d 31 (5th Circuit 1975).

These contract prices, the sum of base price and adjustments, may be affected by various contract terms relating to delivery points, take-or-pay obligations, length of contract, renegotiation provisions, etc. Furthermore, some of the prices summarized in this report reflect prices in sales between affiliated companies.

SUMMARY OCTOBER TO DECEMBER
BY MONTH

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High	211.67	209.20	233.00	233.00
Average	178.84	164.81	185.47	180.41
Low	47.45	115.63	46.25	46.25
% Contract Volumes Sold Between				
201 - 250¢	11.7		9.1	10.0
151 - 200	56.7	96.9	86.9	70.5
101 - 150	31.6	3.1	4.0	19.5
51 - 100				
0 - 50				
Contract Volumes Mcf	41,270,957	4,643,330	27,106,366	73,020,653

RENEGOTIATED OR AMENDED CONTRACTS

High	216.17	198.58	217.11	217.11
Average	158.25	162.69	176.27	165.52
Low	47.66	50.27	114.00	47.66
% Contract Volumes Sold Between				
201 - 250¢	3.0		4.4	3.1
151 - 200	71.9	66.1	94.2	79.2
101 - 150	8.1	30.2	1.4	8.9
51 - 100	12.5	3.7		6.6
0 - 50	4.5			2.2
Contract Volumes Mcf	31,685,468	9,677,183	23,953,029	65,315,680

ALABAMA
BY STATES

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High		170.93		170.93
Average		170.93		170.93
Low		170.93		170.93
% Contract Volumes Sold Between 201 - 250¢				
151 - 200		100.0		100.0
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf		453,770		453,770

RENEGOTIATED OR AMENDED CONTRACTS

High	
Average	
Low	
% Contract Volumes Sold Between 201 - 250¢	
151 - 200	
101 - 150	
51 - 100	
0 - 50	
Contract Volumes Mcf	

CALIFORNIA
BY STATE

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High				
Average				
Low				
% Contract Volumes Sold Between				
201 - 250¢				
151 - 200				
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf				

RENEGOTIATED OR AMENDED CONTRACTS

High			97.47	97.47
Average			97.47	97.47
Low			97.47	97.47
% Contract Volumes Sold Between				
201 - 250¢				
151 - 200				
101 - 150				
51 - 100			100.0	100.0
0 - 50				
Contract Volumes Mcf			33,450	33,450

COLORADO
BY STATES

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High				
Average				
Low				
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf				

RENEGOTIATED OR AMENDED CONTRACTS

High	79.57			79.57
Average	79.57			79.57
Low	79.57			79.57
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150				
51 - 100	100.0			100.0
0 - 50				
Contract Volumes Mcf	617,385			617,385

KANSAS
BY STATES

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High		150.82	167.11	167.11
Average		150.82	160.73	151.85
Low		150.82	155.00	150.82
% Contract Volumes Sold Between 201 - 250¢				
151 - 200		100.0	100.0	100.0
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf		812,230	95,000	907,230

RENEGOTIATED OR AMENDED CONTRACTS

High	164.25	144.21		164.25
Average	111.72	144.21		117.74
Low	55.20	144.21		55.20
% Contract Volumes Sold Between 201 - 250¢				
151 - 200	51.8			42.2
101 - 150		100.0		18.5
51 - 100	48.2			39.3
0 - 50				
Contract Volumes Mcf	316,600	72,000		388,600

LOUISIANA
BY STATES

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High	155.00		203.14	203.14
Average	144.64		194.51	156.33
Low	132.35		152.86	132.35
% Contract Volumes Sold Between				
201 - 250¢			0.1	0.1
151 - 200	2.7		99.9	25.5
101 - 150	97.3			74.4
51 - 100				
0 - 50				
Contract Volumes Mcf	12,322,540		3,772,490	16,095,030

RENEGOTIATED OR AMENDED CONTRACTS

High	173.91	147.00	158.76	173.91
Average	149.91	131.91	152.45	149.99
Low	47.66	123.53	117.61	47.66
% Contract Volumes Sold Between				
201 - 250¢				
151 - 200	83.7		98.3	84.8
101 - 150		100.0	1.7	3.7
51 - 100				
0 - 50	16.3			11.5
Contract Volumes Mcf	8,636,650	405,610	3,238,383	12,280,643

MONTANA
BY STATES

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High	198.00			198.00
Average	198.00			198.00
Low	198.00			198.00
% Contract Volumes Sold Between 201 - 250¢				
151 - 200	100.0			100.0
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf	2,000,000			2,000,000

RENEGOTIATED OR AMENDED CONTRACTS

High				
Average				
Low				
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf				

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NEW MEXICO
BY STATES

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High	47.45	152.34		152.34
Average	47.45	152.34		152.12
Low	47.45	152.34		47.45
% Contract Volumes Sold Between 201 - 250¢				
151 - 200		100.0		99.8
101 - 150				
51 - 100				
0 - 50	100.0			0.2
Contract Volumes Mcf	1,500	735,000		736,500

RENEGOTIATED OR AMENDED CONTRACTS

High	143.00	110.60	114.00	143.00
Average	90.35	110.60	114.00	96.91
Low	66.27	110.60	114.00	66.27
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150	34.0	100.0	100.0	55.2
51 - 100	66.0			44.8
0 - 50				
Contract Volumes Mcf	4,457,328	2,011,000	101,000	6,569,328

OKLAHOMA
BY STATE

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High	187.38	187.00	186.97	187.38
Average	163.48	162.57	167.55	166.26
Low	125.00	118.69	107.58	107.58
% Contract Volumes Sold Between				
201 - 250¢				
151 - 200	64.4	95.0	91.4	86.8
101 - 150	35.6	5.0	8.6	13.2
51 - 100				
0 - 50				
Contract Volumes Mcf	2,860,050	1,675,980	10,892,319	15,428,349

RENEGOTIATED OR AMENDED CONTRACTS

High	189.28	169.01	193.24	193.24
Average	161.16	90.73	175.98	172.61
Low	85.00	50.27	124.31	50.27
% Contract Volumes Sold Between				
201 - 250¢				
151 - 200	92.8	25.9	99.0	97.1
101 - 150		1.1	1.0	0.9
51 - 100	7.2	73.0		2.0
0 - 50				
Contract Volumes Mcf	3,272,249	252,185	17,242,844	20,767,278

PENNSYLVANIA
BY STATES

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High				
Average				
Low				
% Contract Volumes Sold Between				
201 - 250¢				
151 - 200				
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf				

RENEGOTIATED OR AMENDED CONTRACTS

High	148.46			148.46
Average	148.46			148.46
Low	148.46			148.46
% Contract Volumes Sold Between				
201 - 250¢				
151 - 200				
101 - 150	100.0			100.0
51 - 100				
0 - 50				
Contract Volumes Mcf	273,000			273,000

TEXAS
BY STATES

NEW CONTRACTS
C/Mcf

	October	November	December	October December
High	211.67	209.20	233.00	233.00
Average	196.58	186.80	198.71	197.06
Low	115.63	115.63	46.25	46.25
% Contract Volumes Sold Between				
201 - 250¢	20.1	0.1	20.1	19.7
151 - 200	79.8	92.7	78.8	79.7
101 - 150	0.1	7.2	1.1	0.6
51 - 100				
0 - 50				
Contract Volumes Mcf	24,086,867	846,350	12,346,557	37,279,774

RENEGOTIATED OR AMENDED CONTRACTS

High	216.17	198.58	217.11	217.11
Average	188.80	182.82	202.54	189.01
Low	74.59	90.00	196.06	74.59
% Contract Volumes Sold Between				
201 - 250¢	6.7		31.4	8.2
151 - 200	87.6	91.7	68.6	86.1
101 - 150	5.6	6.3		5.0
51 - 100	0.1	2.0		0.6
0 - 50				
Contract Volumes Mcf	14,112,256	6,902,938	3,370,802	24,385,996

WYOMING
BY STATES

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High		189.22		189.22
Average		189.22		189.22
Low		189.22		189.22
% Contract Volumes Sold Between 201 - 250¢				
151 - 200		100.0		100.0
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf		120,000		120,000

RENEGOTIATED OR AMENDED CONTRACTS

High	
Average	
Low	
% Contract Volumes Sold Between 201 - 250¢	
151 - 200	
101 - 150	
51 - 100	
0 - 50	
Contract Volumes Mcf	

AREA 1 APPALACHIAN-ILLINOIS
BY AREAS

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High				
Average				
Low				
% Contract Volumes Sold Between				
201 - 250¢				
151 - 200				
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf				

RENEGOTIATED OR AMENDED CONTRACTS

High	148.46			148.46
Average	148.46			148.46
Low	148.46			148.46
% Contract Volumes Sold Between				
201 - 250¢				
151 - 200				
101 - 150	100.0			100.0
51 - 100				
0 - 50				
Contract Volumes Mcf	273,000			273,000

AREA 2 OTHER SOUTHWEST
BY AREAS

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High	197.29	168.08		197.29
Average	190.55	165.14		171.34
Low	125.00	153.08		125.00
% Contract Volumes Sold Between 201 - 250¢				
151 - 200	90.7	100.0		97.7
101 - 150	9.3			2.3
51 - 100				
0 - 50				
Contract Volumes Mcf	201,250	624,000		825,250

RENEGOTIATED OR AMENDED CONTRACTS

High	198.28	50.27	184.00	198.28
Average	170.96	50.27	177.95	176.77
Low	153.43	50.27	124.31	50.27
% Contract Volumes Sold Between 201 - 250¢				
151 - 200	100.0		100.0	99.6
101 - 150				
51 - 100				0.4
0 - 50				
Contract Volumes Mcf	1,419,820	53,730	12,798,889	14,272,439

AREA 3 SOUTHERN LOUISIANA
BY AREA

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High	155.00		203.14	203.14
Average	144.64		194.51	156.33
Low	132.35		152.86	132.35
% Contract Volumes Sold Between 201 - 250¢			0.1	
151 - 200	2.7		99.9	25.5
101 - 150	97.3			74.5
51 - 100				
0 - 50				
Contract Volumes Mcf	12,322,540		3,772,490	16,095,030

RENEGOTIATED OR AMENDED CONTRACTS

High	173.91	147.00	153.00	173.91
Average	149.91	131.91	152.40	149.97
Low	47.66	123.53	117.61	47.66
% Contract Volumes Sold Between 201 - 250¢				
151 - 200	83.7		98.3	84.7
101 - 150		100.0	1.7	3.8
51 - 100				
0 - 50	16.3			11.5
Contract Volumes Mcf	8,636,650	405,610	3,211,153	12,253,413

AREA 4 TEXAS GULF COAST
BY AREAS

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High	209.00	209.20	198.28	209.20
Average	197.93	192.35	198.23	197.82
Low	186.01	177.05	196.09	177.05
% Contract Volumes Sold Between				
201 - 250¢	20.9	0.1		16.8
151 - 200	79.1	99.9	100.0	83.2
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf	22,394,867	785,150	4,626,090	27,806,107

RENEGOTIATED OR AMENDED CONTRACTS

High	216.17	198.24	217.11	217.11
Average	197.70	167.01	216.63	196.58
Low	74.59	90.00	216.53	74.59
% Contract Volumes Sold Between				
201 - 250¢	23.5		100.0	33.6
151 - 200	76.2	83.6		63.7
101 - 150				
51 - 100	0.4	16.4		2.7
0 - 50				
Contract Volumes Mcf	4,031,086	870,768	1,058,500	5,960,354

AREA 5 PERMIAN BASIN
BY AREAS

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High	211.67		233.00	233.00
Average	176.98		199.48	195.82
Low	47.45		125.68	47.45
% Contract Volumes Sold Between				
201 - 250¢	11.1		32.3	28.8
151 - 200	88.8		66.4	70.1
101 - 150			1.3	1.1
51 - 100				
0 - 50	0.1			
Contract Volumes Mcf	1,492,500		7,677,967	9,170,467

RENEGOTIATED OR AMENDED CONTRACTS

High	196.20	198.58	196.51	198.58
Average	178.25	168.57	196.09	176.88
Low	100.55	110.60	196.06	100.55
% Contract Volumes Sold Between				
201 - 250¢				
151 - 200	81.3	71.9	100.0	80.1
101 - 150	18.7	28.1		19.9
51 - 100				
0 - 50				
Contract Volumes Mcf	10,951,370	7,159,170	2,312,302	20,422,842

AREA 6 HUGOTON-ANADARKO
BY AREAS

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High	187.38	187.00	186.97	187.38
Average	163.42	155.28	167.27	165.12
Low	115.63	115.63	46.25	46.25
% Contract Volumes Sold Between 201 - 250¢				
151 - 200	64.4	92.5	91.1	86.4
101 - 150	35.6	7.5	8.9	13.6
51 - 100				
0 - 50				
Contract Volumes Mcf	2,859,800	1,925,410	11,029,819	15,815,029

RENEGOTIATED OR AMENDED CONTRACTS

High	189.28	169.01	193.24	193.24
Average	155.11	140.92	170.23	161.37
Low	55.20	67.37	124.31	55.20
% Contract Volumes Sold Between 201 - 250¢				
151 - 200	84.7	44.8	96.1	85.3
101 - 150		43.9	3.9	8.3
51 - 100	15.3	11.3		6.4
0 - 50				
Contract Volumes Mcf	2,549,829	1,154,455	4,471,185	8,175,469

AREA 7 ROCKY MOUNTAIN
BY AREAS

NEW CONTRACTS
C/Mcf

	October	November	December	October-December
High	198.00	189.22		198.00
Average	198.00	157.51		185.87
Low	198.00	152.34		152.34
% Contract Volumes Sold Between 201 - 250¢				
151 - 200	100.0	100.0		100.0
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf	2,000,000	855,000		2,855,000

RENEGOTIATED OR AMENDED CONTRACTS

High	143.00		114.00	143.00
Average	76.27		114.00	77.24
Low	66.27		114.00	66.27
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150	6.9		100.0	9.3
51 - 100	93.1			90.7
0 - 50				
Contract Volumes Mcf	3,823,713		101,000	3,924,713

AREA 8 OTHER AREAS
BY AREAS

NEW CONTRACTS
C/Mcf

	October	November	December	October December
High		170.93		170.93
Average		170.93		170.93
Low		170.93		170.93
% Contract Volumes Sold Between 201 - 250¢				
151 - 200		100.0		100.0
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf		453,770		453,770

RENEGOTIATED OR AMENDED CONTRACTS

High		97.47		97.47
Average		97.47		97.47
Low		97.47		97.47
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150				
51 - 100		100.0		100.0
0 - 50				
Contract Volumes Mcf		33,450		33,450

Mr. DINGELL. The committee thanks you, Mr. Allen.
Our next panel member is Mr. Hefner.

STATEMENT OF ROBERT A. HEFNER III

Mr. HEFNER. Thank you.

My name is Robert A. Hefner III. I am a partner in the GHK Companies. I am a petroleum geologist and exploration geophysicist. Our companies have been in the natural gas exploration business for 18 years, and today I am here to talk to you as chairman of the Independent Gas Producers Committee.

One thing that I would like to make as clear as I can, and I think it is the same message that has been given to you by Mr. Allen, of Phillips, and Mr. Davis here, is that we who are petroleum geologists and exploration geophysicists who spent our lifetimes looking for oil and natural gas, are in complete disagreement with both Mr. O'Leary, who appeared here before you this morning, and Mr. Zareski, who has submitted written testimony to this committee previously, as to the resource base and the price elasticity of natural gas.

Part of my written testimony, which I ask you to place in the record, if you would, with its exhibits, Mr. Chairman.

Mr. DINGELL. Without objection, your full statement will appear in the record.

I was reading the summary of it while you were talking. Go ahead.

Mr. HEFNER. We believe that that written testimony which is now in the record totally and completely refutes the idea that we have heard Mr. O'Leary espouse nationally that natural gas has "had it," and the Zareski argument that, based on looking into the past, his statistics and economic parameters indicate that there is nothing there in the future.

I want to point out and make it crystal-clear, if I can, that unlike domestic oil, which indeed is in a mature state of development, natural gas is practically pervasive within the sedimentary basins of the Continental United States. Natural gas methane exists from garbage pails to swamp gas to mature to all sediments; it is throughout Appalachia, the sediment of the Rocky Mountain Basin, Midcontinent, Pennsylvania, and Ohio. We believe totally that the resource base is, in fact, here.

I ask you that you listen to us because we are not economists who look back, but petroleum geologists and petroleum geophysicists who have made our careers and professions to investigating what the resource base is, where it might be found and how we can develop it.

One example I would like to give that refutes the idea that there is no price responsiveness above a ceiling of 1975's is a province that we know a lot about, the Anadarko Basin of the Midcontinent area, which we predict, based on over 5,000 miles of modern seismic techniques, the most modern techniques available to the industry and over 100 man-years of interpretation and investigations of those techniques and geological data, engineering data, we estimate with a great deal of confidence that there is from 60 to 300 trillion cubic

feet of gas remaining in this one province. We point to that significant number because that one number is a large supply that is equal to some people's estimates for the inland of the entire United States and the point we wish to make is that the majority of that supply within the time frame the Nation needs that gas is totally price-responsive above $1.75, the ceiling that has been proposed by the administration's natural gas plan.

Now, the question I think here before us today is how do we get the gas that is needed in this country, the gas that I gave an example of here, and the rest of the gas that the consumers around the country are demanding.

Yesterday, our committee had a meeting and we are about to propose to you something that is different from that which you will find in our written statement and somewhat different from that presented to you here today by Mr. Jones, the IPAA. We think that it is time now, possibly long past time, to enact a natural gas policy which can be enacted within the time constraints that are placed upon us and those constraints, to me, are in the national interest because the time demands of the declining supplies of natural gas in the past cold winter and the possibilities of additional winters of 1977's in the forthcoming years.

We think that natural gas is the root and the key issue and a national energy policy, and its resolution is absolutely necessary for the success of a national energy policy of any kind. We think as it is the root of the cause of our supply-demand imbalances that it must be the first step toward the resolution of our problems.

Now, we today think it is time for statesmanship, and we believe that the proposals we are about to offer you should begin to be hammered out right here in this committee today; that our proposals are practical and workable; that they will lead to a practical and workable compromise that will resolve the natural gas issue in a realistic and fair way at both ends of the pipeline.

Therefore, the Independent Gas Producers Committee proposes the following: First, that we write a strict definition of new onshore gas, so that only truly newly discovered gas—that is, gas that has not yet been "risked for"—is included.

We have done that, and you will find in exhibit 2 of our written statement our proposed definitions for new natural gas which we believe will meet the criteria of simplicity and will not require the large bureaucracy of interpretation as those proposed within the President's plan.

We have defined natural gas from in-fill drilling, recompletions, expiring contracts, as "special category gas." I may have left out one, but, in any event, you will find our "Special Category Gas" defined in exhibit 2.

It is our proposal that a price ceiling of $2.25 be placed on new gas.

Next, that we place a price ceiling of $1.45 on all our defined gas as "Special Category Gas."

Four, that the ceiling prices be allowed to escalate quarterly, commensurate with the rate of increases in natural gas exploration and production costs.

Five, that the new gas price ceiling phase out over a 4-year period, while we maintain price controls on our special category gas.

Now, in response to Dr. Schlesinger this morning, telling you that many, one time he said "many", and another time "most" and other adjectives, producers could live with and make money at $1.75; we independents completely refute that. We don't believe that is possible, and therefore, we propose our point number six, which is to exempt from any controls new gas discovered by independent producers from the new gas price ceilings; that we define, without restrictions or complications independent producers as companies which produced less than 200 billion cubic feet of gas in the year 1976.

One very important point which we believe would be in the national interest is that this would exempt all independent producers from the bureaucratic morass of regulation, and let us get on with our business of forming risk capital to go into the development of new natural gas reserves. Our proposals would increase significantly the levels of competition within the onshore domestic industry.

Seven, we propose that there be an exemption of all new gas produced from reservoirs below 15,000 feet in depth. The general justification for such an exemption for all producers is that there are within the traditional supply areas, and within the timely reach of consumers, vast supplies of nonassociated natural gas, price-responsive totally to the price at the wellhead, that we think it is in the national interest to produce so long as that natural gas can come to the markets, to the consumers at least, than the imported prices of LNG.

Eight, we would subject all flowing gas sold under contracts with favored-nation or price redetermination clauses to the new gas price ceilings.

And, nine, allow the emergency sales to continue under the present law.

Our committee believes that this proposal is practical because we believe that it can be enacted into law within the time constraints given to you by the administration, but more importantly given to us by the natural decline in natural gas supplies and the shortages of the interstate markets and the commensurate economic disruptions that we are facing.

We believe that it is workable because it would, one, create the political and economic circumstances to allow sufficient risk capital formation to finance the expanded onshore exploration effort in consortium with the ongoing programs of independent producers in this country today.

Two, it would result in the rapid development of vast onshore U.S. natural gas supplies flowing to the interstate markets.

Three, it would tend to fuel increases in near-term employment and economic growth, giving us the vitally needed near-term energy source to fuel a stimulated economy before we can meet the completion and hard-to-achieve conservation of our domestic economy's infrastructure.

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Four, eliminate any so-called windfall profit aspect from new gas production, because our strict definition would allow the exemption for only that gas that has yet to be risked for.

Five, reverse in the very near term the trend toward greater and greater concentration within the gas-producing industry by allowing the circumstances to exist to increase competition within the independent sector and allow the circumstances necessary and the certainty necessary within the economic system to raise the risk capital necessary to do the job at hand.

Six, protect the interstate and intrastate consumers from sudden and sharp price increases.

Seven, encourage natural gas conservation by making steady price increases predictable. In other words, allow the consumers of this country a predictable understanding as to where the natural gas prices are going to go so that they can begin to make capital expenditures for conservation technology.

Eight, displace significant volumes of imported petroleum and,

Nine, benefit the Nation's environmental health.

I think a good point there is the whole population of Southern California, air quality standards are a significant problem to them now, and without continued supplies of natural gas within that environment, I think that they will have severe deterioration in air quality, and it would be a concern, they tell me, to the health problems of the entire Southern California area.

In short, we believe this proposal makes sense, both economically and politically and a bill based on these provisions could be signed into law this summer and help alleviate the coming social and economic problems we are facing in the following winters.

The enactment of this legislation would refocus U.S. resources, those being experienced people, capital, drilling equipment, supplies and technology, on the rapid development of the vast potential supplies of onshore natural gas.

Thank you. That is the end of my summary, and I will be glad, of course, to answer any questions.

[Mr. Hefner's prepared statement follows:]

Statement of Robert A. Hefner III

National Chairman, Independent Gas Producers Committee

Hearings Before The
Subcommittee on Energy and Power of the
Committee on Interstate and Foreign Commerce
U. S. House of Representatives

May 12, 1977

The President's natural gas proposals are based on a misunderstanding of the nation's natural gas resource base. This erroneous view has been summed up by the head of the Federal Energy Administration, John O'Leary, in his remark that "Natural gas has had it."

A policy based on this defeatist outlook would result in the nation marching backwards into the future, sinking deeper and deeper into the morass of economic dislocation resulting from our energy crisis.

Natural gas has not had it. Natural gas price controls have had it. Price controls have denied consumers the vast potential supplies of natural gas that could be found and produced in the United States if consumers were free to pay what this gas is worth to them.

Natural gas -- within or near traditional supply areas already connected to the nation's consumers by existing pipelines -- is the *only* domestic resource that can significantly relieve the energy crunch in the next three years without sacrificing environmental standards.

The resolution of the natural gas issue by Congress and the administration must be foremost within our national energy policy for it is natural gas shortages, not oil, that will have an *immediate* impact on the amount of personal hardships and economic loss suffered by the American people as a result of the Winters of '78, '79, and '80!

Certainly conservation is important, But major conservation steps will take time to implement. The American people will not accept rationing or other stringent mandatory conservation measures. Unnecessary economic hardships, dislocations and inflation would result from increases in the real price of energy sufficient to reduce energy consumption over such a short period of time. Thus, regardless of what laws are enacted to slow the long-term growth energy demand, we cannot achieve an expanded economy and increased employment in the next three years without using more energy.

Where will this energy come from? There are only two near-term alternatives: more imported oil, or increased onshore natural gas production. Our other domestic alternatives -- offshore oil and gas, coal, nuclear, SNG, etc. -- will require four or more years to begin making major new contributions, even if an all out development effort were started today.

Therefore, national energy policy must operate to refocus United States resources (experienced people, capital, drilling equipment and supplies and technology) toward the rapid development of the vast potential supplies of onshore natural gas.

The Potential Gas Committee[1] estimates that between 923 and 973 trillion cubic feet of natural gas remain to be discovered in the United States. This *conservative* estimate represents a 45 to 50 year supply. With consumers free to select the energy source best suited for their needs and pay the price they deem acceptable to meet those needs, natural gas supply and demand can be brought into balance within four years, and natural gas can continue to supply a significant part of the nation's energy well into the next century.

Consideration of all economic, social and environmental costs places natural gas as by far America's most valuable fuel. And yet, the Administration proposes to keep new natural gas priced below the price of new domestic oil, below the price of foreign oil and below the price of LNG. In effect, the Carter plan would perpetuate regulations keeping new natural gas priced below its value, maintaining the gap that has distorted the nation's energy economics for more than two decades. The President's proposals is to continue to subsidize natural gas consumption, confiscate the assets of thousands of farmers, ranchers and other mineral owners in the producing states, restrict the high risk search for new supplies, and erect new institutional barriers that would penalize independent producers unfairly and result in increased concentration and restricted competition within the natural gas industry. This is nothing less than the formula for institutionalizing the Winter of '77 natural gas shortages as an annual event, and putting the government into the business of spreading the shortages more evenly around the country.

The view that "natural gas has had it" was supported by Gordon K. Zareski, chief, resource evaluation and analysis division, Bureau of Natural Gas, Federal Power Commission in his summary statement to the Subcommittee on Energy and Power on

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[1]The Potential Gas Committee consists of volunteer representatives from large and small exploration and production companies, consultants, officials of state geological surveys, and from academic institutions. Observers from federal and state agencies also participate. The Committee works under the auspices of the Potential Gas Agency of the Colorado School of Mines.

March 24, 1977. Zareski stated that, "...regardless of what happens to gas prices, production will not substantially increase nor will it remain at present levels for a sustained period." Zareski based this erroneous conclusion on an outdated U. S. Geological Survey estimate of the nation's natural gas resource base, and on a faulty analysis of historical natural gas exploration trends.

A detailed rebuttal of Zareski's statement is included as Exhibit I to this statement. In summary, the reported cited by Zareski as his source for resource data and the basis for his argument that natural gas is "price inelastic", Geological Survey Circular 725, relied on pre-1974 price trends not reflecting today's totally new economic, political and environmental pressures on natural gas prices. (Unlike oil, which usually accumulates in geological structures, natural gas is pervasive in sediments. Throughout the United States, many known and potential natural gas reservoirs have been intentionally by-passed and ignored because federal price controls made virtually all natural gas not associated with oil unprofitable to find and produce.) Price increases since 1974 have established some important geological basins as economical for exploring for non-associated natural gas, and deregulation of interstate prices would open every basin of the continental U. S. as a new frontier.

The price elasticity of natural gas although more than adequately proven on a regional basis has never been adequately tested on a national basis due to the distortions of the dual market systems. Increases in interstate gas prices in the past five years have come from an extremely low base, and natural gas prices remain below the Btu equivalent price of oil. Within the unregulated intrastate markets, natural gas has been proven to be highly responsive to increases in price. Reserves dedicated to intrastate markets increased 3.5 trillion cubic feet during 1975.

In Oklahoma, for example, more than 85% of the natural gas reserves discovered since 1972 have been dedicated to the intrastate market. Increased drilling has led to intrastate reserve additions exceeding consumption each year between 1972 and 1976. Intrastate reserves increased 669 billion cubic feet despite a 6.2% increase in annual consumption. Thus, with supply and demand already in balance, the intrastate demand has not been strong enough to support the higher prices required to bring on still more exploration in the state's deep and ultradeep basins.

The state's consumers now enjoy adequate supplies because they have been free to pay the actual value of new gas. Average residential prices in Oklahoma increased at a rate of 12.8% between 1970 and 1976. In the first quarter of 1976, the average intrastate wellhead price in Oklahoma was 84 cents per mcf, nearly three times as much as the 31.6 cent average price for Oklahoma gas leaving the state. Despite paying much higher wellhead prices, average Oklahoma residential consumer in 1975 paid $1.21 per mcf,

well below the national average for residential consumers of $1.71 per mcf. This illustrates the importance of natural gas transportation and distribution costs to the consumer.

Deep Gas Potential

On March 24, 1977, I submitted a statement to this subcommittee concerning the potential natural gas resources of the Deep Anadarko Basin of western Oklahoma and the Texas Panhandle. My company, GHK, estimates that 60 to 300 trillion cubic feet of natural gas remain to be discovered at depths between 15,000 and 30,000 feet in this basin. Since submitting this statement, I have met with geologists at the U. S. Geological Survey to present the scientific evidence supporting our estimates. As I explained in this meeting, GHK used five different methods to calculate this potential gas supply. All five methods reinforced each other by giving similar results. This redundancy of results, combined with our knowledge of recent discoveries and current drilling in the Deep Anadarko Basin, gives us increasing confidence in the accuracy of our estimates of the basin's potential natural gas supply. Your subcommittee is encouraged to discuss these estimates with USGS experts, because our Anadarko potential reserves are the same order of magnitude as those which may exist in other "frontier areas" -- the Arctic, offshore Alaska, and the Outer Continental Shelves and are equal to or larger than some pessimistic estimates for the entire inland U. S. potential supply.

Why Decontrol?

Decontrol of new onshore natural gas prices is the only policy that will result in rapid development of the domestic natural gas resources in time to prevent the layoffs and hardships suffered during the Winter of '77 from becoming annual events. Risk capital of the magnitude necessary to do the job will not be forthcoming without the chance to earn profits commensurate with the risks encountered. Price controls merely restrict drilling to low risk areas where producers believe they still have a chance to still make acceptable profits within the economic parameters determined by the controls.

But much of the nation's remaining natural gas supplies lie in deep onshore and other frontier areas, where the operating costs and risks are so great that the explorer planning a wildcat well does not know what the final cost of the well will be. Investors will not take extraordinary risks for the chance to earn a normal or regulated profit. Exploring in deep onshore and remote frontier areas requires a chance to earn profits commensurate with the extraordinary risks involved. Risk capital formation for the extraordinary risks of exploring for natural gas in the deep onshore provinces of North America will be severely restricted to the point of disappearing within a regulated market.

Definitions

The President's proposed definition of new gas is meaningless in geologic terms. For example, filings at the Oklahoma Corporation Commission indicate 161 active locations in Oklahoma classified as wildcats. Under the Administration's definition, oil or gas discoveries made by only about half of these exploratory wells would qualify as new. Assuming normal success ratios, this would mean only about eight wells in the entire state could be expected to produce new oil or gas.

With deregualtion of new gas, we believe it is important that new gas be defined in a way that eliminates any "windfall profit" aspect from any new production. Therefore, we propose that federal price controls be maintained on all natural gas sold or delivered into interstate commerce except for truly new gas, that is gas that had not been "risked for" before the effective date of decontrol. Our proposed definition is contained in Exhibit II of my statement.

Cost of Deep Natural Gas

We believe that deep onshore natural gas (produced from reservoirs below 15,000 feet) should be exempted from price controls. The President's proposal is correct in identifying deep drilling as requiring special pricing considerations. The Federal Power Commission has had the authority to set higher prices for deep drilling, but has failed to use this authority. The Commission has cited the lack of productivity data for deep drilling as its reason for not taking action on this issue. By productivity, the Commission means the amount of gas discovered per foot drilled. In its most recent national rate decision, ruling 770-A, the Commission uses a productivity factor of 300 mcf per foot drilled. My company's experience in and studies of finding rates in the Deep Anadarko Basin in western Oklahoma indicate that a higher productivity factor of 500 to 1,000 mcf per foot drilled should be projected when drilling for natural gas at depths between 15,000 and 30,000 feet. Using these productivity factors and 1977 deep drilling costs, we have applied the methodology used by the FPC in 770-A to calculate a range of natural gas prices required to provide various rates of return. The results are shown in Exhibit III of my statement. To summarize, assuming a producer is highly successful and earns only a 15% rate of return, he would need to receive $1.93 per mcf. However, no one is likely to take on the high risks associated with deep drilling for a 15% rate of return. Instead, a 33% rate of return is more reasonable for deep drilling. Assuming this rate of return and a 500 mcf per foot productivity factor, the required price is $6.25 per mcf. Of course, when an independent explorer who drills a $2 million dry hole, his productivity factor is zero, and he can take small comfort in national averages. Thus, we are not presenting this data to advocate higher ceiling prices for deep gas, but to illustrate the range of possible prices that will be required to elicit

deep drilling efforts on the scale required to help meet the near term demand for natural gas. Even assuming high productivity factors well above the national average, the development of deep gas requires not a higher price, but an unregulated price. The risks and costs associated with deep drilling are just too great to allow development under arbitrary ceilings which would deny this gas to consumers and force them to rely on higher priced and less secure imports of LNG.

EXHIBIT I

RESPONSE TO THE MARCH 24, 1977, STATEMENT OF GORDON K. ZARESKI
CHIEF, RESOURCE EVALUATION AND ANALYSIS DIVISION
BUREAU OF NATURAL GAS
FEDERAL POWER COMMISSION

HEARINGS BEFORE THE
SUBCOMMITTEE ON ENERGY AND POWER
OF THE
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
U. S. HOUSE OF REPRESENTATIVES

BY ROBERT A. HEFNER III
MANAGING PARTNER OF
THE GHK COMPANY AND GASANADARKO, LTD.
Oklahoma City, Oklahoma
May 12, 1977

Natural gas is *the most price responsive* of all domestic energy sources. Unlike oil, which usually accumulates in geological structures, natural gas is pervasive in sediments. Throughout the United States, many known and potential natural gas reservoirs have been intentionally bypassed and ignored because federal price controls kept virtually all natural gas not associated with oil[1] uneconomic to find and produce. Therefore, onshore new gas deregulation bringing natural gas prices to the equivalent of new oil prices and higher will create a greatly expanded exploration effort for onshore U. S. natural gas.

A careful analysis of the nation's natural gas resource base and the dynamics of the gas producing industry completely and totally refute the March 21, 1977, statement by Gordon K. Zareski to the House Subcommittee on Energy and Power that "regardless of what happens to gas prices, production will not substantially increase nor will it remain at present levels for a sustained period." After describing historical trends in the natural gas industry, Zareski proposes that energy policies be based on "the expectation of decreasing gas availability." A policy based on this erroneous view would result in the nation marching backwards into the future. Vast supplies of onshore natural gas, sufficient to meet "true demand" (based on prices at parity with other energy sources) well into the next century, remain to be developed within the continental U.S. (Rockies, Appalachian, and Mid-continent).

Anyone can predict that continued use of a finite resource will eventually exhaust the supply, but such a prediction is useless!

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[1]Everytime a barrel of oil is produced natural gas is also produced. However, the largest gas fields of the world are "non-associated".

To have significance for existing civilization, *meaningful* resource projections must include both time and price dimensions and must be measured within the present and forecast economic, political and environmental conditions.

Thus, considering the historic unrealistic underpricing of natural gas when compared to competing fuels, the environmental advantages of natural gas over other fuels, and the potential for rapid development of large new natural gas supplies from traditional supply areas, one must conclude that *natural gas is a fuel whose time has come!* Major increases in natural gas prices and decreases in demand are inevitable and necessary to a realistic economy. Therefore, with an understanding of the vast remaining supplies, it becomes clear that, barring government created institutional barriers in the form of price regulation, natural gas (as opposed to oil) supply and demand can be brought into balance within four years and that balance can be maintained well into the next century.

Such a balance in natural gas produced from domestic supplies will not only have a strong beneficial impact on balance of trade and national security, but also and equally important will allow this country an invaluable economic and political opportunity to convert our energy consuming infrastructure and economic system to various suitable long term alternative energy sources outside of a "crisis" atmosphere. Natural gas can provide a domestic energy source sufficient to allow the circumstances to make judgements about our energy direction, measured by optimum long term goals rather than the necessity of short term reactions to existing emergencies.

Natural Gas Resource Base

Zareski states that only about one-third of the lower 48 resource base remains to be discovered. His basis for this premise is a U. S. Geologic Survey estimate which *relied on pre-1974 price trends* not reflecting today's totally new economic, political and environmental pressures on natural gas prices. Prices higher by an entire order of magnitude than those envisioned in 1974 result in major increases in the estimated "attainable"resource base.[2]

The very report cited by Zareski as his source for resource figures and basis for his price inelastic argument, Geological Survey Circular 725, explains the relationship between natural gas prices and resource estimates as follows:

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[2]An example of the 1972 Potential Gas Supply Committee's Area J North estimate of 25 trillion cubic feet at depths between 15,000 and 30,000 feet. Recent deep drilling technology and an order of magnitude price increase has opened up the possibility of a new deep natural gas frontier with potential reserves of 60 to 300 trillion cubic feet.

"The estimates of undiscovered recoverable resources take into account relevant past history and experience and are based on assumptions that undiscovered recoverable resources will be found in the future *under conditions represented by a continuation of price-cost relationships and technological trends generally prevailing in the recent years prior to 1974. Price-cost relationships since 1974 were not taken into account because of the yet undetermined effect these may have on resource estimates. Clearly a new pattern of exploration economics is now under development*, and, in cooperation with the Bureau of Mines, work to determine the effect of this new pattern on discovery and recovery of oil and gas is beginning. Assuming an increase in price-cost ratio, undiscovered recoverable resource estimates will expand and, at some threshold level, recovery percentages on discovered petroleum will improve. The higher price-cost ratios existing in 1975, if they should continue or increase even higher, *would likely increase estimates of both undiscovered recoverable resources and reserves significantly* -- some economists think perhaps by half again."

Price Elasticity

Zareski states that "...even though real wellhead prices have increased substantially over the past five years," higher prices have not resulted in the discovery of many large deposits necessary to sustain deliverability at present levels. GHK argues that "real" price increases must be specifically described within the market within which risk capital is employed. There is no meaning in an average "real" price increase, for as of this statement the only meaningful increase in interstate wellhead prices is under attack in the courts and certainly not either secure or high enough to open up for interstate commerce the deep or ultradeep non-associated natural gas frontiers!

Zareski then erroneously concludes that gas supply from traditional source areas appears to be highly price inelastic. Zareski's error originates from his fact base for he uses average national prices and significantly out of date trends to project a hypothetical national result when the economic regional distortions in natural gas have been building for the past 23 years! The price elasticity of natural gas has never been adequately tested on a national basis, because natural gas throughout its exploration and production history has been either a by-product of oil or federally controlled at prices well below that of oil. Increases in interstate gas prices in the past five years have come from an extremley low base and remain well below the equivalent price of oil! However, natural gas has proven to be highly price elastic on a regional basis where intrastate prices have brought natural gas wellhead sales to a parity with new oil.

The price elasticity of natural gas has irrefutably been shown to be very high in specific provinces within major producing states like Texas and Oklahoma. In the Fort Worth Basin, for example, higher intrastate prices resulted in a 283% increase in the number of wells drilled and resulted in increased supplies of up to 1500% above 1971 levels. The basin's natural gas potential had been known for many years as subcommercial, but higher prices proved the high price elasticity of natural gas.

Within intrastate markets, where consumers are free to pay what natural gas is worth to them, reserves increased 3.5 trillion cubic feet during 1975. In Oklahoma, for example, more than 85% of the natural gas reserves discovered since 1972 have been dedicated to the intrastate market. Drilling has allowed intrastate reserves to increase. Thus, with supply and demand already in balance, intrastate demand has not been strong enough to support the higher prices required to bring on still more exploration. It is our government's reluctance to allow consumers to pay what they deem reasonable that both withholds the development of American natural gas and requires these same U. S. consumers to purchase higher cost foreign imports.

Until recently, federal price ceilings were set by regulators who focused entirely on historical costs. The regulators failed to understand that for many years the *natural gas found during the search for oil was essentially free*, because the capital expended was based on economic risk calculations relying almost entirely on oil prices. Associated natural gas was merely a by-product, but as every barrel of oil produced brings with it associated natural gas, the nation soon began to rely on this essentially free source of energy for its largest domestic source of energy. Today, however, based on the idea that new natural gas will become valued equally with imported oil, explorers are ready to search for non-associated natural gas within all the geologic provinces of America. This exploration must rely solely on the wellhead price of natural gas.

Over the past 23 years federal price ceilings on natural gas eliminated the possibility of developments of the majority of known supplies of natural gas within the United States. Equally important, these price ceilings eliminated from the estimates of "potential reserves" vast known supplies for they were determined to be sub-commercial at the time of origin of most recent resource projections.

The regulators looked backwards to low cost and associated natural gas operations as the basis for figuring future prices. This process continued over 23 years causing the gap between what appeared to be a "reasonable" price to the regulators and the price required to attract risk capital into continually deeper and higher cost, high-risk exploration to grow wider and wider, thereby distorting both the demand for gas (eliminating much U. S. coal production) and destroying the risk capital market for natural gas exploration and development. Therefore, by 1972 natural gas

prices bore no relation to replacement costs nor did natural gas demand bear any relationship to the social value of our presently most efficient and environmentally attractive source of energy.

The courts have upheld interstate prices of 52 cents per mcf, equal to only about $3.00 per barrel of oil. The present $1.44 rate set by the FPC for wells commenced after January 1, 1975, was not issued until July 27, 1976, and the gas included in the order of that date was redefined resulting in prices for much gas originally included being rolled back before the final order was issued on November 5, 1976. This ruling has continuously been challenged in the courts, thus discouraging exploration and severely limiting risk capital expenditures for interstate natural gas development.

For these reasons there remains no doubt that interstate markets have not tested the positive price elasticity of natural gas on a national basis. However, if one gives credibility to by far the majority of petroleum geologists within this country who continue to estimate enormous remaining supplies of natural gas, then one must accept the fact that price ceilings over 23 years at a fraction the price of oil have irrefutably established the negative side of the price elasticity model! Therefore, the facts used for the basis of the Zareski arguments of natural gas price inelasticity actually go far to establish the negative side of price elasticity.

Potential of Lower 48 States

Zareski continues to rely on the past by using outdated resource estimates to dismiss the potential of major new discoveries in the lower 48 state "traditional" exploration areas. Zareski notes that large deposits are generally found at an earlier stage in the exploration cycle, and concludes that only "frontier" areas (Atlantic and Pacific offshore, Alaska on-and-offshore) hold the hope of future large discoveries. While he observes that potential gas bearing formations exist at great depth in the major sedimentary basins, he writes off this source by noting that "a declining portion of the exploration effort over the past five years has been devoted to drilling wells to depths of more than 15,000 feet," and that "in 1975, these deep wells accounted for less than 1% of the total drilling effort."

I believe that the deep formations in the major onshore basins are the most important "frontier area" remaining to be explored (see map). An "exploration cycle" for the vast deposits of deep natural gas can only begin when interstate markets value new natural gas at parity with new oil. These deep formations are found within traditional supply areas laced with networks of pipelines reaching the nation's natural gas consumers. Therefore, the vast potential natural gas supplies awaiting discovery in these deep formations can be found and delivered to consumers rapidly.

However, because of the very high costs and risks associated with deep drilling, and the fact that deep gas is non-associated and therefore totally dependent on the price and pricing system of natural gas, most of this gas will not become available to consumers within a regulated price system.

Zareski cites USGS figures placing the remaining undiscovered natural gas resources in the lower 48 states (onshore and offshore) in a range from 286 to 529 trillion cubic feet. By comparison, my company recently completed a study[3] of the gas potential of one deep basin -- the Deep Anadarko Basin of western Oklahoma and the Texas Panhandle -- and concluded that the deep formations (below 15,000 feet) hold 60 to 300 trillion cubic feet of natural gas that can be found and produced at deregulated prices.

Zareski has overlooked the reality that in natural gas the order of magnitude change in price has established some important geologic basins as economical for natural gas "frontier areas", and that deregulation would open every basin of the continental U. S. as a new frontier. Natural gas economics, remaining reserves, resource estimates, statistics, supply and demand relationships, value, and public and political understanding must once and for all be removed from thinking formed within the *oil* industry.

Potential of the Deep Anadarko Basin

The Anadarko Basin is one of the world's largest gas producing provinces and one of the two largest natural gas producing regions of North America (proven ultimate reserves of 130 TCF). The historical natural gas production from this province has come from the heavily developed areas along the shallow rim of the Basin, where productive sediments occur at depths of less than 15,000 feet, and well costs on the average are *ten times* less than those within the deep trough. GHK has recently completed a survey predicting the remaining potential for this province below 15,000 feet. Our company relied not on one method but on a range of results from five basic methods of potential resource calculations. The redundancy of results and the vast data and understanding of the shallow sediments (see Chart I), along with the knowledge that gas exists from the surface of the ground to more than 31,000 feet below the ground within this province, allow us to predict with higher levels of confidence than could be expected from estimates made by others about less explored and less understood frontiers such as the Gulf of Alaska, the Arctic, or offshore Atlantic. For example, in the entire Anadarko Basin there remains untested and undeveloped over 70,000 cubic miles of potentially productive sediments. This is about equal to the total volume of sediment estimated to exist within the highly potential offshore Atlantic basins of Baltimore Canyon and Georges Bank.

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[3]The GHK study includes 5,000 miles of the most modern geophysical data, the largest geological and petroleum engineering library on the deep Anadarko province and 100 manyears of data investigation, interpretation and integration.

It is important for one to realize that the GHK estimates of 60 to 300 trillion cubic feet of natural gas for the deep Anadarko are similar in size to the estimates for these other frontier provinces and those published by Exxon for the entire "inland" United States.

The Deep Anadarko Basin (below 15,000 feet) remains virtually unexplored. Our volumetric study found that about 18,000 cubic miles of sediments remain undrilled below 15,000 and above 30,000 feet. (The Anadarko has in places been seismically measured to contain up to 60,000 feet of sediments.) Of the total volume of potentially gas productive sediments below 15,000 feet and above 30,000 feet, only 1% has been tested through 1976. The ultimate *proven* recovery from this limited exploration is 2.5 trillion cubic feet. For each cubic mile explored in the Deep Anadarko Basin, 11.4 billion cubic feet of natural gas has been found.

We assign a high level of confidence -- a probability approaching 100% -- to our prediction of 60 trillion cubic feet of gas in the Deep Anadarko Basin. The probability that potential supplies will exceed 300 trillion cubic feet is low (less than 5%). This probability range roughly corresponds to those assigned to the USGS figures. Our "most reasonable" estimate of potential natural gas to be recovered from the Deep Anadarko Basin is in the range of 125 to 175 trillion cubic feet of gas and is given with a high degree of confidence (a probability range of 60% to 40%).

These estimates are a result of our continuing analysis of the industry's exploration and production activities within the deep Anadarko area. The total number of deep wells drilled in the Oklahoma portion of the Anadarko Basin increased by 65% from 1972 through 1976. *The number of natural gas wells completed below 15,000 feet in this area doubled from 53 in 1972 to more than 100 by the end of 1976.* During this time, several new fields were discovered and prolific natural gas producing potential was demonstrated in ultradeep formations. As of April 1977, 65 rigs are operating in this area to depths of 15,000 feet and below.

Figure 1 compares the number of producers completed at depths below 15,000 feet each year to the number of dry holes below 15,000 feet. Figure 2 shows the amount of natural gas discovered in the Deep Anadarko Basin each year since 1955, while Figure 3 shows the annual footage drilled below 15,000 in the deep basin. As more and more information has become available from actual drilling, our confidence in estimates of potential reserves has grown measurably.

It is important to repeat that any meaningful resource base projections must be based on realistic economic, political, environmental and technological assumptions. Our projections require no new technology nor multi-billion dollar capital expenditures for new long distance transportation systems. The environmental costs have largely been paid. However, our projections are based

on the premise that *consumers will be free to pay* what new onshore natural gas supplies are worth to them when compared to less secure and less environmentally attractive alternatives. A ceiling price on natural gas tied to imported oil prices on a Btu equivalency basis would deny much of this deep natural gas to consumers. However, the majority of deep gas can be discovered and produced at prices below or equal to LNG prices. If deep natural gas is exempted from ceiling prices, the average cost of this gas to consumers will be well below the delivered price of new LNG projects.

In addition to the Deep Anadarko Basin, large deposits of deep natural gas may be found in the Appalachian Basin, Gulf Coast, the Delaware Basin, the Arkoma Basin, the Mississippi Embayment (including Alabama and Florida), the Rocky Mountain basins, and in other areas as well. The American Gas Association reports that "All major estimates of potential gas resources in the U. S. agree that there is between 800 and 1,000 tcf of remaining recoverable gas resources." I believe these estimates are conservative and will be increased in the years ahead.

Deliverability

Time is the crucial difference between potential natural gas supplies from onshore areas like the Anadarko Basin and from other "frontier" areas. Important new supplies of Anadarko gas and other deep frontiers within traditional supply basins can be found and delivered to consumers within one to two years of a surge in drilling activity. By comparison, it takes four to ten years to find, develop and deliver new supplies from other frontier areas. (Natural gas was discovered on Alaska's North Slope in 1969, and a pipeline route is yet to be determined.) The Anadarko Basin is already laced with pipelines which could immediately deliver new gas to some 85% of the nation's interstate consumers.

Using our potential reserve estimates, GHK forecast production rates under varying sets of circumstances and rates of success from development of the Deep Anadarko Basin. For 1980, these forecasts range from 186 billion cubic feet of gas per year to 1,240 billion cubic feet of gas per year.

We believe that increased shallow exploration in a unregulated national market will discover enough gas to offset the current decline in annual production rates from the Anadarko Basin. Thus, deep gas production would represent new supplies.

Zareski Errs in Frequency of Finding Argument

Much of Zareski's argument is based on evidence that the frequency of finding large or "significant" fields is declining. A significant *field* is defined by the American Association of Petroleum Geologists as one that will produce 6 billion cubic

feet in its *lifetime*. He cites AAPG figures that the number of significant field discoveries declined from 99 in 1957 to 44 in 1969, the last year for which six years of development history is available. It is unfortunate that Zareski stopped his analysis of significant fields in 1969, because since that year, a total of *262 individual wells* (as opposed to fields) have been discovered *within the Anadarko basin alone* that will *each individually* produce more than 6 billion cubic feet in their lifetime.

A study of these prolific deep gas wells in Oklahoma and Texas revealed the phenomenon we call the "superwell". Superwells are individual wells which have produced in *one year* 6 billion cubic feet of natural gas, equivalent to one million barrels of oil.

The Resource Analysis and Management Group of Oklahoma City has identified more than 250 superwells, each of which produced more than six billion cubic feet of natural gas in 1974. About 75% of these wells produced from depths below 15,000 feet. Geographically, the more heavily explored Delaware Basin contained about 60% of the group, while over 15% were in the Anadarko Basin. The wells are young -- about 75% began producing in 1969 or more recently.

The importance of these individual superwells, and perhaps even their existence, is not widely known. Consequently, neither industry nor national policies have given adequate support to the discovery of these deep wells.

The energy value of superwells is demonstrated as follows:

45 superwells produce more energy annually than is produced by the entire Tennessee Valley Authority.

Three superwells produce as much energy as two 700 megawatt nuclear electric generating plants (costing over $1 billion).

Each addition of one superwell to our national energy production reduces fuel oil imports required to meet natural gas shortages by 1.3 million barrels, thus reducing the U. S. balance of payments deficit by $17 million annually.

In the near term, total reserve additions will not be of primary importance. Rather, rapid delivery of newly discovered natural gas to consumers is of major significance. Thus, the discovery of superwells in traditional supply areas should receive a higher priority than exploration in more remote frontier areas, which require four to ten years to begin producing.

Zareski's "Figure 4" does not even agree with his own figures. He notes that "preliminary data for 1976 indicate that natural gas production continued on a downward trend but at a substantially reduced rate of decline when compared to the precipitous 4.6 and

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6.9 percent decreases experienced in 1974 and 1975 respectively." Actually, natural gas production dropped only 1.5% in 1976, but his Figure 4 projects the earlier trend continuing.

I believe that price decontrol of onshore natural gas prices would easily end production declines by the close of 1977. By 1980, the Deep Anadarko Basin could be providing an additional one trillion cubic feet per year, and additional incremental supplies could be flowing from other deep onshore basins (see map). Alaskan and OCS natural gas will not be flowing in significant volumes until the mid-1980's. The GHK forecast is shown in our Figure 4.

My confidence in future delivery rates for natural gas is shared by others in the natural gas industry. Dr. William McCormick, Jr., American Gas Association Vice President for planning and analysis, believes that the gas industry "could continue to supply a substantial fraction of U. S. energy requirements into the 21st century." Speaking at the Cleveland Energy Conference recently, McCormick explained that "While it is true U.S. gas production has been declining since 1973, it should not be assumed that such a decline must necessarily continue." He pointed out that today's residential user pays 50 percent less for gas than fuel oil and five times less for gas than electricity. "It is little wonder that, at an average wellhead price of 60 cents per mcf or an equivalent of $3.60/bbl. of oil, U. S. gas production is beginning to decline." On conventional supplies, McCormick emphasized that "reserve additions have continued to decline largely because the predominance of drilling and well completions is in older, less risky, and less costly areas -- generally onshore and at shallow to moderate well depths." *With new gas deregulation, he predicted that "lower 48 gas production can be leveled out at about 20 tcf into the early 1980's."* Supplemental supply production, McCormick added, could reach 5.5 tcf by 1985 and by the 1990's the contribution for supplementals would more than offset any declines in conventional gas production. *Total gas production could rise to about 32 tcf by the year 2000, he concluded.*

Why Decontrol?

While Zareski states that increased price incentives "might ameliorate the situation somewhat," he also finds that "the form of the price determination mechanism is almost irrelevant due to the mature stage of development of our natural gas resource bases." Zareski is totally in error on two points:

1. While the nation's oil resources may be in a "mature state of development", this is certainly not true for non-associated natural gas (see map).

2. The "form of price determination" is *extremely relevant*, especially to those planning exploration in deep and frontier areas. Risk capital of the magnitude necessary to elicit a significant supply response from the deep

frontiers will not be forthcoming without the chance to produce extraordinary profits commensurate with the extraordinary risks encountered.

In deep frontier areas, the operating costs and risks are so great that the explorer planning a wildcat well does not know what the final cost of the well will be. Cost overruns are almost inevitable; the only question is their magnitude. But once an explorer has invested several million dollars in a well, it is very difficult for him to stop short of his target, regardless of the operating problems and expensive delays he may encounter along the way. For example, my company drilled one Deep Anadarko Basin wildcat well that was estimated to cost $2.5 million and was completed at a cost of $4.5 million. Another more recent well was estimated at less than $5 million and ended up a failure for $10 million. Figure 5 compares average drilling costs for shallower wells in the U. S. with current costs of completed gas wells in the Deep Anadarko Basin. Figure 6 shows the number of shallow wells drilled in the U. S. in 1975 versus the number of deep wells. Note that the number of wells drilled to increasing depths varies inversely with drilling costs.

Investors will not take extraordinary risks for the chance to earn a normal or regulated profit. Exploring in deep and frontier areas requires a chance to earn extraordinary profits commensurate with the extraordinary risks involved. [Based on my 18 years of experience in deep natural gas exploration, I can state with confidence that the extraordinary risks of exploring for natural gas in the deep provinces of onshore America will not be taken within the regulated market. Therefore, ceiling prices will deny consumers vast quantities of natural gas that could be made available to them in a unregulated market at prices less or equal to foreign supplies and will deny our economic system of an important positive impact on American jobs and Gross National Product.]

The regulation of all onshore natural gas markets will slowly eliminate the small independent gas producers, concentrating market power in the hands of the oil producing majors and will create new institutional barriers to increased competition for onshore natural gas.

[A ceiling price on new natural gas will go much further toward subsidizing consumption and eliminating incentives for conservation than it will hold the line on inflation. If our country's direction is toward conservation, we must put an end to the subsidization of consumption.] The existence of the ceiling implies that, given a choice, the consumer would be willing to pay more. A subsidy to natural gas consumers distorts the true social costs of their

consumption and eliminates incentives for investing in conservation technology. Thus, if federal policies work to encourage consumption, then there should be no surpise that demand continually exceeds supply. [Unless we want to institutionalize last winter's natural gas shortages as an annual event, deregulation of newly discovered natural gas is the only clear policy choice we have. Such a policy will achieve a balance of supply and demand within the next four years at minimal if any inflationary impact. That supply-demand balance can be maintained well into the next century.]

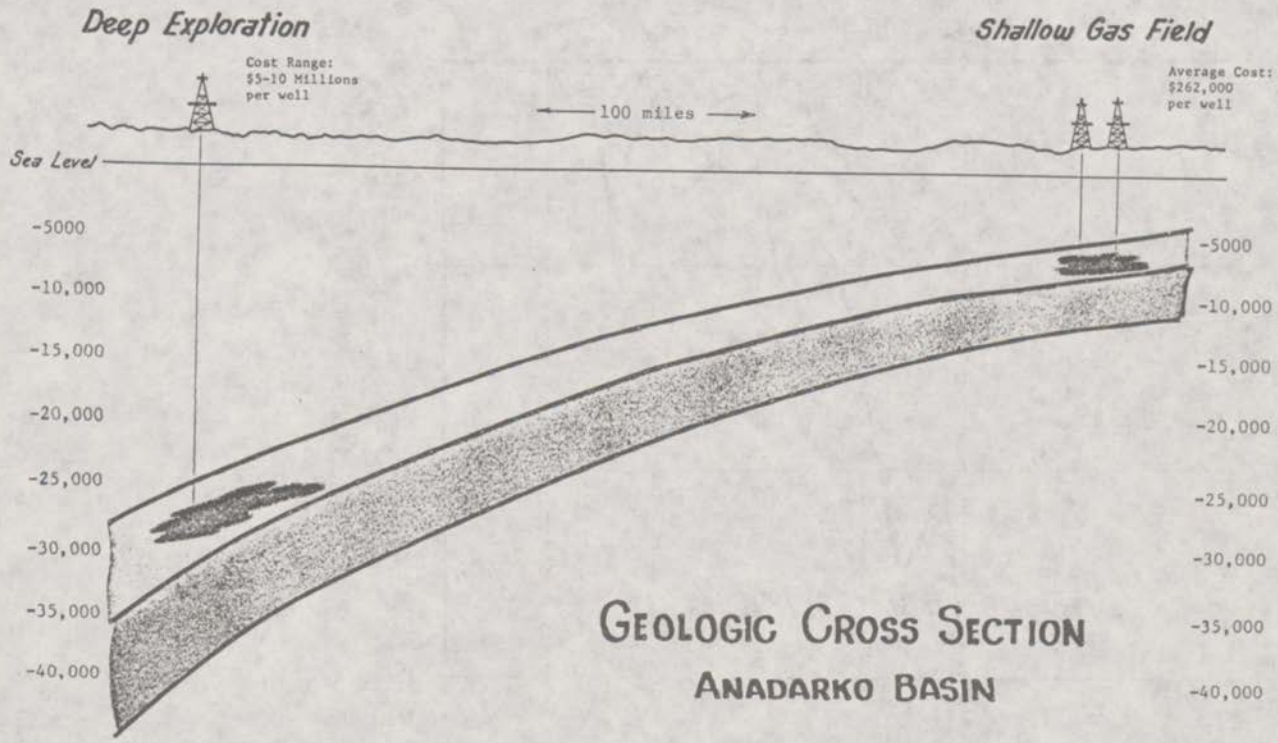

Deep Exploration
Shallow Gas Field
Cost Range:
$5-10 Millions
per well
100 miles
Average Cost:
$262,000
per well
Sea Level
-5000
-10,000
-15,000
-20,000
-25,000
-30,000
-35,000
-40,000
GEOLOGIC CROSS SECTION
ANADARKO BASIN

Chart I

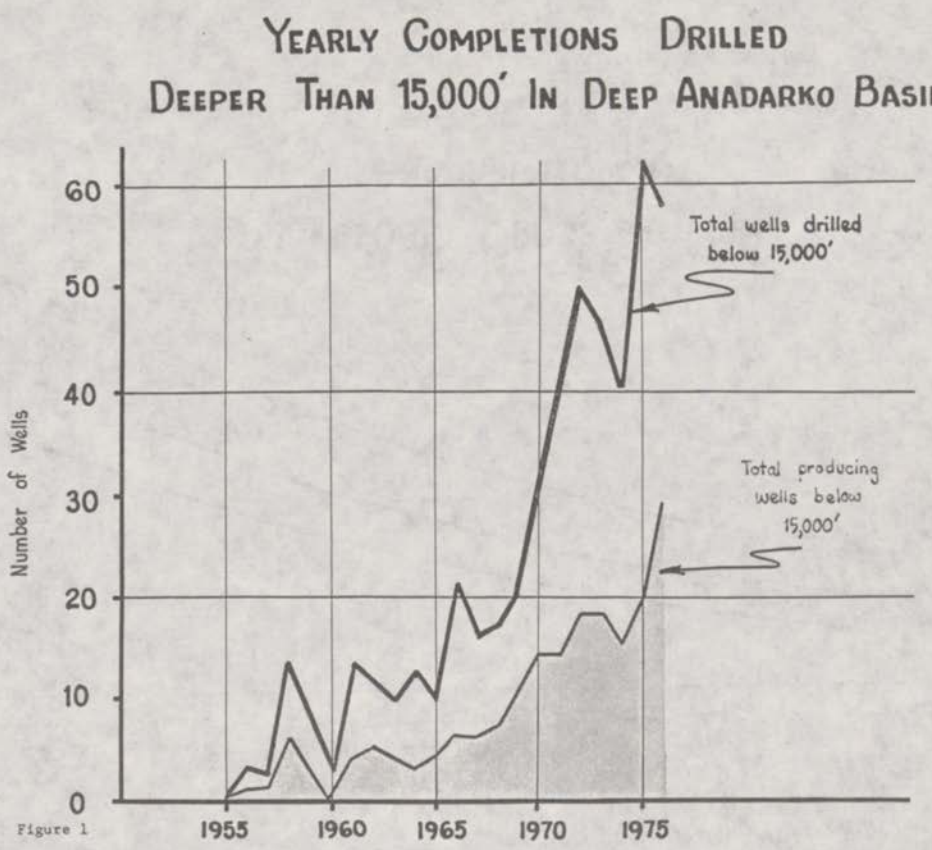

YEARLY COMPLETIONS DRILLED
DEEPER THAN 15,000' IN DEEP ANADARKO BASIN
Number of Wells
60
50
40
30
20
10
0
1955
1960
1965
1970
1975
Total wells drilled below 15,000'
Total producing wells below 15,000'

Figure 1

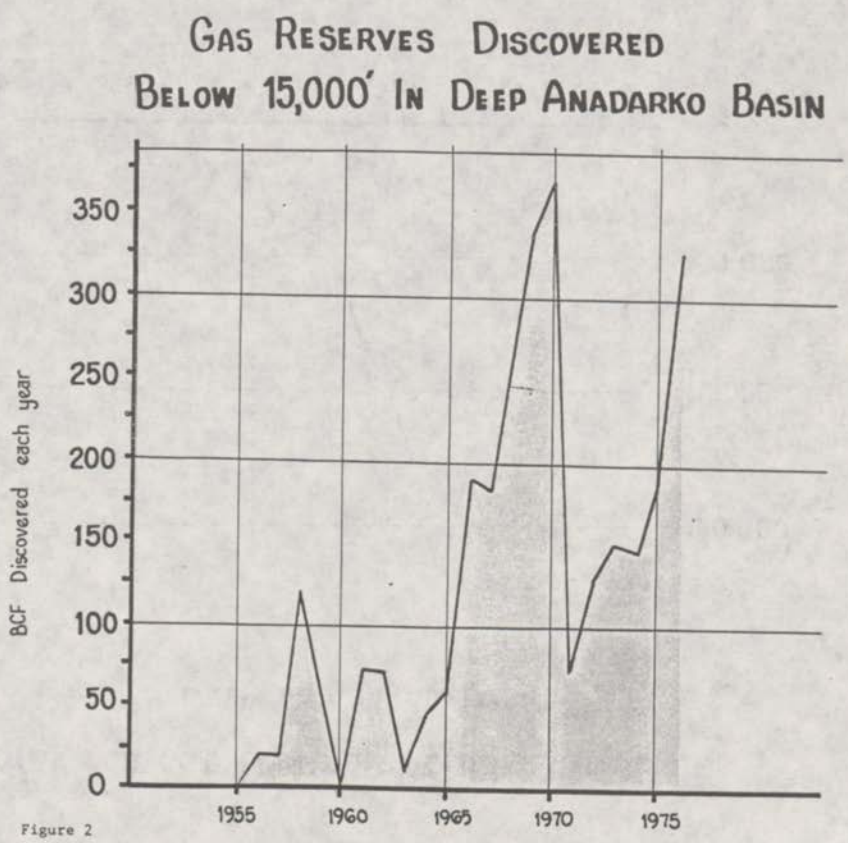

GAS RESERVES DISCOVERED
BELOW 15,000' IN DEEP ANADARKO BASIN
BCF Discovered each year
350
300
250
200
150
100
50
0
1955
1960
1965
1970
1975

Figure 2

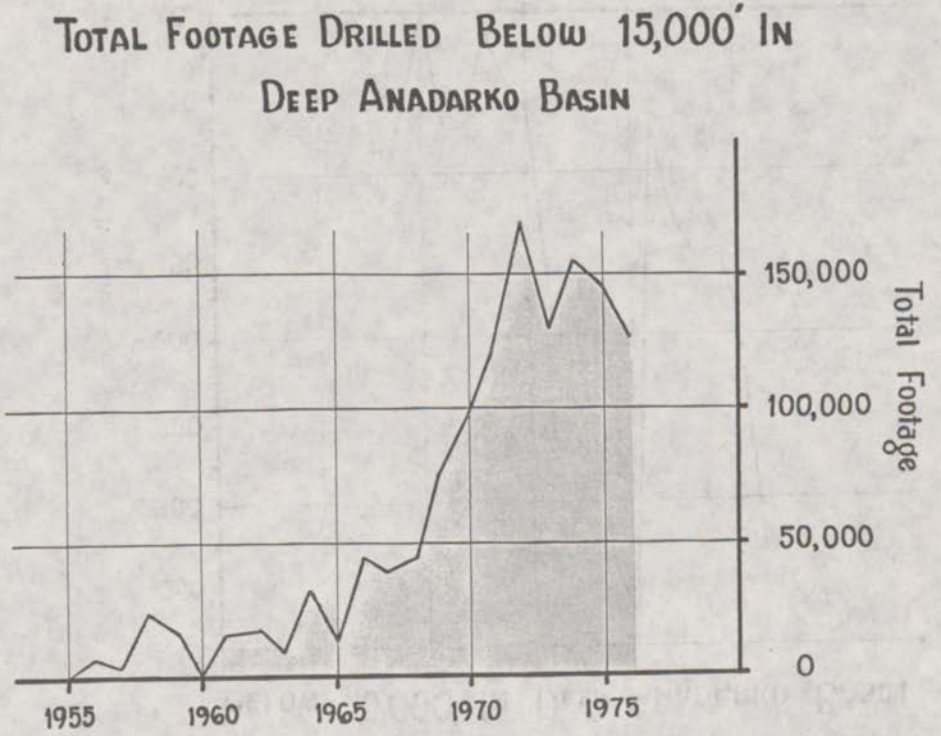

TOTAL FOOTAGE DRILLED BELOW 15,000' IN
DEEP ANADARKO BASIN
150,000
100,000
50,000
0
Total Footage
1955
1960
1965
1970
1975

Figure 3

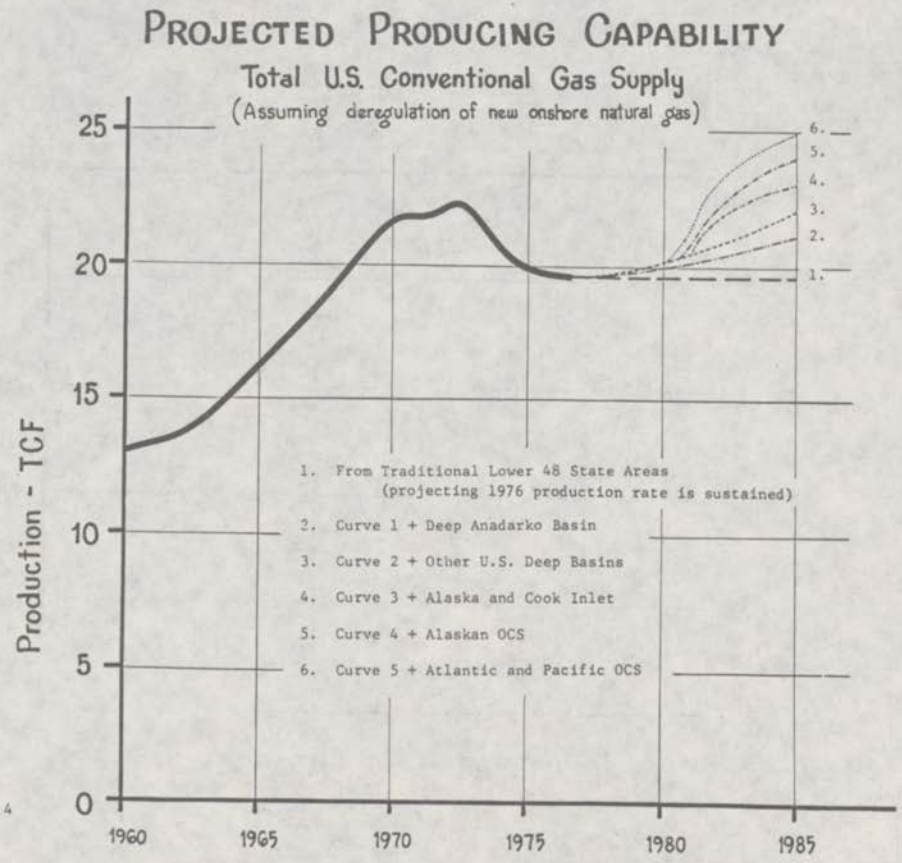
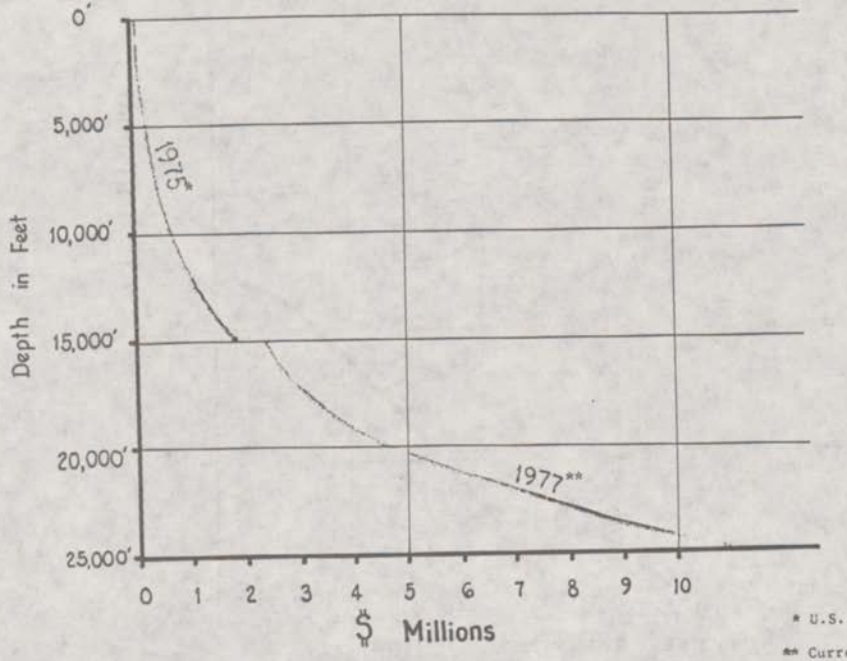

PROJECTED PRODUCING CAPABILITY
Total U.S. Conventional Gas Supply
(Assuming deregulation of new onshore natural gas)
Production - TCF
25
20
15
10
5
0
1960
1965
1970
1975
1980
1985
6.
5.
4.
3.
2.
1.
1. From Traditional Lower 48 State Areas
(projecting 1976 production rate is sustained)
2. Curve 1 + Deep Anadarko Basin
3. Curve 2 + Other U.S. Deep Basins
4. Curve 3 + Alaska and Cook Inlet
5. Curve 4 + Alaskan OCS
6. Curve 5 + Atlantic and Pacific OCS

Figure 4

Cost Of A Completed Gas Well



* U.S. Average

** Current Costs in Deep Anadarko Basin

Figure 5

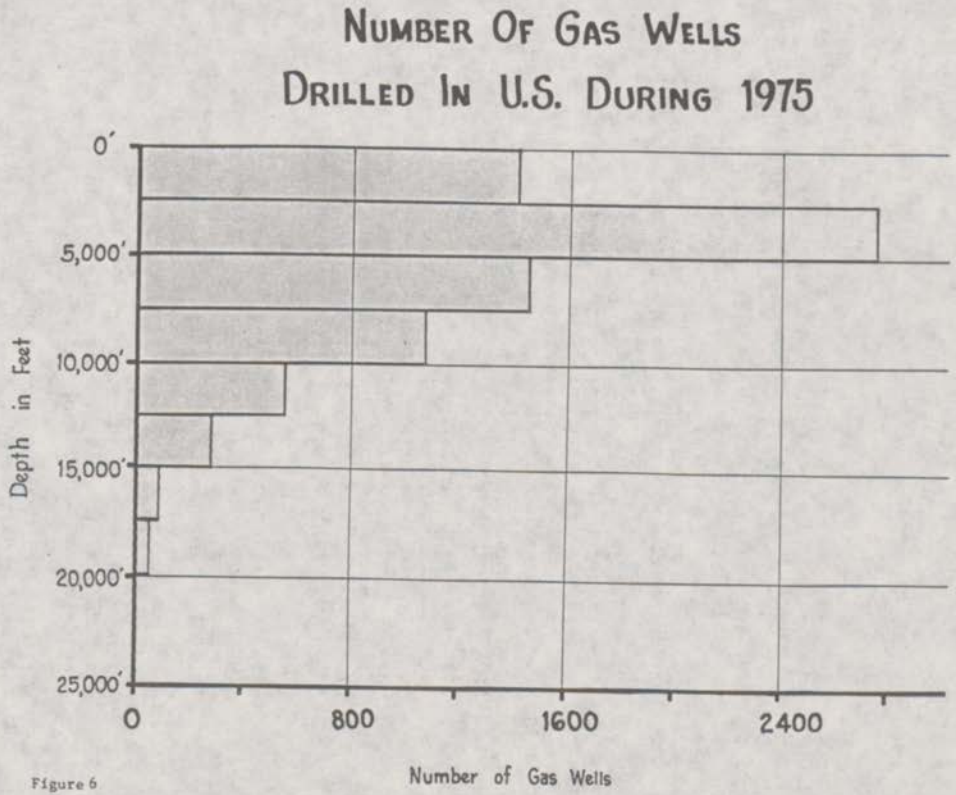

NUMBER OF GAS WELLS
DRILLED IN U.S. DURING 1975
0'
5,000'
10,000'
15,000'
20,000'
25,000'
Depth in Feet
0
800
1600
2400
Number of Gas Wells

Figure 6

EXHIBIT II

Definition of New Natural Gas

The Independent Gas Producers Committee proposes the maintenance of federal price controls for all natural gas sold or delivered into interstate commerce except for truly new onshore gas. We suggest that natural gas produced from recompletions up hole, from in-fill drilling, from development wells, or from offshore federal lands, should be considered "Special Category new gas" and subject to price control. We suggest that natural gas previously dedicated to intrastate customers should, upon contract expiration and dedication to interstate commerce, be included in the "Special Category new gas" definition and subject to price control. We further suggest that old, flowing interstate gas which, upon contract expiration is rededicated to interstate commerce, should be priced in accordance with the existing Orders of the Federal Power Commission. Only that new natural gas which is yet to be discovered from new onshore wells should be exempt from federal price control.

Our definition of new natural gas is as follows:

> (7) 'New natural gas' means (A) natural gas other than in-fill natural gas, or natural gas produced from offshore federal lands, which is produced from wells commenced on or after January 1, 1977; or (B) natural gas produced from a well which is deepened by actual drilling commenced on or after January 1, 1977.
>
> (8) 'In-fill natural gas' means natural gas produced from a well, the actual drilling of which was commenced on or after January 1, 1977, which resulted in a greater density of producing wells than that which exists under the spacing pattern established at the time such well is drilled, either by appropriate regulatory authority or by custom and practice, for the drilling of wells in the reservoir from which such well produces.
>
> (9) 'Special Category new natural gas' means (i) in-fill natural gas; (ii) natural gas produced as a result of the recompletion of a well on or after January 1, 1977, except that category of natural gas defined in paragraph 7(B) herein; and (iii) natural gas produced from a well after the expiration, by its own terms, of a contract under which the gas from such well has been sold in intrastate commerce for resale, provided that such expiration occurred on or after January 1, 1977.

EXHIBIT III

Natural Gas Wellhead Prices Required to Support Deep Drilling

This Exhibit presents an analysis of natural gas wellhead prices that would be required for wells drilled 15,000 feet and deeper using FPC Opinion 770-A methodology; 1975 and projected 1977 JAS drilling costs; 15, 20 and 33 percent rates of return on investment and productivities of 500 and 1,000 MCF per foot drilled.

The summary tables in this Exhibit show the wellhead natural gas prices required for natural gas produced from wells 15,000 feet and deeper onshore in the lower forty-eight states. This analysis was made by the Resource Analysis & Management Group, Oklahoma City.

The methodology and assumptions used in the analysis are outlined in Attachment A. The required natural gas wellhead prices for the various rates of return on investment and productivity factors using the FPC 770-A methodology and values, except for 1975 and projected 1977 deep dry hole and gas well costs and investment tax credit, are presented in Table I.

Exhibits I and II attached provide backup information on drilling and completion costs.

TABLE I

NATURAL GAS PRICES FROM WELLS 15,000 FEET AND DEEPER
BASED ON F.P.C. OPINION 770-A METHODOLOGY WITH
ADJUSTMENTS[2,3] FOR 15, 20 AND 33 PERCENT
RETURN ON INVESTMENT AND PRODUCTIVITIES OF
500 AND 1,000 MCF PER FOOT DRILLED

Natural Gas Wellhead Price
1977 Projected JAS Costs[1] For Gas Wells Drilled
15,000 Feet and Deeper

	Productivity	
Return on Investment	1,000 MCF/FT	500 MCF/FT
15%	193.77 ¢/MCF	276.27 ¢/MCF
20%	266.92 ¢/MCF	372.52 ¢/MCF
33%	462.93 ¢/MCF	625.68 ¢/MCF

Natural Gas Wellhead Price Based On
1975 Actual JAS Costs[1] For Gas Wells Drilled
15,000 Feet and Deeper

	Productivity	
Return on Investment	1,000 MCF/FT	500 MCF/FT
15%	178.36 ¢/MCF	245.49 ¢/MCF
20%	246.56 ¢/MCF	331.85 ¢/MCF
33%	430.59 ¢/MCF	561.61 ¢/MCF

NOTES:

[1] *See Exhibit I.*

[2] *All factors such as working capital, other explorations, exploratory overhead, lease acquisition costs, production facilities and re-completion were based on the value used in F.P.C. Opinion 770-A.*

[3] *No cost allocation was made to natural gas liquids since deep gas (15,000 + feet) is dry gas.*

ATTACHMENT A

METHODOLOGY AND ASSUMPTIONS USED IN THE NATURAL GAS WELLHEAD PRICE ANALYSIS FOR NATURAL GAS PRODUCED FROM WELLS 15,000 FEET AND DEEPER

Methodology

- F.P.C. discounted cash flow methodology contained in F.P.C. Opinion 770-A was employed with the following exceptions:
  - productivity factors of 500 and 1,000 MCF per foot drilled for productive wells were used (770-A used 300 MCF per foot)
  - no cost allocations were made to natural gas liquids since deep (15,000 feet and deeper) gas is dry gas
  - no future price escalations were recognized
  - additional rate of return computations for 20 percent (F.P.C. Opinion 742) and 33 percent (per GHK presentation in F.P.C. Docket RM75-14)
- 1975 JAS total onshore United States less Alaska drilling costs for wells 15,000 feet and deeper were used.
- 1977 projected total onshore United States less Alaska drilling costs for wells 15,000 feet and deeper were used.

Assumptions

- The 1977 total onshore United States less Alaska drilling costs for wells 15,000 feet and deeper were projected using the 1975 JAS actual costs and the 1975-1976 increase in cost per foot drilled 15,000 feet and deeper from the March 1977 issue of Petroleum Engineer (see Exhibit II). The 1975-1976 cost deflator was compounded to obtain the 1977 projected costs.
- Productivity factors of 500 and 1,000 MCF per foot drilled were used since informed opinion is that wells drilled deeper than 15,000 feet in the Anadarko Basin, for example, have an average productivity of approximately 600-700 MCF per foot drilled.

EXHIBIT I-1

1975 JOINT ASSOCIATION SURVEY
SHOWING

1975 AND PROJECTED 1977 ESTIMATED COSTS OF
DRILLING AND EQUIPPING WELLS
BY DEPTH INTERVALS FOR
TOTAL ONSHORE UNITED STATES LESS ALASKA

Depth (Feet)	Actual 1975[1] JAS Cost[1] $/Foot		Projected 1977[2] JAS Cost $/Foot	
	Dry Hole	Gas Well	Dry Hole	Gas Well
7,500 - 9,999	24.75	36.27		
10,000 - 12,499	36.15	55.75		
12,500 - 14,499	54.12	73.47		
15,000 - 17,499	78.46	106.21		
17,500 - 19,999	107.16	125.49		
15,000 - 19,999	88.26	114.48	106.86	138.61
20,000 and Over	148.88	132.39	173.41	154.20
15,000 and Deeper	97.22	117.87	120.60	144.47

NOTES:

[1] *$/Ft calculated by using total United States (Exhibit I-2) less total offshore (Exhibit I-3) less onshore Alaska (Exhibit I-3).*

[2] *Projected 1977 cost was based on 1975 JAS Cost X* $\left(\frac{\text{1976 Petroleum Engineering Cost}}{\text{1975 Petroleum Engineering Cost}}\right)^2$

(See Exhibit II attached.)

EXHIBIT I-2

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Table 2

ESTIMATED COSTS OF DRILLING AND EQUIPPING WELLS, BY DEPTH INTERVALS — 1975

TOTAL UNITED STATES*

	Depth interval (feet)	Total Number of Wells, Footage Drilled, and Costs: Oil Wells	Gas Wells	Dry Holes	Total	Average Depth and Cost Per Well: Oil	Gas	Dry	Total
Wells		2,814	214	1,027	4,055				
Footage	0 - 1,249	2,383,013	196,817	775,138	3,354,968	847	920	755	82
Costs $		56,250,659	5,059,872	12,467,474	73,778,005	19,990	23,644	12,140	18,19
Wells		3,214	1,195	1,979	6,388				
Footage	1,250 - 2,499	5,745,785	2,371,079	3,719,938	11,836,802	1,788	1,984	1,880	1,85
Costs $		124,224,539	54,970,316	55,733,860	234,928,715	38,651	46,000	28,163	36,77
Wells		2,973	1,599	2,142	6,714				
Footage	2,500 - 3,749	9,309,806	5,103,759	6,698,004	21,111,639	3,131	3,192	3,127	3,14
Costs $		223,774,905	121,470,674	99,347,511	444,593,090	75,269	75,967	46,381	66,21
Wells		2,135	1,144	2,268	5,547				
Footage	3,750 - 4,999	9,458,468	4,990,742	9,904,837	24,354,047	4,430	4,363	4,367	4,39
Costs $		247,012,067	115,773,092	148,352,143	511,137,302	115,697	101,200	65,411	92,1
Wells		2,901	1,468	2,716	7,085				
Footage	5,000 - 7,499	17,773,601	9,034,620	16,708,655	43,536,876	6,127	6,148	6,152	6,14
Costs $		559,976,112	272,103,949	372,869,946	1,204,955,007	193,029	185,360	137,288	170,07
Wells		1,578	1,092	1,529	4,169				
Footage	7,500 - 9,999	13,563,126	9,100,826	13,173,899	35,837,853	8,595	8,570	8,616	8,59
Costs $		515,788,597	390,678,121	487,598,985	1,394,265,703	326,862	368,058	318,901	334,49
Wells		479	532	847	1,858				
Footage	10,000 - 12,499	5,265,172	5,954,362	9,422,156	20,641,690	10,992	11,192	11,124	11,11
Costs $		306,304,418	380,932,073	467,243,619	1,154,480,110	639,466	716,038	551,645	621,3
Wells		138	271	321	730				
Footage	12,500 - 14,999	1,832,475	3,657,637	4,323,980	9,814,092	13,279	13,497	13,470	13,44
Costs $		135,078,101	300,729,747	295,115,215	730,923,063	978,827	1,109,704	919,362	1,001,26
Wells		34	91	124	249				
Footage	15,000 - 17,499	548,155	1,468,014	1,987,895	4,004,064	16,122	16,132	16,031	16,08
Costs $		60,487,581	167,555,814	173,901,272	401,944,667	1,779,047	1,841,273	1,402,430	1,614,23
Wells		9	54	53	116				
Footage	17,500 - 19,999	167,651	995,953	980,641	2,144,245	18,628	18,444	18,503	18,48
Costs $		24,287,675	128,133,459	118,818,362	271,239,496	2,698,631	2,372,842	2,241,856	2,338,27
Wells		1	24	24	49				
Footage	20,000 and over	20,550	512,113	503,200	1,035,863	20,550	21,338	20,967	21,14
Costs $		3,322,318	67,798,308	77,848,139	148,968,765	3,322,318	2,824,930	3,243,672	3,040,17
Total Wells		16,276	7,654	13,030	36,960				
Total Footage		66,067,802	43,375,974	68,198,413	177,642,189	4,059	5,667	5,234	4,80
Total Costs $		2,256,506,972	2,005,410,425	2,309,296,526	6,571,213,923	138,640	262,008	177,229	177,79

* Includes the following states which are not shown separately: Arizona, Georgia, Idaho, Maryland, Missouri, Nevada, South Dakota, Tennessee and Virginia.

EXHIBIT 1-3

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Table 3

ESTIMATED COSTS OF DRILLING AND EQUIPPING WELLS, BY DEPTH INTERVALS — 1975

TOTAL OFFSHORE

	Depth Interval (feet)	Total Number of Wells, Footage Drilled, and Costs				Average Depth and Cost Per Well			
		Oil Wells	Gas Wells	Dry Holes	Total	Oil	Gas	Dry	Total
Wells		—	—	2	2				
Footage	0 - 1,249	—	—	1,943	1,943	—	—	972	972
Costs $		—	—	1,353,750	1,353,750	—	—	676,875	676,875
Wells		1	—	6	7				
Footage	1,250 - 2,499	2,070	—	9,837	11,907	2,070	—	1,640	1,701
Costs $		521,577	—	3,872,872	4,394,449	521,577	—	645,479	627,778
Wells		16	2	2	20				
Footage	2,500 - 3,749	53,615	7,008	5,120	65,743	3,351	3,504	2,560	3,287
Costs $		3,444,311	2,420,375	1,707,928	7,572,614	215,269	1,210,188	853,964	378,631
Wells		24	14	10	48				
Footage	3,750 - 4,999	103,654	64,117	45,250	213,021	4,319	4,580	4,525	4,438
Costs $		6,619,200	8,320,729	8,310,555	23,250,484	275,800	594,338	831,056	484,385
Wells		49	35	93	177				
Footage	5,000 - 7,499	305,528	230,266	611,655	1,147,449	6,235	6,579	6,577	6,483
Costs $		31,300,934	27,114,570	80,802,708	139,218,212	638,795	774,702	868,846	786,544
Wells		108	85	155	348				
Footage	7,500 - 9,999	945,487	753,560	1,365,253	3,064,300	8,755	8,865	8,808	8,805
Costs $		86,625,788	84,813,850	182,863,173	354,102,311	802,091	995,457	1,179,762	1,017,537
Wells		64	78	128	270				
Footage	10,000 - 12,499	714,698	879,621	1,425,087	3,019,406	11,167	11,277	11,133	11,183
Costs $		80,428,817	98,017,060	156,728,775	335,174,672	1,256,700	1,256,629	1,224,444	1,241,388
Wells		15	41	55	111				
Footage	12,500 - 14,999	203,804	560,763	748,568	1,513,135	13,587	13,677	13,610	13,632
Costs $		26,747,401	73,199,186	79,549,954	179,496,541	1,783,160	1,785,346	1,446,363	1,617,086
Wells		6	13	17	36				
Footage	15,000 - 17,499	97,647	214,010	271,071	582,728	16,275	16,462	15,945	16,187
Costs $		16,863,691	34,369,993	39,206,231	90,439,915	2,810,615	2,643,846	2,306,249	2,512,220
Wells		—	3	5	8				
Footage	17,500 - 19,999	—	52,956	89,600	142,556	—	17,652	17,920	17,820
Costs $		—	9,799,517	23,337,247	33,136,764	—	3,266,506	4,667,449	4,142,096
Wells		—	—	1	1				
Footage	20,000 and over	—	—	20,988	20,988	—	—	20,988	20,988
Costs $		—	—	6,056,507	6,056,507	—	—	6,056,507	6,056,507
Total Wells		283	271	474	1,028				
Total Footage		2,426,503	2,762,301	4,594,372	9,783,176	8,574	10,193	9,693	9,517
Total Costs $		252,551,719	337,855,300	583,709,700	1,174,190,719	892,409	1,246,609	1,231,624	1,142,215

EXHIBIT I-4

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Table 6

ESTIMATED COSTS OF DRILLING AND EQUIPPING WELLS, BY DEPTH INTERVALS — 1975

ONSHORE ALASKA

	Depth Interval (feet)	Total Number of Wells, Footage Drilled, and Costs				Average Depth and Cost Per Well			
		Oil Wells	Gas Wells	Dry Holes	Total	Oil	Gas	Dry	Total
Wells		—	—	—	—				
Footage	0 - 1,249	—	—	—	—	—	—	—	—
Costs $		—	—	—	—	—	—	—	—
Wells		—	—	—	—				
Footage	1,250 - 2,499	—	—	—	—	—	—	—	—
Costs $		—	—	—	—	—	—	—	—
Wells		—	1	1	2				
Footage	2,500 - 3,749	—	2,731	2,855	5,586	—	2,731	2,855	2,793
Costs $		—	595,358	1,384,675	1,980,033	—	595,358	1,384,675	990,017
Wells		—	—	—	—				
Footage	3,750 - 4,999	—	—	—	—	—	—	—	—
Costs $		—	—	—	—	—	—	—	—
Wells		2	1	3	6				
Footage	5,000 - 7,499	13,470	7,000	18,803	39,273	6,735	7,000	6,268	6,546
Costs $		3,394,440	1,242,570	7,415,529	12,052,539	1,697,220	1,242,570	2,471,843	2,008,757
Wells		8	1	2	11				
Footage	7,500 - 9,999	78,161	9,480	18,172	105,813	9,770	9,480	9,086	9,619
Costs $		16,350,360	3,893,341	12,943,900	33,187,621	2,043,798	3,893,341	6,471,950	3,017,056
Wells		17	—	7	24				
Footage	10,000 - 12,499	188,009	—	78,768	266,777	11,059	—	11,253	11,116
Costs $		33,105,605	—	24,272,104	57,377,709	1,947,389	—	3,467,443	2,390,738
Wells		2	—	3	5				
Footage	12,500 - 14,999	26,825	—	40,939	67,764	13,413	—	13,646	13,553
Costs $		4,533,386	—	24,272,957	28,806,343	2,266,693	—	8,090,986	5,761,269
Wells		1	—	—	1				
Footage	15,000 - 17,499	16,247	—	—	16,247	16,247	—	—	16,247
Costs $		3,917,802	—	—	3,917,802	3,917,802	—	—	3,917,802
Wells		—	—	—	—				
Footage	17,500 - 19,999	—	—	—	—	—	—	—	—
Costs $		—	—	—	—	—	—	—	—
Wells		—	—	—	—				
Footage	20,000 and over	—	—	—	—	—	—	—	—
Costs $		—	—	—	—	—	—	—	—
Total Wells		30	3	16	49				
Total Footage		322,712	19,211	159,537	501,460	10,757	6,404	9,971	10,234
Total Costs $		61,301,613	5,731,269	70,289,165	137,322,047	2,043,387	1,910,423	4,393,073	2,802,491

EXHIBIT II

Up From '75: Costs Hit Record

by John Scott, *Editor*

A 2-year decline in U.S. deep drilling ended last year when operators hard pressed to develop additional natural gas reserves spent nearly a billion dollars drilling 439 wells to 15,000 ft or deeper.

All the increase was in development drilling. Exploratory work declined some, but not as much as in 1975, and the wildcat success ratio was up substantially, indicating the trend in this type drilling should continue higher this year. Success ratio for all deep drilling last year was 58%, up sharply from 1975 but in line with 1974.

Costs boomed to another historic high. All 439 wells cost the industry $927,391,828, or more than $2,000,000 per well and $122/ft.

Comparable costs for 1975 were $779,417,330 for 410 wells, breaking out to $1,900,000 per well and $110/ft.

Tables accompanying this text break down numbers and cost data for all wells drilled last year in the states in which this activity took place. A running 3-year comparison is included in the computerized Deep Well Survey.

Climate might be right for a solid, long range upsurge in deep drilling in the U.S. Certainly the need is there, since majority of the wells drilled to 15,000 ft or deeper are in search for or development of natural gas reserves.

Schools and factories have been closed this winter and thousands have lost their jobs because interstate systems were unable to supply enough gas during abnormally cold weather.

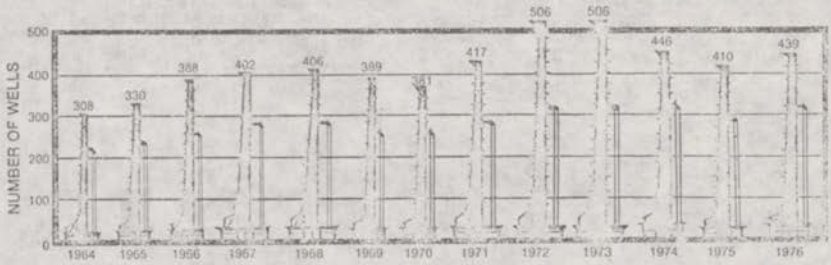
It may be that after more than 20 years of warnings by the petroleum industry of shortages, the U.S. Congress will deregulate interstate wellhead prices. The

interstate market, and this is the market that serves the sprawling nonproducing consuming areas of the U.S. Northeast, Midwest and Southeast, has suffered for years because producers found it difficult to break even on costs at wellhead prices which have varied from 50¢/Mcf to $1.43/Mcf. The unregulated intrastate market is faring well this winter but even intrastate demand, which is moving in some cases at more than $2/Mcf, has been hard to fill.

PETROLEUM ENGINEER International's cost data confirms the producers' cost problems. That $2,000,000 per well cost figure was influenced by 59 recorded ultradeep holes which were drilled to 20,000 ft or deeper (at $3,600,000 a throw).

The 439 wells drilled last year accounted for 7,603,041 ft of hole, making the average well 17,319 ft deep. A year earlier 410 wells accounted for 7,098,330 ft of hole, or an average of 17,313 ft each.

The industry drilled a record 506 deep wells in each of the years 1972 and 1973 but the totals dropped off to 446 in 1974 and 410 in 1975. Runaway inflation in recent years on all fronts — crew wages, equipment



Wells Completed 15,000 ft and Below by Years of Completion

Year	No. Wells by Date of Completion	Explor-atory	Total Producers	Average Sits/Well	Mud Costs Average	Well Costs Average	Average Costs/ft	Total Footage Drilled	Ft/Well Average	Deepest Well	Deepest Producer
1938	1	1	1	—	—	—	—	15,004	—	15,004	13,175
1944	1	1	0	—	—	—	—	15,279	—	15,279	13,175
1945	3	3	0	222	—	—	—	63,480	15,870	16,655	13,175
1946	1	1	1	—	—	—	—	15,452	—	16,655	13,175
1947	8	8	1	161	$ 24,000	$570,000	$35.87	127,128	15,891	17,523	13,904
1948	7	6	2	303	28,000	551,000	34.34	112,329	16,047	17,823	14,255
1949	11	8	5	199	64,000	534,000	32.52	180,631	16,421	20,521	15,530
1950	5	2	3	181	63,000	577,000	36.72	78,565	15,713	20,521	15,530
1951	12	5	6	116	54,000	577,000	33.56	189,864	15,822	20,521	15,530
1952	25	17	9	138	66,000	548,000	34.77	396,850	15,874	20,521	16,012
1953	25	14	20	159	75,000	779,000	44.79	407,936	16,117	21,482	17,895
1954	56	30	31	117	92,000	651,000	40.87	892,021	15,929	21,482	17,895
1955	98	63	43	87	116,000	649,000	40.09	1,587,008	16,031	22,559	17,895
1956	155	77	78	89	122,000	683,009	42.16	2,510,050	15,988	22,559	20,745
1957	165	114	89	89	121,000	743,000	46.25	2,987,841	16,064	22,559	20,745
1958	197	136	100	79	107,000	692,000	43.13	3,171,762	16,019	22,559	20,745
1959	228	147	119	71	83,000	660,000	40.48	3,660,857	16,056	25,340	20,745
1960	242	134	136	66	86,000	675,000	42.50	3,858,622	15,945	25,340	20,745
1961	243	84	153	63	81,000	614,000	38.07	3,918,324	16,124	25,340	20,745
1962	254	74	130	63	92,000	654,000	38.00	4,414,300	17,000	25,340	20,745
1963	271	96	126	52	97,246	696,000	42.85	4,401,363	16,241	25,340	21,410
1964	308	141	150	51	95,507	653,256	39.33	5,115,938	16,610	25,340	21,790
1965	330	117	156	59	90,160	610,784	36.38	5,522,541	16,735	25,340	22,098
1966	388	130	149	71	84,007	727,996	42.20	6,683,785	17,252	25,340	22,483
1967	402	142	192	66.8	96,375	762,656	45.29	6,769,371	16,839	25,340	22,483
1968	406	156	194	65	100,305	849,191	52.13	6,931,232	17,072	25,340	22,790
1969	389	116	206	53.6	101,529	866,349	50.19	6,619,216	17,016	25,340	22,790
1970	381	168	189	53.7	117,674	999,343	57.87	6,579,870	17,270	25,600	22,790
1971	417	149	210	60.3	146,040	949,959	54.81	7,227,414	17,332	25,600	22,790
1972	506	230	299	43.6	103,507	919,484	54.21	8,513,278	16,053	30,050	24,546**
1973	506	213	272	37.7	122,067	1,107,059	63.58	8,810,918	17,413	30,050	24,546
1974	446	220	258	36.9	168,476	1,456,522	84.08	7,726,058	17,323	31,441*	24,546
1975	410	191	198	37	197,279	1,901,017	109.80	7,098,330	17,313	31,441	24,546
1976	439	185	255	32.8	214,276	2,112,509	121.98	7,603,041	17,319	31,441	24,546

[illegible] recorded depth. Now completed as Oklahoma's Anadarko Horse at May 1974 by Lone Star Producing Co.
** Deepest OIL or GAS completion reaching the recorded depth indicated on mark on Nov. 17 well completed Nov. 1 Hunter in Beckham County, Oklahoma. Gargoyle's 500,000 ft from the Hunton at 24,760-546 ft.

and other contractor costs -- cut profit prospects to nearly nil in light of the wellhead price ceilings imposed by the Federal Power Commission.

President Carter has promised the industry he will deregulate wellhead prices, at least those for new gas production. Deregulation is a complex question for all phases of the industry to accept. And this includes the pipeline systems, the utilities and, yes, the producers. However, should the lid be removed from even new natural gas wells, chances are excellent that deep drilling will in future years set new industry records in terms of wells drilled, and rigs and pipe and other related equipment needed.

Costs Hit New Record

For second year running, cost of drilling and completing U.S. deep wells rose to record high levels. Total cost for all 439 wells, 58% of which required production completion equipment, was $927,391,828. This of course averages out to a record $2,112,509 per well and $121.98/ft.

Drilling costs alone amounted to $714,890,589 for all

Location of 1976 Wells 15,000 ft and Deeper

State	Wells	Average Bits/Well	Average Cost/Well	Average Mud Cost/Well
Alabama	37	19.3	$1,634,932	$ 192,155
Alaska	2	27.5	$3,400,000	$ 393,300
California	2	71.0	$3,300,000	$ 350,000
Colorado	1	154.0	$8,711,064	$1,361,952
Florida	3	12.3	$ 749,090	$ 71,732
Louisiana*	152	34.5	$2,149,505	$ 333,230
Mississippi	41	22.9	$1,166,490	$ 95,019
Montana	2	79.0	$2,103,754	$ 201,802
New Mexico	2	31.0	$2,234,092	$ 216,850
Oklahoma	50	32.5	$2,219,017	$ 201,544
Texas*	117	32.9	$2,255,183	$ 222,664
Utah	11	30.9	$1,830,455	$ 173,255
Wyoming	19	56.1	$3,382,906	$ 394,532

*Includes offshore

Table 1. U.S. Deep Drilling
(Wells Drilled to 15,000 ft or Deeper)

	1976 (439 wells)	1975 (410 wells)	1974 (446 wells)
Average well depth	17,319 ft	17,313 ft	17,323 ft
Average cost/well	$2,112,529 ($121.98/ft)	$1,901,017 ($109.80/ft)	$1,456,522 ($84.06/ft)
Average mud cost/well	$214,276 ($12.37/ft)	$197,279 ($11.39/ft)	$168,426 ($9.72/ft)
Total bits/well	32.8 (527 ft/bit)	37.0 (468 ft/bit)	36.9 (470 ft/bit)
Success ratio	58.1%	46.3%	57.8%
Wildcat success ratio	40.3% (186 wells)	29.8% (191 wells)	39.1% (220 wells)
Development success ratio	71.1% (253 wells)	60.2% (219 wells)	76.1% (226 wells)
Total Costs: Mud	$ 94,067,370	$ 80,604,569	$ 75,118,065
Drilling	$714,890,589	$570,737,473	$437,170,181
Total cost	$927,391,828	$779,417,300	$649,609,687

Table 2. Alabama Deep Drilling
(Wells Drilled to 15,000 ft or Deeper)

	1976 (37 wells)	1975 (32 wells)	1974 (32 wells)
Average well depth	17,196 ft	17,139 ft	16,585 ft
Average cost/well	$1,634,932 ($92.91/ft)	$1,228,479 ($71.68/ft)	$917,432 ($55.58/ft)
Average mud cost/well	$192,155 ($10.63/ft)	$115,148 ($6.72/ft)	$110,916 ($6.72/ft)
Total bits/well	19.3 (913 ft/bit)	21.8 (794 ft/bit)	24.3 (680 ft/bit)
Success ratio	56.8%	43.8%	56.0%
Wildcat success ratio	0% (0 wells)	16.7% (12 wells)	28.3% (10 wells)
Development success ratio	75.0% (28 wells)	60.0% (20 wells)	64.0% (13 wells)
Total Cost: Mud	$ 7,109,740	$ 3,684,722	$ 2,549,375
Drilling	$39,718,617	$26,342,613	$19,673,781
Total cost	$60,492,492	$39,311,330	$29,357,831

Table 3. Alaska Deep Drilling
(Wells Drilled to 15,000 ft or Deeper)

	1976 (2 wells)	1975 (0 wells)	1974 (1 well)
Average well depth	16,583 ft	0 ft	15,583 ft
Average cost/well	$3,400,000 ($205.04/ft)	$0 ($.00/ft)	$1,456,000 ($92.84/ft)
Average mud cost/well	$393,300 ($23.72/ft)	$0 ($.00/ft)	$86,000 ($5.48/ft)
Total bits/well	27.5 (603 ft/bit)	.0 (0 ft/bit)	39.0 (402 ft/bit)
Success ratio	100.0%	0%	0%
Wildcat success ratio	100.0% (1 well)	0% (0 wells)	0% (1 well)
Development success ratio	100.0% (1 well)	0% (0 wells)	0% (0 wells)
Total Costs: Mud	$ 786,600	$0	$ 86,000
Drilling	$5,010,430	$0	$1,018,000
Total cost	$6,600,000	$0	$1,456,000

Table 4. California Deep Drilling
(Wells Drilled to 15,000 ft or Deeper)

	1976 (2 wells)	1975 (6 wells)	1974 (5 wells)
Average well depth	19,023 ft	18,109 ft	18,223 ft
Average cost/well	$3,300,000 ($173.47/ft)	$2,217,540 ($122.48/ft)	$2,007,815 ($110.18/ft)
Average mud cost/well	$350,000 ($18.40/ft)	$235,105 ($12.98/ft)	$351,000 ($19.26/ft)
Total bits/well	71.0 (268 ft/bit)	54.2 (334 ft/bit)	54.2 (336 ft/bit)
Success ratio	100.0%	33.3%	25.0%
Wildcat success ratio	100.0% (1 well)	33.3% (6 wells)	25.0% (8 wells)
Development success ratio	100.0% (1 well)	0% (0 wells)	0% (0 wells)
Total Costs: Mud	$ 700,000	$ 1,410,678	$ 2,808,500
Drilling	$5,600,000	$10,984,327	$11,057,655
Total cost	$6,600,000	$13,307,641	$16,063,000

Table 5. Colorado Deep Drilling
(Wells Drilled to 15,000 ft or Deeper)

	1976 (1 well)	1975 (3 wells)	1974 (1 well)
Average well depth	17,647 ft	16,960 ft	15,117 ft
Average cost/well	$8,711,064 ($493.63/ft)	$3,647,067 ($214.79/ft)	$1,350,000 ($89.00/ft)
Average mud cost/well	$1,361,952 ($77.16/ft)	$403,935 ($23.79/ft)	$100,000 ($6.62/ft)
Total bits/well	154.0 (115 ft/bit)	84.0 (202 ft/bit)	90.0 (168 ft/bit)
Success ratio	100.0%	0%	0%
Wildcat success ratio	0% (0 wells)	0% (3 wells)	0% (1 well)
Development success ratio	100.0% (1 well)	0% (0 wells)	0% (0 wells)
Total Costs: Mud	$1,361,952	$ 1,211,800	$ 100,000
Drilling	$2,459,751	$ 8,998,400	$1,350,000
Total cost	$8,711,064	$10,941,200	$1,300,000

439 and this breaks down to $94/ft to cut the average deep well to total depth.

Mud costs averaged $12.37/ft., or $214,276 per well. Each of 1976's deep wells required on the average 33 bits and this means each bit accounted for 527 ft of hole. The accompanying tables reflect improved bit performance last year and continued higher mud costs.

Most of the higher costs then can be attributed to pipe expense and increasing contractor costs and this latter cost includes increased crew wages.

All 439 deep wells required some 768,250 tons of tubulars at an overall cost of $215,110,000. This represents roughly 20% of the total cost of the 1976 U.S. deep wells.

Feeling is that the contract drilling industry will be forced into purchases of new equipment in order to cope with the increase in deep hole activity. Most all the equipment is being utilized at this time and many rigs capable of drilling to these depth ranges are nearing replacement age.

Table 6. Florida Deep Drilling
(Wells Drilled to 15,000 ft or Deeper)

	1976 (3 wells)	1975 (9 wells)	1974 (10 wells)
Average well depth	16,144 ft	16,210 ft	15,646 ft
Average cost/well	$749,000 ($46.39/ft)	$703,600 ($43.41/ft)	$513,583 ($32.82/ft)
Average mud cost/well	$71,733 ($4.44/ft)	$68,186 ($4.21/ft)	$40,696 ($2.60/ft)
Total bits/well	12.3 (1309 ft/bit)	16.9 (960 ft/bit)	13.6 (1134 ft/bit)
Success ratio	0%	0%	40.0%
Wildcat success ratio	0% (2 wells)	0% (7 wells)	0% (2 wells)
Development success ratio	0% (1 well)	0% (2 wells)	50.0% (8 wells)
Total Costs: Mud	$ 215,200	$ 613,677	$ 406,958
Drilling	$2,067,000	$5,601,422	$3,709,800
Total cost	$2,247,000	$6,332,399	$5,135,200

Table 7. Louisiana Land Deep Drilling
(Wells Drilled to 15,000 ft or Deeper)

	1976 (102 wells)	1975 (110 wells)	1974 (110 wells)
Average well depth	17,925 ft	17,072 ft	16,924 ft
Average cost/well	$1,842,201 ($108.31/ft)	$1,627,831 ($96.35/ft)	$1,163,509 ($68.85/ft)
Average mud cost/well	$215,650 ($12.67/ft)	$208,487 ($12.27/ft)	$155,325 ($9.17/ft)
Total bits/well	35.5 (479 ft/bit)	37.5 (455 ft/bit)	38.4 (441 ft/bit)
Success ratio	43.1%	40.0%	52.9%
Wildcat success ratio	15.6% (32 wells)	27.9% (43 wells)	34.5% (58 wells)
Development success ratio	55.7% (70 wells)	47.8% (67 wells)	70.5% (61 wells)
Total Costs: Mud	$ 21,994,326	$ 23,043,550	$ 12,483,622
Drilling	$160,308,216	$139,630,120	$104,653,425
Total cost	$187,504,557	$179,681,482	$130,706,331

Table 8. Louisiana Offshore Deep Drilling
(Wells Drilled to 15,000 ft or Deeper)

	1976 (50 wells)	1975 (31 wells)	1974 (29 wells)
Average well depth	15,827 ft	16,050 ft	16,055 ft
Average cost/well	$2,774,369 ($174.10/ft)	$2,238,033 ($139.02/ft)	$1,873,178 ($116.65/ft)
Average mud cost/well	$239,864 ($15.06/ft)	$207,436 ($12.88/ft)	$205,702 ($12.81/ft)
Total bits/well	32.7 (437 ft/bit)	32.8 (437 ft/bit)	32.9 (413 ft/bit)
Success ratio	66.0%	41.9%	51.7%
Wildcat success ratio	31.3% (16 wells)	0% (9 wells)	28.6% (7 wells)
Development success ratio	82.4% (34 wells)	58.3% (22 wells)	50.1% (22 wells)
Total Costs: Mud	$ 11,933,179	$ 5,435,529	$ 5,965,349
Drilling	$114,084,441	$64,363,231	$38,811,849
Total cost	$138,719,418	$69,378,023	$54,322,094

Table 9. Mississippi Deep Drilling
(Wells Drilled to 15,000 ft or Deeper)

	1976 (41 wells)	1975 (41 wells)	1974 (25 wells)
Average well depth	16,728 ft	17,316 ft	17,421 ft
Average cost/well	$1,168,450 ($69.85/ft)	$1,408,915 ($81.37/ft)	$987,923 ($56.71/ft)
Average mud cost/well	$95,019 ($5.68/ft)	$111,920 ($6.46/ft)	$88,458 ($5.08/ft)
Total bits/well	22.9 (730 ft/bit)	25.2 (686 ft/bit)	30.7 (575 ft/bit)
Success ratio	56.1%	39.0%	36.5%
Wildcat success ratio	42.1% (19 wells)	15.0% (20 wells)	31.8% (22 wells)
Development success ratio	68.2% (22 wells)	61.9% (21 wells)	75.0% (4 wells)
Total Costs: Mud	$ 3,895,779	$ 4,568,712	$ 7,399,918
Drilling	$36,261,831	$37,040,614	$14,362,010
Total cost	$47,908,085	$57,765,535	$25,685,995

Table 10. Montana Deep Drilling
(Wells Drilled to 15,000 ft or Deeper)

	1976 (2 wells)	1975 (0 wells)	1974 (0 wells)
Average well depth	17,286 ft	0 ft	0 ft
Average cost/well	$2,103,764 ($121.71/ft)	$0 ($.00/ft)	$0 ($.00/ft)
Average mud cost/well	$201,802 ($11.67/ft)	$0 ($.00/ft)	$0 ($.00/ft)
Total bits/well	79.0 (219 ft/bit)	0 (0 ft/bit)	0 (0 ft/bit)
Success ratio	.0%	0%	0%
Wildcat success ratio	.0% (2 wells)	0% (0 wells)	0% (0 wells)
Development success ratio	.0% (0 wells)	0% (0 wells)	0% (0 wells)
Total Costs: Mud	$ 403,603	$0	$0
Drilling	$3,803,905	$0	$0
Total cost	$4,207,508	$0	$0

Table 11. New Mexico Deep Drilling
(Wells Drilled to 15,000 ft or Deeper)

	1976 (2 wells)	1975 (6 wells)	1974 (7 wells)
Average well depth	17,097 ft	15,643 ft	17,338 ft
Average cost/well	$2,234,887 ($130.67/ft)	$1,308,316 ($83.63/ft)	$1,379,645 ($81.11/ft)
Average mud cost/well	$216,850 ($12.68/ft)	$139,254 ($8.45/ft)	$136,867 ($7.90/ft)
Total bits/well	31.0 (552 ft/bit)	27.2 (726 ft/bit)	31.9 (544 ft/bit)
Success ratio	100.0%	83.3%	85.7%
Wildcat success ratio	100.0% (2 wells)	75.0% (4 wells)	83.3% (6 wells)
Development success ratio	0% (0 wells)	100.0% (2 wells)	100.0% (1 well)
Total Costs: Mud	$ 433,800	$ 293,576	$ 958,700
Drilling	$2,144,306	$1,960,964	$ 8,691,000
Total cost	$4,468,164	$7,849,888	$11,007,500

Texas and Oklahoma

All the U.S. rise last year was in Texas and Oklahoma, with the two states showing a combined rise of 44 completions. Louisiana with 152 completions was 11 higher than 1975, and its 50 offshore deep wells set a state record for deep marine activity. Texas with five offshore completions also had more deep marine holes on record for 1976 than any year in its drilling history.

Alabama, Mississippi and Wyoming continue to draw steady deep well activity. Reference is again made to the accompanying tables which show Utah and Florida in steady decline.

Texas, with its huge intrastate market requirements, had more land deep holes cut last year than any other state, including Louisiana. Totals were 112, which represented an increase for Texas, and 102, which was another decline for Louisiana. Louisiana's 50 offshore wells however kept that state the country's top deep well area. ■

Table 12. Oklahoma Deep Drilling
(Wells Drilled to 15,000 ft or Deeper)

	1976 (58 wells)	1975 (28 wells)	1974 (29 wells)
Average well depth	17,301 ft	16,970 ft	16,974 ft
Average cost/well	$2,219,017 ($128.26/ft)	$2,230,701 ($131.48/ft)	$2,310,751 ($125.78/ft)
Average mud cost/well	$201,544 ($11.65/ft)	$249,019 ($14.67/ft)	$349,794 ($17.96/ft)
Total bits/well	32.5 (532 ft/bit)	41.0 (414 ft/bit)	50.6 (375 ft/bit)
Success ratio	64.0%	65.5%	62.1%
Wildcat success ratio	50.0% (22 wells)	46.7% (15 wells)	57.9% (19 wells)
Development success ratio	75.0% (28 wells)	85.7% (14 wells)	70.0% (10 wells)
Total Costs: Mud	$ 10,877,213	$ 7,221,556	$ 9,883,032
Drilling	$ 85,247,648	$40,253,092	$39,158,166
Total cost	$110,950,850	$64,690,333	$67,011,768

Table 13. Texas Land Deep Drilling
(Wells Drilled to 15,000 ft or Deeper)

	1976 (112 wells)	1975 (53 wells)	1974 (134 wells)
Average well depth	18,301 ft	18,283 ft	18,151 ft
Average cost/well	$2,269,133 ($123.99/ft)	$1,886,382 ($103.73/ft)	$1,541,623 ($84.93/ft)
Average mud cost/well	$721,647 ($12.22/ft)	$184,259 ($10.06/ft)	$165,276 ($9.55/ft)
Total bits/well	33.3 (549 ft/bit)	39.1 (507 ft/bit)	35.9 (505 ft/bit)
Success ratio	66.1%	55.9%	61.9%
Wildcat success ratio	56.8% (58 wells)	45.2% (42 wells)	42.9% (63 wells)
Development success ratio	75.9% (54 wells)	64.7% (31 wells)	78.9% (71 wells)
Total Costs: Mud	$ 25,048,518	$ 17,136,133	$ 20,806,832
Drilling	$202,638,175	$124,435,321	$125,769,776
Total cost	$254,142,576	$178,363,565	$206,577,473

Table 14. Texas Offshore Deep Drilling
(Wells Drilled to 15,000 ft or Deeper)

	1976 (5 wells)	1975 (1 well)	1974 (0 wells)
Average well depth	17,252 ft	15,763 ft	0 ft
Average cost/well	$1,966,120 ($113.96/ft)	$3,671,300 ($232.91/ft)	$0 ($.00/ft)
Average mud cost/well	$201,120 ($11.66/ft)	$100,000 ($6.34/ft)	$0 ($.00/ft)
Total bits/well	26.8 (664 ft/bit)	26.0 (563 ft/bit)	0 (0 ft/bit)
Success ratio	60.0%	0%	0%
Wildcat success ratio	33.3% (3 wells)	0% (1 well)	0% (0 wells)
Development success ratio	100.0% (2 wells)	0% (0 wells)	0% (0 wells)
Total Costs: Mud	$1,005,600	$ 100,000	$0
Drilling	$5,184,200	$3,571,300	$0
Total cost	$9,830,600	$3,671,300	$0

Table 15. Utah Deep Drilling
(Wells Drilled to 15,000 ft or Deeper)

	1976 (11 wells)	1975 (18 wells)	1974 (35 wells)
Average well depth	17,267	16,675 ft	16,396 ft
Average cost/well	$1,830,455 ($106.01/ft)	$1,813,300 ($108.74/ft)	$1,424,037 ($86.89/ft)
Average mud cost/well	$173,255 ($10.03/ft)	$197,820 ($11.86/ft)	$153,834 ($9.38/ft)
Total bits/well	30.9 (559 ft/bit)	42.8 (390 ft/bit)	30.7 (534 ft/bit)
Success ratio	63.6%	66.7%	91.4%
Wildcat success ratio	25.0% (4 wells)	.0% (4 wells)	50.0% (2 wells)
Development success ratio	85.7% (7 wells)	85.7% (14 wells)	93.9% (33 wells)
Total Costs: Mud	$ 1,905,800	$ 3,560,761	$ 5,286,351
Drilling	$13,287,200	$24,152,191	$39,301,133
Total cost	$20,135,000	$32,839,309	$49,862,302

Table 16. Wyoming Deep Drilling
(Wells Drilled to 15,000 ft or Deeper)

	1976 (19 wells)	1975 (72 wells)	1974 (11 wells)
Average well depth	17,694	17,637 ft	16,696 ft
Average cost/well	$3,362,906 ($191.19/ft)	$3,273,960 ($185.63/ft)	$2,756,308 ($165.03/ft)
Average mud cost/well	$394,532 ($22.30/ft)	$358,863 ($20.35/ft)	$324,569 ($19.44/ft)
Total bits/well	56.1 (315 ft/bit)	63.5 (276 ft/bit)	69.0 (242 ft/bit)
Success ratio	57.9%	54.5%	72.7%
Wildcat success ratio	46.7% (15 wells)	47.1% (17 wells)	66.7% (9 wells)
Development success ratio	100.0% (4 wells)	80.0% (5 wells)	100.0% (2 wells)
Total Costs: Mud	$ 7,496,115	$ 7,804,976	$ 3,570,257
Drilling	$47,841,815	$48,386,877	$20,082,206
Total cost	$64,275,219	$73,027,299	$30,300,281

Acknowledgement. Coordinator and computer program developer of PETROLEUM ENGINEER International's Deep Well Survey is Mary Jane Ellis, assistant editor, assisted in data gathering by Rich McNally, assistant editor. PETROLEUM ENGINEER International has been analyzing U.S. deep drilling on an annual basis since 1941. Base data is acquired from various industry sources including contract drilling companies and Petroleum Information of Denver, Colo. Operating companies confirm the wells and through a special arrangement with PETROLEUM ENGINEER International provide cost data on a confidential basis. The accompanying report on ultra-deep drilling (wells drilled to 20,000 ft and deeper) is part of the overall Deep Well Survey. Some cost data was estimated, based on reliable industry benchmarks, when operating data didn't reach the editorial staff by copy deadline.

Ultradeep Drilling Rises

In line with the general increase of all U.S. oil and gas drilling and especially deep drilling to 15,000 ft and deeper, ultradeep drilling moved higher during 1976, according to PETROLEUM ENGINEER International's annual Deep Well Survey.

The annual study showed 59 wells drilled to 20,000 ft or deeper, the depth range identified as ultradeep. This compares with 46 in 1975 and 65 in 1974.

These are the big expensive projects aimed at finding new natural gas reserves or at development of existing reserves. Current U.S. natural gas crisis, together with strong signs that natural gas wellhead prices might be decontrolled this year, are two factors which have been cited for the stepped up activity.

Majority of the ultradeep holes were drilled in the prolific gas basin areas of West Texas. In all Texas drew 34 of the ultradeep holes to account for more than half the country's activity.

Nationwide the ultradeep wells averaged 21,803 ft each and cost on the average $3,601,971. This is $165/ft for all 59 wells, 68% of which were equipped with production equipment.

Drilling costs jumped 27% to $137/ft during 1976.

Mud costs averaged $369,196 per well, or $16.93/ft. This compares with $350,384 and $16.40/ft a year earlier.

Each of the 20,000-ft class wells required 53 bits (408 ft/bit) last year, compared with 50.5 (423 ft/bit) a year earlier. Diamond bit use averaged 2.6 per well, about the same as 1975.

Success ratio on both exploratory and development wells last year hung in there well at around 68%, and exploratory drilling was at a 3-year high level. This points to additional development work in the next few years if traditional industry trends continue.

Accompanying tables provide a clear statistical picture of all U.S. ultradeep drilling for 1976 and the prior two years.

Wyoming could be considered as a case in point when the industry discusses the high cost of living in the oil country. The state recorded three ultradeep wildcats during 1976 and all of them were completed as gas producers. Total cost was $25,169,850 ($370/ft). Drilling cost for all three was $21,720,000 and the total mud bill was $2,700,000 ($40/ft). On the average, the Wyoming projects cost $8,390,000 each and that's expensive.

— John Scott

Table 1. U.S. Ultradeep Drilling
(Wells Drilled to 20,000 ft or Deeper)

	1976 (59 wells)	1975 (46 wells)	1974 (65 wells)
Average well depth	21,803 ft	21,356 ft	21,582 ft
Average cost/well	$3,601,971	$3,270,425	$2,609,464
	($165.20/ft)	($153.07/ft)	($120.91/ft)
Average mud cost/well	$369,196	$350,384	$294,628
	($16.93/ft)	($16.40/ft)	($13.62/ft)
Total bits/well	53.4	50.5	54.2
	(408 ft/bit)	(423 ft/bit)	(398 ft/bit)
Success ratio	67.8%	47.8%	67.7%
Wildcat success ratio	67.7%	28.0%	50.0%
	(31 wells)	(25 wells)	(34 wells)
Development success ratio	67.9%	71.4%	87.1%
	(28 wells)	(21 wells)	(31 wells)
Total costs: Mud	$ 21,782,544	$ 16,117,671	$ 19,111,272
Drilling	$176,419,065	$106,454,105	$101,002,905
Total cost	$212,518,271	$150,439,608	$169,615,182

Table 2. California Ultradeep Drilling
(Wells Drilled to 20,000 ft or Deeper)

	1976 (1 well)	1975 (2 wells)	1974 (3 wells)
Average well depth	22,030 ft	21,551 ft	20,986 ft
Average cost/well	$4,600,000	$3,925,295	$3,019,333
	($208.81/ft)	($178.99/ft)	($146.74/ft)
Average mud cost/well	$500,000	$343,294	$557,667
	($22.70/ft)	($15.65/ft)	($24.19/ft)
Total bits/well	95.0	73.0	71.3
	(232 ft/bit)	(300 ft/bit)	(294 ft/bit)
Success ratio	100.0%	0%	66.7%
Wildcat success ratio	100.0%	0%	66.7%
	(1 well)	(2 wells)	(3 wells)
Development success ratio	0%	0%	0%
	(0 wells)	(0 wells)	(0 wells)
Total costs: Mud	$ 500,000	$ 686,587	$1,523,000
Drilling	$4,000,000	$6,699,054	$8,704,000
Total cost	$4,600,000	$7,850,590	$9,230,000

Table 3. Louisiana Ultradeep Drilling
(Wells Drilled to 20,000 ft or Deeper)

	1976 (12 wells)	1975 (7 wells)	1974 (0 wells)
Average well depth	21,215 ft	20,965 ft	20,683 ft
Average cost/well	$3,078,094	$3,205,157	$2,617,101
	($142.73/ft)	($152.88/ft)	($126.53/ft)
Average mud cost/well	$377,040	$603,738	$367,462
	($17.77/ft)	($29.04/ft)	($17.77/ft)
Total bits/well	51.4	49.3	54.7
	(413 ft/bit)	(425 ft/bit)	(378 ft/bit)
Success ratio	58.3%	28.6%	66.7%
Wildcat success ratio	66.7%	25.0%	33.3%
	(3 wells)	(4 wells)	(3 wells)
Development success ratio	55.6%	33.3%	100.0%
	(9 wells)	(3 wells)	(3 wells)
Total costs: Mud	$ 4,524,481	$ 4,261,163	$ 2,204,772
Drilling	$29,749,898	$18,705,269	$11,246,411
Total cost	$36,337,132	$22,436,098	$15,702,607

Table 4. Mississippi Ultradeep Drilling
(Wells Drilled to 20,000 ft or Deeper)

	1976 (2 wells)	1975 (5 wells)	1974 (3 wells)
Average well depth	20,995 ft	21,393 ft	20,876 ft
Average cost/well	$1,401,100	$4,239,952	$2,941,748
	($66.73/ft)	($198.20/ft)	($140.90/ft)
Average mud cost/well	$145,055	$377,414	$347,696
	($6.91/ft)	($17.64/ft)	($16.65/ft)
Total bits/well	53.0	55.0	48.3
	(395 ft/bit)	(389 ft/bit)	(432 ft/bit)
Success ratio	.0%	33.3%	33.3%
Wildcat success ratio	.0%	.0%	33.3%
	(1 well)	(2 wells)	(3 wells)
Development success ratio	0%	50.0%	.0%
	(1 well)	(4 wells)	(0 wells)
Total costs: Mud	$ 290,109	$ 2,264,484	$1,043,089
Drilling	$2,182,200	$13,556,307	$3,959,121
Total cost	$2,802,200	$25,439,710	$8,825,243

Table 5. Oklahoma Ultradeep Drilling
(Wells Drilled to 20,000 ft or Deeper)

	1976 (6 wells)	1975 (2 wells)	1974 (11 wells)
Average well depth	22,330 ft	20,928 ft	22,499 ft
Average cost/well	$4,726,550	$3,912,505	$3,795,598
	($211.67/ft)	($186.95/ft)	($168.70/ft)
Average mud cost/well	$484,865	$485,000	$554,887
	($21.71/ft)	($23.17/ft)	($24.66/ft)
Total bits/well	57.3	50.0	73.6
	(389 ft/bit)	(419 ft/bit)	(306 ft/bit)
Success ratio	50.0%	.0%	63.6%
Wildcat success ratio	50.0%	.0%	60.0%
	(6 wells)	(2 wells)	(10 wells)
Development success ratio	.0%	.0%	100.0%
	(0 wells)	(0 wells)	(1 well)
Total costs: Mud	$ 2,909,188	$ 970,000	$ 6,103,760
Drilling	$23,837,113	$3,193,254	$26,448,003
Total cost	$28,359,301	$7,825,000	$41,751,573

Table 6. Texas Land Ultradeep Drilling
(Wells Drilled to 20,000 ft or Deeper)

	1976 (33 wells)	1975 (25 wells)	1974 (38 wells)
Average well depth	21,882 ft	21,509 ft	21,643 ft
Average cost/well	$3,304,157	$2,670,675	$2,113,020
	($151.00/ft)	($124.16/ft)	($97.63/ft)
Average mud cost/well	$312,217	$243,627	$184,517
	($14.27/ft)	($11.33/ft)	($8.53/ft)
Total bits/well	46.2	45.0	48.3
	(454 ft/bit)	(478 ft/bit)	(448 ft/bit)
Success ratio	75.8%	68.0%	73.7%
Wildcat success ratio	73.3%	41.7%	45.5%
	(15 wells)	(12 wells)	(11 wells)
Development success ratio	77.8%	92.3%	85.2%
	(18 wells)	(13 wells)	(27 wells)
Total costs: Mud	$ 10,303,168	$ 6,090,664	$ 7,011,651
Drilling	$ 91,215,653	$47,646,885	$44,147,870
Total cost	$109,037,188	$66,766,866	$80,294,759

Table 7. Texas Offshore Ultradeep Drilling
(Wells Drilled to 20,000 ft or Deeper)

	1976 (1 well)	1975 (0 wells)	1974 (0 wells)
Average well depth	21,890 ft	0 ft	0 ft
Average cost/well	$3,210,600	$0	$0
	($146.67/ft)	($.00/ft)	($.00/ft)
Average mud cost/well	$255,600	$0	$0
	($11.68/ft)	($.00/ft)	($.00/ft)
Total bits/well	58.0	0	0
	(377 ft/bit)	(0 ft/bit)	(0 ft/bit)
Success ratio	100.0%	.0%	.0%
Wildcat success ratio	100.0%	.0%	.0%
	(1 well)	(0 wells)	(0 wells)
Development success ratio	.0%	.0%	.0%
	(0 wells)	(0 wells)	(0 wells)
Total costs: Mud	$ 255,600	$0	$0
Drilling	$1,014,200	$0	$0
Total cost	$3,210,600	$0	$0

Table 8. Utah Ultradeep Drilling
(Wells Drilled to 20,000 ft or Deeper)

	1976 (1 well)	1975 (1 well)	1974 (0 wells)
Average well depth	21,786 ft	20,450 ft	0 ft
Average cost/well	$3,000,000	$4,242,269	$0
	($137.70/ft)	($207.45/ft)	($.00/ft)
Average mud cost/well	$300,000	$429,126	$0
	($13.77/ft)	($20.98/ft)	($.00/ft)
Total bits/well	35.0	103.0	0
	(622 ft/bit)	(199 ft/bit)	(0 ft/bit)
Success ratio	0%	.0%	.0%
Wildcat success ratio	.0%	.0%	.0%
	(1 well)	(1 well)	(0 wells)
Development success ratio	.0%	.0%	.0%
	(0 wells)	(0 wells)	(0 wells)
Total costs: Mud	$ 300,000	$ 429,128	$0
Drilling	$2,700,000	$3,813,141	$0
Total cost	$3,000,000	$4,242,269	$0

Table 9. Wyoming Ultradeep Drilling
(Wells Drilled to 20,000 ft or Deeper)

	1976 (3 wells)	1975 (1 well)	1974 (0 wells)
Average well depth	22,681 ft	21,322 ft	0 ft
Average cost/well	$8,389,950	$6,669,075	$0
	($369.91/ft)	($313.72/ft)	($.00/ft)
Average mud cost/well	$869,999	$908,645	$0
	($39.68/ft)	($42.62/ft)	($.00/ft)
Total bits/well	103.0	59.0	0
	(220 ft/bit)	(361 ft/bit)	(0 ft/bit)
Success ratio	100.0%	100.0%	.0%
Wildcat success ratio	100.0%	100.0%	.0%
	(3 wells)	(1 well)	(0 wells)
Development success ratio	.0%	.0%	.0%
	(0 wells)	(0 wells)	(0 wells)
Total costs: Mud	$ 2,699,998	$ 908,645	$0
Drilling	$21,720,001	$4,919,695	$0
Total cost	$25,169,850	$6,669,075	$0

Mr. DINGELL. Gentlemen, I guess you heard the bell. We have another vote on the floor. I apologize to you. We will go over and vote again and be back as quickly as we can. The committee will stand in recess.

[Brief recess.]

Mr. DINGELL. The subcommittee will come to order.

The Chair, with some pleasure, announces that is the last vote of the day.

The Chair recognizes the gentleman from Ohio, Mr. Brown, for the purpose of asking questions for five minutes.

Mr. BROWN. Almost the first question is how do you know that is the last vote for the day?

I just had a colloquy with Secretary Blumenthal of the United States Treasury in which he advised me that the gross tax take in the President's plan is somewhere in excess of $100 billion a year, according to his estimate, but he wasn't sure. He knew what the net would be, which I guess equates with profits for the Government, which was somewhere around $51 billion. I would like to ask—I don't know that I have ever had the figure before—but what is the total expenditure by the oil and gas industry, in searching out new sources of oil and gas; can anyone tell me that?

Mr. FOSTER. This year, I don't know whether I can give you all of the total expenses, the capital expenditures which includes exploration and discovery for the oil and gas industry for this year, is budgeted at about $27.5 billion.

Mr. BROWN. So you could quadruple, I guess, on the basis of those figures the effort, if all that was recovered by the industry, which, God forbid, but what is the profit in the total oil and gas idustry?

Mr. FOSTER I would guess probably for 1977 we are looking at $14 to $16 billion.

Mr. BROWN. This program would work a little better for the Federal Government than apparently it is running for the industry.

Mr. Hefner, you have presented us a very interesting proposition here that seems to provide a formula for setting the price of gas by the Government in the future.

Who does this represent? I see that you speak for the Independent Gas Producers Committee made up of——

Mr. HEFNER. Between 25 and 30 members, and we are growing. We originally were formed——

Mr. BROWN. Did they all participate in the establishment of the program?

Mr. HEFNER. The majority of the people were represented at our meeting yesterday, and we will submit a full list of the members for the record.

Mr. DINGELL Without objection, that will be inserted in the record at this point.

[The material referred to had not been received at the time the record was closed.]

Mr. BROWN. I am just curious to know if anybody concurred in the program. We just reported out a bill yeterday from the Government Operations Committee on a 22-21 vote, which is not really a strong mandate for the program. I wondered if your group——

Mr. HEFNER. It's a majority opinion. I don't think every independent has ever concurred in one position in the history of the industry. However, I would like to say our group does represent the potential to expend new risk capital in the order of magnitude of $3 million to $5 million in the year 1978, to give you an idea of the size.

Mr. BROWN. The independent gas producers, are any of you represented in the panel?

Of you all, do you concur in the plan or have you participated in the development of the plan, and tell who you represent, if I could ask that.

Mr. DAVIS. I am caught in the middle, Mr. Congressman. I am a director of the group of which Mr. Hefner is the chairman.

Mr. BROWN. Did you participate in developing the plan?

Mr. DAVIS. Yes, sir. I am also the vice president, chairman of the Natural Gas Committee for the IPAA and I think what we see here is an example that independents are truly independent.

Mr. BROWN. As a director, you were solicited on the plan, I assume.

Mr. DAVIS. Yes; and I did not attend the meeting yesterday.

Mr. BROWN. What happens is you get to be chairman of the PTA that way.

Mr. DAVIS. I think my greatest personal fear about this particular plan is that it will be perceived as something that is self-serving. I think most independents truly believe—and I certainly personally do—that deregulation of gas is for the national good, and that we are not beating a drum for deregulation for our own personal gain.

I don't see that much wrong with what Mr. Hefner has said, except as I say, the way it will be viewed by the public.

Mr. FOSTER. Congressman Brown, the Natural Gas Supply Committee, which I have the honor to represent consists of both majors and independent members. Sitting on the Steering Committee of the Natural Gas Supply Committee are representatives of the American Petroleum Institute, the Independent Petroleum Association of America, the Mid-Continental Oil and Gas, Rocky Mountain Oil and Gas Association, Western Oil and Gas Association, as well as a number of independent companies.

As I indicated in my testimony, our membership produces about 90 percent of the gas that goes into interstate commerce and a slightly smaller percentage of the gas shipped in intrastate commerce.

We think we have a broadly representative membership and our policies are based upon the consensus of that membership.

We have always opposed any proposal which treats major producers and independent producers differently, or that attempts to tinker with the pricing mechanism based upon differences in size.

We have also opposed any measure which attempts to treat drilling in one geographical area or under one set of circumstances differently in a pricing mechanism. That seems to us to be just one more example of the kind of tinkering that has got us in the sort of trouble we have been in so far.

It is one of the reasons we opposed the Smith amendment last year, H.R. 9464, which we felt literally destroyed the traditional working relations between the major and independent producers in

this country, and although I have not had a chance to look at Mr. Hefner's proposal in detail, we are very concerned this kind of proposal which seeks to treat producers differently will again upset the traditional working relationships between the major and independent producers.

Mr. BROWN. Mr. Jones, do you represent an independent?

Mr. JONES. Yes, Congressman Brown. I am the president of the IPAA which represents about half of the independents in the country, now 4,500 independents, give or take however many might have joined or dropped out today.

As Bob says, there is a state of flux always within the opinions of independent producers. The name is very aptly put. As I pointed out in my testimony, and you have attached to it there a resolution that we drew at our convention this is where we had around over 1,000, close to 1,200 independents from all over the country, and we came out with what I think pretty well expresses the unilateral opinion of the independent producer that the country's best interests are served only by a complete deregulation of new natural gas.

I would concur with what David Foster has just said, that it seems like by the time you get through with any type of exemption, you are in worse shape than you were when you started out, as the Smith bill would have done to us. So I think we have got to be for what's best for this country, and that is complete deregulation of new natural gas.

Mr. BROWN. Perhaps it would be well, Mr. Chairman, if we asked the groups to ask their boards what they think of the proposal presented to us by Mr. Hefner, and maybe get back to us within the week or whatever timeframe in which that could be accomplished, so we can have some kind of reading on the proposal.

Mr. DINGELL I have no objection to that. If it meets Mr. Hefner's approval and those at the table, I have no objection to that at all.

Without objection, that response will be inserted into the record at this point.

[The following letter was received for the record:]

Natural Gas Supply Committee

1025 Connecticut Avenue, N.W.
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(202) 223-9575

David H. Foster
Executive Vice President

May 31, 1977

Honorable John D. Dingell
Chairman
Subcommittee on Energy and Power
Committee on Interstate and Foreign Commerce
House of Representatives
Washington, D.C. 20515

Dear Chairman Dingell:

During the course of the hearing on Thursday, May 12, 1977, Congressman Brown requested that the spokesmen for Independent Petroleum Association of America and the Natural Gas Supply Committee ascertain from their respective organizations "what they think of the proposal presented to us by Mr. Hefner" (Transcript, p. 205) and report the results to the Subcommittee.

At a meeting of the Steering Committee of the Natural Gas Supply Committee on May 27, 1977, the question was raised and there was unanimous opposition to Mr. Hefner's proposal as well as to any proposal exempting certain portions of the producing industry.

The fragmentation of the producing industry and imposition of several constraints upon a small portion of it would not be a productive step toward solving the energy problems of the country. The responsibility for finding and developing supplies of oil and natural gas has historically rested upon a diverse group of concerns ranging in size from individuals to large corporations. Each of these concerns performs an important function in the total effort in finding and developing oil and gas, and the contribution of all parts is essential to the success of the whole group in discharging its responsibility.

As one noted independent operator, Collis P. Chandler, stated in testimony before the Senate Commerce Committee in 1973, "For some reason, exploration seems to thrive most efficiently in a geological province when there is some relative balance between majors and independents. Majors contribute sophisticated knowledge from thorough long-range geological studies and often heavy pre-drilling expenditures such as geophysical expenditures. Independents act as a catalyst, often working out trades between three or four companies to drill a wildcat well."

The Natural Gas Supply Committee respectfully requests that this response be inserted in the record of the Subcommittee's proceedings at the point reserved therefor (Transcript, Vol No. 4, p. 206).

Very truly yours,

David H. Foster
Executive Vice President

Mr. FOSTER. Mr. Chairman, I know your record is going to be voluminous in this matter already. When I heard this testimony I was reminded of a study prepared by the Petroleum Industry Research Foundation in June of last year which talks about the relations in the oil and gas industry between major oil companies and independent producers, and I don't know whether you would like this in the record or whether you would like me to give it to the staff.

Mr. DINGELL. Without objection staff will review it to ascertain its appropriateness for the record.

The time of the gentleman has expired.

The Chair recognizes the gentleman from Louisiana, Mr. Moore.

I am sorry. The Chair apologizes; the Chair recognizes the gentleman from Texas, Mr. Krueger.

Mr. KRUEGER. Thank you, Mr. Chairman.

I have two areas of questioning I would like to pursue.

One is on the question of our resource base. I think one of the cardinal assumptions of the Freeman, Goldman, Schlesinger, all of your other friends, Carter, proposal that we have received is that there is not only a declining resource base but perhaps a minute resource base, and that there is really very little gas to be found.

I wonder whether Mr. Foster and Mr. Jones, whether from your two different organizations you would care to comment on your conceptions of what resource base is, and what kind of additional natural gas supplies might be brought on in a short period of time; that is two or three or four years, as a result of deregulation of wellhead pricing.

Mr. JONES. I will start out, Mr. Krueger.

Of course, I think this is one of the things that may be the industry failed in its input into the Carter administration policy. We didn't do a very good job of selling them on what the resource base truly is.

In the case of natural gas, we have continually repeated the fact that we do have around 1,000 trillion cubic feet of gas to be discovered in this country. We are using somewhere around 21 trillion cubic feet per year, so that indicates that we have a 50 year supply of gas at current usage levels left to be found and produced.

We also say that the restraints that the Carter administration bill would put on the discovery of gas would keep from the public a lot of the gas that would come on the quickest, where the gas pipelines now exist.

We agree that the frontier type drilling—the Rocky Mountains, the Overthrust Belt—is going to be a real source of gas in the future, but that gas is going to be five and six and ten years coming on.

We believe the administration overlooked the real situation, where the gas is and where it will be brought on the quickest. We feel if the Texas intrastate gas supply situation is a good model—and we think it is—that we would have almost instantaneous response to a proper price level.

Mr. FOSTER. If you will forgive me, I think I will defer to the geologist on our panel.

Mr. KRUEGER. Sure; Mr. Allen.

Mr. ALLEN. I have to agree with Mr. Jones on that. The potential gas estimate is right in that neighborhood of 923 to 973 trillion cubic feet.

Mr. KRUEGER. Mr. Allen, would that be economically recoverable or is that sort of gas, that is a geological rather than economic estimate, or is it both?

Mr. ALLEN. I cannot quote the exact definition of this gas but I am sure that the next witness will be able to quote it for you, Mr. Krueger. However, the estimate is based on an assumption of adequate prices and normal improvement in technology.

In that estimate there is no estimate of some exotic gas like gas from coal seams, or gas from the very tight formations in the Rockies, which would be recovered with nuclear fracture and that type of thing. None of those are in that estimate. This is conventional gas.

I think I would like to state one more thing: 215 trillion of that is potential gas that is in and around these presently producing structures in addition to proved reserves. That is their estimate.

Mr. KRUEGER. Not necessarily beyond 2½ miles?

Mr. ALLEN. Right, and that to me is the gas that can come on fast and quickest and the stuff we are really working on as we go along as a part of this business. The pipelines are right there; they don't have a big incremental investment in more transportation facilities; they are ready to take, and that to me is the gas for a quick answer; that is the quickest you can get.

Thank you.

Mr. KRUEGER. Are there any other members of the panel who would like to comment on this particular question?

Mr. HEFNER. I certainly would.

Very quickly, Mr. Schlesinger said this morning that $1.75 is a price that will produce an additional 1.1 trillion cubic feet by 1985.

Our estimates, based on our proposal we presented today for one province of America, the Anadarko or Mid-Continent alone, are in an additional 200 billion to 1.2 trillion by 1980. I think you can see a drastic difference between what the administration was working on and what we believe is possible based on geological and geophysical estimates of what exists, the amount of drilling rigs and techology presently existing and ongoing programs that are capable of developing that gas.

Mr. KREUGER. Mr. Davis?

Mr. DAVIS. I would like to mention the 2½ mile limitation.

For example, we have a field that is being developed now in Eastland County, Texas, where a new sand has been discovered between sands that have been producing in there for years. Some of the wells, about 200 in this general area, were drilled as early as 1920.

Many were drilled in the 1930's and in the 1940's, but we have a new sand that was found strictly on the basis of new technology and new logging techniques. The risk in drilling these wells and in extending this field is just as great as if we had been 50 miles away. It is a new prime reservoir with prime pressure in it.

Mr. KRUEGER. I thank you.

I would like now to look particularly at the notion that we should offer special incentives to small drillers such as Mr. Hefner proposed.

I think, Mr. Hefner, in your testimony you indicated that you rejected Mr. Schlesinger's statement, that is you said that first of all you didn't think $1.75 was adequate. Then you also indicated that there was a great deal of bureaucratic regulation in Mr. Schlesinger's proposal.

What I don't understand is why larger companies and larger producers should be forced to undergo bureaucratic regulations but smaller ones should not? I am not sure the bureaucratic regulation is undesirable and antiproductive.

I am not sure why we should only exempt the smaller producers from it.

Mr. HEFNER. Under the circumstances that exist I think it's important that we go on with natural gas policy in the country. It seems to me that this proposal might break the logjam. The reason we propose what we have is that this will allow increases in small producers that we will have rather than concentrate the industry, and we will gain to sustain large increases in the number of independent producers who will be exploring for natural gas.

Mr. KRUEGER. It is really undertaken then as a sort of a nonconcentration approach.

Mr. HEFNER. That is one of the reasons.

Mr. KRUEGER. Rather than an approach that would specifically assist.

Mr. HEFNER. It would allow new entrants into the producing and exploration industry, and allow the formation of large amounts of new risk capital to be expended in consortium with the independent producers of the country.

Mr. KRUEGER. The second observation I would make is that I can imagine some people arguing in my home town, for example, when food prices go up that maybe what we want to do is to impose Federal price controls on the supermarkets that serve most people, but we can say to the small corner grocer he should not have those.

I guess my sense of equity is maybe we have too much special tax provisions already in the country, and too many special pricing provisions, but I can't really see why we would want to treat the supermarkets differently from the smaller grocers, and I can't really see why policy that would be healthy for one and would help the country, why it wouldn't also be healthy for another, and if it's primarily a concern about concentration, my recollection was that the eight largest producers of gas together didn't quite get up to 50 percent.

When I tried to compare that with IBM computers, AT&T telephones, General Motors or any other, I can't think of most other areas in the country in which the eight largest corporations would not have over 50 percent. So I really don't see the logic of that.

Mr. HEFNER. We simply believe it's the political realities of the day. We have been at this issue, the industry and Congress, since 1972, and we haven't seen the resolution of it. We think our proposals will work, and they are practical.

Mr. KRUEGER. That sounds reminiscent of Mr. Schlesinger, political judgment, but if it were politically desirable to deregulate the majors and regulate the independents, would you see that one too?

Mr. HEFNER. Of course, that would not work. The independents couldn't stand the regulatory process and the bureaucracy. I think that is what led to the demise of thousands of independents over the past 10 or 15 years.

Mr. KRUEGER. You don't think Mr. Schlesinger's plan gives you that certainty and predictability?

Mr. HEFNER. We do not.

Mr. KRUEGER. Thank you.

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes the gentleman from Louisiana, Mr. Moore.

Mr. MOORE. Thank you, Mr. Chairman.

May I ask the members of the panel other than Mr. Hefner, I think I got the impression in your answers to Mr. Brown, but do any of you agree with the position Mr. Hefner has taken?

Mr. HEFNER. Can I answer it first?

Mr. DAVIS. No, sir, I don't agree with it.

Mr. JONES. No; I think as far as polling the IPAA I would be very happy to do it.

Mr. BROWN. I suggested the board or something.

Mr. JONES. We have just completed a meeting where our executive committee was pretty well exposed to any alternative plans that might be suggested.

The chairman of the committee was gracious enough to come out and address us, and was very kind to stand some of the heat that I get standing up before them at times, and I think our position is very clear on the matter.

Mr. FOSTER. I would certainly agree, and I was very happy to hear my good friend, Bob Hefner, acknowledge that at least his solution was in large part politically motivated, because, as I mentioned before, this kind of solution really does upset a lot of the traditional business patterns upon which small producers have relied as well as major producers including farm-outs by the majors to the independents, the practice of geological information being developed by the majors and made available to the independents, financial arrangements between majors and independents, all of which have been traditional practices which have created a very healthy synergism in the natural gas industry, and which would now be made unavailable.

Mr. MOORE. Mr. Hefner, how many companies are members of your organization?

Mr. HEFNER. Between 25 and 30. To size it, we have the capacity, as added up between the members, to expend some $300 to $500 million in 1978.

Mr. MOORE. How many of these 25 to 30 were consulted in the decision?

Mr. HEFNER. They were all consulted, and the majority concurred.

Mr. MOORE. Majority of them. Are any of those from Louisiana?

Mr. HEFNER. I don't believe we have a member from Louisiana.

Mr. MOORE. That is some salvation.

Mr. HEFNER. I will submit the full membership. I would suspect we could get some though.

Mr. MOORE. You have a company that you are partner in, I believe, am I correct?

Mr. HEFNER. That is correct.

Mr. MOORE. Is that company primarily one that produces less than 200 million cubic feet of gas a year?

Mr. HEFNER. That is correct.

Mr. MOORE. I understand your major area of concern is for the deep gas.

Mr. HEFNER. No. My major concern is for onshore U. S. natural gas reserves.

Mr. MOORE. How deep?

Mr. HEFNER. If you are talking about me personally, and my business interests, that is something different.

Mr. MOORE. That is what I am talking about. How deep is your company looking for gas?

Mr. HEFNER. From 4,000 to 30,000 feet in depth.

Mr. MOORE. What percent of your efforts now are below 15,000 feet?

Mr. HEFNER. A majority of our expenditures for exploration are within the deep area.

Mr. MOORE. Then really this amendment would tailor suit your company perfectly.

Mr. HEFNER. Which amendment are you speaking of?

Mr. MOORE. I am talking about your plan, your plan would exempt your company, obviously.

Mr. HEFNER. Certainly, and the majority or all of the independents in the United States, and all producers who produce gas from below 15,000 feet of any size.

Mr. MOORE. All of those haven't asked for that, you have.

Let me ask you one step further.

Mr. HEFNER. Nor did they ask for that during the various FPC hearings when we submitted testimony as to what the costs between 15,000 feet are.

Mr. MOORE. Would it be fair to say in your State, as it is in mine, that guaranteeing our consumers a steady price for natural gas and not letting it go up is a popular political issue?

Mr. HEFNER. Yes. It's a popular political issue to criticize the various regulatory agencies who try to fix the price.

Mr. MOORE. And to criticize the oil companies too for higher prices for natural gas, and would it also be rather unpopular politically to run on a platform that you want to deregulate natural gas and let the prices go high and the oil companies rip off the public and let everybody's utility rates go up?

Mr. HEFNER. I think you get a mixed reaction in the producing States of at least Oklahoma and I think Texas to that question.

Mr. MOORE. There, but there is a sizable number of consumers that feel that way in Oklahoma and Texas; there aren't in Louisiana.

Mr. HEFNER. True. In Oklahoma the majority of our economy is agricultural or oil and gas.

Mr. MOORE. Would be fair to say, I understand you are running for the Senate from Oklahoma next year; is that right?

Mr. HEFNER. I have not made that a matter of public record.

Mr. MOORE. Are you willing to do so now?

Mr. HEFNER. That is certainly a possibility.

Mr. MOORE. I would like to ask the other gentlemen if anybody has any studies?

Mr. DINGELL. If the gentleman would yield, I don t know what it matters whether the witness is running for the Senate or that it has anything to do with his appearance today or what his being a candidate for the Senate might indicate. I don't know what his politics are, but I do regard him as a successful businessman and a man of integrity.

Mr. MOORE. Mr. Chairman——

Mr. HEFNER. I would also guess every member of the panel is running for some office.

Mr. MOORE. I regard him as a businessman as well, but I also regard him as a politician, and I think the position he has taken is very politically popular, and I don't think it's popular among the people in his own industry. It is among voters.

Mr. HEFNER. Are the issues you support politically popular among your constituency?

Mr. MOORE. I am not concerned about that; I am concerned about what is right.

Mr. HEFNER. So am I. I am on the small track. I am glad to see we are all on the same track.

Mr. MOORE. I was about to ask, we have had a lot of testimony about what are the reserves for natural gas, and we had testimony this morning—and many of you heard that—and I heard one of you testify a moment ago as to what the reserves are.

Do you have any figures or studies you can submit to the committee as to what you believe the achievable reserves in natural gas in this country are?

Mr. HEFNER. We have included our studies in the written testimony presented to the committee.

Mr. MOORE. Good. Does anybody else have any they have not submitted in the testimony?

Mr. JONES. I think Potential Gas Supply Committee is going to testify immediately upon our finishing here and the IPAA concurs with those numbers pretty well.

We are concerned that we haven't been able to establish this number. It looks like maybe the gist of the disagreement between the industry and Mr. Carter right now is on what the potential supplies of energy, petroleum based energy, are in this country. I think it's very important that this be established once and for all, and if I get up and say what they are, as a geologist from Albany, Texas, I probably haven't got the credit you need to go and convince Mr. Carter.

I don't know what is going to establish what those reserves are, but it needs to be done.

Mr. BROWN. How about an organization like the CIA?

Mr. JONES. I don't know. This needs to be established for the good of the people of this country, so we will be talking about the same thing.

Mr. MOORE. Anybody else have any figures?

Mr. ALLEN. I believe I was the witness that did mention the potential reserves. I didn't go into it in detail because it was called to my attention that Mr. Kent would be a witness this afternoon, and he is the director of the Potential Gas Agency.

I am a member of the Potential Gas Committee.

Mr. MOORE. Your figures came from that agency.

Mr. ALLEN. That was the report, and the estimate that I alluded to, yes.

Mr. MOORE. Another question that comes up, of course, and that is how much gas will be produced within the $1.75 cap amount? Gas will be produced if we use the Krueger-Brown stair step decontrol plan. Have any of you done any studies you can give the committee on that score? We have some for other agencies.

I wonder if you all have done any studies in that regard?

Mr. FOSTER. We have not developed independent studies. There are a number of studies that are around as to price supply elasticity. I know of at least four of them. The American Gas Association has done it; the Institute of Gas Technology; the FEA has done it; we have not done any independently.

Mr. MOORE. We have those.

Mr. FOSTER. I know you have those, and I think those are the ones, and that of the Stanford Research Institute, the MIT model, and some work being done up at Harvard. There are a lot of supply elasticity studies around. I am amazed the administration has yet to provide us with their price elasticity model upon which their proposal is based.

I heard today Dr. Schlesinger was prepared to supply it for the record. We have been trying to find out what their model was all of this time so perhaps we might have been able to critique it, and if it is persuasive we might be able to agree.

Mr. MOORE. Does anybody else have any such models or studies other than the ones we just mentioned which we have?

Mr. ALLEN. I am looking at one that is a publication, "Energy Topics, published by IGT."

Mr. MOORE. We have that one, too, I am told.

Mr. ALLEN. That does show a good bit of supply response with prices higher than $1.75.

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes counsel, Mr. Demarest, for questions.

Mr. DEMAREST. Gentlemen, if I could, I would like to go through some of the definitions in this legislation very briefly, by asking you a few questions.

For the new gas definition, the location or the situs of the completion location is very important.

Could you tell me if a natural gas producer, 1) knows with any degree of precision where that completion location is, and 2), whether that information is publicly available? If it is not, would it be considered by a producer to be proprietary and something he would not want to release to a competitor?

Mr. JONES. We object very much to this type of definition.

Mr. DEMAREST. That is not the question. I only have five minutes. I just want to get a very narrow question answered. The question is: Do we have the information on where the situs of a completion location is?

Mr. JONES. It could be gathered, but what I was starting to say, it could be gathered, but it would be expensive. It would be a bottom hole survey run in every well drilled in the United States to exactly pinpoint that bottom hole, and this is a very expensive process.

Mr. DEMAREST. Is it known today?

Mr. JONES. No; we don't ordinarily do this today as a matter of course in drilling a well. If you have a directionally drilled well that calls for an exact bottom hole location, then you can control it very carefully, and you do run these surveys. These surveys are very expensive and would add greatly to the cost of the drilling at a time when I think we want to bring on supply as cheaply as possible, and that is why I was starting to say we object to this type of definition being in the definition of new gas or oil.

Mr. DEMAREST. Is this kind of information commonly on file anywhere?

Mr. JONES. No. It is not on file commonly.

Mr. DEMAREST. If you were to develop this information, presumably at some cost to yourself, would this be the information that you would tend to treat as proprietary because it would give you information about a structure?

Mr. DAVIS. Mr. Demarest, I think I understand what you are asking. Are you asking about the location of the hole, the development well, the well itself, or are you asking for an exact location of the bottom of the hole?

Mr. DEMAREST. I am not asking for the bottom of the hole; I am asking for what is defined as the completion location, the point at which the perforations exist and from which gas or oil, the hydrocarbons, are produced from the rock.

Mr. DAVIS. That is commonly known. That must be filed with most State agencies as to exactly where those perforations are made below the surface of the ground.

Mr. JONES. Pardon me; that is the definition of completion location, not site.

Mr. DAVIS. What Mr. Jones has been decribing is that sometimes a hole will wander off from its surface site.

Mr. DEMAREST. I understand.

Mr. DAVIS. It's very complicated and expensive to find exactly where that hole is in relation to where it started, but the depth is filed wherever that hole is.

Mr. DEMAREST. For purposes of the new gas definition, you have a three-dimensional matrix here, and it's not just the depth but it's the location, longitude and latitude, which is also important.

Mr. JONES. That is what I was talking about.

Mr. DEMAREST. That is on file. The depth is on file, the longitude and latitude is not?

Mr. DAVIS. Longitude and latitude is not, but the geographical location of surface of that hole is.

Mr. DEMAREST. That is not material to the definition.

Mr. JONES. We are back to what I was talking about. That is very complex, and would be very hard to ascertain; impossible to ascertain would be a better word.

Mr. DAVIS. I agree.

Mr. DINGELL. The point of extraction is a bottom of the hole where the hydrocarbons are produced; it is not necessarily directly over the top of the hole?

Mr. DAVIS. Yes.

Mr. HEFNER. Let me add one thing, particularly applicable here, too. Sometimes we perforate over a long series of zones and we have no exact way at the surface of the ground to know which of the perforations are the completion location as defined in the bill, and it would take techniques that are applicable to do that as to which formations are actually producing gas, but those are not always definitive, so you could have a vertical error of over 1,000 feet in many cases.

Mr. JONES. To go back to your question, though, in reading from the definition you are talking about the completion location is the completion zone, and in modern oil well drilling, a survey is run and, I would say is unilaterally very well known that zone is easily identifiable.

Mr. HEFNER. We don't know which zone it is coming from, however.

Mr. DEMAREST. So that we are clear though; again, you are talking about the information being available as to the depth, the vertical distance down the pipe, of the completion locations?

Mr. JONES. That is right.

Mr. DEMAREST. But whether that is directionally offset?

Mr. JONES. Where it is impossible to ascertain, not completely impossible but very difficult and very hard.

Mr. DEMAREST. That information is not on file?

Mr. JONES. No.

Mr. DEMAREST. It would be expensive to develop.

Would it be fair to say that, given the definition of the term "depth," there appears to be an assumption here that all gas is produced below sea level.

Mr. JONES. That again, in geological terms, we use sea level as the reference point in everything, and everything is so far above sea level or so far below sea level, but in most of the Mid-Continent areas you have a lot of gas that is produced above sea level. Again, it would be a fallacy in these definitions to assume that all depths are below sea level. Sea level is the reference on which all geological data is obtained.

Mr. DEMAREST. This morning I inquired of Dr. Schlesinger regarding the existence of two types of impediments to sales of natural gas to the interstate market, and suggested that clearly one was price, and the other might be forms of regulation under the Natural Gas Act, certification, abandonment requirements.

Mr. Hefner, you are a producer. If you have a choice of making a sale under similar contract terms to an interstate pipeline where the sale would be a sale for resale, within the meaning of the Natural Gas Act, or to make a sale to an intrastate pipeline which would not be subject to the jurisdiction of the FPC, which sale would you prefer to make?

Mr. HEFNER. There would be no question about it; the intrastate sale.

Mr. DEMAREST. Does anyone on the panel disagree with that?

Mr. JONES. No. I agree one-hundred percent.

Mr. DAVIS. I agree.

Mr. DEMAREST. I knew if we persevered long enough we would get you to agree with Mr. Hefner.

Mr. BROWN. Would counsel yield?

Do I infer from that then, that if the price is the same that we aren't going to get any more gas in Ohio than we got before?

Mr. JONES. I would have to say the price being the same and the massive amount of regulation that comes upon one's head once he decides to go into the interstate market, and this is why we say that deregulation and getting rid of those problems is the answer to the question. Once you have an interstate sale, at least the way it has been defined in the past, you have bought yourself a lot of trouble.

Mr. BROWN. You haven't answered yet directly the question I am asking. That question I think, is answered by inference in the question of counsel, and that is that if the price at which gas can be sold in the intrastate market and the interstate market is the same, then it isn't going to encourage any gas in particular to be sold in the interstate market.

Mr. KRUEGER. Would the gentleman from Ohio yield?

I think I would just like to clarify in your question——

Mr. BROWN. Are you going to answer my question?

Mr. KRUEGER. I might, but I know you haven't asked, but I just want to make sure that your question is understood by the group, and I think what your question is is if the price is the same interstate and intrastate and both markets are under FPC price controls and regulation, or if both are without FPC regulation, then what would happen? I really have clarified it beautifully.

Mr. BROWN. If counsel would continue to yield I sure appreciate the help, Mr. Krueger, but I would like to go back to the way the question was asked by counsel.

Mr. JONES. In the terms that I understand the question, and going back to understanding the gas business, most of the time you don't have that many alternatives. You are either close to an interstate line or an intrastate line, and if the prices were the same and all other things were the same I don't think there would be any difference between the two markets.

Mr. BROWN. With the fixed price anticipated in this bill of $1.75 and the regulation by the Federal Government in the interstate market as opposed to the relative lack of regulation in its intrastate market, who is going to get the gas if you have two lines side by side over the wellhead?

Mr. JONES. The intrastate market is going to get it the way it's developed right now.

Mr. HEFNER. Intrastate.

Mr. DAVIS. If I understand what you are saying, Mr. Brown, there would be no difference between interstate and intrastate. It's just gas.

Mr. DINGELL. If my colleagues would permit, the Chair has a couple more questions I would like to ask.

The Chair recognizes Mr. Demarest.

Mr. DEMAREST. We previously addressed the first half of that issue, which is if there is removal of the price impediment to sales

to the interstate market but no other action taken with respect to the burdens of FPC regulation, there may be incentives for producers to make a sale at the same price in intrastate rather than interstate commerce.

Does this legislation do anything to address such regulatory disincentives to interstate sales?

Mr. FOSTER. No, sir, it does not.

Mr. HEFNER. No, it does not.

Mr. DAVIS. It does not.

Mr. JONES. It does not.

Mr. DEMAREST. Thank you, Mr. Chairman.

Mr. DINGELL. The Chair has a couple of questions I would like to ask.

Gentlemen, there are certain problems with regard to the commingling of interstate and intrastate natural gas. There also are certain problems that arise because once gas is committed to the interstate market, under the Natural Gas Act, that gas must remain interstate gas.

How are these two matters addressed or affected by the legislation before us?

Mr. FOSTER. I think I will permit my counsel to answer that since he is more familiar with it.

Mr. DINGELL. It's a good question for counsel.

Mr. JOHNSON. Mr. Chairman, I was just looking in the President's, the administration bill here, and I believe section 412 says that the Commission may grant an abandonment under section 7(b) of the Natural Gas Act at any time prior to the committing or dedication of natural gas for interstate commerce.

That is a very difficult phrase, and I defy anyone to tell me what it means because it seems to say if you never committed the gas then you can get it abandoned, and I don't understand that.

I think the answer to your question is that the distinction between interstate and intrastate is preserve insofar as regulation is concerned. The current law, the *Permian Basin Area Rate Proceeding* case still applies. The only difference in the intrastate market now is that the ceiling price set out in the bill also applies to the intrastate market, but none of the other controls which currently are in the Natural Gas Act, are imposed on the intrastate market, as I understand.

Mr. DINGELL. Would the practical effect of that be that natural gas would seek the interstate market, would be neutral or would seek the intrastate market?

Mr. JOHNSON. Mr. Chairman, I think that the answer is that producers would prefer not to undergo the regulatory burden of participating in the Federal Power Commission procedures, even though those procedures are now limited to certify procedures and abandonment procedures. That is still a burden on the interstate market, which is not imposed on the intrastate market under the bill, as I understand it.

Mr. DINGELL. Even if the intrastate market is under price control as provided in the proposed legislation.

Mr. JOHNSON. That is my understanding; the intrastate market is controlled as to the ceiling price alone.

Mr. DINGELL. Do you regard that as an anomaly?

Mr. JONES. It certainly is a difference in the intrastate market as opposed to the interstate market.

Mr. DINGELL. Mr. Hefner, you had a comment.

Mr. HEFNER. Yes; I do. Given the same price and the regulatory burdens, et cetera, of the interstate market, I would still attempt to sell to the intrastate market, because I think in those circumstances there would be at least several years of due process on the Constitutional issues. We would like to keep our gas still in the intrastate market until that is resolved.

Mr. DINGELL. Gentlemen, you will recall that in our earlier discussions I spoke to the IPAA and suggested that we would look to you for your comments with regard to technical problems and drafting problems which exist in the legislation.

I would like to call on you to submit to us such suggestions with regard to technical problems, language difficulties and drafting problems which might exist in the legislation to assist the committee in drafting a proper piece of legislation from the standpoint of technically sound legislation which accomplishes the goal of the drafter.

Mr. JONES. Mr. Dingell, we haven't had, as you well know, the time to complete our analysis. You are running under relative time restraints with these hearings as we appreciate, and we would like to submit things like this at a later time.

Mr. DINGELL. I think that is proper.

Mr. FOSTER. We certainly will cooperate with you, too. I think that when we get down to fighting out the substantive issues, which we must at some point, we want to be dealing with an internally coherent bill we can all understand.

Mr. DINGELL. We should all be speaking the same language.

Mr. JONES. The definitions, as some of them are drawn, give us some real problems.

Mr. DINGELL. Your assistance in this particular area would be valuable.

Mr. HEFNER. We believe it's so poorly drafted that it's almost impossible to techically assess, and think that this committee should start over on the definitions of new gas and we have proposed our definitions and supplied them to the committee in our written testimony, which are defined really as new wells drilled after a certain date.

Mr. DINGELL. You chose the date distinction between new and old?

Mr. HEFNER. Yes, because in natural gas as opposed to oil the traditional historical development program has been generally on square miles, and each square mile is a new ball game. Therefore, if we are going to develop the onshore natural gas within the country we have got to be able to drill wells within the next traditional drilling and spacing unit, and I don't think that can be altered if we really want to effectively do anything to find new gas reserves.

We suggest that the committee start over.

Mr. DINGELL. I suspect that is the second item on which your colleagues at the table would be able to agree.

Let me read from a letter I received recently where some one in the industry suggested the following to describe new gas:

He said: "A new field wildcat is a well located on a structural feature or other trap which has not previously produced oil or gas."

I get a negative nod from Mr. Hefner.

Mr. JONES. When you say structural feature, you have already started something that I think geologically is very hard to define, because I think the vast reserves to be found in ths country are going to be stratigraphic features which are just not a structure as you can define structure.

Mr. DINGELL. You are talking about gas as opposed to oil?

Mr. JONES. Gas and oil; oil is the same, the structures are things you can find, and anticlines and things like that. The tremendous reserves left to be found in this country are not going to be easy to define as structural traps, and will be more stratigraphic in nature, and this would prohibit a lot of gas from being found by definition. It would be very difficult to define a structure.

Mr. HEFNER. May I add one thing? Let me say one thing about the problem of such definitions. A structural feature is also the entire Anadarko Basin of the Mid-Continent, so it really out of hand makes no sense whatsoever.

Mr. DINGELL. Mr. Allen?

Mr. ALLEN. Mr. Chairman, I think you will find the definitions of exploratory wells, and I think these are pretty well accepted all over, if you will refer to the August 1975 bulletin of the American Association of Petroleum Geologists.

The language in that letter that you are quoting I believe is the beginning of the definition of new field wildcats from that reference. The definitions appear beginning on page 1280 of this AAPG bulletin. I am sure your staff has this.

Mr. DINGELL. Would you give us some additional comment though, and tell us whether you agree or disagree, or you may suggest a different definition.

Mr. ALLEN. I wouldn't suggest another definition for a new field wildcat.

Mr. DINGELL. You wouldn't suggest that as a definition for new natural gas?

Mr. ALLEN. No, sir; I don't believe I would, for this reason.

Let me give you an example, which, in fact, I point out in that written statement.

Take in the first instance a field producing from about 6,000 feet. You go over here three or four miles beyond the 2½ mile limit, and you have another structure with similar characteristics.

You can go in there and drill a test well for something in the neighborhood of $170,000, and really, that probably isn't too risky. If you have the same type structure and the same characteristics, you have a pretty good shot at production. On the other hand, if you have a field with producing zones at a depth of 16,000 feet and you have a large fault with no production on the other side of that fault. You have the same zone, and you want to test that structure; your well is going to cost you about $1.7 million, about ten times the cost of the first well, but under the bill—and the way the definitions work—for that gas you would be limited to some lower price, and the shallow well would, of course, get the higher price.

That doesn't make a whole lot of sense from a producer's standpoint, but there are other definitions there of new field wildcats, new pool wildcats and that type of thing. I think any well that gets you some new supply, which is really what we are after, is new gas and should get the higher price.

Mr. DINGELL. Let me ask you: How do you avoid including in-field drilling as new gas?

Mr. ALLEN. I believe New Mexico just passed a law that went to this point. I don't have that before me, but they defined new gas and set some type of ceiling on it. To qualify as new gas it would have to be from a well which added to supply and that is not drilled just as another straw to go into the same old gas and merely change its qualification by drilling that well.

I think you should be able to do this if you have proven some additional reserves or additional supply then it's new gas.

I don't know that New Mexico language, but my understanding is that it does have those safeguards.

Mr. DINGELL. It raises dark suspicions in my mind. I have great problems to simply drill an offset hole from an existing rig, and call it new gas.

I would have real differences with anybody who wanted to say he could get a substantially higher price for something of that kind. It would strike me as lacking fairness to both other drillers and to the consuming public.

Am I in error in that?

Mr. ALLEN. No; you are not as far as I am concerned, Mr. Chairman; you are not.

Mr. ALLEN. The thing is that you have to have a little faith in the drillers or in the conservation bodies of the States or perhaps if you wanted to, the USGS or something like that if you are proving up new gas. This bill, as I read it, they define producing formation in such a manner that it doesn't even have to be connected to the production in the other wells. That means a different reservoir entirely. When you find a new reservoir, to me that is new gas.

Mr. DINGELL. Well, I don't have any quarrel with that. You admit that that is an area rich in litigation. I am not sure whether that kind of definition would produce more new gas or more litigation. I am rich in faith and hope, but I am not sure whether I have quite that much charity.

Mr. HEFNER. Our definition does address that issue if you would like us to read it.

First, let me read our definition of new natural gas. "New natural gas means (a) natural gas other than in-fill natural gas, or natural gas produced from offshore Federal lands which is produced from wells commenced on or after the date of legislation, or (b) natural gas produced from a well which is deepened by actual drilling commenced on or after that date."

Then we define in-fill natural gas. "In-fill natural gas means natural gas produced from a well, the actual drilling of which was commenced on or after that date which resulted in a greater density of producing wells than that which exists under the spacing pattern established at the time such well is drilled, either by the appropriate regulatory authority or by the custom and practice, for the drilling of wells in the reservoir from which such well produces."

We think that adequately covers the problem that you are addressing.

Mr. DINGELL. I agree it does. I'm not sure whether it provides for simple administration at the same time.

Mr. HEFNER. The spacing pattern has been established either as a matter of law or practice and is definitive at this time. So it is very simple to see whether or not you are increasing or decreasing the existing spacing pattern. The majority have been established by law within the State agencies for onshore natural gas.

Mr. DINGELL. Gentlemen, my time is up. I recognize Mr. Collins for questions.

Mr. COLLINS. Thank you, Mr. Chairman.

I wanted to say to the gentleman from Oklahoma who took an independent view which, from the southwest, of course, we always admire a fellow with an independent view, but I want to also understand him.

Mr. HEFNER. We would rather be admired than understood.

Mr. COLLINS. As I understand this now, you are from down in our area and you are a producer so you know what you are talking about. You said that you wanted a cap but you don't want the cap. Now just how do you figure that?

Mr. HEFNER. What we said was that we recommended a ceiling price that would phase out beginning at $2.25 and that we would exempt from that ceiling price all independent natural gas producers.

Mr. COLLINS. Why should they be exempt? What is fair for one is fair for all.

Mr. HEFNER. That may be true. However, we think it is in the national interest to increase the competition within the industry and allow the independents who can raise the risk capital formulation to drill within their ongoing programs within the United States for new supplies of natural gas and they should be given that opportunity.

Mr. COLLINS. When we had deregulation, over 85 percent of the drilling was done by independents. What is wrong with going back to that?

Mr. HEFNER. If you could enact that today as the national policy, I would join you. But we believe that the realities of the time are such that the country badly needs natural gas legislation. We don't think it is fair for anyone in the country to face what happened in the winter of 1977. We think we must break the logjam and get on with natural gas policy and that this would be a plan which is workable and practical.

Mr. COLLINS. Let me just ask the general panel, if I can, we turned this gas situation into a political Santa Claus situation up here. They are proposing to let Washington allocate to everybody that wants some or needs it.

What complications do you all see with a proposal such as that, Washington just going around allocating wherever they want to?

Mr. FOSTER. Congressman Collins, we, of course, disagree with that, not only because it upsets the one bright spot in our national energy picture, the intrastate market for gas, but because it just compounds the nightmare and extends it to the whole country.

We are going to be trying to do some things by bureaucratic fiat instead of the way it is done best and that is market pricing. I know people argue that the intrastate market should be controlled just like interstate because we ought to have parity between the two and you can't get along with two market prices, one controlled and one uncontrolled.

I guess there is a certain amount of logic for that. The last time this argument was made was at the time of the Civil War when somebody said we couldn't have a country that was half slave and half free. We in Texas have come to agree with that. You can't have two markets, one slave and one free, but now they want to make the whole thing into a slave market.

We disagree. The whole thing ought to be free and we could avoid all these problems that I have referred to.

Mr. COLLINS. Mr. Hefner, as I understand it now, you say you would prefer to deregulate gas, that is your preference, is that right? Do you believe that is the best thing?

Mr. HEFNER. We believe that the market system is the best way, yes. But we think at this time that it is time to get on with legislation. We think that our plan is workable, as I said, and practical.

Mr. COLLINS. How do you see this working? As I understood it, you said that you thought your approach was a more pragmatic approach. You would favor the deregulation, but you want to find some legislation that would work. Is that what you are advocating?

Mr. HEFNER. That is correct.

Mr. COLLINS. If we are taking a pragmatic approach, how do you think the multiple structure with the government allocating, how do you visualize that working?

Mr. HEFNER. I don't think under our plan the government would have to allocate. We think natural gas is price responsive enough that we would under our plan bring supply and demand in balance within three to four years and sustain the balance well into the future of the country.

Mr. COLLINS. What do you think is a potential in America for coming back in for these small fields when the price is right?

Mr. DAVIS. I think it is fantastic. It is just like one of the fields we have in North Texas right now where people have known or suspected at least for many, many years that the gas was there. But at 17 cents when everybody stopped drilling in the early sixties, you just could not make any money. You would literally go bankrupt trying to drill wells and sell gas at that price. But as the price came up, then that did become price responsive.

The wells have been drilled. The consumers have benefitted. I don't mean to say that everybody in Texas has bit the bullet of higher prices willingly. Some of them are a little bitter about it, in fact. But in Texas we have avoided much of the economic disruption that other people have had and that example should be extended to the Nation.

There are many, many fields all over this country, many areas where that price responsiveness would bring forth low producibility gas wells, I guess you would call them.

Mr. COLLINS. I would like for you all to tell us something about the 15,000 foot drilling where they say there is tremendous potential. Independents can't afford to drill there, can they?

Mr. JONES. Mr. Hefner is an independent and he does a lot of the drilling. But this is one of the things that we have to say as an absolute. We wish that we could say, "Well, we are going to bring on a lot of reserves or cheap gas." When we start talking about the thousand trillion cubic feet of potential reserves, we are going to have to acknowledge that they are in the deeper, more difficult to drill areas. They are in the deep Appalachian, deep offshore, deep Anadarko and the deep basins in the Rocky Mountains.

This will have to be recognized, along with the fact that we say the reserves are there but the costs of drilling those wells are going to be higher and the incremental unit of gas is going to be more expensive in the future than it has been in the past.

Mr. COLLINS. Mr. Hefner, have you drilled any of those deep ones?

Mr. HEFNER. Yes, we have. I think you might be interested in an example. We drilled one of the early wells in the deep Anadarko in 1969 at a project cost of $6½ million. After producing it for several years we found that it was one of the Nation's best gas-producing wells. As a matter of fact, among the top 15 percent. However, we have not yet recouped 25 percent of our investment. That is the system that is withholding gas in this country. We have obviously not been able to develop that field.

Mr. COLLINS. And you have not since 1969.

Mr. HEFNER. That is correct.

Mr. COLLINS. You have not been able to recover but 25 percent.

Mr. HEFNER. That is correct and I think the cost of deep drilling relative to average drilling, and this is what has been wrong with the regulatory system in this Nation, it is that our well equipment, one piece, costs $250,000. That one single piece of equipment is more than the total average cost of a gas well within the country that same year.

So our one piece of equipment you say costs the same as the average cost of the gas wells being drilled then.

Mr. COLLINS. What are your costs of drilling deep wells today compared to 1969?

Mr. HEFNER. We have submitted the information on the Anadarko and used joint association figures. How can you say what the costs are? The costs of drilling a dry well may be infinite and the costs of drilling a good well may be low.

We have submitted some costs in relation to the FPC cost methodology. We have used productivity figures higher than the national average which is 300 Mcf per foot. We have used 500 to 1,000 which we think are the range for these high productivity deep basins. Our costs range from $1.93 to a high of $6.25. So within that window would be the costs of producing ultra-deep gas.

Mr. COLLINS. Thank you, Mr. Chairman.

Mr. KRUEGER [presiding]. At this time the Chair will recognize minority counsel for questions.

Mr. VLCEK. Mr. Hefner, in reference to your now famous proposal, I am curious to know why you choose 200 billion cubic feet of gas as the cut-off point.

Mr. HEFNER. That is an arbitrary number. It is a judgmental decision.

Mr. VLCEK. My figures for 1972 tell me that if you use a cut-off point of 200 billion cubic feet a day, you get small independents such as Marathon, Chaplin, Kerr Macky, Diamond Shamrock, Columbia Gas, Mitchell Energy and others who are in your exempt category.

Mr. HEFNER. Obviously it just eliminates the largest of the producing companies within this country.

Mr. VLCEK. Do you know what percentage of gas that included group produces?

Mr. HEFNER. I don't think what they produce is relative. What we are doing is trying to determine a policy that will bring on new supplies.

Mr. VLCEK. That is not answering the question.

Mr. HEFNER. I don't think the relationship is significant.

Mr. VLCEK. The percentage I have is 71 percent is produced by companies that produce 200 Bcf or more per year which leaves 29 percent that is produced by those who produce less.

Mr. HEFNER. That is correct. At what point in time are your figures?

Mr. VLCEK. 1972 and 1973. Has that changed substantially?

Mr. HEFNER. Sure it has. During 1945, up until that point in time the majority of those gas reserves were discovered by independents who sold out to major companies. So I don't think the future can be judged by a look at the past. That is the problem we get when Mr. Zareski tries to propose to use what the resource might be in the future based on a look at the past economics.

Mr. VLCEK. I wonder if you can provide for the record as background information for your proposal, first, a list of the companies that would be included and those excluded in the first year. We will have a problem next winter.

And also would you provide a percentage of production for the included group and excluded group at 200 Bcf?

Mr. HEFNER. Yes, we will attempt to provide that information to the committee. Let me be sure I am clear. The number of companies that would be included?

Mr. VLCEK. The names of the companies that would be included in the group that produces 200 Bcf gas or more. This is going to be a steady line as I read your legislative specifications here and then, secondly, the percentage of production of those companies of our total natural gas supply in a given year. You can use 1976 figures.

Mr. HEFNER. If those are available in the public record, we will try to submit them to you.

[The following letter and attachments were received for the record:]

INDEPENDENT GAS PRODUCERS COMMITTEE

2601 NORTHWEST EXPRESSWAY, SUITE 300
OKLAHOMA CITY, OKLAHOMA 73112
(405) 848-7621

May 18, 1977

Mr. Jan Vlcek
Associate Minority Counsel
Interstate and Foreign Committee
2322 Rayburn House Office Building
Washington, DC 20515

Dear Mr. Vlcek:

As you requested during the May 12, 1977, hearings of the Subcommittee on Energy and Power (and later followed up with a request to Martha Patterson), I am enclosing a list of the current membership of the Independent Gas Producers Committee. Our committee was formed earlier this year to concentrate on the natural gas issue, which we felt was not receiving adequate attention by the established trade associations.

We do not intend to become a permanent lobby group, and we have not directed our efforts toward recruiting members. We have devoted our efforts to developing realistic and fair proposals on natural gas issues. We hope that our proposed compromise will be considered on its merits, and that it will eventually receive by-partisan support.

The enclosed position paper sets forth the reasons why we believe that immediate decontrol of independent producers is in the national interest.

We hope you find this information useful.

Cordially,

William E. Dutcher

William E. Dutcher
Executive Director

WED:ls

Enclosure - Membership List
Position Paper

cc: Honorable John Dingell
Mr. Bill Demarest

INDEPENDENT GAS PRODUCERS COMMITTEE

2601 NORTHWEST EXPRESSWAY, SUITE 300
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MEMBERSHIP LIST

May 18, 1977

Apache Corporation
Tulsa, Oklahoma

Allen Oil Corporation
Ringling, Oklahoma

Malouf Abraham Company, Inc.
Canadian, Texas

Wessely Energy Corporation
Dallas, Texas

French Oil Company
Midland, Texas

Amarex, Inc.
Oklahoma City, Oklahoma

Gasanadarko, Ltd.
Oklahoma City, Oklahoma

Grady H. Vaughn
Dallas, Texas

Natural Gas Finders, Inc.
Dallas, Texas

Inca Oil Company
Tulsa, Oklahoma

Pacific Oil and Gas
Oklahoma City, Oklahoma

E. R. Perkins
Wichita Falls, Texas

Mabee Petroleum Corp.
Tulsa, Oklahoma

H. L. Brown Company
Midland, Texas

Swan Petroleum Corporation
Oklahoma City, Oklahoma

Unit Drilling Company
Tulsa, Oklahoma

Pitts Oil Company
Dallas, Texas

Rutherford Oil Corporation
Houston, Texas

Permian Basin Group
Midland, Texas

John A. Taylor Petroleum
Oklahoma City, Oklahoma

Juniper Petroleum Corporation
Denver, Colorado

Maguire Oil Company
Dallas, Texas

The GHK Company
Oklahoma City, Oklahoma

Bell Petroleum Company
Encino, California

Cordele Operating Company
Corsicana, Texas

Ard Drilling
Midland, Texas

Western Oklahoma Royalty Owners
Sayre, Oklahoma

Service Drilling Company
Tulsa, Oklahoma

INDEPENDENT GAS PRODUCERS COMMITTEE

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OKLAHOMA CITY, OKLAHOMA 73112
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Position Paper
May 18, 1977

Why Exempt Independents?

The Arab oil embargo of 1973-74 shocked America's political leaders into an awareness of the interdependence of the world economy and the importance of petroleum to world trade. Therefore, our national energy policy cannot be isolated from the requirements of U. S. foreign policy and the realities of global political and economic systems.

The major multi-national oil companies have shifted most of their exploration efforts to foreign countries and to Alaska and offshore U.S., where their operations are necessarily intertwined with extensive governmental regulations, economic controls, foreign policy decisions and global politics. The multi-national majors have gradually evolved into quasi-utilities, heavily regulated by the governments of both energy exporting and importing nations around the world. The operations of the major oil companies both effect and are affected by policies of governmental bodies and international agencies (such as the International Energy Agency of the Organization for Economic Cooperation and Development.)

Under present world economic and political circumstances, continuation of natural gas price controls on the major, multinational, fully integrated oil companies is inevitable. The world in which the multi-national oil companies will in the near term conduct the bulk of their future exploration efforts is far removed from and very unlike the onshore continental United States, where mineral rights are private property, and where thousands of independent producers compete. If the United States is to maintain our free enterprise democracy, independents must move decisively to extract themselves from natural gas price controls. If independent producers, who are still operating in the free enterprise system, continue to hold out for decontrol of the entire industry, the result could be increased controls for the entire industry and another setback for the free enterprise system.

By concentrating on natural gas deregulation for independent producers, independents can avoid a host of inter-related multi-national company issues that have helped stop deregulation efforts in the past. These issues include vertical and horizontal divestiture, multi-national company relationships with OPEC, offshore leasing procedures, underdevelopment of discoveries on offshore federal lands, and windfall profits taxes.

Historically, but especially since the 1973-74 oil embargo, the federal government has enacted legislation and issued regulations designed to control the large multi-national companies. These laws and regulations have become so pervasive in the petroleum industry that large staffs of lawyers and accountants are needed to interpret and comply with them, tending to reduce competition and further concentrate the industry. The Carter energy plan escalates this trend toward more and more regulations to a new high. But what the government fails to realize is that the relative burden of coping with federal controls always falls more heavily on independent producers. The effect of the federal controls has been to create pressures for more and more concentration in the industry, at a time when many in Congress are concerned about this trend and have proposed vertical and horizontal divestiture as a remedy.

Public opinion polls indicate that the majority of Americans support free enterprise and want less government interferrence in their lives. However, the public also supports federal controls on the multi-national oil companies while we are in a seller's market for energy. These findings are not as contradictory as they might seem, when one recognizes that the public tends to equate free enterprise with small businesses and not with large international corporations.

Moving from 23 years of federal price controls to a free market for natural gas confronts national policy makers with a transition problem. This transition problem has both political and economic dimensions. The best way to begin this transition process is to immediately remove price controls on new onshore natural gas produced by independents. This action will stimulate competition by allowing independents to attract more risk capital for investing in their ongoing exploration programs.

Exempting independents from controls, while imposing realistic ceiling prices on the 18 major companies who accounted for 60% of the nation's natural gas production in 1975, will rapidly increase competition within the industry and will refocus U. S. resources on onshore areas where existing pipeline systems will allow new production to have an immediate impact on the nation's near-term energy supplies.

-2-

Mr. VLCEK. We have had a lot of testimony about the problems of the new gas definition. I want to ask you specifically what you think about this. I guess it is fair to say this is based on geography rather than having geological logic to it.

One of the arguments we received when we criticized a definition like this is, of course, there are the provisions of section 408, the special pricing provisions which will take care of any real problems.

Would you comment on section 408 as to why it will or will not serve to solve any difficulties that the arbitrary new gas definition would create?

Mr. JOHNSON. I, of course, don't know what is intended by the provision in this bill, but it has a very familiar ring. The Federal Power Commission has been offering the producers something called special relief from the price ceilings which are imposed by the Power Commission based on the average price system ever since the first *Permian* case back in 1965.

The trouble is that that is an illusion. The producers are offered this, but the burden of proof they have to put on to receive it is almost an impossible burden.

What the producer has to show is project costs or costs which apply to the particular category of gas for which he is seeking the special price. The trouble is, if this is required before he actually makes the investment, we are dealing with an uncertainty, an area of great uncertainty here, particularly as to the amount of reserves which will result from making that investment. You can make an estimate of that, but you have a Catch 22 situation because if your estimate is too low and you don't find as much reserves as you expected to find, then the result of that is that the producer is not going to have enough gas at that price to recover his costs.

On the other hand, if he finds more gas than he expected, then his price is too high and the Power Commission or in this case whatever regulatory authority ultimately administers the act would simply say, "Well, you didn't tell us correctly what your reserves were and they are more than you expected and therefore we are going to reduce your price back to what it was before."

The producer with this kind of experience is not going to base a great deal of reliance on this special provision.

I have read the bill very carefuly. I can't find anywhere in here the kind of procedure that is contemplated for obtaining this special price. I think that kind of uncertainty is going to make a producer hesitate a long time before he places any great reliance on this special provision.

Mr. VLCEK. I think in fact the bill addresses that implicitly by saying that they are going to provide for regulations to be written by the rule which I understand triggers the provisions of 553 of the Administrative Procedure Act which gets you in a procedure where you are going to have an informal procedure for the writing of rules. You will not have the automatic right for oral testimony and the cross-examination of the witnesses in a case-by-case determination necessarily.

Mr. JOHNSON. That is the way I read it, too. The administration has pretty much of a blank check to write whatever procedure in there they want to when the time comes.

Mr. VLCEK. Thank you, Mr. Chairman.

Mr. KRUEGER. The time of the gentleman has expired. We have another panel yet to come.

Recognizing that, I would simply ask one request of this panel before preparing for the next panel. There are a whole series of exceptions allowed under the Carter energy proposal and if that proposal were to become law and if these exceptions, particularly with regard to price, are to be under the purview of political appointees, is there in your judgment some enlarged opportunity for politics to enter into the whole pricing system?

Offhand, to me it seems like we would be establishing, among other things, an immense temptation, we might say, because it is more than simply the matter of apportioning government funds. What we are doing is saying, "Mr. A, we will allow you this price for your product and Mr. B, you will produce an identical product, but we will allow a higher price because we think as we look at this mysterious geology, that you deserve more."

To me that is to offer a great deal of temptation. I realize that most political figures are above temptation, but nevertheless I wonder if this panel would wish to comment on that.

Mr. FOSTER. I think you put your finger on one of the prime defects of this bill. We must have some certainty on which investment decisions can be placed. This bill offers complexities, confusion and vagueness in all of it. On top of that complexity and vagueness is a tremendous amount of political intrusion. That worries us. That doesn't provide certainty for investment decisions. It provides a prime opportunity for even further intrusion on an industry which is struggling to get back to health, not only for itself but for the entire economy.

Mr. KRUEGER. In the short run it might make more Democrats out of oil producers.

Mr. BROWN. I would like to ask consent that the record remain open for the possibility of written questions.

Mr. KRUEGER. Without objection it will be ordered that the record will remain open for the possibility of written questions to the panel and we will ask your assistance in response, if possible.

Mr. MOORE. I would like to develop a point you touched on and were not able to get completed.

Mr. KRUEGER. The gentleman from Louisiana is recognized for one minute.

Mr. MOORE. I thank the Chair.

As I understood the testimony a moment ago, we all agree, if I understood you correctly, that if we simply accept the President's plan, there will be no increased flow of natural gas in interstate commerce. I think all of you agree.

Mr. HEFNER. We all agree, very much so.

Mr. FOSTER. That is right.

Mr. MOORE. If we get down to the situation where we have decontrol, assuming that we could pass a decontrol bill and we decontrol and we get the specter of regulation and control out of it altogether and if as other witnesses have stated, that we increase our supply thereby by the increased supply and production, would you then find natural gas going into the interstate market?

Mr. JONES. I think so without exception.

Mr. DAVIS. Positively.

Mr. HEFNER. Yes, absolutely.

Mr. MOORE. Let the record show everybody was in the affirmative.

I thank the Chair.

Mr. KRUEGER. With that final note of concord, this panel is excused.

[The following letter and attachments were received for the record:]

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

1101 SIXTEENTH ST., N.W.
WASHINGTON, D. C. 20036
(202) 466-8240

OFFICE OF THE PRESIDENT
P. O. BOX 787
ALBANY, TEXAS 76430
(817) 762-3256

June 2, 1977

A. V. JONES, JR.
PRESIDENT

The Honorable John Dingell, Chairman
Energy and Power Subcommittee of the
House Interstate and Foreign Commerce Committee
U. S. House of Representatives
Washington, D.C. 20515

Dear Mr. Chairman:

At the time I appeared before your Committee on May 12, I indicated that I would submit additional material for the record relating to President Carter's National Energy Plan. Please find the following attached information for that purpose: (1) a 1975 "Review of Current United States Fossil Fuel Resources" by J. D. Parent and H. R. Linden of the Institute of Gas Technology, Chicago, Illinois, adopted as part of a 1976 report of the F.P.C., Study Subgroup on Gas Reserves and Resources Classification, National Gas Survey; and (2) supplements to my previous statement dealing with capital needs of our industry and the related impact on GNP and economic growth; and "Capabilities of the Petroleum Industry Infrastructures to Respond to Increased Oilfield Activity."

The Parent/Linden report includes a number of important factors which should be considered. In summary, it states:

> "Estimates of remaining economically recoverable oil and gas have come from many sources, varied widely, and have been a focus of controversy. This unsettled state does not apply to the proved reserves portion of the total remaining recoverable oil and gas.
>
> It can also be seen that the reported results have shown only limited agreement. This is hardly surprising, since widely differing mathematical and geological methods have been used, geographical coverage has not always been the same or complete, assumptions of what constitutes technical and economic feasibility of recovery have varied substantially (as indicated by different limits of drilling and offshore water depths and on ultimate recovery factors), and so forth.
>
> Two ambiguities of special importance are encountered. One relates to interchange of the terms oil, petroleum, crude oil and crude oil plus natural gas liquids. While the difference is not great, say 15 to 20 percent, it is an unnecessary cause of variation and uncertainty.

> An even more serious ambiguity in some of the published accounts of gas and oil resource data lies in what is reported as potential supply above and beyond proved reserves. Additional reserves of gas and oil may be found in the future in either known (old) fields, or in new fields. Reserve additions in known fields take the form of new reservoir discoveries as well as of extensions and revisions of known reservoirs.
>
> In summary, realization of the new, lower estimates of total remaining economically recoverable natural gas and crude oil resources - about 900 tcf and 150 billion bbl, respectively - would still provide sufficient lead time for an orderly transition to increased direct use of coal and to synthetic gaseous and liquid fuels produced from coal and oil shale. Further, the extent of these recent downward revisions may be substantially reduced by current and prospective changes in price-cost relationships and by improvements in technology. Moreover, the new estimates are large enough, even without upward adjustments, to permit substantial response of production rates to economic incentives during the critical years until the end of the century. Over the longer range, the lead time for conversion from a fossil-fuel-based economy to one based primarily on nuclear and solar energy seems adequate, even at substantial energy demand growth rates, if our abundant coal and oil shale resources are developed to their fullest extent. (Underlining added.)

I believe these statements and their accompanying charts make an undeniable case for the fact that decontrol of new natural gas prices would represent a needed sound investment by consumers in assuring economic and social stability now and in the future.

In addition, I would like to make a further case for decontrol. Last year, with our full support, the Congress decontrolled wellhead prices of stripper well crude oil. As an indication of producer response to incentives, I note the following results. Abandonments of producing stripper wells have declined sharply...44 percent in the three states which contain about one-half of all the stripper wells in the country--Texas, Louisiana, and Kansas. Total producing wells in the United States increased from 497,000 to 503,000 during 1976. Increased drilling was very significant, but the increase in the total is approximately the number of stripper wells estimated to have been saved from abandonment by the removal of price controls and resultant increase in economic life of many wells.

Equally important is that stripper well production now accounts for 16 percent of domestic oil production--up from 13 percent a year earlier--and stripper reserves are now estimated at 7.5 billion barrels--up from

5.8 billion in 1973. We believe decontrol of new natural gas will produce even greater results in providing additional reserves of fossil fuels.

Again, we direct your attention to the army of more than 10,000 independent oil and gas producers which is waiting to get on with the job. We believe we have good prospects. We have the tools, or could soon obtain them, to get on with the needed exploration and development. All that appears to be missing are the incentives needed to attract the capital required for the task. Removing price controls on new natural gas would provide a major key to providing those needed incentives.

Thank you for your consideration. Please call upon us for any assistance we can give as you move forward with the task before you.

Sincerely,

A. V. Jones Jr.

A. V. Jones, Jr.
President

ADDENDUM TO THE STATEMENT OF A. V. JONES, JR.
DELIVERED TO THE ENERGY AND POWER SUBCOMMITTEE OF THE HOUSE INTERSTATE AND FOREIGN COMMERCE COMMITTEE
MAY 12, 1977

REVIEW OF CURRENT UNITED STATES FOSSIL FUEL RESOURCES*

by
J. D. Parent and H. R. Linden
Institute of Gas Technology, Chicago, Illinois

In these times of ever-tightening domestic natural gas and crude oil supplies, increased attention is being given to the reliability of estimates of the total remaining economically recoverable resources of these fuels, that is, both proved reserves and potential additional supplies. Until their own recent modest revision, estimates of coal resources by the U.S. Geological Survey have remained quite stable over the years and have not been questioned by anyone. However, estimates of remaining economically recoverable oil and gas have come from many sources, varied widely, and have been a focus of controversy. This unsettled state does not apply to the proved reserves portion of the total remaining recoverable oil and gas. Estimates of proved reserves of these fuels, published annually by the American Gas Association and the American Petroleum Institute, have been validated within reasonable limits repeatedly, as in the case of the Federal Power Commission study of gas reserves and, most recently, by the Federal Energy Administration. The real issue has been the quantities of oil and gas economically recoverable in the future over and above proved reserves.

As shown in Tables 1 and 2, there has been no lack of quantity of independent estimates in recent years. It can also be seen that the reported results have shown only limited agreement. This is hardly surprising, since widely differing mathematical and geological methods have been used, geographical coverage has not always been the same or complete, assumptions of what constitutes technical and economic feasibility of recovery have varied substantially (as indicated by different limits on drilling and offshore water depths and on ultimate recovery factors), and so forth.

It has been difficult to make a fair comparison of these estimates, since full details of procedure and the data base are seldom published. Further, in published summaries of resource estimates, and sometimes in

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* This manuscript was published in its original form in Pipeline and Gas J. 202, No. 12, 60-62, 64-65 (1975) October. Subsequently, the U.S. Geological Survey released updated coal reserves in the revised bulletin noted in the first reference on page 14, necessitating changes in Table 3. Table 3 is as up-to-date as possible as of November 17, 1975.

Table 1.-ESTIMATES OF REMAINING RECOVERABLE U. S. NATURAL GAS RESOURCES AT YEAR-END,
Trillion cubic feet

Year End	Sources	Potential Supply: Old Fields	Potential Supply: New Fields	Proved Reserves (A.G.A.)	Total
1974	U. S. Geol. Survey (Miller, Thomsen, et al.)[a]	201.6	322-655	237.1	761-1094
	National Academy of Sciences	118.6 (calc.)[b]	530		886
	Moody[c]	65	485		787
	Average, Some Major Oil Cos. (Garrett)	100	500		837
1973	Mobil Oil (Moody & Geiger)	65	443	250.0	758
1972	U. S. Geol. Survey (McKelvey)[d]	130-250	1000-2000	266.0	1396-2516
	Potential Gas Committee[e]	266	880		1412
	IGT (Linden)	634 (old & new fields)			900
1971	U. S. Geol. Survey (Hubbert)[d]	130 (calc.)[f]	361[g]	279.0	770[h]
	IGT (Linden)	575-704 (old & new fields)			854-983

a. Based on 80 percent recovery and 660 ft water depth.
b. Calculated as half of the proved reserves.
c. Water depth to 6000 ft.
d. Water depth to 660 ft.
e. Water depth to 1,500 ft and drilling depth to 30,000 ft.
f. Calculated by subtracting the sum of the proved reserves and new field discoveries from the estimated remaining recoverable gas.
g. As given in U.S. Geological Survey Circular 725 for undiscovered gas.
h. Ultimate recoverable given as 1184 trillion cu ft for the total United States. Subtracting cumulative production as of year-end 1971 of 414 trillion cu ft gives 770 trillion cu ft remaining recoverable.

Table 2.-ESTIMATES OF REMAINING RECOVERABLE U.S. CRUDE OIL RESOURCES AT YEAR-END, Billion barrels

Year End	Source	Potential Supply: Old Fields	Potential Supply: New Fields	Proved Reserves,[a] (A.P.I.)	Total
1974	U.S. Geol. Survey (Miller, Thomsen, et al.)[b]	23.1	50-127	38.9	112-189
1974	National Academy of Sciences (Incl. natural gas liquids)	22.7 (calc.)[c]	105-120	45.3	173-188
1973	Mobil Oil Corporation (Moody and Geiger)[d]	11 (calc.)[e]	88[f]	40.4	139
1972	U.S. Geological Survey (Incl. natural gas liquids) (McKelvey)[h]	24-45[g]	200-400	48.3	272-493
1971	U.S. Geological Survey (Hubbert)[h]	18 (calc.)[i]	55[j]	43.0	116[k]
1970	U.S. Geological Survey (Incl. natural gas liquids) (Theobald, et al.)[l]	450 (old and new fields)		52.1	502
1970	National Petroleum Council	--	--	--	339[m]

a. Includes A.P.I. indicated additional reserves.
b. Based on 32 percent recovery and 660 ft water depth.
c. Calculated as half of the proved reserves.
d. Water depth to 6000 ft.
e. Proved plus potential in known fields given as 51 billion bbl.
f. Also reported as including natural gas liquids.
g. Listed as indicated-inferred reserves, although the reported proved reserves also includes the indicated reserves of 5.2 billion bbl.
h. Water depth to 660 ft.
i. Calculated by subtracting the sum of the proved reserves and new field discoveries from the estimated remaining recoverable oil.
j. As given in U.S. Geological Survey Circ. 725 for undiscovered crude oil.
k. Ultimate recoverable given as 213 billion bbl. Subtracting cumulative production as of year-end of 97 billion bbl gives 116 billion bbl remaining recoverable.
l. Water depth to 8200 ft.
m. Based on estimated oil in place and 60 percent recovery.

the original documents, two ambiguities of special importance are encountered. One relates to interchange of the terms oil, petroleum, crude oil and crude oil plus natural gas liquids. Frequently, estimates of total petroleum liquids, i.e., crude oil plus natural gas liquids, are reported as "crude oil" and vice versa. While the difference is not great, say 15 to 20 percent, it is an unnecessary cause of variation and uncertainty.

An even more serious ambiguity in some of the published accounts of gas and oil resource data lies in what is reported as potential supply above and beyond proved reserves. Additional reserves of gas and oil may be found in the future in either known (old) fields, or in new fields. Reserve additions in known fields take the form of new reservoir discoveries as well as of extensions and revisions of known reservoirs. The annual A.G.A. and API reports on reserves give data for each of these categories. Recent press reports, however, have generally related the potential supplies of gas and oil to new fields only, so the reader may not be aware of the potential supply expected to be developed in old fields. Even the source documents often do not clarify this point sufficiently. As a particular example, the National Academy of Sciences discusses both discovered and undiscovered gas and oil, but makes only a brief reference to the additional or inferred supply in known fields. Under the heading of "Total Discovered Reserves," the report states: "In addition to the proved reserves discussed above there is a sizeable increment of reserves that have been discovered but are not considered to be 'proved.' This increment, estimated to average 50 percent, is the difference between ultimate production actually obtainable from any given reservoir, and the proved reserves assigned to that reservoir at any given time." Presumably, this includes new reservoir discoveries in known fields as well as extensions and revisions.

A particular source of difficulty in the case of crude oil is that quite different ultimate recovery factors of oil in place may be used on the basis of expected economic and technical feasibility, and these factors are not always stated by the authors. In some cases, recovery is assumed to remain at the current average level of about 32 percent because the impact of post-embargo changes in oil prices, exploration and development costs, and tax and regulatory policies has not yet been fully assessed.

Returning to the general problem of disagreement among various investigators, the evolution of the current relatively low estimates is of interest. M. King Hubbert, one of the most active workers in this field, has relied on a mathematical approach, based largely on fitting historic production and discovery data to the logistic equation and evaluation of the decreasing finding rate per foot drilled. Even while with the U. S. Geological Survey in recent years, he has published estimates of potential oil and gas supplies which have been substantially lower than geologically-based estimates of the U.S.G.S. The conflict was heightened in 1974 when Moody and Geiger of Mobil Oil Corporation also published estimates which were considerably lower than those of the U.S.G.S. Because of the great importance of having reliable resource data in the formulation of national energy policy, the National Academy of Sciences agreed to consider the issues involved. The data and procedures used by the disagreeing agencies were reviewed and it was decided by the N.A.S. review panel that a major problem was that, up to that time, the U.S.G.S. had probably been crediting too much gas or oil per unit volume of rock to the unexplored prospective sediments. The N.A.S. panel then proceeded to give its own estimates based on the work of others.

Meanwhile, the U.S.G.S. had under way a new and more critical study. This resulted in publication of Geological Survey Circular 725 in June of 1975. This new study represents a review of pertinent geological and geophysical data relating to more than 100 different provinces by more than 70 specialists. Accordingly, the results can be expected to have considerable validity, even though proprietary data of petroleum producing companies were not used. An excellent feature of this new set of estimates for potential oil and gas supply is the use of 5 percent and 95 percent probability estimates, much as Moody and Geiger had done. Of considerable importance is the fact that the new estimates are considerably lower than those published earlier by U.S.G.S. (with the exception of Hubbert's) and are reasonably in accord with recent estimates by other agencies.

It is also important to note the points of economic cutoff used in Circular 725: "The estimates of undiscovered recoverable resources take into account relevant past history and experience and are based on assumptions that undiscovered recoverable resources will be found in the future under conditions represented by a continuation of price-cost relationships and technological trends generally prevailing in the recent years prior to 1974." However, rather than quote some particular level of price to cost relationship, the report actually used a recovery factor of 32 percent for that part of the undiscovered oil in place which was assumed to be economically recoverable; the comparable figure for gas was 80 percent. For that part of the undiscovered oil in place reported as subeconomic, the report used an additional 28 percent of the oil in place* (total of 60 percent for economic plus subeconomic) and an additional 10 percent of the gas in place for the subeconomic undiscovered gas.

Figure 1 is taken from Circular 725. It shows 322 to 655 Tcf of as-yet-undiscovered natural gas expected to be economically recoverable from new fields, and 201.6 Tcf as identified-inferred, i.e., additional gas expected to be found in known fields. The comparable figures for crude oil are 50 to 127 billion bbl and 23.1 billion bbl, respectively. It should be noted here again that most press reports of this study omitted reference to the additional (inferred) 201.6 Tcf of natural gas and 23.1 billion bbl of crude oil in known fields, thereby giving a much darker picture of remaining resources and heightening the appearance of disagreement with earlier estimates.

Press reports have also generally omitted any mention of the large quantities of "subeconomic" (on the basis of pre-embargo price-cost

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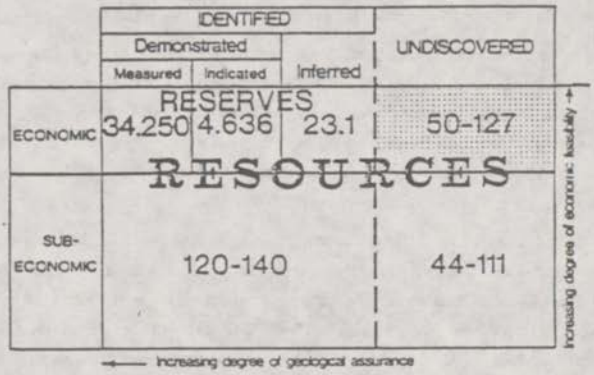
* Here, we use a term, oil in place, which, as far as we can determine, has never been precisely defined. Presumably, some point of cutoff is implied, so that deposits smaller than some reasonable limiting value are not considered. The character of the oil and reservoir rock are also taken into consideration, since extremely viscous oil and oil in very tight reservoirs are evaluated separately.

relationships) potential supplies. When th : total (identified and undiscovered) "subeconomic" natural gas resources of 1 0 to 197 Tcf are considered (see Figure 1), what appears in Table 1 to be a very substantial disagreement with the Potential Gas Committee es: mates (which include a large "speculative" component) may be narrowe . The same applies to the new U. S. G. S. oil values with respect to some of the older estimates. If the total 164 to 251 billion bbl of "subeconomi " crude oil is considered. The subeconomic potential gas and oil will be : least partially recoverable economically in the future, given sufficien economic incentive and appreciable technological development in : covery methods. It is stated in Circular 725 that: "The higher price-c st ratios existing in 1975, if they should continue or increase even high r, would likely increase estimates of both undiscovered recoverabl resources and reserves significantly — some economists think perh ps half again. This possible added potential is being considered in a fol ow-on study planned for completion within a year." A study of the ffect of price-cost ratios on potential supply would be of great value to e industry. Although increased recoveries are expected, it is stated that would be extremely optimistic to expect (ultimate) recovery of as much a 60 percent of the oil in place and that "if such is realized it is likely to cur only through a gradual development over an extended period of tim ."

Returning to Figure 1 for explanation of the quantities given for subeconomic undiscovered gas, in keeping ith the assumed possible increase from 80 to 90 percent recovery of he gas in place, we note that $\frac{10}{80}$ X (322 to 655 Tcf) = 40 to 82 Tcf. For c: de oil, the assumed possible increase from 32 to 60 percent recovery of he undiscovered oil in place corresponds to $\frac{28}{32}$ X (50 to 127 billion bbl) = 44 to 111 billion bbl. These are the numbers given in Figure 1.

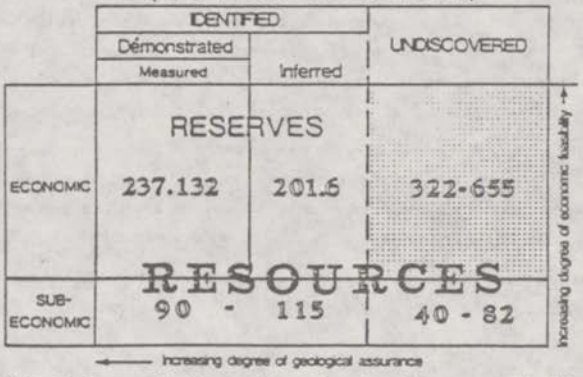
If one applies similar ratios to the sum of cumulative production plus measured (proved) reserves and to the sum of cumulative production plus measured and inferred reserves, estimates re obtained for the subeconomic identified (already known) recover ble resources. Thus, for

CRUDE OIL RESOURCES OF THE UNITED STATES
(BILLION BARRELS)



Total U.S. Cumulative Oil Production 106 Billion Barrels
12/31/74

NATURAL GAS RESOURCES OF THE UNITED STATES
(TRILLION CUBIC FEET)



Total U.S. Cumulative Gas Production 481 Trillion
Cu Ft 12/31/74

Figure 1.-From U.S. Geological Survey Circular 725.

92-911 O - 77 - 27

gas, $\frac{10}{80}$ X (480 +237 Tcf) = 90 Tcf, and $\frac{10}{80}$ X(480 + 237 + 202) = 115 Tcf. This,again,agrees with the numbers shown in Figure 1. Similar computations can be made for crude oil which also check with the data of Figure 1 quite well.

An interesting final point with respect to Figure 1 is the use of Hubbert's α factors to calculate the identified-inferred recoverable resources. This is one of the several methods which have been published for accounting for the expected rate of growth of new discoveries attributed initially to a given year, i.e., how subsequent drilling and testing adds to the original estimates.

The periodic Potential Gas Committee estimates also deserve particular attention, because of the sponsorship (American Gas Association, American Petroleum Institute and Interstate Gas Association of America) and the expertise of the members. The PGC estimates as of year-end 1972 are rather high relative to more recent estimates by others. However, they must be given considerable weight,because they represent the work of regional committees of highly qualified oil and gas industry personnel who have had access to producing company proprietary information. It is not known at this time if and when PGC will update its last estimates, or how they would be affected by the developments already discussed. In any event, with recent estimates converging to reasonable agreement, the reduced level of expected potential supplies with respect to earlier more generous estimates must be accounted for in realistic planning and policy making by the oil and gas industries and governmental agencies.

The various estimates which have been reviewed have been taken into consideration in preparing Table 3, which shows IGT estimates of remaining recoverable fossil fuel resources in both conventional and common energy units. The very recent revision of U.S. coal resources is included.

Supply estimates are most meaningful when considered in relation to present and anticipated future annual production and consumption. For

Table 3 - U.S. FOSSIL FUEL RESOURCES AS OF DEC. 31, 1974

	Proved and Currently Recoverable		Estimated Remaining Recoverable	
Dry Natural Gas				
Trillion (10^{12}) cu ft	237[a]		900-1375[b]	
10^{18} Btu		0.24		0.93-1.42
Natural Gas Liquids				
Billion (10^{9}) bbl	6.4[a]		24-36[c]	
10^{18} Btu		0.03		0.10-0.15
Crude Oil				
Billion (10^{9}) bbl	34.3[a]		150-380[d]	
10^{18} Btu		0.20		0.87-2.20
Coal				
Billion (10^{9}) short tons	216[e]		1038-1790[f]	
10^{18} Btu		4.75		20.76-35.80
Shale Oil				
Billion (10^{9}) bbl	74[g]		1026[h]	
10^{18} Btu		0.43		5.95
Bitumens				
Billion (10^{9}) bbl	2.5[i]		15[i]	
10^{18} Btu		0.01		0.09
Total, 10^{18} Btu		5.66		28.70-45.61

a) "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1974." Vol. 29, published jointly by American Gas Association, American Petroleum Institute, and Canadian Petroleum Association, 1975. Includes 3.9 trillion cu ft of gas in storage.

b) The higher figure is based on the potential natural gas supply of 1146 trillion cu ft given in "Potential Supply of Natural Gas in the United States as of December 31, 1972," prepared by Potential Gas Committee, Sponsored by Potential Gas Agency, Mineral Resources Institute, Colorado School of Mines Foundation, Inc., Golden, Colo., Nov., 1973; and proved reserves of 237 trillion cu ft including gas in storage as of Dec. 31, 1973. The PGC estimate of 1146 Tcf potential was decreased to 1138 as of Dec. 31, 1974 to allow for discoveries in new fields and reservoirs totaling 8 Tcf during 1973 and 1974. The lower figure is a rounded value based on the potential reserves as estimated by the U.S. Geological Survey as of Dec. 31, 1974 (Geol. Survey Circ. 725), the estimate of the National Academy of Sciences given in "Mineral Resources and the Environment" (N.A.S., 1975) and estimates of several major oil companies as reported by Garrett at the June 1975 A.G.A. Executive Conference.

Note-Heating values used in the calculation of heat energy content of fossil fuel resources were: 1031 Btu/cu ft for dry natural gas; 4.1 million Btu/bbl for natural gas liquids; 5.8 million Btu/bbl for crude oil, shale oil and bitumens; and 20 million Btu/ton for coal (incompletely specified mixture of anthracite, bituminous and sub-bituminous coal, and lignite); and 22 million Btu/ton for the higher average rank proved coal reserves.

Table 3, Continued

c) Based on 900-1375 trillion cu ft estimated total remaining recoverable natural gas and the average ratio of the reserves of natural gas liquids to natural gas given in the reference listed in (a) for 1950-1974. The ratio is 26.27 bbl per million cu ft.

d) The higher figure is based on 810.4 billion bbl of original oil-in-place as given in "U.S. Energy Outlook, A Report of the National Petroleum Council's Committee on U.S. Energy Outlook," Washington, D. C., December 1972, an ultimate recovery of 60 percent as suggested in "Future Petroleum Provinces of the United States," National Petroleum Council, Washington, D. C., July 1970, and cumulative production of 106.1 billion bbl through 1974 as stated in the reference listed in (a). The lower figure is a rounded value based on the potential reserves as estimated by the U.S. Geological Survey as of Dec. 31, 1974 (Geol. Survey Circ. 725), the estimate of the National Academy of Sciences given in "Mineral Resources and the Environment" (N.A.S., 1975) and the estimate of the Mobil Oil Corp. as published by Moody & Geiger in Technology Review, p. 39, March/April 1975. These estimates include 4.6 billion bbl indicated additional reserves as given by API.

e) Based on a demonstrated reserve base of 434 billion short tons of economically mineable coal as given by the U.S. Bureau of Mines in "Demonstrated Coal Reserve Base of the United States on January 1, 1974," U.S. Dept. Int., June 1974. Recovery factor of 50 percent assumed.

f) The lower figure (1038) is as given in Geol. Survey Bull. 1412. It excludes thin beds (14-28 inches thick for anthracite and bituminous coal and 2.5-5 ft thick for sub-bituminous coal and lignite) from the new total of identified coal (1731 billion tons) plus hypothetical coal (1849 billion tons)to a maximum overburden of 3,000 ft. The higher number includes the thin beds on the assumption that they may be economically recoverable in the future (not immediate). In both cases, 50 percent mining recovery is assumed, and allowance is made for 1974 production (U.S. Bureau of Mines, Mineral Industry Surveys, Weekly Coal Report No. 3005, April 18, 1975).

g) Based on only the most accessible and better defined oil shale deposits in the Green River formation in the Uintah and Piceance basins of Colorado and Utah at least 30 feet thick and averaging 30 gallons of oil per ton by Fischer assay as given in the first reference cited in (d) and assuming 60 percent recovery of shale in the mineable seam and oil recovery corresponding to 96 volume percent of Fischer assay.

h) Based on the total quantity of oil shale resources in the Green River formation ranging down to 15 gallons of oil per ton by Fischer assay as estimated in the first reference cited in (d) and assuming 60 percent recovery of shale in the mineable seam and oil recovery corresponding to 96 volume percent of Fischer assay.

i) Averitt, P., "Coal Resources of the United States, January 1, 1974, "U.S. Geol. Survey Bull. 1412, U.S. Govt. Print. Office, Washington, D.C., 1975.

evaluation of the adequacy of supply over the intermediate and long range, it is desirable to consider all of the fossil fuels collectively. The static (zero growth) life index at the current annual production rate of fossil fuels (currently oil, gas and coal) amounts to 100 years in terms of proved reserves and to 508 to 807 years in terms of the estimated remaining recoverable resources of oil, gas, coal, shale oil and bitumens.

Zero growth is not only undesirable but unlikely, since energy consumption has for many years paralleled GNP. If we calculate dynamic life indexes based on fixed percent per year growth rates and a requirement that reserves at each year-end equal ten times the annual production rate during that year, we obtain the following effective life estimates: At a growth rate of total fossil fuel production of 2 percent per year, proved reserves would be reduced to a 10-year life span in 46 years and the midrange of total remaining resources in 124 years. At a growth rate of 3 percent per year, proved reserves would reach this point in 38 years, and the midrange of total remaining resources in 93 years. At a growth rate of 4 percent per year, proved reserves would last in the same sense for 32 years, and the midrange of total remaining resources for only 75 years.

If the United States were to be self-sufficient in fossil fuels, i.e., if there were to be zero net imports of fossil fuels, and if annual consumption increased 2 percent per year with respect to the 1974 level, proved fossil fuel reserves, with a 10-year supply remaining, would last 39 years, and the midrange of total remaining fossil fuel resources would last 115 years. At a growth rate of 3 percent per year, proved reserves would last 31 years, and total remaining resources (midrange) would last 87 years. At a growth rate of 4 percent per year, these figures would be reduced to 28 years and 70 years, respectively.

In summary, realization of the new, lower estimates of total remaining economically recoverable natural gas and crude oil resources — about 900 Tcf and 150 billion bbl, respectively — would still provide sufficient lead time for an orderly transition to increased direct use of coal and to synthetic gaseous

ADDENDUM TO THE STATEMENT OF A. V. JONES, JR.
DELIVERED TO THE ENERGY AND POWER SUBCOMMITTEE
OF THE HOUSE INTERSTATE AND FOREIGN COMMERCE COMMITTEE
MAY 12, 1977

The 94th Congress removed more than $5 billion yearly in capital from the domestic petroleum industry by tax changes in percentage depletion which were directed only at oil and gas among more than 100 extractive industries and through crude oil price rollbacks under the Energy Policy and Conservation Act. Independent producers were hit particularly hard when intangible drilling costs (IDC) were subjected to the minimum tax.

Furthermore, the Administration's proposal does not recognize the enormous cash flow and capital requirements that the domestic industry must be able to generate if it is to make the contribution it can and should make to the nation's energy supply position. Since the 1973 embargo, dozens of analyses of domestic petroleum capital requirements have been made and widely reported - by financial as well as academic institutions. By any such estimates that I have seen, the domestic industry would be incapable of generating future capital needs under the Administration proposal for permanent, rigid price regimentation for both oil and gas.

The Chase Manhattan Bank has estimated capital needs to maximize domestic petroleum supplies. The Bank's December 1976 report on capital needs estimated oil and gas investments for domestic exploration and development at $265 billion (current dollars, assuming 10% inflation) in the 10 years ending 1985. (See chart: Expenditures - U.S. Exploration and Development) This is more than four times the actual investment in each of the two preceding decades. This report stresses that its projections assume adequate incentives for the private investor who requires a return on investment commensurate with the risk involved.

In the face of these capital requirements, the President in a recent press conference acknowledged that so-called "old" domestic crude oil, representing half of our production, and I quote, "is sold at a price of which is very low - an artificially low - price." Dr. Schlesinger, in a recent appearance on television, stated, "right now prices are far below the replacement costs of energy, oil and gas notably."

Having acknowledged that the industry is selling its product below replacement cost, the Administration now proposed to Congress that it enact a price control, taxing and regulatory scheme which will force the industry permanently to price its products at the wellhead below the cost of replacing those products. No other industry in America is expected, much less compelled by government, to sell its products below the acknowledged cost of replacement. The Administration proposal would place the petroleum industry permanently outside of the mainstream of the economy.

The Administration's pricing proposal simply ignores the industry's capital needs with the declaration that (and I quote), "Higher costs (prices) do not yield more oil and gas." There is nothing in our historical experience that substantiates such a conclusion. The only way to find and produce more oil and gas is to drill more wells. The level of drilling always has been and always will be determined by price. I call your attention to the chart, "U.S. Oil and Gas Prices vs. Drilling Expenditures," which shows the distinct relationship between prices and drilling expenditures for a 15-year period. For each 10¢ change in the per barrel price of domestic petroleum throughout this period, there has been a change of $120 million in drilling expenditures.

It is submitted that an energy policy based on the conclusions that increased price will not solicit additional supplies is contrary to the national interest. For the next decade or more, this requires maximizing the exploration for and

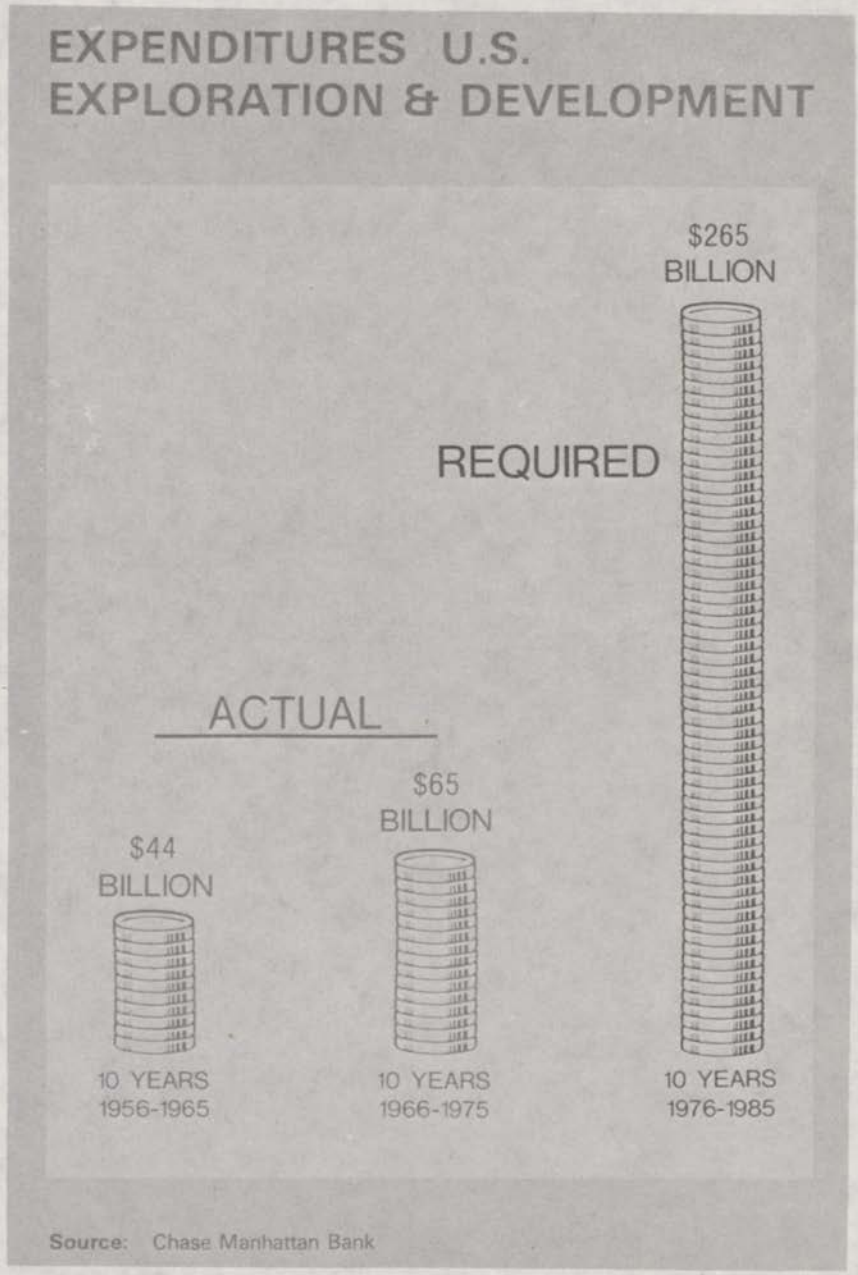
development of oil and gas. If this is to be achieved, the Congress must reject the "can't do it" approach of the Administration.

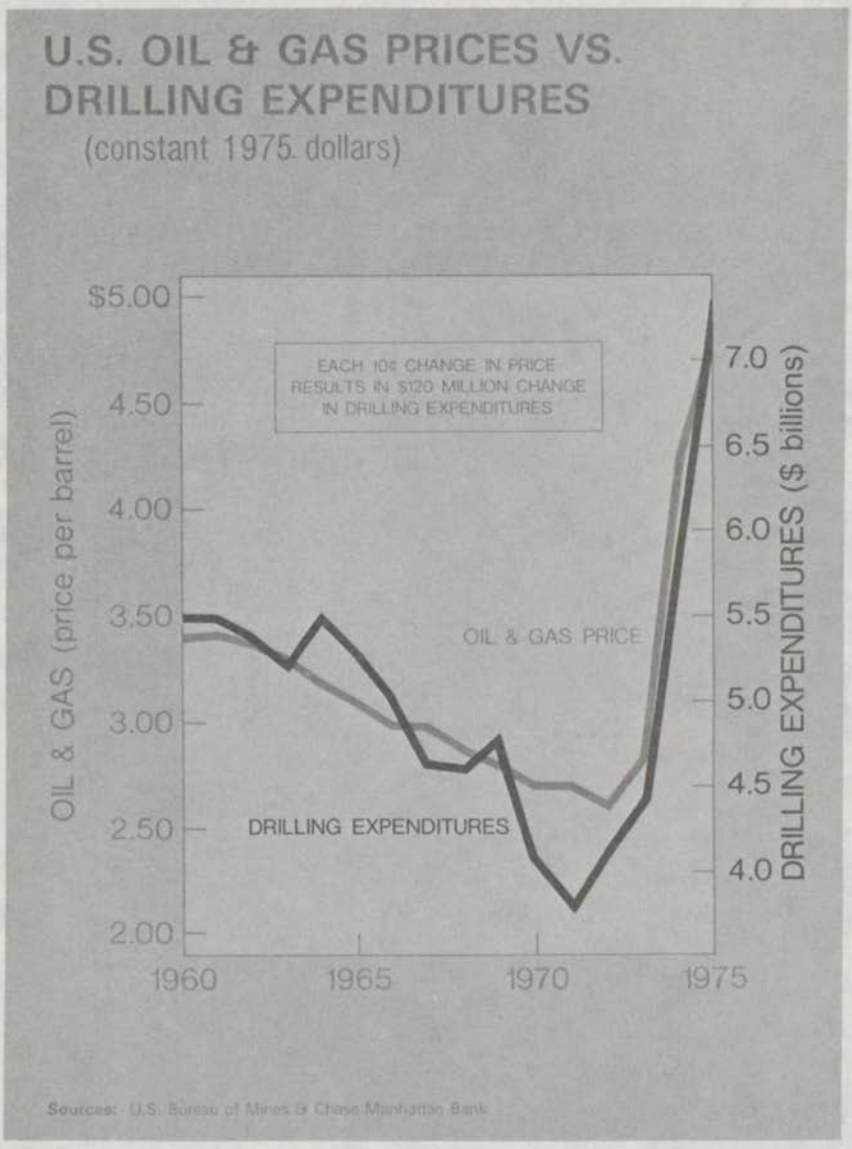
What are the implications and potential dangers to our economy of discouraging oil and gas exploration and development? Here again, the Administration energy advisers have attempted to justify their recommendations with totally unsubstantiated assumptions and premises. They contend that reduced energy growth is, "fully compatible with economic growth, development of new industries, and the creation of new jobs." Contrary to all past experience, they state flatly that, "there is no fixed relationship between energy and GNP."

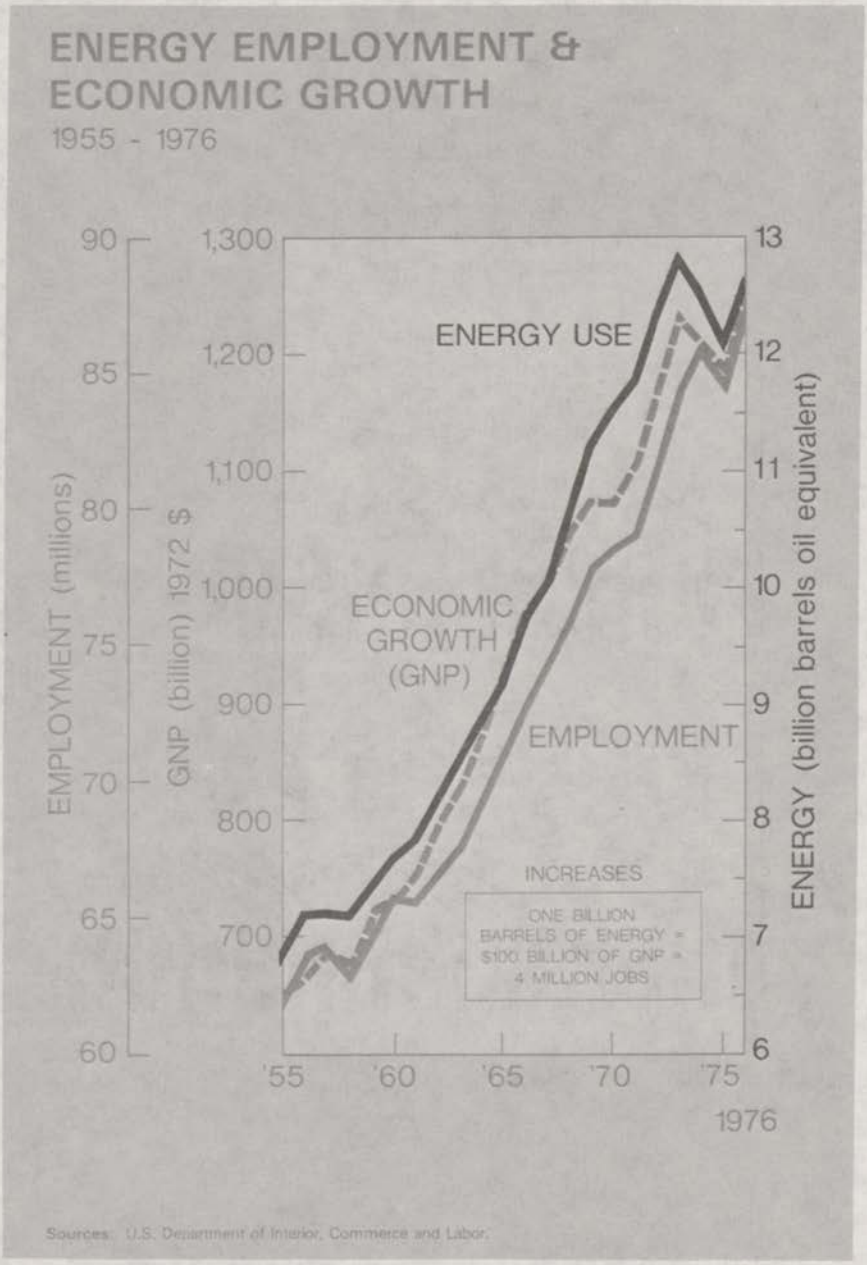
I call attention to the chart, "Energy, Employment and Economic Growth" which covers 20 years of experience that refutes this contention of the White House energy staff. As can be seen, energy consumption, GNP and employment throughout this period have been mirror images of each other. In fact, energy consumption equivalent to one billion barrels of oil consistently has been accompanied by $100 billion in GNP and four million jobs.

What about employment in the future? I would call your attention to the next chart which shows the Department of Labor's projections showing that our economy must accommodate 104 million working Americans by 1985. This work force would generate a 1985 GNP of $1,850 billion in 1972 dollars. Based on past experience, this expansion in economic growth will require an increase in energy use of about 50 percent.

President Carter deserves credit for focusing the attention of the people of this country on the seriousness of the energy situation. Independent producers have been trying to do this for more than 20 years. We can produce more crude oil and natural gas, but we are far behind in facing up to the realities of that critical need. The President's energy plan fails to deal with the fundamental problem of increasing domestic oil and natural gas supplies in the next decade or so. It is totally unrealistic to assume that we can "conserve" our way out of our energy dilemma. That we must utilize energy more efficiently is evident, but we must also produce more energy to solve the problem.


EXPENDITURES U.S.
EXPLORATION & DEVELOPMENT
$265
BILLION
REQUIRED
ACTUAL
$65
BILLION
$44
BILLION
10 YEARS
1956-1965
10 YEARS
1966-1975
10 YEARS
1976-1985
Source: Chase Manhattan Bank

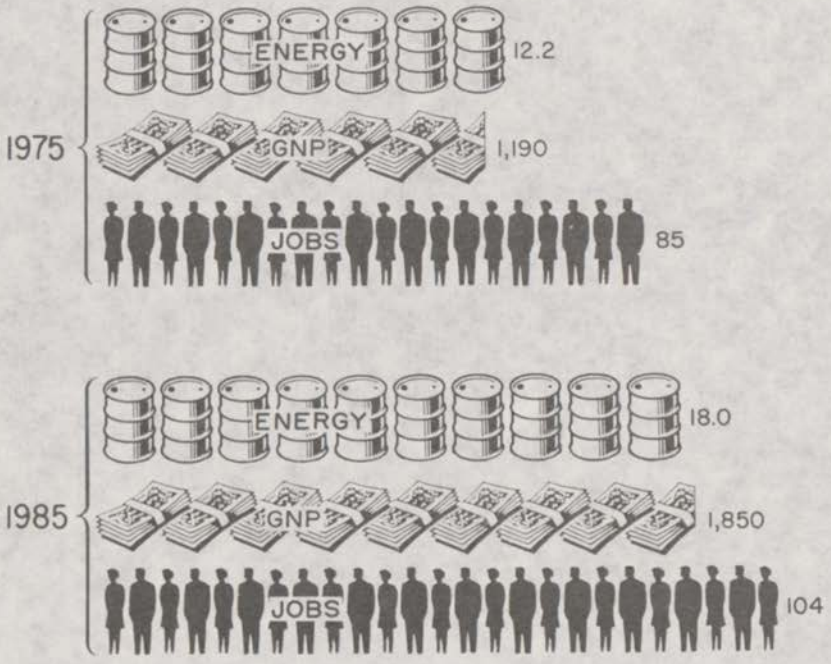

U.S. OIL & GAS PRICES VS.
DRILLING EXPENDITURES
(constant 1975 dollars)
$5.00
4.50
4.00
3.50
3.00
2.50
2.00
OIL & GAS (price per barrel)
EACH 10¢ CHANGE IN PRICE
RESULTS IN $120 MILLION CHANGE
IN DRILLING EXPENDITURES
OIL & GAS PRICE
DRILLING EXPENDITURES
7.0
6.5
6.0
5.5
5.0
4.5
4.0
DRILLING EXPENDITURES ($ billions)
1960
1965
1970
1975
Sources: U.S. Bureau of Mines & Chase Manhattan Bank


ENERGY EMPLOYMENT &
ECONOMIC GROWTH
1955 - 1976
EMPLOYMENT (millions)
GNP (billion) 1972 $
ENERGY (billion barrels oil equivalent)
90
85
80
75
70
65
60
1,300
1,200
1,100
1,000
900
800
700
13
12
11
10
9
8
7
6
ENERGY USE
ECONOMIC GROWTH (GNP)
EMPLOYMENT
INCREASES
ONE BILLION BARRELS OF ENERGY = $100 BILLION OF GNP = 4 MILLION JOBS
'55
'60
'65
'70
'75
1976
Sources: U.S. Department of Interior, Commerce and Labor.

ENERGY EMPLOYMENT & ECONOMIC GROWTH

1975-1985

Energy in billion barrels of oil equivalent
Employment in millions of jobs
Economic growth in billion $ of GNP



Sources: U.S. Department of Interior, Commerce and Labor.

IPAA Chart - Feb. 1977

ADDENDUM TO THE STATEMENT OF A. V. JONES, JR.
DELIVERED TO THE ENERGY AND POWER SUBCOMMITTEE
OF THE HOUSE INTERSTATE AND FOREIGN COMMERCE COMMITTEE
MAY 12, 1977

CAPABILITIES OF THE PETROLEUM INDUSTRY INFRASTRUCTURE TO RESPOND TO INCREASED OILFIELD ACTIVITY

The cornerstone of President Carter's energy plan as it relates to domestic crude oil and natural gas production is an unrealistically pessimistic appraisal by the President and his advisors of the potential crude oil and natural gas resources in the United States and the ability of the petroleum industry and its support industries to respond to greater incentives to increase their activities. However, as yet a substantial case to back up the validity of these presumptions has not been made - and for good reason. In fact, the opposite is true.

The American petroleum industry has been abandoned by the Administration without a trial and, operating under an insidious system of federal controls, has been judged as unable to respond to the energy challenge.

The American people have tremendous ingenuity. American industry can respond to this challenge if not arbitrarily throttled by regulatory fiat. The capabilities of our American system of free enterprise should not be underestimated.

The attached chart entitled "U.S. Oil & Gas Prices vs. Drilling Expenditures" demonstrates a close historical relationship between the combined price of crude oil and natural gas and drilling expenditures by the domestic petroleum industry. There is no reason to believe that relationship will cease to exist.

In response to a request from the Secretary of Interior, the National Petroleum Council (NPC) issued in September 1974 a report on Availability of Materials, Manpower, and Equipment for the Exploration, Drilling and Production of Oil - 1974-1976. In that report the NPC concluded that "Over the long term, drilling

rig availability will most likely be the primary restraining influence on increase drilling activity." The report went on to say that it believed that rig level could reach 2,400 rigs in 1980 and about 2,900 workable rigs by 1985. Even though the NPC noted that these were "ambitious" levels of drilling activity, NPC's estimates have proven thus far to be low estimates as can be seen in the following table.

TOTAL U.S. RIG ACTIVITY - 1973-1976

	1973	1974	1975	1976
Rotary Rigs Running (Actual)[1]	1,194	1,475	1,660	1,557
" " " " (NPC Estimates)[1]	1,194	1,440	1,480	1,520
Total Rotary Rigs[2]	1,763	1,894	2,028	2,204
Stacked Rigs[2]	294	125	151	225
Active Rigs[2]	1,473	1,769	1,877	1,979

Sources: 1)Hughes Tool Company - Rotary Rigs Running
2)Reed Roller Bit Survey - Total Rotary Rigs, Stacked Rigs, and Active Rigs as of Mid-August

Rotary rigs running went from 1,194 in 1973 to 1,660 in 1975 compared to the National Petroleum Council estimate of only 1,480 in 1975. Even the experts from the petroleum industry itself had underestimated the capability of the drilling industry by almost 200 rigs.

Unfortunately, last year's activity suffered after the enactment of the Tax Reduction Act of 1975, the Energy Policy and Conservation Act which rolled back crude oil prices, and the Tax Reform Act of 1976 which imposed additional tax burdens on independent drillers; and drilling averaged only 1,557 rigs running, which was still much higher than the NPC projection of only 1,520 rigs.

Almost 200 rigs had been added to the total rigs available in 1976 for a grand total of 2,204 - but those rigs were underutilized. Even with today's current rig activity of 1,998 rigs, there are at least 200 rigs which are stacked.

Energy "experts" in the Carter Administration have made some specious arguments about limited resource inputs such as rigs. They argue that as industry revenu increase, an increasing amount of capital ends up chasing a fixed amount of equipment and the cost of these fixed resources is bid-up. They say this results in an oil industry cost inflation in excess of the general economy's inflation rate, but does not result in production of any more energy. Nothing can be farther from the truth! The oil industry infrastructure, particularly manufacturers of tubular goods, is retooling after 20 years of declining activity in the late 1950's through the 1960's and into the early 1970's during the Cost of Living Council's price controls. Clearly the economicclimate during this period discouraged commitments of capital by these industries.

A similiar situation occurred when the country was confronted with an oil shorta following World War II as a result of wartime price controls and shortages of materia Substantial price increases occurred in 1947 and 1948. As a result, expenditures for exploration and development were encouraged greatly and domestic supply was increased so that shortages were overcome. Obviously, the petroleum industry infrastructure was also making significant capital commitments in order for the total number of wells drilled to almost double in only 10 years to its peak activity in 1955 when 2,586 rigs were operating. Significant capital expenditures must be made. The signal to make those expenditures will be increased profitability and longer term certainty.

In testimony before the Energy and Power Subcommittee of the House Committee on Interstate and Foreign Commerce on March 25, 1977, James F. Justiss, Jr.,

President-elect of the International Association of Drilling Contractors (IADC) (statement attached), said, "There is no doubt that the contract drilling industry can and will meet the challenge of a substantial increase in levels of on-shore and off-shore drilling."

Also, in testimony before the Energy and Power Subcommittee, George A. Helland Jr., President of the Petroleum Equipment Suppliers Association (PESA) (statement attached), testified that plant capacity currently exists to produce 779 drilling rigs and 12 million feet of jointed drill pipe this year and due to increased capacity could produce 1,057 additional drilling rigs and 18 million feet of drill pipe next year if required.

He further stated that "we, the manufacturers have invested more than $1 billion in the past five years to expand our plant capacity. Additional expansion is planned by some of our member companies if, and when, economic forecast and political realities show that such massive investment in equipment will be met with increased petroleum equipment orders."

PESA is made up of 174 U.S. companies which manufacture petroleum equipment and provide services and supplies to the exploration, drilling and producing segments of the energy industry. Members of that association supply approximately 85% of the petroleum equipment used to develop and produce oil and gas reserves in the United States.

The Commerce Department has reported that employment in the petroleum equipment supply industry has increased from 25,000 in 1973 to 62,500 in 1977. Obviously, this expansion of activity was in anticipation of increased demand for petroleum equipment. However, Mr. Hellend noted, "We expanded our facilities and hired

and trained new employees, only to find that the energy industry could not sustain, under the present political atmosphere, such rapid growth in search for energy. The result was a slack in the petroleum equipment business. Many major oil tool manufacturers have had lay-offs. But the productive capacity is available to produce any anticipated requirements as our survey shows.

SUMMARY:

At this time the petroleum industry and the infrastructure industries in the petroleum industry are looking for a clear signal from the federal government that there should be all-out expansion of efforts to provide energy from domestic energy sources to the consumers of America. If this signal is given we can expect technological advances and innovations that outrun man's capability to assess within the confines of existing limited knowledge.

Individuals considering professional careers in the petroleum industry, steel companies, manufacturers of tubular goods, well servicing contractors, as well as rig manufactures are looking for signs that the federal government desires them to expand their services. The Carter Administration runs the risk of self-prophecy; its pessimistic assessment of potential oil and gas resources and the ability of private enterprise to cope with our energy problems may become a reality if the federal government artificially limits incentives.

Mr. KRUEGER. The next witness before the committee is Mr. Harry C. Kent, representing the Potential Gas Supply Committee, Colorado School of Mines.

Mr. Kent, we have a full statement from you which will be included in the record. I would invite you at this time to summarize your testimony for us, if you could, and then we would like to ask you some questions.

STATEMENT OF HARRY C. KENT, DIRECTOR, POTENTIAL GAS AGENCY, COLORADO SCHOOL OF MINES

Mr. KENT. Thank you very much, Mr. Chairman.

My name is Harry Kent. I am a professor of geology and director of the Potential Gas Agency at the Colorado School of Mines. I have been teaching at the School of Mines for 21 years in the geology department and joined the Potential Gas Agency as director in April of 1976.

What I would like to address this afternoon is the question of the resource base, or the remaining undiscovered potential, for natural gas in the United States. This report is based on the work of the Potential Gas Committee and it is a function of my office, the Potential Gas Agency, to guide and assist that committee in its task of preparing estimates.

Again, this is of the undiscovered potential supply of the United States.

We have just completed our study for the end of the year 1976. So the figures I wanted to give you are our latest estimates as of the end of last year.

As we look at the Potential Gas Committee, we are looking at a group of about 150 individuals. They represent a fairly broad spectrum of the natural gas industry, both large and small producing companies, distributors and pipeline companies, members from academic institutions, State geological surveys and observers from Federal agencies. Each of the members contributes his services, or his company does, to the committee.

The estimates I am about to give you are what we consider a most likely or mean value. They do not have a range of probability as some other estimates, but simply represent the consensus of the committee.

I would also emphasize that the estimates are geological. They are not related to economics in the sense of any specific price for natural gas. We believe that this gas occurs in a situation where in the geologist's estimation, it is reasonable to assume that it could be recovered if there is reasonable economic incentive.

We also are looking at things which are recoverable under present technological conditions or within reasonable developments of technology. So the committee has excluded gas which occurs in ultra-deep areas such as below 30,000 feet or in offshore areas in water depths greater than 1,500 feet.

These are not considered in the report.

We also have not included other more nonconventional sources such as the low permeability reservoirs of the Rocky Mountains or from gaseous coal seams, shales or geopressurized reservoirs.

So I would emphasize this is a series of estimates of what we would consider conventional supplies.

As of last December 31st, the Potential Gas Committee estimates that there still remained 215 trillion cubic feet of natural gas, in addition to the proved reserves in the probable category. This category refers to the growth of known gas fields and for new pools to be developed by further exploration within existing fields.

This is the category for which we have the best geologic control and hence this estimate is the most certain of the three categories.

The committee further estimates that there are an additional 363 trillion cubic feet of natural gas in the possible category. The possible category includes gas which would be developed from further exploration in provinces which are already productive but beyond the limits of known existing fields.

Furthermore, there are an estimated additional 345 to 395 trillion cubic feet of speculative natural gas which we expect to be found in exploration of formations and provinces which are not currently productive.

The latter category, speculative, obviously consists of the areas for which we have the least geologic knowledge, such as offshore, or the deep portions of some basins and this is geologically the least certain amount.

Mr. MOORE. Excuse me one moment. I find his testimony most interesting. He has referred to the proven reserves. Can you tell us what they are?

Mr. KENT. Our committee does not get involved with that. We take the estimates of the Committee on Natural Reserves of the AGA which are about 216 cubic feet at the end of 1976.

Mr. BROWN. Does that square with USGS?

Mr. KENT. They have not gotten into the area of proved reserves, to the best of my knowledge. In their last report, circular 725 of 1975, they accepted the Committee on Natural Gas Reserves' figures for that year also.

Mr. MOORE. Mr. Chairman, if I might, we have a chart in the record that shows that they have and they estimate 228 as of 1976.

Mr. KENT. Again, that would be the Committee on Natural Gas Reserves' figure for the end of the year 1975. So those figures are the same.

Mr. MOORE. National Academy of Sciences, Potential Gas Committee, USGS?

Mr. KENT. Yes.

While emphasizing the differences in these three categories, because there is certainly difference in the geologic knowledge of the categories, this would mean the Potential Gas Committee would say we have about 923 to an upper range of 973 trillion cubic feet of undiscovered potential supply which is not too far from the figure which was expressed here earlier today of about 1,000 trillion cubic feet, and certainly if we add proved reserves, it would be well within that.

Now I have attached to my testimony a copy of the news release which we have just issued which summarizes this information in more detail. To put it in some other comparisons, I would say the probable category, that is related to existing fields, includes a volume which is about equal to the present estimate of proved reserves, an additional volume about equal to that. Each of the volumes in the other two categories is more than 1½ times the amount of proven reserves.

If we add together the total potential, we would have about 4½ times the amount of proved reserves still to be discovered or about twice the cumulative production in the United States to date.

In other words, if we look ahead at the future, we can find and produce probably twice as much as we have produced in all the history of the United States up to the present day.

We have looked also at the problem of how credible are these figures, how do they compare with the work of other people. We have recently completed a study by a subcommittee of ours which was trying to compare the estimates which have been presented by a number of different people in industry, government, scientific groups and so forth in recent years.

We find that one of the greatest points of confusion is differences in terminology, differences in definition, what one man is talking about is not the same as what one other is.

So we have tried to point all estimates out on a comparable basis.

I have prepared a couple of charts I will refer to. I had hoped to have a copy of this report ready for you this afternoon; however, it is still on its way from the printer.

I will make it available to the committee and would like to have that as part of my testimony as the second exhibit.

Mr. KRUEGER. Without objection, it is so ordered.

Mr. KENT. The summary of this comparison study is that there is considerable uniformity in recent estimates, and what we are saying is that there is an undiscovered potential supply which is on the order of one to one-and-a-half times as large as the previously discovered volume.

That is, we look at the present total of cumulative production as at the end of 1976, plus the estimate of proved reserves at the end of 1976, and that total is 731 trillion cubic feet.

That means that our committee feels, and this is a consensus of other people working in the same area, that there is on the order of 700 to 1,200 trillion cubic feet in addition to the 731 which can still be discovered.

If I may, I will point this out briefly on the charts. Each of these separate bars represents a different study by a different organization or oil company; this is Mobil; here is an estimate by Institute of Gas Technology, and so forth. Some of them have given us maximum/minimum values and mean values, and, therefore, there is more than one bar for each of those.

If we look at the mean here, we are going to come out somewhere in this order for mean value; that is, somewhere between 500 and 1,000 trillion cubic feet is a fairly good figure. There are a few that stick out here as rather larger. Those are based on a totally different approach to the estimation, and, therefore, we are not too surprised they are larger.

Mr. BROWN. Do you have the CIA figure in there?

Mr. KENT. They haven't given us a comparable figure. There is no resource estimate I can find in the CIA report.

As I say, if we take the mean values of most studies, we are going to hit somewhere on this order, some going up to about a thousand or so; some down to perhaps around 500. A few lower bars which are the more pessimistic, and this is essentially what we know we have in proved reserves.

The lower chart here takes the same information and converts it into the ratio of undiscovered to previously discovered, and what we are saying here is that there is from about one to one and one-half times as much, on that order of magnitude, gas yet to be discovered as has been discovered to date.

Mr. Chairman, that completes my statement.

[Mr. Kent's prepared statement follows:]

TESTIMONY
OF
HARRY C. KENT
REPRESENTING POTENTIAL GAS AGENCY
AND POTENTIAL GAS COMMITTEE

My name is Harry C. Kent and I am a Professor of Geology and Director of the Potential Gas Agency at the Colorado School of Mines. I have been a member of the C.S.M. faculty for 21 years and joined the Potential Gas Agency as Director in April 1976.

A major function of the Potential Gas Agency is to guide and assist the Potential Gas Committee in that Committee's task of preparing estimates of the undiscovered potential gas supply of the United States. Through the past year we at the Agency have been working with the Committee as they have made a study of the potential as of the end of the year 1976.

The Potential Gas Committee is an independent committee comprised of approximately 150 members representing a broad spectrum of the natural gas industry and including members and observers from academic institutions, state geological surveys, and federal agencies. The services of the various members are contributed by themselves or their employers. The function of the Committee is to evaluate the future potential for natural gas exploration and discovery in the United States as a basis for energy resource planning.

Estimates prepared by the Committee represent "most likely" or mean values and are stated in terms of varying levels of geologic knowledge about prospective areas. The estimates are geological in nature and are not related to any specific price for natural gas; rather it is assumed that there will be adequate economic incentive to develop that gas which is believed to be present

under reasonable geologic conditions. In terms of technological developments, the Committee assumes that there will be a steady, evolutionary improvement in drilling and completion techniques and that recovery of the estimated gas will not depend on revolutionary new breakthroughs in technology. In line with these conditions, the Committee has limited its estimates to gas which might occur at drilling depths less than 30,000 feet and, in offshore areas, to water depths of less than 1,500 feet. The Committee has not included the gas which might be recovered from very low permeability reservoirs such as in some areas of the Rocky Mountains or from nonconventional sources (gaseous coal seams, shales, or geopressured reservoirs).

As of December 31, 1976, the Committee estimates that there still remain 215 trillion cubic feet of natural gas, in addition to Proved Reserves, in the Probable category to be developed from the growth of known gas fields and from new pools to be discovered by further exploration associated with existing fields. This is the category for which we have the best geologic control and hence this estimate is the most certain of the three categories.

The Committee further estimates that there are an additional 363 trillion cubic feet of natural gas in the Possible category to be developed from further exploration in provinces which are already productive. Further, there are an estimated additional 345 to 395 trillion cubic feet of Speculative natural gas to be found in exploration of formations and provinces which are not currently productive. The latter category, Speculative, consists of areas in which we have limited geologic knowledge such as some

offshore areas and the very deep portions of some basins. The volume in the Speculative category is geologically least certain but represents the Committee's best estimate based on available information.

A more complete summary of the Committee's findings has just been issued in a News Release and a copy of that News Release is attached as Exhibit I for your information.

The Probable category includes a volume of gas estimated to be about equal to the present estimate of Proved Reserves. Each of the volumes in the other two categories is estimated to be more than one-and-one-half times the amount of Proved Reserves. Thus the Potential Gas Committee believes that there is a total potential for future discovery and development about four-and-one-half times the amount of Proved Reserves or almost twice the U.S. cumulative production to date.

In addition to its work on estimates of Potential Supply, the Potential Gas Committee has had a subcommittee working to prepare a comparison of the various estimates of potential supply, which have been published by industry, government, and other groups in recent years. One of the points of confusion and difficulty in understanding the status of gas supply in the United States has been that a number of estimates have been issued, many of which have used different terminology and definitions and different approaches to estimation.

This subcommittee report attempts to place all of the published estimates on a comparable basis. A copy of this report is attached as Exhibit II.

In brief, there is reasonable uniformity in recent estimates that there is an undiscovered potential supply of natural gas in this country from one to one-and-one-half times as large as the previously discovered volume. That is, the total of cumulative production and proved reserves is presently 731 trillion cubic feet. There remains yet to be discovered, according to a consensus, about 700 to 1200 trillion cubic feet.

EXHIBIT I

NEWS RELEASE

Potential Gas Agency
Harry C. Kent, Director
(303) 279-4320

Colorado School of Mines
golden, colorado 80401

For release May 4, 1977

ESTIMATES OF FUTURE NATURAL GAS POTENTIAL FOR THE UNITED STATES RELEASED BY POTENTIAL GAS COMMITTEE

The Potential Gas Committee today released its estimate of the future potential natural gas supply for the United States. The Committee estimates that, as of December 31, 1976, there still remain 215 trillion cubic feet (TCF) of natural gas in addition to Proved Reserves to be developed from the growth of known gas fields and new pools discovered by further exploration associated with existing fields (*Probable* category). In addition, there are an estimated undiscovered 363 TCF in the *Possible* category to be developed from exploration in provinces which are already productive and 345 to 395 TCF in the *Speculative* category to be found in exploration of formations and provinces which are not currently productive. The amount of natural gas estimated in the *Probable* category is a quantity in addition to Proved Reserves and is about equal to the current volume of Proved Reserves (estimated at 216 TCF as of December 31, 1976) or approximately 10 times current U.S.

annual production. (Annual production was 19.5 TCF during 1976.) The quantities estimated in the Possible and Speculative categories are each more than one and one-half times the volume of current Proved Reserves. A complete report of the Committee's findings is scheduled for June publication.

Since 1964, the Potential Gas Committee (and its predecessor, the Future Gas Supply Committee) has prepared estimates of the undiscovered potential natural-gas supply of the United States. The Committee is comprised of volunteer members representing the natural-gas industry, government agencies, and academic institutions.

The estimates which are made by this Committee are of Potential future supplies of natural gas which are largely undiscovered. They are in addition to the amounts of proved gas reserves as published by the American Gas Association Committee on Natural Gas Reserves. Estimates of undiscovered resources of natural gas are, by their very nature, somewhat subjective. They are necessarily based on the geological information that is available for each potentially productive reservoir and basin. The Potential Gas Committee emphasizes that some background knowledge of the procedures and conditions under which estimates of natural gas potential are made is required in order to avoid misuse of estimates.

To express the varying levels of geologic knowledge, the Committee presents its estimates in terms of three categories: *Probable*, *Possible*, and *Speculative* resources. *Probable* resources are the expectable extensions of gas fields that have already been discovered. They include extensions and new pools in productive discovered reservoirs and shallower or deeper new

pool discoveries within existing fields in formations productive elsewhere within the same geologic province or sub-province. Probable resources represent quantities of gas in addition to those included in proved reserves. *Possible* resources are in a geologically somewhat less certain category and relate to discoveries which might be reasonably expected to be found by future exploration in formations which are currently productive elsewhere within the same province. *Speculative* resources are those amounts of gas which members of the Committee feel might be reasonably expected to be found in formations or areas in which there is no current production--areas in which geological information is relatively limited. An example of Speculative resources would be those which are currently attributed to the Atlantic Continental Shelf, or in some very deep formations beneath previously productive areas.

Quantities estimated by the Potential Gas Committee are "most likely" or mean values. They represent the consensus of the Committee as to the most likely quantity of natural gas remaining to be developed in each of the three categories. The Committee emphasizes the differing degrees of geologic knowledge of the three categories and encourages comparisons only within the separate categories of Probable, Possible and Speculative. The values for each category represent estimates of potential volumes of natural gas under quite different conditions and levels of geological knowledge; hence it is not appropriate to add the quantities estimated for the different categories although this has sometimes been done in order to arrive at a single "most likely" quantity of potential supply.

ESTIMATES OF FUTURE NATURAL GAS POTENTIAL--4

Estimates are not related to any specific price for natural gas; rather, it is assumed that there will be adequate economic incentive to develop that gas which is believed to be present under reasonable geologic conditions. In terms of technological developments, the Committee assumes that there will be a steady, evolutionary improvement in drilling and completion techniques and that recovery of the estimated gas will not depend on revolutionary new breakthroughs. In line with these conditions, the Committee has limited its estimates to gas which occurs at drilling depths less than 30,000 feet and, in the offshore areas, to water depths of less than 1,500 feet. The Committee has not included the gas which might be recovered from very low permeability reservoirs such as in some areas of the Rocky Mountains or from nonconventional sources (gaseous coal seams, shales, or geothermal reservoirs).

At the end of 1976, the Potential Gas Committee estimates that there were approximately 215 trillion cubic feet (TCF) of natural gas in the *Probable* resources category in addition to the amount currently attributed to Proved Reserves. (Proved Reserves at the end of 1976 were estimated at 216 TCF.) The estimate of Probable resources compares to an estimate of 266 TCF at the end of the year 1972. During the four-year period, from 1973 through 1976, an estimated 25 TCF were added to Proved Reserves from revisions, extensions and new reservoirs, which essentially represents transfers from Probable resources to Proved Reserves. In addition, the Potential Gas Committee has transferred 26 TCF which are considered as Proved Reserves in the Prudhoe Bay, Alaska, field.

ESTIMATES OF FUTURE NATURAL GAS POTENTIAL--5

The Committee further estimates that there are approximately 363 TCF in the *Possible* resources category and 345 to 395 TCF in the *Speculative* resources category. These estimates compare to 384 TCF Possible and 496 TCF Speculative at year-end 1972. During the four years, from 1973 through 1976, approximately 9 TCF were added to Proved Reserves from Possible and Speculative categories. The remainder of the decrease in estimates for these categories came from downward revisions of previous estimates based on additional geologic knowledge and the discouraging results of some exploratory drilling, notably in the Mafla area of the northeastern Gulf of Mexico; the Illinois basin; northeast Texas, north Louisiana, and Arkansas; offshore Louisiana; offshore and south Texas; Arizona and New Mexico; and areas of Alaska.

Estimates are prepared by the Committee for each of 12 geologically significant areas of the United States (as indicated on the accompanying map).

ESTIMATES OF FUTURE NATURAL GAS POTENTIAL--6

The estimates for each Potential Gas Committee area are as follows:

Area	Probable (TCF)	Possible (TCF)	Speculative (TCF)
A (Eastern States and offshore)	25	9	68
B (Southeastern States and offshore)	5	6	40
C (North Central States)	less than 1	4	2
D (North Louisiana, Arkansas, and Central Texas)	8	21	25
E (South Louisiana and offshore)	49	69	less than 1
G (Texas Gulf Coast and offshore)	39	50	4
H (Northern Rocky Mountains)	15	31	18
I (Southern Rocky Mountains)	2	3	2
J-North (Mid-Continent)	27	72	8 to 58
J-South (Permian Basin)	18	37	1
K (Alaska)	23	45	157
L (Pacific Coast States and offshore)	4	16	20
Totals	215	363	345 to 395

The Potential Gas Committee is an independent committee whose members' services are contributed by their employers or by themselves, and it functions to evaluate the future potential for natural-gas exploration and discovery in the United States as a basis for energy-resource planning. Members of the Committee come from both large and small exploration and production companies, consultants, state geological surveys, and academic institutions. Observers from a number of Federal agencies and various associations are also included. The Committee functions independently but with the guidance and assistance of the Potential

Gas Agency of the Colorado School of Mines. The Agency operates under the direction of the administration of the Colorado School of Mines through a grant to the School from the American Gas Association.

The Chairman of the Potential Gas Committee is Mr. E. A. Rassinier, Director of Resource Planning for Trunkline Gas Company, Houston. The Vice Chairman of the Committee, and Chairman-designate, is Mr. George C. Grow, Jr., consulting geologist of Westfield, New Jersey. Mr. Richard J. Murdy, Vice President and General Manager of CNG Producing Company, Clarksburg, West Virginia, is Chairman of the Executive Committee, and Mr. E. Floyd Humphries, Manager of Geology for the Natural Gas Pipeline Company of America, Houston, is Vice Chairman of the Executive Committee and Chairman of the Editorial Committee.

The estimates of potential natural gas resources are prepared by Area Work Committees, one for each of the 12 areas into which the Committee has divided the country. Each Work Committee consists of a number of members from producing companies, consulting geologists and state geological surveys, and includes an observer each from a gas pipeline company and a gas distribution company. For administrative purposes, the Area committees are organized into regional groups, with a Regional Vice Chairman coordinating activities, one for the Eastern states, one for the Central states and one for the Western states.

Each Area Work Committee functions independently. Its members are charged with gathering all available information about the geology and occurrence of natural gas in the assigned area. The members review past exploration and production history and, based on the historic record and their collective geological and operating expertise, evaluate the potential for further discoveries in both partially explored and unexplored basins.

ESTIMATES OF FUTURE NATURAL GAS POTENTIAL--8

The function of the Potential Gas Agency is to oversee the work of the Potential Gas Committee, at all levels, to assist in coordinating activities and to publish the results of studies. The Agency acts to assure that Area Work Committees follow the established procedures for estimation and that the estimates published by the Potential Gas Committee represent objective evaluations insofar as possible. The Agency selects the Chairman and Vice Chairman of the Potential Gas Committee and approves the appointments of Regional Vice Chairmen and Area Work Committee Chairmen and Vice Chairmen. The current Director of the Potential Gas Agency is Dr. Harry C. Kent who has been a member of the faculty of the Department of Geology at Colorado School of Mines for 21 years.

In addition to the preparation of its forthcoming report on the estimated potential supply of natural gas in the United States, the Potential Gas Committee has completed a report on comparison of estimates of potential natural-gas resources of the United States which have been made by various groups. This report will be released in May 1977.

[Exhibit II to Mr. Kent's statement had not been received at the time the record was closed.]

Mr. KRUEGER. We thank you very much, Mr. Kent.

The Chair first recognizes the gentleman from Ohio, Mr. Brown, for, let's be extravagant, 8 minutes of questions.

Mr. BROWN. Thank you, Mr. Chairman.

Mr. Kent, the result of your study would infer that most of the people seemed to conclude that most people who made studies indicate that there is from one to two times the amount of gas that we have extracted from the earth available to be extracted in the future. Is that correct?

Mr. KENT. Yes.

Mr. BROWN. Now, I have a chart which shows me that there are such things as exploratory wells, and total wells drilled, and I am told that an exploratory well is a well that is out beyond the near location of some other gas well. This chart would seem to indicate that most gas wells are drilled within a reasonable range of where other gas wells are located, presumably to try to find gas from the general field that in which you know you have gas in. Is that correct?

Mr. KENT. I think I would phrase it differently.

Mr. BROWN. It is your business; help yourself.

Mr. KENT. The term development well is what is normally applied to those wells, the difference between exploratory wells and total wells. Development wells are drilled after a field has been discovered. The initial discovery well would indicate that there is gas present. The development wells are then drilled subsequent to that initial discovery in order to fully develop that field and extract that material.

Mr. BROWN. If one has a discovery well, then, I suppose the natural step with the first discovery well is to drill a number of development wells nearby?

Mr. KENT. That would be correct.

Mr. BROWN. How many discovery wells relatively are being drilled currently in comparison to the developmental wells?

Mr. KENT. There are approximately 9-10,000 exploratory wells being drilled annually in this country. I think I have the total figure here.

Mr. BROWN. By comparison to how many developmental wells?

Mr. KENT. The total number of wells in 1976 was 39,700, and out of that 9,000 were exploratory wells.

Mr. BROWN. So that is between a quarter and a fifth of the wells are exploratory wells?

Mr. KENT. Right.

Mr. BROWN. And of the wells that are exploratory, how many of those wells become producing wells at current price levels? Do you have any way of determining that?

Mr. KENT. This would be off the top of my head. I think we are talking about possibly 18 percent of those being successful wells, of the exploratory wells.

Mr. BROWN. Successful at the present economy?

Mr. KENT. Successful in finding gas which can be produced, and sometimes that gas is produced even if it isn't economical, simply because the company needs it or has the obligation to produce any gas found on the lease whether or not it can be extracted at profit. It depends on the requirement of that particular lease.

Mr. BROWN. Do you have any general picture in your prediction of future gas possibilities as to where the gas might be found, either in some geographic definition, in some depth definition, or some definition that we could grasp here in our lay knowledge in this field?

Mr. KENT. Yes, I have given that to you in the complete news release. I have given an estimate of potential by geographic reported areas. We will have a more complete report which will be available in June, which will give it also by depth breakdown.

Mr. BROWN. Would these generally be in areas more expensive to produce the gas from?

Mr. KENT. In many cases yes, because there is considerable potential for deep areas and offshore areas where the costs are higher.

Mr. BROWN. What about the size of the field or the well, which I understand contributes something to the cost of the gas? If it is a small field, a field that has low pressure or something, it costs a little more to get the gas out?

Mr. KENT. Yes, but we are getting beyond the area in which I have any expertise in that field.

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Mr. BROWN. So you don't have any figure as to where the price factor would contribute to this. Finally, are there any of these geothermal very deep methane wells in your projection?

Mr. KENT. No, there are not. We don't feel that the technology presently exists, or exists in the immediately foreseeable future, to produce the gas from those wells, and we have not included them in our report.

Mr. BROWN. Is the quality of the gas in the wells that you project what we might call conventional natural gas as opposed to the methane gas which is supposed to be trapped in the salt water?

Mr. KENT. Yes, these would be sources of conventional gas.

Mr. BROWN. Mr. Chairman, I think I have overstepped my time only very modestly.

Mr. KRUEGER. The gentleman has consumed 5½ minutes, and he is so accustomed to brevity, he hasn't required all eight.

I would like to ask whether in your speculative category you have any estimate of how soon that gas could perhaps be brought on into production and whether or not it would be economical to do so within the next few years?

Mr. KENT. Mr. Chairman, I would be stepping beyond my immediate knowledge to go very far into that area. Much of that speculative category would be some of the gas that Mr. Hefner was talking about in deeper parts of the Anadarko Basin, and he discussed that with the committee. A good part of it might perhaps be on the Atlantic Continental Shelf, and that will depend a great deal on the situation in leasing and the speed of development of that area.

It is not solely a matter of cost or solely a matter of where it is. These are all factors which enter into the total picture of whether or not it can be produced and when.

Mr. KRUEGER. Secondly, I wonder, when we talk about this area of reserves, whether there are already pipelines into many of the areas for the larger numbers that you suggest, or whether the gathering and delivery system is something that would still need to be developed for these?

Mr. KENT. As a general rule of thumb, I think you could say there are already existing pipelines, for the most part, in areas where our probable resource exists. For the others, there would be minimal extensions of pipelines or lesser degree of extension of pipelines necessary to develop the possible category. Speculative would require a total new system.

Mr. KRUEGER. Third, what portion of the kinds of reserves which you have described are to be found onshore, 48 States, and what percentage offshore, and what percentage Alaska; if you could divide it into those categories, if that isn't too difficult?

Mr. KENT. Let me see if I have those figures. Mr. Chairman, I really don't find those.

Mr. KRUEGER. I observe at one point someone looked further back in your testimony, and although it is not what I requested, there is a geographical breakdown by area of the United States, on- and offshore.

Mr. KENT. Yes, and I can provide for the committee the percentages and the breakdowns onshore and offshore, if you would like me to do so.

Mr. KRUEGER. If you would have them broken down that way, I would appreciate it.

Mr. KENT. Yes, sir.

[The following letter was received for the record:]

COLORADO SCHOOL OF MINES
Mineral Resources Institute
Golden, Colorado 80401

Potential Gas Agency

Telephone: 303/279-4320

May 18, 1977

The Honorable John Dingell
House Committee on Energy
2210 Rayburn House Office Bldg.
Washington, D.C. 20515

Dear Congressman Dingell:

During the questioning that followed my testimony before the Subcommittee on Energy and Power on Thursday, May 12, 1977, I was asked to provide figures regarding the percentage of the potential natural-gas supply estimated by the Potential Gas Committee which is to be found in onshore vs. offshore areas, in shallow vs. deep drilling, and in Alaska vs. the lower 48 states. I am pleased to provide the following information for the use of the Subcommittee:

PER CENT OF POTENTIAL SUPPLY IN LOWER 48 STATES

Onshore vs. Offshore Areas

	Located in Onshore Areas	Located in Offshore Areas
Probable Resources	73%	27%
Possible Resources	74%	26%
Speculative Resources	66 - 74%	26 - 34%
Total Potential Resources	72 - 74%	26 - 28%

Shallow vs. Deep Drilling

	To be Found by Shallow Drilling (less than 15,000 ft.)	To be Found by Deep Drilling (15,000 to 30,000 ft.)
Probable Resources	75%	25%
Possible Resources	66%	34%
Speculative Resources	57 - 79%	21 - 43%
Total Potential Resources	66 - 72%	28 - 34%

Comparing the potential for Alaska to the lower 48 states:

	Percentage of Potential Natural Gas Resources Located in Lower 48 States	Located in Alaska
Probable Resources	89%	11%
Possible Resources	88%	12%
Speculative Resources	54 - 60%	40 - 46%
Total Potential Resources	76 - 77%	23 - 24%

I hope that this information will be of value to the committee.

Sincerely yours,

Harry C. Kent

Harry C. Kent
Director
Potential Gas Agency

HCK:lr
cc: Messrs. E. A. Rassinier
George C. Grow, Jr.
E. Floyd Humphries
Richard J. Murdy
C. M. Allen
Robert B. Kalisch
Congressman Robert Krueger
Mr. W. E. Williamson
Clerk, Committee on Interstate
and Foreign Commerce

Mr. BROWN. Mr. Chairman.

Mr. KRUEGER. Yes.

Mr. BROWN. If you would like to yield, I would like to ask a couple of questions of the gentleman before you terminate.

Mr. KRUEGER. I will be happy to yield, and I was just going to ask the gentleman from Ohio whether he recalls the figures that we were shown several months back in which there was a substantial increase in the number of wells drilled, and we were also told there was decline in the total amount of production, and it was a kind of Methuselah-doomsday theory, and I don't remember who presented it to us, but I remember they said more wells, less production of gas, and I remember seeing the chart, but I don't remember who presented it. I believe it was Mr. O'Leary.

If we have that, perhaps we would be able to get Mr. Kent to comment on it.

But meanwhile, while someone searches, I will recognize you for a couple of questions at this time.

Mr. BROWN. Mr. Kent, we have heard the suggestion that the United States, being a very sophisticated energy-consuming area

and also a sophisticated energy-producing area, is literally an acupuncture chart of places that have been drilled. Are there vast areas where we have not looked for natural gas in this country?

Mr. KENT. Yes, there are, and especially some deep areas where we have not yet looked.

Mr. BROWN. Is it your feeling that these areas are particularly promising?

I noticed, for instance, there seems to be no correlation between probable, possible and speculative here in some instances. You have indicated that the potential gas committee estimates that there is a probable 8 trillion cubic feet of gas in North Louisiana, Arkansas and Central Texas; that there is a possible 21 trillion and speculative 25. To sort of go the other way, in the North Midcontinent area, you indicate that there is 27 probable, 72 possible, and 8 to 58 speculative.

Now, are these areas that are heavily drilled? North Louisiana has been rather heavily drilled, hasn't it?

Mr. KENT. Yes, although I think probably the density of drill is greater in the Midcontinent, and the most positive and speculative area in Midcontinent would be the deeper portions of the basin which have not been explored nearly as much as shallower. In North Louisiana, Arkansas, and Texas, we would be talking about additional areas for deep wells within the already productive areas.

I would point out in South Louisiana offshore, area E, that we have very little speculative, because we think the stage of exploration in that region has progressed to the point that there are virtually no formations or areas which have not been looked at, at least in some cases.

Mr. BROWN. Finally, do you have any change of prices where these things might be productive? Is there any way you can talk about the amount of gas that might be found, say, in the northern Rocky Mountains in that 15 probable, 31 possible area?

Mr. KENT. I cannot speculate on what the price structure would be.

Mr. BROWN. Am I right in concluding that these wells would be mostly developmental wells?

Mr. KENT. No, this would all be gas found by exploratory wells.

Mr. BROWN. All new fields?

Mr. KENT. Yes, all new fields, or in some cases deeper extensions, deeper pools within existing fields.

Mr. BROWN. Let's look at the definition in the legislation presented by the President. Would these all be in excess of the 2½-mile limit?

Mr. KENT. No, in this case it would not. The probable category in many instances would fall within the 2½-mile limit. The other two categories would not.

Mr. BROWN. What about the depth limits covered in the legislation?

Mr. KENT. There is a limit of a thousand feet, I think, beneath existing production. Some of the probable category possibly would fall in there; I don't know for sure how much would. A large part of the probable category would fall within that 2½-mile radius.

Mr. BROWN. Have you had a chance to look at the CIA report?

Mr. KENT. Briefly.

Mr. BROWN. Do you have any analysis of it in terms of its competence from the standpoint of the availability of the probable, possible, or speculative gas sources?

Mr. KENT. I could find nothing in the CIA report which would give me any basis for comparison, no figures which could be used to compare to anything we do. There was very little in there about natural gas.

Mr. BROWN. How do you do what you do? You don't go around with a peachtree branch, I suppose.

Mr. KENT. No longer.

Mr. BROWN. I watched it work once.

Mr. KENT. No, I think we perhaps have progressed. The committee works in this way: We have divided the country into essentially 12 geographic areas. For each area we have a committee of individuals representing large and small producers, piplelines and distributors, mostly geologists, some reservoir engineers, who have knowledge and expertise in that area. They have worked in exploration for a number of years.

This committee then uses its individual member's knowledge and information to look at that region to try to visualize the geology which exists, both within known areas and unknown areas, to look at the potential and the formations present for containing gas, to look at the history of the area so we might know whether there is a structure or another trap for gas, and on that basis they say I think we can probably find another field of this size and perhaps three more of this size, and so on down the line.

Mr. BROWN. Could you give us a Jimmy-the-Greek odds on what is meant by probable, possible and speculative?

Mr. KENT. No, because the committee phrases this—those terms refer to the geologic knowledge of the area. Each estimate I have given you is a 50-50 or mean value for each of the three geological categories.

Mr. BROWN. I am not sure I know what you means.

Mr. KENT. We have defined probable in its geological relationship to existing fields. We define possible as further developments in basins or provinces which are already productive. Then we have defined speculative as nonproductive formation or basins. The figure we have derived for the estimate of gas in each of these categories is a mean value. It is the consensus of the committee. Some committee members feel there is more gas; some feel there is less gas. This is the consensus number they have arrived at as the reasonable and most likely one.

Mr. BROWN. These are sophisticated geologists. Do they use any methods to test the areas, themselves, other than their knowledge of the geology of the area?

Mr. KENT. That is primarily the way it is done. There is internal testing in that members of the committees must defend their work to other members of the committee, and I have been in sessions where there have been arguments, where one has said estimates can't be right for these reasons, and they look at it again to try to come up with reasonable answers.

Recently, we had a pilot study by the American Association of Petroleum Geologists done at the request of the Secretary of Interior, and this pilot study looked at four basins in the Rocky Mountain region which happened to be four of the basins included in our study, and the totals they came up with in their study are very comparable to the totals we came up with in our study. This is a different group of geologists, a few members in common, but generally different people using a still basically geologic approach, and they have come up with about the same order of magnitude of numbers.

We have done other independent studies using additional sources of information, additional workers on specific areas to do studies and try to doublecheck our figures. This is the way we are trying to verify them.

Mr. BROWN. Thank you.

Mr. KRUEGER. I would like to ask one more question on my own before recognizing the gentleman from Louisiana, and that is in terms of the potential gas committee's estimates on reserves yet to be developed, what portion of the gas would you say is likely to be found in major fields versus nonmajor fields? We have had testimony in the past on major fields as being in the case of oil, fields that produce 100 million barrels or more, and I am not sure exactly what the figure is for a major gas field, but are we talking about the discovery of additional major gas fields, or are we talking largely about many smaller gas fields totaling to this full amount?

Mr. KENT. I can't give you a breakdown in percentages. I am certain that the committee feels that there are still some major gas fields to be found in many areas. There are especially some of the deeper portions of some basins which have been quite productive, and there is a strong feeling there will be good size fields found to justify the drilling.

On the other hand, of course, I think there are quite a few small fields. I cannot give you an accurate percentage breakdown.

Mr. KRUEGER. At this time, I recognize the gentleman from Louisiana, Mr. Moore, for questions.

Mr. MOORE. Thank you, Mr. Chairman.

Mr. Kent, in adding up the total, you come to somewhere around 1,000 trillion cubic feet you testified to.

Mr. KENT. Slightly less than that in terms of the undiscovered potential.

Mr. MOOORE. Right; I am adding the proven in there.

Mr. KENT. Yes.

Mr. MOORE. How many years' supply at our current rate of usage would that be?

Mr. KENT. We are using right at about 20 trillion cubic feet a year, so if we don't increase our usage that would be around 50 years.

Mr. MOORE. You went to great length explaining what things you do not include in your study. I understand that. Do you have any figures as to how much gas is in those areas below 30,000 feet are in the Devonian shale and Rocky Mountain areas?

Do you have any idea how much gas is in those areas in addition to the ones you testified to here?

Mr. KENT. No, sir; we have not done studies on those. There are other groups who have done it, and it is an area we might look into. It is a future job I have envisioned for us. We haven't done it as yet. I doubt anyone would have a figure for below 30,000 feet. That is considered the technological basement.

Mr. BROWN. Is that the geothermal level?

Mr. KENT. Not necessarily. There is some evidence there is gas below that, but it is felt that technologically it is at the very limit of what can be done today or in the near future with normal improvement.

Mr. MOORE. My next question is if we have about 50 years' supply of gas, technologically, we can get to now, do you think, in your opinion, during the next 50 years we can get at the technology to get at the gas below 30,000 feet and in the Rocky Mountain shale and Devonian areas?

Mr. KENT. As a personal opinion, I would say so.

Mr. MOORE. If you look at where we have come in the last 50 years, in particular?

Mr. KENT. Yes, and certainly there are people working on those projects now.

Mr. MOORE. Would it also be fair to say much of the gas that you testified to here that we will be producing, possible and probable and even speculative areas, is going to be expensive to produce because it is not the traditional shallow production type we have been used to?

Mr. KENT. That is exactly correct.

Mr. MOORE. I thank you, Mr. Kent.

Mr. KRUEGER. The gentleman's time has expired.

Counsel, Mr. Demarest, is recognized for a question.

Mr. DEMAREST. Mr. Kent, you pointed to the spikes on you chart. Could you tell us what they represent and how the methodology which produced them differs from the methodology utilized to produce the other estimates which form a band across the middle of the chart?

Mr. KENT. This tall one here is an estimate published by the U.S. Geological Survey in a news release issued in 1974. They have a high and low estimate. The low estimate is not too far off the rest of them. What they did was to calculate the total volume of sedimentary rock basins in the United States and apply a factor to those rocks to say if we multiply the volume and other things by this fact we will come up with the amount of gas. The problem is that factor had to be determined arbitrarily. They used two different factors, and that is the way they came up with it. They used a factor we will find as much gas per unit volume of sediment as we have found in the past, and they used a half as much factor, and we know from experience that probably both of those two factors are somewhat too high, especially as much as in the past, because, as we go into further development of areas, gas does become harder and harder to find. It is less readily available; exploration is more difficult; so our success ratio does go down with time.

This is another USGS estimate; in fact, the two highest are U.S. Geological Survey estimates, and that is based om a similar type of analysis and did not have a factor problem but was based on a

volumetric approach to sediments and simply saying that we will find as much gas in the future per unit volume as in the past.

Many of the other estimates are based on geological approach in which we are trying to look at individual studies or projects within the basins and evaluate them more on an individual basis. This is a shotgun approach.

Mr. DEMAREST. Is it fair to say that that approach is no longer widely held in high regard?

Mr. KENT. I think that is true, and that is particularly shown here in the most recent U.S. Geological Survey figures; this is circular 725, and they are quite comparable to other figures.

Mr. DEMAREST. Thank you, Mr. Chairman.

Mr. KRUEGER. Since there seems to be no further questions, I will make a comment that the world will little note nor long remember, and that is that in conversation we were just discussing the fact that the USA, with about 6 percent of the world's population, uses each year about a third of the world's energy. We were observing that the United States, also with 6 percent of the population, produces about one-third of the world's wealth. We have had actually a very consistent pattern in the USA of Btu usage and overall wealth, and I belive if one looks at the last 20-odd years, on can find that there has been a very consistent pattern whereby 60,000 Btu's of energy are generally correspondent to 1 additional dollar in GNP.

For every additional 60,000 Btu's we get of energy, we have traditionally seen an increase in the gross national product of $1. So we are looking into a very murky crystal ball, indeed, when we talk about substantial conservation. No one has yet indicated that with substantial conservation we will have substantial reduction in GNP, but if the world will little note or long member, we might as well leave the rest up to history.

I thank our witness very much.

We are adjourned.

[Whereupon, at 6 p.m., the subcommittee adjourned, to reconvene at 10 a.m., Friday, May 13, 1977.]

NATIONAL ENERGY ACT

FRIDAY, MAY 13, 1977

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY AND POWER,
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE,
Washington, D.C.

The subcommittee met, at 10 a.m., pursuant to notice, in room 2325, Rayburn House Office Building, Hon. Richard L. Ottinger, presiding, Hon. John D. Dingell, Chairman.

Mr. OTTINGER. The Subcommittee on Energy and Power is resuming its hearings on the natural gas portions of the National Energy Act, H.R. 6831.

We are pleased to have with us Governor Dolph Briscoe, Governor of Texas, Governor David Boren, the Governor of the State of Oklahoma, and our colleague, Jack Brooks, from the State of Texas, as well. We welcome you.

This morning the Subcommittee on Energy and Power resumes its hearings on the natural gas pricing proposals of President Carter's energy package. This morning's hearings will focus special attention upon the effects of the President's proposals on natural gas producing States.

Existing law distinguishes between sales of natural gas in interstate commerce and the sales of natural gas within a producing State. President Carter's program would do away with this distinction.

The effects of this proposal upon the economies of natural gas producing States may be significant. For that reason, today's hearings are directed at developing testimony regarding these special impacts.

Other proposals dealing with natural gas issues include deregulation of new natural gas. Just as President Carter's proposals have special implications for producing States, so does this proposal.

Other questions before the subcommittee today will include the impacts upon producing States of consumers, pipeline and distribution companies and industrial end users of the various natural gas pricing proposals before the Congress.

Our first witnesses this morning are the Governors of two of the producing States, Governor Dolph Briscoe of Texas and Governor David Boren of Oklahoma.

Following the testimony of the Governors, the subcommittee will hear from a panel representing members of regulatory bodies of the producing States of Texas, Oklahoma, Louisiana and New Mexico. This afternoon the subcommittee will hear testimony from industrial and individual consumers of natural gas as well as intrastate pipelines and those distribution companies.

Governor Boren, Governor Briscoe, we welcome you. Would you come up and sit at the table? You are welcome to bring Congressman Brooks with you for protection if you would like.

I am informed that Governor Apodaca of the State of New Mexico was not able to be with us, but has submitted testimony. Without objection that testimony will be included in the record as though read.

I will now be pleased to recognize my colleague from Texas, Mr. Krueger, for any remarks he would like to make in welcoming his Governor.

Mr. KRUEGER. Thank you very much, Mr. Chairman.

As a Texan, I am, of course, particularly pleased to have our Governor here today with us. He appeared before this committee about 2-1/2 months ago at the time of the Emergency Natural Gas Act for emergency allocations. He is a person of great popularity in our State. We are very proud of him.

He is probably, I might mention, since we have at this moment a largely Democratic presence on this committee, that he is a person perhaps more responsible than any other for the State of Texas voting Democratic at the national level last November. He is a person that we are extremely pleased to have here because he has long familiarity not only with the problems of our State, but also with national problems.

Obviously, we are honored to have Governor Boren here as well. Governor Boren went to some little second-rate university, I believe, across the water, one of those old places called Oxford. I am delighted to have a classmate here as well as my own Governor. We welcome you.

Mr. OTTINGER. Do any of our other colleagues wish to say anything before we start?

Then, Governor Briscoe, if you would like to go first, you are welcome to make your statement.

STATEMENT OF HON. DOLPH BRISCOE, GOVERNOR, STATE OF TEXAS, ACCOMPANIED BY DR. WALTER ROSTOW, UNIVERSITY OF TEXAS, AND DR. WILLIAM FISHER, BUREAU OF ECONOMIC GEOLOGY, UNIVERSITY OF TEXAS

Governor BRISCOE. Mr. Chairman, I appreciate the opportunity to meet once again with this distinguished committee of Congress.

The rapid rise in oil imports has endangered the independence of our foreign policy, distorted our balance of payments, and threatens the prosperity of our economy as a whole.

I agree with President Carter that in facing our energy crisis we face the moral equivalent of war.

I agree that the minimum targets for energy production are at least those set out in the proposed National Energy Plan. I have

attached those targets to this statement. But it should be pointed out that those minimum energy production requirements are one-third greater than the production achieved last year. Those minimum requirements must be met in face of the current overall decline in domestic energy production.

The pricing policy outlined in the National Energy Plan will not achieve its production target. It will provide, instead, for continued shortfalls of critical fuels which this country has the capability to produce.

The principal point I want to make is that the proposed National Energy Plan's pricing provisions will not allow the country to develop the energy resources which the plan acknowledges are necessary.

I speak on this point as Governor of the State which has produced nearly one-third of all the energy this Nation has ever produced, and which will bear heavy responsibility in the attempt to meet the high production targets called for in President Carter's proposal to Congress.

As you know, natural gas reserves in the United States have been declining since 1967. Natural gas production has been declining since 1972 and the annual rate of decline is now running 4 to 5 percent a year.

The National Energy Plan calls for us to turn that falling curve upward and to achieve again by 1985 nearly the same level of natural gas production we now enjoy. That will call for a drilling rate of approximately double the footage drilled last year. We can see what is involved by looking at the attached chart. We know from careful analyses that the amount of development and exploratory drilling increases as the average price of oil and gas increases. The pricing policy established for oil and gas in the National Energy Plan is simply not consistent with the amount of drilling required to achieve the production targets of the Plan. In calculations we have made, we conclude that under the pricing policy of the National Energy Plan, the present rate of decline in gas production will slow somewhat but that the production level by 1985 will be short of the gas production target of the Plan by the equivalent of approximately 2 million barrels of oil per day. The shortfall in oil production measured against oil production requirements of the Plan will be even greater.

I do not believe in price regulation. History clearly proves that price regulation of any commodity has never worked for the long term benefit of the American consumer. The natural gas shortages of this past winter in the interstate market dramatically illustrate the inevitable results of 23 years of Federal regulation of the natural gas industry.

But, if because of short range political considerations, price controls are extended it makes no sense to set the price of natural gas in relation to the average price of crude oil. While natural gas is the Nation's cleanest, most desirable fuel, crude oil is not a fuel. It must undergo an expensive refining process before it can be used. Natural gas should obviously be allowed a price equal to or greater than replacement fuels in order to encourage the change to other fuels. This principle is clearly stated in the text of the National Energy

Plan, "the pricing of oil and natural gas should reflect the fact that the true value of a depleting resource is the cost of replacing it." But the pricing proposals for gas flatly violate the principle. The correct proposal to implement that principle of the national energy plan would be to deregulate the price of new gas.

There has been some concern expressed about the effect of deregulation on the intrastate market in Texas. I urge you to put that concern aside. If deregulation on a national basis should pose problems in Texas they are our problems and we will deal with them.

A free market price for new natural gas such as we have in Texas would bring about the exploration and drilling effort required to meet the production levels of President Carter's National Energy Plan. It would effectively serve as an inducement to industries and utilities to convert to alternate sources of energy such as coal. This is now occurring in Texas without penalty taxes, special rebates, or Federal Government involvement. Only by allowing natural gas to reflect its true value in the market place can we simultaneously give producers the incentive to produce, users the incentive to conserve, and industries the incentive to convert to alternate fuels.

As all of you well know, during the last 20 years two separate and distinct natural gas markets have developed—the unregulated intrastate market, and the unrealistically regulated interstate market. One effect this difference in regulation has had is that for the past few years Texas consumers have paid up to four times as much for natural gas as have interstate consumers.

The higher price for natural gas has stimulated development of intrastate gas reserves, but perhaps more important to the attraction of risk capital even than price incentives has been freedom from ever-changing regulatory proceedings and never-ending litigation which has accompanied Federal price controls.

It has been a most painful experience but we have developed, in most instances, a dependable supply of natural gas.

The invasion of the intrastate market by Federal control with the authority to allocate intrastate gas would be most unfair to those consumers who have through higher prices paid for the new supply of natural gas. It will amount to nothing less than allowing consumers in other States who have for years reaped the benefits of unrealistically low prices to now reap the benefits of an extensive drilling program which has been financed entirely by Texas consumers.

Taking oil and gas together we estimate the National Energy Plan will fall short of its production targets by the equivalent of more than 4 million barrels of oil per day. And that assumes the Plan's conservation and substantial production targets for other fuels, such as coal, will be met. A shortfall of 4 million barrels would be a disaster for our foreign policy and our balance of payments. Under the most optimistic assumptions it would mean oil imports in 1985 would not be the 7.6 million barrels per day called for by the plan but 12 million barrels per day.

Let me point out another meaning of an American import dependence of 12 million barrels. Western Europe and Japan are counting on us to reduce our oil imports. They do not have available

the reserve energy resources that we command. If we fail to reduce our imports the total demand for OPEC oil will, by 1985, begin to press against the limits of OPEC production capabilities. This is a key point made by President Carter in his presentation to the Congress on April 20th. That pressure would, almost certainly, lead to a sharp rise in the OPEC oil price which would wreck the hopes for the future, developed at the most recent meeting of chiefs of government in London.

In my opinion, good planning in a democracy like ours requires a maximum use of a free price system and the minimum use of direct bureaucratic administration of the economy. That hard earned lesson is not respected in the proposed National Energy Plan. I hope the Congress measures carefully the scale, the cost, and the stultifying effects of the bureaucratic giant now envisioned. Many people think of the proposed National Energy Plan as primarily a plan to save energy, install solar energy units, and to expand coal production. But if you study the balance sheet you will see that it is a two-front war with a conservation front and a production front. You are all aware that we in the present energy producing States are disturbed by some of the attitudes of those in potential energy producing States. Those attitudes suggest that we must continue to produce to the limit and deplete our reserves while environmental considerations should be overriding in other States. But my point today is different. I am convinced that nothing less than a full development effort by all States in coal, atomic energy, oil and gas will see us through to achieve the production and balance of payment targets of the National Energy Plan. In a truly national effort the Congress should zero in on a hard and disturbing fact. The Federal Government owns about 50 percent of our known fossil fuel resources but last year contributed less than 10 percent of our production and most of this production was off the coast of Louisiana and Texas. The largest withholder of energy supply in the Nation is the Federal Government itself. To make any national energy plan work we must begin immediately a full production effort directed at all our domestic energy resources.

I urge you to direct your attention to the production targets of the proposed National Energy Plan and the tremendous challenge they represent. Unless they are met the Plan will fail and the impact on our Nation will be devastating. Without radical changes in the Plan it is my considered judgment the Plan will fail. As a Nation we are fortunate. We command a substantial energy resource base. An essential part of the job must be to reconcile the considerable disparity between the National Energy Plan's pricing policy and its clearly stated and necessary production goals.

In the matter of natural gas I strongly urge you to make available to the interstate consumer of natural gas the only mechanism which has a proven record of balancing supply and demand for this critical commodity, reliance on private enterprise functioning in a marketplace free of government price regulations. I urge you not to allocate the shortages and perpetuate the Nation's problem but to provide instead an opportunity for our American free enterprise system, through utilization of the mechanism of the marketplace to develop the long range supply President Carter's balance sheet calls for.

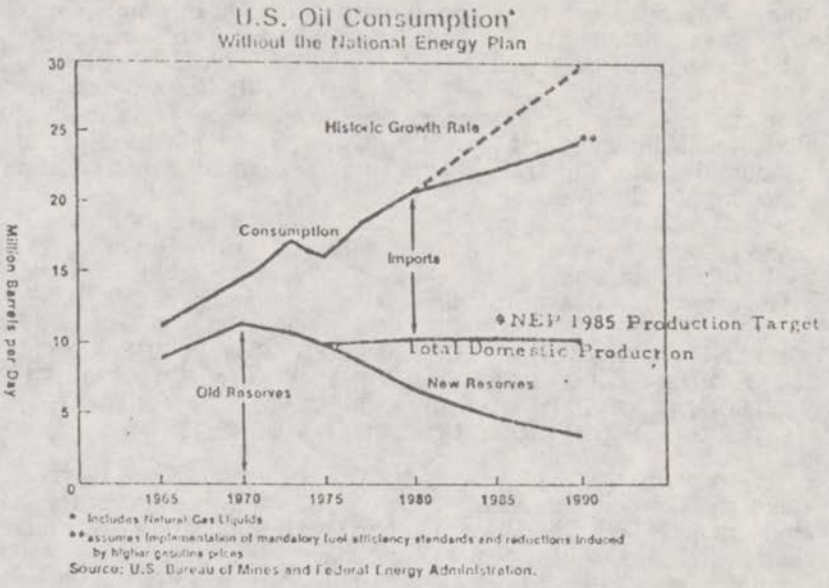
Thank you.

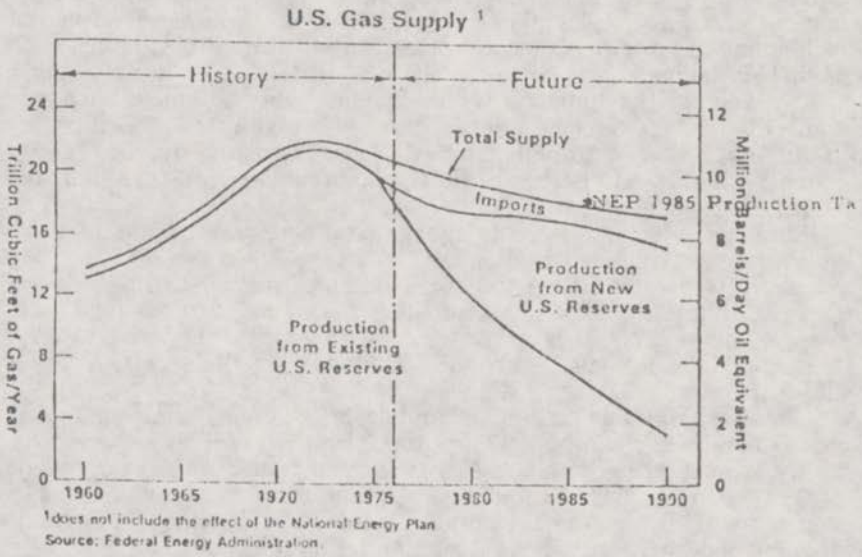
[The attachments to Governor Biscoe's statement follows:]

NEP Balance Sheet
(Millions of barrels of oil equivalent per day)

	1976	1985	Change from 1976
Total	37.0	46.4	25%
Imports	7.8	7.6	-3%
Production			
Coal	7.9	14.5	+84%
Natural gas	9.5	8.8	-7%
Oil	9.7	10.6	+9%
Nuclear	1.0	3.8	+380%
Other (hydro, geothermal, etc.)	1.5	1.7	+13%
Refinery gain	.4	.6	+50%
	37.8	47.6	
Coal export	.8	1.2	
	37.0	46.4	

Source: The National Energy Plan, Executive Office of the President, Energy Policy and Planning, April 29, 1977, p. 96.


U.S. Oil Consumption*
Without the National Energy Plan
Million Barrels per Day
30
25
20
15
10
5
0
Historic Growth Rate
Consumption
Imports
*NEP 1985 Production Target
Total Domestic Production
Old Reserves
New Reserves
1965
1970
1975
1980
1985
1990
* Includes Natural Gas Liquids
**assumes implementation of mandatory fuel efficiency standards and reductions induced by higher gasoline prices
Source: U.S. Bureau of Mines and Federal Energy Administration.


U.S. Gas Supply 1
History
Future
Trillion Cubic Feet of Gas/Year
Million Barrels/Day Oil Equivalent
24
20
16
12
8
4
0
12
10
8
6
4
2
0
Total Supply
Imports
*NEP 1985 Production Ta
Production from New U.S. Reserves
Production from Existing U.S. Reserves
1960
1965
1970
1975
1980
1985
1990
1 does not include the effect of the National Energy Plan
Source: Federal Energy Administration.

Mr. OTTINGER. Thank you very much, Governor Briscoe. I understand that you have some people with you. You are most welcome to have them sit at the table with you. If you would like to introduce them, that would be fine.

Governor BRISCOE. Yes, sir, I have Dr. Walt Rostow now at the University of Texas, former advisor to President Kennedy and President Johnson, and Dr. Bill Fisher, head of the Bureau of Economic Geology of the University of Texas and former Assistant Secretary of the Interior.

Mr. OTTINGER. They are welcome to the witness table.

We recognize next the Honorable David Boren, Governor of the State of Oklahoma.

Governor Boren, we are pleased to have you with us.

STATEMENT OF HON. DAVID L. BOREN, GOVERNOR, STATE OF OKLAHOMA, ACOMPANIED BY DR. WILLIAM W. TALLEY II, CHAIRMAN, AND DR. WILLIAM D. CLEARY, VICE CHAIRMAN, GOVERNOR'S ADVISORY COUNCIL ON ENERGY

Governor BOREN. I have with me the chairman of the Governor's Advisory Council on Energy, Dr. William Talley, and the vice chairman, Dr. William Cleary, is here with me. I appreciate having them with me for this testimony today.

I am very pleased to have the opportunity to testify before this committee. It has a special meaning to me because my father, several years ago, a Member of Congress from Oklahoma, served as a member of your parent committee. So I feel a special association with this body.

I appreciate the opportunity to appear today to share with you some thoughts about the energy plan before you. One job in every 10 in my State is provided directly or indirectly by the energy industry. Oklahoma is the third largest producer of natural gas and ranks high in oil as well.

But I did not come here to speak from a regional point of view, but very sincerely about what I believe is the national interest. My home State also ranks in the top 10 consuming States for natural gas. Oklahoma, too, feels the impact when factories and businesses close in Ohio or New England. Our people sincerely want to offer the expertise and experience which they have in the energy field for the good of the entire Nation.

The President has said it is time to lay it on the line about the need to end our wasteful consumption of energy. Likewise, it is time to lay it on the line with the American people about the supply side of this energy crisis. As much as I applaud the President's conservation aims, the energy crisis cannot be solved by working on only the demand side of a supply and demand imbalance.

VICTORY OR DEFEAT?

What is the bottom line of the plan on the supply side? To be blunt, this Congress is being asked to take two positions which are unthinkable. First, you are being asked to declare defeat, and to say that our people do not have the ingenuity to meet a challenge. The

vast majority of the funds derived in higher energy prices by the consumer will go to the government for transfer payments instead of going to stimulate more production and development of old and new energy sources.

This proposal is tragically shortsighted. It provides for the most part only the rationing of a shortage and not for any long-range victory for the consumer through more adequate supplies. The American people have always been willing to sacrifice, but not when we declare defeat before we begin.

Second, you are being asked to substitute government control for free enterprise in the energy field. I cannot believe that the American people, if it were clearly presented to them, would agree with such a choice. Such a choice could well set a precedent that would destroy our free economy in all areas. In short, how we approach the energy crisis may well determine whether or not we maintain a free economic system in this country.

CAPITAL INVESTMENT

From the supply side, the energy shortages may be viewed primarily as a shortage of capital investment. Without a large increase in the rate of investment, not only in oil and gas production, but also in development of and conversion to other forms of energy the shortage can't be reduced.

Yet the President's plan puts few additional funds into the hands of the producers to stimulate investment. Only the government will have sufficient funds and that means a switch from the private to the public sector. Governments have a very bad record when it comes to making investment decisions. There are many examples in other nations.

THE PLAN'S EFFECT

What is the effect of the plan before you.

1. Instead of reducing government controls, which have helped cause the crisis, it extends them. The intrastate market, which was not controlled, stimulated adequate supplies for consumers in those States while interstate markets, which were controlled, led to severe shortages and unemployment.

Over 10 years, from 1964 to 1974, interstate reserves dropped by 25 percent while intrastate reserves increased. Had it not been for incentive wellhead prices paid by Oklahomans under the free market for years, there would have been no gas in our State to share last winter.

Oklahomans have shared huge amounts of gas over the past two years, at less than $1.50 per Mcf on the average, with little public comment, while headlines of thanksgiving are written when Mexico makes emergency sales at $3.20. It is clear that the answer is to deregulate the interstate market for new gas.

Yet, instead of moving the interstate market toward the free market which has worked, this plan imposes controls, which have failed, on the last healthy market system which we have left. Instead of providing more capital investment, it provides less by

cutting back the price on new gas to $1.75, which is below the current new price in Oklahoma.

2. The proposal does not allow the prices to keep pace with the increased finding costs. Since 1973 finding costs have escalated at about 19 percent a year and that is a conservative estimate because oil and gas are increasingly harder to find. The free market works much better than government controls in reflecting true replacement costs.

3. By keeping the price of natural gas artificially low compared with the Btu equivalency of other fuels like coal, conservation and conversion are impeded, not stimulated.

4. By controlling domestic oil and gas prices far below the international price, not only do we encourage increased dependence on foreign supplies, we also encourage exportation of American jobs and capital to other nations.

If we want an example, we can look at what happened in Canada in the not too recent past and the exportation of their capital and some jobs to the United States.

5. The definition of new oil and new gas under the proposal will make it impossible to have new production in areas such as the deep Anadarko Basin in Oklahoma, where 90 percent of the land is already under lease. Most of the major gas reserves found in the last 15 years have been in or around existing production areas.

By allowing new oil and gas discoveries in the proximity of existing production, the onstream time can be shortened, the environmental costs reduced, and costs to the consumer kept lower due to the accessibility of delivery systems. These definitions are so much in error that only 16 percent of the last 200 wildcat or discovery wells drilled in Oklahoma would qualify for the definition.

I have had a map posted here on the left showing the active locations in Oklahoma at the present time. There are 1,329. You can see a number of the lighter tabs. The darker tabs are those that would fit the definition of new oil or gas under the plan before you.

Of the 1,329 current active locations in Oklahoma, only 6.2 percent would qualify as newly discovered oil and gas under the definition in the plan. I certainly think that casts a doubt as to the credibility of the plan itself, when we have such an error in definitions.

6. The plan does not provide for certainty in pricing for high cost gas such as that from wells deeper than 15,000 feet. It is impossible to make investment decisions when prices are subject to negotiation and possible litigation. Investors simply will not enter into such ventures and the Nation will suffer a loss of potential supply.

Can you imagine investors going out and investing from $5 to $10 million in a well when they are going to negotiate the price later and have it litigated if the Department of Energy sets a price? It won't happen.

7. The plan can be modified relatively easily to provide a much more adequate approach on the supply side and to enable the President to keep his pledge to work for deregulation made to me and other Governors in a letter dated October 19, 1976.

Other aspects of his conservation plan will suppress demand for natural gas sufficiently to allow for deregulation. The definitions of new oil and gas can be changed to allow price incentives for all new wells which increase net production. More of the funds being taken from consumers by the government can be allowed to flow into private investment.

To assure everyone, including consumers in Oklahoma and across the country that private companies do not profit unduly from their sacrifice, an excess profits tax can be applied with a plow-back provision for funds reinvested in energy supply development.

This is not the time to declare defeat. This is not the time to junk the free enterprise system. As the President said in his acceptance speech, when there is a choice between government and free enterprise, we should choose free enterprise. As he said in his October 19, 1976, letter, "The decontrol of producer's prices for new natural gas would provide an incentive for new exploration and would help our Nation's oil and gas operators to attract needed capital." The President was making good sense at the time that he was a candidate for the office.

Mr. Chairman, I urge you and the members of the committee to set the example for the entire Congress by looking to the national interest. The energy issue is too important for the future of the Nation to be treated as a short-term issue for potential political gain.

Thank you very much.

Mr. OTTINGER. Thank you, Governor Boren.

STATEMENT OF GOVERNOR JERRY APODACA, OF THE STATE OF NEW MEXICO

Governor APODACA. We appreciate the opportunity to present our comments concerning the proposed natural gas legislation. Although the State of New Mexico strongly supports a number of approaches President Carter has proposed in his National Energy Plan, we are very concerned about some of the proposals involving natural gas.

We have in the past supported and will continue to support the deregulation of natural gas. Our view on full deregulation may sound strange in view of your knowledge that New Mexico has imposed its own regulations on the pricing of natural gas at the wellhead, sold in intrastate commerce.

But this price ceiling legislation was passed only because of the frustration on New Mexicans in paying an average wellhead price for intrastate gas which averages more than double the interstate prices. The intrastate wellhead price of natural gas has risen sharply in the past two years and without some sort of ceiling would have continued to rise substantially. This trend has already caused severe hardship for many New Mexicans, especially farmers, low income families and certain industries in addition to the hard-pressed middle class.

The legislation passed by the New Mexico Legislature in the past session places a ceiling on natural gas prices at the wellhead for use within the State and makes certain that any price increases in the

next two years will be moderate and that the possibility of enormous increases will be mitigated. The legislation further provides that if Federal deregulation of natural gas prices occurs, then New Mexico's regulation is null and void. I cannot overemphasize our hope that full deregulation of Federal price controls wil occur.

In addressing the natural gas provision of the President's National Energy Plan, I would first like to make a number of general comments and then make some specific comments.

Generally speaking, I believe it is fair to state that one of the basic goals of this part of the plan is to increase interstate natural gas supplies to our Nation.

In my mind, there are two ways you can increase interstate supplies. First, you can encourage new exploration and development or, second, you can take gas from the intrastate market for interstate use.

The State of New Mexico strongly believes that the first approach is the best one to take. Not only would it preserve the intrastate market, but it would produce new gas supplies that would benefit the Nation, the consuming States, the producing States and the gas producers themselves.

But the natural gas provisions of the President's National Energy Plan do not, in reality, provide new incentives. In fact, these provisions provide a number of disincentives.

By establishing a ceiling of $1.75 per Mcf on newly contracted gas, our Nation would be providing a disincentive to the natural gas industry. In respect to finding and producing more gas, this price ceiling would simply not be adequate to meet the Nation's needs much less what would be desirable.

A price ceiling of $1.75 might enable producers to earn a profit. But the profit margin might be so low after exploration costs are taken into account that a producer, like any investor, probably would be tempted to invest his capital in other areas that promised a larger return.

Further, the $1.75 ceiling would not materially improve the cash flow of the natural gas industry and, under certain circumstances, could reduce it. As a consequence, there would not only be less incentive to find and produce more gas, but there will be less capital with which to find and produce gas.

Instead of providing adequate incentives for new exploration, the President's National Energy Plan would seem to have chosen to obtain new gas for the interstate market by taking gas from the intrastate market.

This strategy will have an adverse effect on all of the producing States, but it will have an especially adverse effect on New Mexico.

In New Mexico, we only use about one-eighth of the natural gas we produce. We export the remaining seven-eighths to our sister States.

As a result of these massive exports, New Mexico is experiencing a growing number of problems stemming from natural gas shortages.

I want to emphasize that a substantial number of these shortages are being experienced by high priority users. Passage of these provisions would accelerate the rate of these shortages and would

make it much more difficult for New Mexico to obtain adequate supplies.

I think it should be noted that New Mexico is moving very quickly to convert from oil and gas to coal wherever feasible. By no later than 1986, for example, the State's chief utility plans to be generating no more than 20 percent of its electricity from oil and gas.

In short, I think it is evident that New Mexico is doing almost all it can to help solve our Nation's energy problem. But the provisions of this act would place a burden on New Mexico so heavy that severe economic dislocation and human suffering could result.

We believe the situation we have here, in some respects, resembles a pie. Our recommended approach is for the Federal Government to provide incentives to producers so we can increase the size of that pie. But the approach the President's National Energy Plan seems to take is for the interstate market to increase the size of its slice of the pie at the expense of the intrastate market's slice.

And in New Mexico, where we use only one-eighth of our own production, we would be faced with some very, very serious problems if this was allowed to happen.

If this was permitted to occur, it's not only possible, but probable, that you would not only be cutting New Mexico's gas supply to the bone, but actually cutting into the bone itself.

This approach may be fine for a producing State where a large glut of gas exists on the intrastate market. But in New Mexico, where no glut exists, it would hurt us while we're already hurting.

Let me present you with a few specific examples of how the natural gas provisions in this bill could hurt New Mexico.

First, New Mexico would be hard-pressed to keep the gas flowing from existing intrastate contracts for consumption within the State. This is because this gas, when contracts expire, would command a $1.75 per Mcf price in the interstate market, while it would command a maximum of $1.44 per Mcf in our intrastate market under New Mexico's Natural Gas Pricing Act.

It should be emphasized that the State of New Mexico implemented this price control ceiling only after the Federal Power Commission refused to protect us from skyrocketing prices and, in effect, told us to protect ourselves. So we did act to protect ourselves, and now we find the rules of the game are being changed.

Second, all "new gas" would be subject to a ceiling of approximately $1.75 per Mcf at the beginning of 1978 whether the gas is intrastate or interstate. Under New Mexico's Natural Gas Pricing Act, the intrastate part of this gas would be free of controls. This provision was included in the law in an effort to provide incentives for exploration and production of new gas. The President's program would eliminate this incentive to a large degree. As a result, New Mexico could be expected to experience a decrease in drilling activity, gas supplies and tax revenues to the State.

Third, some of the post-1975 contracts which have been entered into prior to April 20, 1977, and which are not controlled under the Natural Gas Pricing Act, are carrying a price in excess of $1.75 per Mcf. When they expire, according to the President's program, their prices may have to be rolled back to the maximum ceiling existing at that time.

Fourth, the program ties the price of "new gas" to the historically regulated wellhead equivalent for domestic crude oil. But the President's advisors have chosen the wrong figure. A price in excess of $2 per Mcf more accurately reflects the true value of natral gas based on heating value when compared to other fuels.

Finally, New Mexico is very concerned about the effect the provisions of the President's plan would have on New Mexico's natural gas load factor. New Mexico's intrastate system is characterized by a much poorer load factor than that of interstate pipelines. As a result, the State's intrastate suppliers have been forced to pay a higher price for gas than interstate suppliers which have better load factors. This situation leaves the intrastate suppliers at a disadvantage compared to interstate suppliers when bidding for gas.

It should be noted that the average load factor New Mexico's intrastate system does have has been achieved and maintained by an extensive use of natural gas for electrical generation and boiler fuel. In 1976, about 36 percent of the gas the State consumed was used for electrical generation, and about 24 percent was used for industrial uses.

The President's program contains provisions which would eventually stop the use of gas for these purposes. As a result, the State's load factor can be expected to deteriorate even further in the future. Although other States will experience the same problem, the problem will be much worse in New Mexico because there is relatively little industry in the State. This situation poses further problems for New Mexico's intrastate suppliers because of the average load factor, and forces these suppliers to pay producers more for gas than interstate suppliers which tend to have better load factors.

My specific observations about the portion of the National Energy Plan that relates to natural gas include the following:

With respect to section 402, "Definitions," first of all, there is subsection (4), which includes in the definition of "person" all States and political subdivisions. By broadening the definition of "person" from that which has prevailed in the Natural Gas Act, New Mexico might no longer be able to act directly to purchase State-owned or royalty gas and arrange for its transportation through interstate pipelines for the benefit of communities in the State which are suffering from inadequate supplies of natural gas. This result would not seem to be in the public interest.

Secondly, the definition of "new natural gas" in subsection (5) would seem to exclude so-called "in-fill" wells, which account for a very substantial proportion of newly-produced natural gas in New Mexico. Thus utilizing such a restrictive definition would not seem to be consistent with the administration's goal of "increasing the supply" of natural gas.

Thirdly, the definitions of "old" and "new" wells, in subsections (8) and (9) may not together cover all relevant possibilities, for example, a well, the drilling of which was begun before April 20, 1977, but which was at that date neither producing nor capable of producing oil or gas.

As for section 404, regarding "Sales of New Natural Gas," New Mexico finds numerous difficulties, both generally and specifically. My general objections are noted earlier in more detail, but, in brief, they relate to the likelihood that this extension of price ceilings to the intrastate market, at an initial ceiling of approximately $1.75 per Mcf, will inhibit the exploration for and development of new natural gas in the State, thereby inhibiting the State's tax revenues and its employment and income prospects. The major specific objection worth noting is the setting of the ceiling price.

We now arrive at the sections of the act which relate to so-called "old gas." I would begin by noting that both sections 405 and 406 are extremely difficult to understand and are not expressed as clearly as would seem to be possible under the circumstances. My advisors and I are not certain that intrastate gas under existing contracts are excluded from the provisions of section 405. We understand this to be the intent of the administration but are not certain that the language in this section is fully appropriate.

As for section 406, subsection (b), part (2) the language would seem to set a ceiling price of $1.45 per Mcf for certain categories of intrastate gas, as well as interstate gas. In particular, it would seem to encompass "in-fill" wells—as noted in my comments above—as well as any intrastate gas for which a contract expired after April 20, 1977. Thus, as contracts would expire prices could often be rolled back—if gas continues to be sold in the intrastate market—to a ceiling of $1.45 even though the previous price would often have been over $2.50 per Mcf. Such a sequence of events could well reduce severance and other tax revenues for New Mexico, among the possible deleterious consequences.

There is also a question of equity, because while there would be forced price rollbacks in the intrastate market, prices in the interstate market would increase upon the expiration of existing contracts. It would seem that an expiring interstate contract for flowing gas could go from $0.52 to $1.45, while an identical intrastate situation could result in a rollback from $2.25 to $1.45.

Section 406 also would create a service equity problem in its final subsection (c), in which it is proposed that when contracts expire for old gas sold in intrastate markets, sales could be made to the interstate market for up to $1.75, in comparison with a ceiling allowable price of $1.45 if that gas were to continue to be sold intrastate. Thus, this subsection would seem to represent a deliberate attempt to divert natural gas from intrastate to interstate markets. Such an attempt raises serious questions of equity, of course; but for New Mexico the effects would be especially harsh, because it already suffers from inadequate supplies of natural gas in many areas of the state. Currently, our State exports seven-eighths of the gas produced within its boundary and retains only one-eighth for its own use. For the Federal Government to attempt to take over an even larger proportion of New Mexico's gas would clearly seem to be unjust and unfair.

I would now like to address two other sections of the act which have raised questions for State's citizens. First, there is section 412, which is concerned with abandonment. The section seems to prohibit contractural provisions that would permanently allocate quan-

tities of gas to the intrastate market. Yet the Federal Power Commission has not permitted the converse to occur. Gas sold interstate, under appropriate conditions, is not permitted to be later sold in intrastate markets.

Finally, there is section 414, regarding "Incremental Pricing of Natural Gas." The effect would be to raise the price of natural gas for "low priority" uses. But it seems possible that this category would include some or all uses of natural gas for agriculture, which would not be fair or just, we believe. In addition, New Mexico's load factor could well further deteriorate, placing even greater financial burdens on residential and light commercial users of natural gas.

Thank you, Mr. Chairman.

Mr. OTTINGER. I am now going to recognize members in the order in which they appeared this morning. We have a panel of State regulatory officials that we invited for 11:30, so I am going to have to stick rather rigidly to the 5-minute rule.

Mr. Krueger, you are first recognized.

Mr. KRUEGER. Thank you, Mr. Chairman.

Now you understand the particular pleasure I had in the testimony of the two gentlemen before us. I think they have indeed spoken good sense.

I would like to point out both as an opening to both the panel before us and to my committee members that if the Congress were to impose a tax on the States, for example, of Oklahoma and Texas and the proceeds of that tax were then to be paid and redistributed to other States in the Union, there might be thought to be some regional unfairness and disparity in such a tax.

Now what happens if the people of one section of the country are required to sell some of their basic natural resources, required to sell one of their principal sources of wealth, at a price vastly below the world price and yet they are required to buy back whatever they purchase at the world price?

It works precisely the same as a tax imposed on one section of the country to be distributed to other sections of the country.

What the President is proposing is a tax on Texas and Oklahoma done through the device of price controls in which these States are asked to sell some of their precious resources at far below the world price in order that they can buy back at the world price.

Now when one nation does this to another nation, we have a term for it. We call it colonialism. We call it discrimination. That is what it is. I feel very strongly about that. I suspect that we have among others a number of economists here as advisors to the Governors. I should appreciate knowing whether the Governors and their advisors can see any faulty logic in that little parable.

Governor BOREN. Well, I certainly think it is correct. I certainly think that there is a regional imbalance. I want to make it clear that the people of Oklahoma are certainly willing to make their share of the sacrifices.

We know the energy crisis before us requires sacrifice from the entire country and we want to do our part. I do think there is definitely a regional imbalance in taking our product below its true value. I think even more damaging than what it is going to do to Oklahoma and Texas is what it is going to do to the Nation in the

form of temptations to export our capital, jobs and technology into other areas.

It simply does not make any sense to me, as I said a while ago. We are willing to pay prices much higher for oil and gas produced in other countries than we are willing to give to our own producers as an incentive. The worse thing that is going to happen for the country simply is that the wells are not going to be drilled. Producers are not hurt when they just don't drill. We have to keep that absolutely in mind.

The President has said, "We must pay the true cost of energy." He said we must pay the true costs. We are going to have to face up to that as consumers. Yet, we are under this plan not allowing the true cost of energy to be paid to the producer so that the consumer may have more of it.

It makes no sense at all, Congressman Krueger, and it is regionally imbalanced as well, as you have indicated.

Governor BRISCOE. Mr. Krueger, of course, I agree with everything you have said. Let me say the viewpoint of the State of Texas is that we have done our part in the past. We have produced. Over 600,000 holes have been drilled in Texas soil searching for oil and gas. Some 1,200 are in the bays and estuaries of our State. We have done our part in the past. We want to be allowed to do our part in the future.

I agree with every statement that you made. Perhaps Dr. Rostow would like to comment.

Dr. ROSTOW. Mr. Chairman, as an economist I would only say that with tariffs and other inhibitions on imports, that we in Texas and we consumers in the United States pay higher than the world price. These tariffs exist, of course, to try to protect interests in other parts of the country.

But my attitude, sir, is a bit different. It reflects the mood of the statement of both Governors. What has concerned me as I have come to study this program against the background of the history of the past 200 years is that we are in a situation where the whole Nation will have to try to play its part in both the conservation and the production sides of this program.

I spoke in Springfield, Massachusetts, not so long ago and explained the depth of the feeling in the part of the country in which I have the privilege of living about what seems to be the attitude that it is quite all right for people in the Gulf to take the risks with their environment and actually the Gulf environment is excellent, but other parts of the country must not put an absolute priority on environmental considerations and must develop our energy resources.

I believe that that is the most aching popular feeling in our part of the country. I also believe that if the other parts of the country, and that would include western coal as well as Atlantic and Pacific offshore oil or middle western resources, if all the parts of the country were making a maximum effort or were taking the kinds of steps to preserve the environment that were rational that have been done with respect to coal and offshore oil in the Gulf, I believe that from my impression of that part of the world, the people of Oklahoma, Louisiana and Texas would be prepared to make a

disproportionate contribution just as they did in the Second World War and in other crises.

Mr. KRUEGER. I think what we have heard then is that we are not asking for other people to pay us any more than we pay ourselves. We are not asking to discriminate against other parts of the country. All we are asking for is equity.

Thank you, Mr. Chairman.

Mr. OTTINGER. The time of the gentleman has expired.

The gentleman from Connecticut, Mr. Moffett.

Mr. MOFFETT. I am glad both of you gentlemen are here. Just a comment to my good friend from Texas that I think his comment indicates that he wants Texas to join OPEC as soon as possible. I really would not want to see that happen.

We like having you here, Bob.

Mr. KRUEGER. Thank you. I don't want to join.

Mr. MOFFETT. If we were to ask Texas how they would feel if the market in automobiles and consumer products was not the result of market pricing but was a result of all autos being manufactured overseas and controlled by a cartel, I think Texas would feel a bit slighted by that.

I wonder how quickly our friends from Texas and Oklahoma forget when the so-called free market was one in which foreign producers were dumping oil at very, very low prices and forcing the price down that the U.S. Government stepped in with import quotas and it was our consumers in places like Connecticut who subsidized producers in Oklahoma and Texas for something like 15 years.

So if we are really going to talk about a national perspective, let's understand, Governor Boren and Governor Briscoe, that there is no free market. That is the reality that we face. It is nice to hear you talk about free market and it sounds great and all of us pay lip service to the free enterprise system. But the fact of the matter is, and you are a lot smarter in the energy area than many of us because you look at it close up everyday, but I would think that would lead you to admit that there really is no free market.

If we really want to talk about the free market, then we ought to talk about things like horizontal divestiture and so forth, and really make the ball game a fair one rather than continuing to further what I regard as a myth.

I would like to ask Governor Briscoe, you talk on page 4 of your testimony about the painful experience. You said it has been a painful experience of the production of natural gas I guess it is you are referring to.

I wonder what kind of feedback, Governor, do you get, and I know you are immensely popular in your State, from consumers about consumer prices, because we do hear from Texans and from Texas leaders. They keep saying "Gee, our people have been willing to make this sacrifice."

How is that reflected? How is their willingness to make the sacrifice and pay those higher prices reflected?

Governor BRISCOE. In the first place, I disagree respectfully but most basically with the statements that you have made. I think that there can be a free market system, that the free enterprise system can work, and it has worked where government gives it a chance to work.

Mr. MOFFETT. I believe that too, Governor.

Governor BRISCOE. Basically, if we could get government regulation out of the way, there would be very little problem in solving the energy problem.

Mr. MOFFETT. Could we make a deal then to make the structure of the industry change it so that there is more competition and get the major oil companies out of the competing fuels and then we will take the regulations off? That would be a good compromise, wouldn't it?

Governor BRISCOE. You know that 85 percent of the new reserves for oil and gas are found by the independents, and not by the major companies. I think we need to get the restrictions off so that they will know what they are doing, and let them operate in a free marketplace system, free of regulations, free of litigation.

To your question, specifically, in Texas we have had a free market price system for natural gas. The price of natural gas has increased to a point to where Texans have been paying, as I mentioned in here, some four times as much for natural gas as gas sold in the interstate market. The difference is basically this. We have had gas while in the interstate market have shortages existed.

I think if you trace the entire history of the energy crisis that exists today, it can be traced back to 1954 when the Federal Power Commission first started regulating the price of natural gas. It regulated the price at an unrealistically low price compared to other fuels, so today we are using less coal as a percentage of our total energy than we used in 1954 where really what we need to be doing is utilizing more coal, our largest reserve of fossil fuel. Again if the government would get out of the way, let marketplace, the mechanism of the marketplace determine the price, determine the choice that is made by individuals and industry as to which source of energy to use, instead of it being made, the price decision being made, by somebody in government.

I am convinced that there is no one in or out of government smart enough to make price controls work for the long-range benefit of the consumers of this Nation.

Mr. MOFFETT. I appreciate your answer, but you are attributing the fact that you had gas and we didn't to the fact that you have what is an unregulated situation in Texas I think is a bit inaccurate in that there are other factors as we know. We know quite naturally the difference in the interstate and intrastate market, and what leads producers to go into the intrastate market. It is very natural, it seems to me, just in the same way that it is natural for a producer to wait, if a producer thinks that there is going to be a higher price coming along. I think that might have had more than a little bit to do with the fact that the interstate market did not have enough gas.

What about this Justice Department antitrust investigation of intrastate price fixing? Do we know anything about that, except that it is going on? Do you think that there is anything to that?

Governor BRISCOE. I know nothing about it. I mean I know nothing more than has been in the papers about it. Let's talk about the need to produce. Again some large part, approximately 50 percent of our known reserves of fossil fuel, are under government

lands, lands controlled by the Federal Government and they are producing now only 10 percent of our energy. Some 85 percent of that 10 percent is produced off the coasts of Texas and Louisiana. There is something wrong, basically wrong, when those reserves that are under the direct control of the Federal Government are not being utilized.

Mr. MOFFETT. I understand your point on that, Governor.

Is there anything about windfall profits that you know? I know Governor Boren mentioned excess profit tax, but do we know what the rate of return is on $1.75 gas? Do we have any data on that? Do the Governors have any data on that?

Governor BRISCOE. I think the rate of return would vary considerably from one situation to another. I agree very strongly with Governor Boren that any windfall profit should be put back into the drilling for additional reserves. That should be part of any deregulation plan.

Governor BOREN. Dr. Talley, I think, could answer the question.

Mr. OTTINGER. If he can do it just very briefly, but we are going to run into time constraints.

Dr. TALLEY. Based on FPC methodology on 1977 projected drilling costs, that would approximately be equal to the average well, whatever an average well is. I have no idea what an average well is, but it would not allow the development in many areas of Oklahoma which could yield tremendous amounts of resources and get them on stream in a quick period of time into existing delivery systems to go to your States so that your consumers could have natural gas.

Mr. MOFFETT. Just an inquiry, Mr. Chairman.

I am sorry, Doctor, I didn't catch earlier your affiliation. Are you an aide to the Governor?

Dr. TALLEY. I am chairman of the Governor's Advisory Council on Energy.

Governor BOREN. And he is former director of our State Department of Energy.

Mr. OTTINGER. Mr. Moorhead.

Mr. MOORHEAD. Governor Briscoe, you in your statement, have been pretty general in your comments about the President's plan. The President stated that he felt that we should pay the true replacement costs of energy, but that it should be received from the consumer by adding the tax to what he is presently paying and that that tax should be distributed as well for distributions for people throughout the country who might have higher costs of living, but that it should not go to a few people who would be unjustly enriched.

Would you make a comment on that policy that the administration has adopted?

Governor BRISCOE. I would agree that no one should be unjustly enriched, and I think that would be the basis for the addition, for the inclusion in any plan, of a windfall profit tax.

Let me say personally I am against new taxes, all new taxes, on the State level and on the Federal level.

Mr. MOORHEAD. A windfall tax would be a new tax, wouldn't it?

Governor BRISCOE. Yes, sir. It would be an addition. It would have to be—I think in order to be fair, that there would have to be—a

plowback provision, that those profits, excess profits, would have to be plowed back into additional drilling, into additional exploration.

Mr. MOORHEAD. I happen to agree with you, but how do we answer the questions from the other side which says that allowing the funding of exploration and increased production actually would be enrichment?

Governor BRISCOE. Governor Boren wants to comment.

Governor BOREN. Congressman, I think that there is a very simple answer. The best way to enrich all of the people in this country right now, not just the producers, is to do something on the supply side of energy. In other words, just like I said in my opening statement, we raised the cost price to the consumer but we do not take any of that money and use it to invest in expansion of the supply of energy. All that we have done is soften the blow of the shortage on some economically deprived, and all we have done is effectively conserve the shortage, but we have done nothing to overcome the shortage, and I think that we can assure, with excess profits and plowback, what that assurance is, and I am not saying that all of it should be to the producer, let's use some of it to soften the blow but let's put the rest to the producer to help overcome the shortage. There is no light at the end of the tunnel if you take all of the money for the true cost of energy paid by the consumer and don't put any of it back in investment.

Mr. MOORHEAD. What do you consider to be the replacement cost of natural gas at the present time?

Governor BOREN. I think the replacement cost is reflected best by the market and this is what I think.

Mr. MOORHEAD. That is true and I agree with you but I don't think we are going to get many changes in this program without people becoming alarmed around the country because we have been told that any variation in the program would completely knock it off balance and it can't stand very many amendments.

What if we have to take some price? What is it?

Governor BOREN. I would just say I think it would be a tragic mistake, and hopefully the wisdom of this committee and this Congress will be heard because in this country we have chosen the market over centralized economic planning because we felt the market could reflect costs much better than central planners and I think that is what we should stick with. If the market itself is allowing excess or windfall profits, tinker with it there and adjust it there through the tax mechanism. I think that has to be the answer.

The answer I could give you today, the answer might have been 40 cents or 54 cents at one time but it changed, and yet governmental planning does not adjust to it.

Mr. MOORHEAD. One thing that might be helpful for us, Governor Briscoe, Governor Boren has given us some very interesting information on this map up here. I wondered whether we could get the same kind of information concerning Texas that we got concerning Oklahoma.

Governor BRISCOE. Absolutely.

Mr. MOORHEAD. New gas taxes and so forth.

Governor BRISCOE. Sir? On new wells?

Mr. MOORHEAD. The impact of the new gas definition.

Governor BRISCOE. Oh, the impact of the new gas definition would include very, very few wells that have been drilled in Texas. The chairman of the Texas Railroad Commission will testify here later, and I think he will have that detailed information for you.

Mr. MOORHEAD. Do you have any other specific points in this program that you think need to be corrected, Governor Briscoe? You had a pretty general statement. We are going to be acting on this within the next few months.

Governor BRISCOE. I think to be very specific, the change in the pricing policy should be one of deregulation instead of continued regulation, should not be an invasion of the intrastate market with authority for price controls or allocation.

Mr. MOORHEAD. I think that if that is what you want we will have to forgive you for the mistake which you made last fall. Thank you very much.

Mr. OTTINGER. The gentleman from Louisiana, Mr. Moore.

Mr. MOORE. Thank you, Mr. Chairman.

Yesterday we had testimony from producers, many of whom were from both of your States, Governors, and as I understood their testimony, they felt like under the existing plan that we have before us of regulating the price of intrastate gas and continuing regulations of interstate gas, that there wouldn't be that much new gas produced but what was produced, would tend to stay in the intrastate market or stay within the States.

Do you all agree with that, due to the agencies and producers dealing with the regulated interstate market?

Governor BRISCOE. Yes, I agree with that.

Governor BOREN. Yes.

Mr. MOORE. That being the case, it would appear—and I would ask for comment from both of you—would it not appear then that the only way we are going to get more gas from your two States and from mine, Louisiana, into the interstate market, would be to deregulate, to have our producers lose this fear or this prejudice against doing business in interstate commerce?

Governor BOREN. I certainly think that is the way to do it. This is the reason that we are certainly taking a position in the national interest and not one that is regional because we are opening the gas which we have produced to competition from the interstate market by advocating deregulation.

Going back to a couple of comments that have been made earlier I think that what Governor Briscoe and I are proposing, the changes that can be made by this committee, without really upsetting the balance of the entire plan, because you see with all of the imposition of restraint on consumption of natural gas included in the President's plan, I think there are adequate constraints on the market which will certainly soften demand for natural gas to allow us at this time to safely have deregulation of natural gas, so I think that that is the only way that you are going to assure that States like Connecticut, which Mr. Moffett represents, the only way they are going to get an adequate supply of gas for their consumers is deregulation, and it can be safely accomplished within the balance of this plan.

Governor BRISCOE. I agree. I agree very strongly that deregulation is in the national interest. I think a case could be made that it is not in the short-range interest of a producing State but it is in the national interest. It is the only way that whatever reserves of natural gas there are in this country will be drilled. The only way to find any reserve, to determine whether or not it is there, the extent of the production available from that reserve, is through drilling, and that requires the attraction of great amounts of risk capital.

Mr. MOORE. Would it also be fair to say that if we deregulated, if we had the spurt on production which we believe will take place in natural gas by deregulation, and much of that gas would thereby leave your States and mine and go into interstate commerce, what was left behind in intrastate commerce will probably cost more than we are paying now?

Do you agree with that comment?

Governor BOREN. Perhaps in the short run. I think in the long run the expansion of supply will be in the best interest of the consumer—

Mr. MOORE. —to stabilize the price.

Governor BOREN. Not only in Louisiana, Texas and Oklahoma but nationwide. This is the thing we must not forget and this is something I hope the committee will consider.

How are we going to get more supply? There is only one way to get more supply, more investment. I think that we must—really the energy shortage, the energy crisis, is a capital investment shortage as much as anything else, and I think that we must ask ourselves again and again will this get more money invested? That is the only way you can get the rig count up to 3,500 investments. That is the only way.

Governor BRISCOE. I would like to respond in this way. In the intrastate market in Texas at the time of the peak demand and the lowest supply, the price in the intrastate market of natural gas got up to around $2.10, $2.20, maybe even $2.25. As the result of the additional drilling, the supply of gas built up, the price fell off to $1.80, $1.75. So supply and demand does work. As incentives bring on additional supply, the price will reflect those additional supplies, and I think that will happen in the interstate market exactly as it has in the intrastate market.

Mr. MOORE. Governor Briscoe, I believe you in particular mentioned earlier that any problems that deregulation would cause on the pressure on our own intrastate markets in our States was something that you said in your case you and the Texans would just simply have to work out as best you could, and you were not going to stand in the way of producing these supplies for the rest of the Nation by virtue of what it might do on your intrastate market.

Did I understand you correctly in that regard?

Governor BRISCOE. Exactly.

Mr. MOORE. I want to commend both of you. My Governor was supposed to have been with you here this morning and couldn't be. I think that he takes the same position the two of you do, and I believe that position simply is the only way we are going to get the supply is to produce it even if it hurts our own consumers in our

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States, we are willing to do it. If we continue the way the President's program is right now, that really profits our State by keeping what new gas will be produced, very little, in the intrastate market. It won't get into interstate commerce at all so it actually would be, as I understand it, in our own selfish interest to go along with the program like it has been proposed rather than in the national interest.

Do you all agree with that?

Governor BRISCOE. I most certainly do.

Governor BOREN. I do.

Mr. MOORE. I would also like just in passing, Governor Boren, to say much comment has been made about this letter. I take it you don't accept the existing bill as being fulfillment of the pledge that was made to you on October 19, 1976.

Governor BOREN. I would say that I recognize nothing in the plan which bears resemblance to the statements made in the letter.

Mr. MOORE. Mr. Chairman, at that point I ask that this letter of October 19, 1976, may be made a part of the record since it has been referred to some three times now in the course of testimony.

Mr. OTTINGER. I will be kinder to the gentleman than he was to me sometime ago.

Without objection it will be included.

[The letter referred to follows:]

THE HONORABLE DOLPH BRISCOE,
Governor of Texas,
Capitol Building, Austin, Texas

DEAR GOVERNOR BRISCOE: The formulation of a workable national energy policy implemented by a responsive, understandable governmental structure will be of highest priority in a Carter Administration. If we are to reach our goals of full employment and a healthy, growing economy, we must reduce our dangerous dependence on foreign oil and we must develop our own domestic energy supplies. These resources must be produced and used in an environmentally acceptable manner at a cost that the consumer can afford to pay.

A sound energy policy must aggressively promote conservation of our scarce oil and gas resources. This is the only way in which we can hope to make ends meet in our energy budget. But, coupled with energy conservation, our policy must encourage additional production of our domestic reserves.

Eight years of Republican administration have failed to produce an energy policy. Demand for new energy supplies has increased by over 4% per year since 1968—even though demand was reduced considerably during the recession triggered by the Arab oil embargo. At the same time, domestic production and resources have decreased substantially, and dependence on foreign supplies has increased from 35% prior to the embargo to over 40% today.

To increase our domestic production, I have proposed three important steps.

First, I will work with the Congress, as the Ford administration has been unable to do, to deregulate new natural gas. The decontrol of producers prices for new natural gas would provide an incentive for new exploration and would help our nation's oil and gas operators attract needed capital. Deregulation of new gas would encourage sales in the interstate market and help lessen the prospect of shortages in the non-producing states which rely on interstate supplies. While encouraging new production, this proposal will protect the consumer against sudden, sharp increases in the average price of natural gas.

Second, I believe we should act to encourage enhanced recovery from wells already in production. As you well know, an average of 60% of our oil remains in the ground after standard recovery methods have been exhausted. It is estimated that up to 60 billion barrels of crude could be added to our supply if enhanced recovery techniques are used. Since the environmental costs have already been largely paid on these resources, both consumers and producers alike benefit from development of this resource.

Third, I favor a substantial shift from the use of oil and gas—our highest quality energy sources—to coal, which we have in abundance. We must immediately begin a program to encourage conversion from the use of petroleum and natural gas to coal in those applications for which coal is an acceptable substitute. Our present demand for coal is limited by two important factors. First, we have geared our technological growth to oil and gas for well over 100 years. Second, we have failed to establish a stable regulatory climate in which coal producers are sure of the rules of the game before they make investments in expanded production of new mines. Switching to the use of coal will require strong presidential leadership and proper federal incentives to encourage the conversion process. A Carter Administration will provide this leadership.

I hope these policy recommendations will help to put my views on the supply aspects of the energy problem into focus. Without a strong commitment to increasing our domestic production, while maintaining basic environmental principles, we cannot hope to reverse the unhealthy trends which the lack of leadership of the current administration has produced.

Sincerely,

JIMMY CARTER.

Mr. MOORE. I thank the chairman.

Mr. OTTINGER. The gentleman from Indiana, Mr. Sharp.

Mr. SHARP. Thank you, Mr. Chairman.

I am pleased to hear that the Governors are going to take the selfless route and do this for the national interest and I am delighted to hear that especially after the earlier comments of the gentleman from Texas on the panel. I think you raise important questions about the economics of this and the production, and we have got to assess those very clearly and I don't have a whole series of directed questions on that subject. I have another subject I want to get into as a result of my friend on this panel.

Can you tell me this: How much of the productive resources in oil and gas does the State of Texas own, the State government I am speaking of?

Governor Briscoe. I cannot offhand give you that figure. We will supply to you—

Mr. SHARP. Can you give me any kind of ball park figure? Is that 90 percent, 10 percent, 40 percent?

Governor BRISCOE. No, it is not anything like 90.

Dr. FISHER. Less than 10 percent.

Mr. SHARP. How about in the State of Oklahoma?

Governor BOREN. Between 1 and 2 percent.

Mr. SHARP. Can you tell me what percentage of the population in Texas and Oklahoma would you guess owns either the reserves or the productive facilities, have some stake in ownership of that? Do you have any idea on that? Is that kind of information available?

Governor BOREN. We are calculating.

Mr. SHARP. Again I am just interested in sort of rough percentages.

Are we talking about 90 percent of the population? Are we talking about 10 percent or less of the population?

Governor BOREN. It is very difficult because virtually all of the landowners you see own some mineral interests so I don't know if we are talking about 20 percent of the population or what, would have some interest, direct or indirect. As I pointed out, about one tenth of the jobs in the State are derivatives directly or indirectly to the multiplier and other things. There are approximately 60,000 direct employees.

Governor BRISCOE. Approximately 1 out of 18 in Texas is employed in the oil and gas industry or related to it. I mean if you have some specific questions like that, we will be glad to supply you the answer.

Mr. SHARP. No, I am just trying to establish the proportion. I don't want to generate more paperwork for all of us. What I am trying to drive at a little bit, I am trying to figure out who it is we Yankee imperialists are robbing of all these resources.

You gentlemen have been very kind in your national perspective. This line of questioning is for the gentleman at my left, my friend here. I just am not convinced that the colonialist argument is a valid one whatsoever. I am convinced there is a real regional problem in this situation as to equity in who is going to pay the bill to go into production. I think there is a reasonable regional question represented by Dr. Rostow, I believe is your name, in who is going to be willing to despoil or pay some costs in environment, and I think it is extremely unjust in this country when one segment decides "Well, we don't want to have to produce and take the costs but we will ride on the backs of someone else."

I agree those are legitimate regional concerns, and I hope you will find this committee concerned about that. I just got a little roused up by my friend from Texas.

Mr. KRUEGER. Would the gentleman yield?

Mr. SHARP. Certainly. I used his name in vain.

Mr. KRUEGER. Not in vain. I would simply point out that I think the colonialist argument is a sound one, but the one of three dollars in the economy of my State is directly connected with oil and gas production including the petrochemical industry and a whole host of jobs. I realize that there have been many new jobs coming into that part of the country. The Governors may wish to respond on to what extent the availability of energy supply has brought jobs there, but one out of three dollars in our economy is directly related to oil and gas, and it still seems to me that the analogy is sound.

The land is of course owned by a whole variety of people, Alaska among them.

Mr. SHARP. My constituent.

Mr. KRUEGER. Not among those who own land with minerals. The reason the State of Texas is either wealthiest or the second wealthiest in the U.S.A., is because of the mineral rights of lands set aside by Moses Austin and others who founded our State for education. The reason I suppose that our State is in a fairly healthy financial position is that there have been severance taxes, which is a kind of investment for the future of the citizens of our State, and one of the things I think that the citizens of our State are concerned about is that if we will pay severance taxes to others for coal which we import to our State and which we are required to change over to, what do we do in terms of the reserves that we sell, which have comparably much lower severance taxes?

I thank the gentleman for yielding?

Mr. SHARP. I appreciate that. God was good to Indiana with the land for farming and productive people who create automobiles that go into your section of the country, and people who pay a lot of money in energy costs, increased rates that go into your part of the

country for these resources that people devote their time to get out of the ground. I am just wanting to get us back to a little more national view of things. We paid a lot of taxes that went into the space program which came back very simply to my part of the country and to a whole series of these others. I am not trying to auction one part of the country off against another. I think we are in this together and I just hope that we will try to understand the regional differences.

Mr. KRUEGER. And we will pay you as much for your Chevrolets as you pay yourselves.

Governor BOREN. Mr. Sharp, when we talk about the intrastate market and the interstate market, I really and truly believe in fact that we have had the intrastate market unfettered, and the fact that we are paying about four times on the average at the wellhead for what those in Indiana pay is really the reason why we have adequate supplies, and we are very serious in believing this is in the national interest when we say we have had this experience and it worked.

Mr. SHARP. I fundamentally agree with you that the differential in the market has of course led your consumers to pay a higher price than my consumers have paid over time, and that differential has not worked to the national interest to our long-term interests, and doesn't work to your long-term interests, and we are clearly going to get rid of it. The argument then is whether we immediately let the market set the prices, the question of competition is another issue too, or do we regulate that price at some level in hopes of moving toward more unregulated pricing. That seems to me to be the case. I am sure I have overstepped my time.

Mr. OTTINGER. The time of the gentleman has expired.

The gentleman from Pennsylvania, Mr. Walgren.

Mr. WALGREN. Just to follow up on the thought of the different prices in the intrastate and the interstate, you would agree with me, and I think we all agree that the experience of a market half regulated and half not regulated has been a very disappointing one. That leaves two options. One, either to regulate the market completely, or not to regulate the market at all, and that it would at least be a rational conclusion from our experience that to regulate both interstate and intrastate may yield an acceptable result in our economics.

Governor BOREN. Mr. Walgren, I would say that defies logic for this reason: You have one market that has worked. You have one market that has not worked. The whole basis of our economic system and what we start teaching children from the first grade on in this country is we believe in the market mechanism for reflecting costs and values of products rather than in central economic planning because we have been notoriously so. There is always a lag time built into central economic planning, and so I would say let's not impose the controls which have not worked on the one market mechanism left that is still working, that the logical solution for Pennsylvania as well as for Oklahoma is to allow the market mechanism, which has worked, to prevail for the entire country and the entire country benefits from it.

Governor BRISCOE. May I respond to that too?

Mr. WALGREN. Yes, you may.

Governor BRISCOE. Because I most respectfully disagree of course with your first premise. I agree with Governor Boren. The market, the intrastate market, has worked. We have increased supplies of gas. I mean we are able to meet demands in the intrastate market. The interstate market does not work. There is no logic whatsoever, as I see it, absolutely none, to extend a bankrupt policy, one that is proven that it won't work, to the intrastate market that has worked as a free market system.

Mr. WALGREN. Do you feel that the regulation in the interstate market has assisted the intrastate market in working?

Governor BRISCOE. No.

Mr. WALGREN. Because you have testified that there was a positive disincentive for producers to go into the interstate market, and I think we have seen specific instances where they have shown great biases to stay within the intrastate market, and don't you believe that the fact that the regulation in the interstate market has been a positive factor in the intrastate market, that would not be there if we were to move to a totally regulated market?

Governor BRISCOE. I think the regulation of the interstate market has been a negative factor in every sense of the word, negative in that it has reduced the usage of coal, negative in every sense of the word.

Mr. WALGREN. And it has been negative to the intrastate market, when you say "every sense of the word."

Governor BRISCOE. Yes, absolutely.

Mr. WALGREN. Has it been negative to the intrastate market?

Governor BRISCOE. Because it has discouraged additional drilling that otherwise I think would have taken place. Governor BOREN. The market goes soft, the demand for intrastate goes soft, because it becomes saturated plus there are many fields, Mr. Walgren, that are not on intrastate pipelines, and therefore these reserves are not—the exploration of these areas is not occurring. The reserves are not developing because there is no way that they can produce for the interstate market at the controlled prices.

Mr. WALGREN. Governor Boren, I just wanted to explore a little bit further your advocacy of an excess profit tax, and, specifically, what form of tax? What are the specifics of your proposal in that area?

Governor BOREN. Well, I am not prepared to be very specific except in concept, and that is, that it seems to me, no one, including the Governors of producing States or anyone else, wants to see the sacrifices of the American people go into unjust enrichment of any small group of people. What we want to see is the increased prices that are paid by the consumer, not only going into programs that will soften the blow on the consumer, but also go into stimulating more supply, which in the long run will help the consumer.

Now if we want to make sure that no one makes windfall profits or excess profits, let's impose an excess profits or a windfall profit tax and excuse it only on the basis of money being reinvested, not just oil and gas people reinvesting in oil and gas, but since we have a capital shortage, investment in any form of energy development.

Mr. WALGREN. Do you think it would be adequate to take the average return on capital that is being invested in various areas and put an increment on top of that of, let's say, 5 percent, and, say, that anything that a corporation made over and above that with allowances for carrying forward losses and things like that would be an adequate rate of return and the balance should be taxed off?

Governor BOREN. Let me say that I am not qualified to respond on the details of how you would draw the tax or what rate of return you would set. With all due respect, and I hope this won't be taken improperly, let me say that I believe Congress has never had much difficulty in devising proper methods for taxing the people, and I believe I would certainly be willing to leave it up to the Congress with thorough research to find the proper levels and the proper mechanism for doing it.

Mr. WALGREN. The problem being that under some views there is presently excess profit in the oil and gas industry, and that the return on capital is substantial, and substantially greater than the rest of the economy.

Governor BOREN. I would certainly be willing to see something that would bring equity with the rest of the economy. I am not prepared to argue the figures as to whether those figures are correct or not. I would say we have got to encourage investment. You know, this is one of the things that worries me a little bit about some comments that have been made today, and not necessarily by you, but you know, we ought to have policies in this country that will encourage people in all sorts of other businesses to be investing in energy rather than encouraging people in the energy field to get out of it.

For example, oil and gas companies some day, when our reserves are at the outer limits, will begin to go down hill. We need to invest that capital into other forms of energy. The whole energy field is capitally starved. Instead of having policies that will drive any dollars out of the energy field into other things, we need policies that will have oil and gas companies, I think, with their capital and others investing in other forms of energy as well.

Mr. WALGREN. Thank you very much.

Mr. ECKHARDT. Governor, glad to see you here again, Governor Briscoe.

Governor BRISCOE. Thank you.

Mr. ECKHARDT. I know that some of my friends here on this committee don't know things about you like the fact that you financed a lot of farm to market roads when you were in the Texas legislature on the basis of natural gas taxes, as I recall, and I know that you have the broad interests of the people of Texas at heart.

I was looking back over some of our discussions in sort of an ad hoc subcommittee that preceded this subcommittee even before the House was organized when we had before us the enormously difficult question of meeting the winter emergency with respect to gas. I had thought that perhaps both you and I were looking at these things a bit more pragmatically than perhaps you are today, if you will pardon my so commenting. However, I want to see just how we may stand on this issue today. Even the President has a little flexibility with respect to his promises apparently. I remember that

in January of this year, I noted the fact that mixing a little high priced gas with a lot of cheap gas in the interstate pipelines might run up the price of intrastate gas to $3 or $4. As you recall, at that time I had an amendment which was approved on in our committee that put a kind of a ceiling on the price of natural gas at somewhere around the existing highest intrastate price plus a little margin, and I had asked you about that. I said "Now that would permit prices at around $2.14 at the highest rate, but would prohibit the price from going to, say, $3 or $4 or any figure. I would think that that would be very helpful to Texas. Would you not feel that to be the case?"

And you answered at that time that such a ceiling would be desirable. You answered yes.

Governor BRISCOE. That is right.

Mr. ECKHARDT. Now that is the problem that I think we have got here. We have got some very practical problems. Maybe $1.75 is too low, but I note in your testimony here you are saying without qualification that there should be no limits on the price of gas under the National Energy Act.

If you had no limit, would it not have the same effect that we were discussing in January? Would it not result in intrastate gas bidders being able to go up to, say, $4 for their bids, and would that not have the effect of perhaps doubling the price of gas to Texas users?

Governor BRISCOE. Mr. Eckhardt, we were discussing then a short-range proposal that would have allowed and did allow the interstate pipelines to buy intrastate gas for a limited period of time that would in no way encourage additional exploration, that would not bring on, that would not help bring on in any way new reserves or new supply. I think that was the situation at that time. We were discussing something strictly short range, not discussing a long-range policy, and I would most respectfully point out that I think that that would be the basic difference.

Now in addition to that, at that time we were dealing with short-range legislation for an emergency situation, to meet a very disastrous shortage that existed then in the interstate market, and that was met. We were concerned then about the interstate pipelines setting off the renegotiation clauses in the existing contract in the intrastate market.

That was handled in such a way that it did not happen, and I think from the intrastate market there was a considerable amount of gas moved to the interstate market to help relieve the shortage situation. Now for the long run, let me say for the long range—

Mr. ECKHARDT. If it didn't hurt us in the short range, it was probably because not enough gas went up to that price and there were not enough redetermination clauses in existing contracts triggered. However, if we should go to complete decontrol, wouldn't the impact on Texas consumers be dramatic. Mind you, I am not trying to get you to say we shouldn't go ultimately to decontrol—I know I couldn't get you to say that anyway, but I am trying to perhaps persuade you that there has to be some interim period in which some kind of limitation is put on the price of gas. I think that you take the position, and I think there is much reason to it, that

pricing gas artificially low for a long period of time has caused some very difficult misallocations and problems, but that is water under the bridge. We are faced with having to deal with that situation now.

Could you not say that some kind of limitation of new gas pricing, at least for a period of time, would be necessary in order to protect the Texas consumer primarily, and in the long run, of course, the consumers all over the United States?

Governor BRISCOE. My point today would be that if it becomes necessary—if because of Federal deregulation of the interstate market, it becomes necessary to take any action, if that creates an adverse situation in our intrastate market in Texas, as I see it that is our responsibility in Texas. That is our responsibility and mine and that of the State legislature, and we will take that responsibility. What I ask be done is that the Federal Government stay completely out of our intrastate market as has been the case in the past, and is the case now.

Certainly I am concerned about any invasion of the intrastate market by Federal regulation because along with that I am fearful will come allocation of that gas also.

Mr. ECKHARDT. Governor, I can recall that you have been very impressive in your understanding of the problems involved with gas pricing. I can remember the time when you were concerned about the fact that unlimited prices in the interstate market might suck most of the gas out of industrial use, and of course out of residential use. I really can't see how Texas could protect itself if such gas were sucked out of the State with completely uncontrolled intrastate prices, but perhaps you have a way, and I know that you are very resourceful and perhaps we will hear it at some time.

Governor BRISCOE. Thank you.

Mr. ECKHARDT. Thank you very much.

Mr. KRUEGER. The Chair now recognizes Mr. Stockman for five minutes.

Mr. STOCKMAN. Thank you, Mr. Chairman.

I want to congratulate both the Governors for your statements and the positions you have taken because I share them almost completely. I do want to make one comment which relates to a comment of my colleague from Connecticut. I do not agree with him very often but I think his point about the way your statements use the rhetoric of free enterprise was well taken. Long before we had OPEC, long before the world had to deal with that, the oil market was controlled. It was not controlled by the oil companies, as the gentleman indicated; it was controlled by your States.

I am a strong advocate of free enterprise. I believe that price regulations to protect consumers are just as bad as production regulations to benefit producers, however. So you have a kind of credibility problem when you engage in a very unrestrained fashion in the rhetoric of free enterprise. I think when you say the Federal Government should stay out, I agree with you completely. But for many years it was your States which defended to the death percentage depletion and the subsidies for the market just as they now espouse deregulation.

What I am suggesting here is that maybe what is needed is a little less on the rhetoric of free enterprise and a little more on the

practicality of why we need price deregulation in terms of the incremental supplies that we have provided for the Nation – I am just making that statement.

I know you will tell me that State proration was for conservation, and so forth, but I do not think very many of us believe it. Let that statement stand. I want to pursue a question that has been raised. I support deregulation – maybe not overnight but in a very short period of time – and I want the job of meeting our supply and demand gap done by the market and not by the huge government management systems that are envisioned in this energy package.

An argument that was made yesterday by Dr. Schlesinger was that if we deregulate both gas and oil prices immediately or in a short period of time, you would have a tremendous step up in cash flow into the industry and that cash flow would be dissipated in a bidding spiral for the inputs to the production and the exploration process, in particular for leases, for oilfield rigs, for oilfield supplies, tubular goods, and so forth.

I am wondering whether either of you or some of the advisers you have with us could comment on that. I think maybe in the very short run that might happen. I do not see it over any intermediate period of time. I think if we had a 3- or 4-year period that would take care of the problem. That is one of the arguments we are going to have to contend with.

Governor BOREN. Mr. Stockman, I would like to ask Mr. Cleary to respond to this further, but in short I want to say that is not going to happen. You do not generate cash flow until you actually achieve production. In other words, you have exploration and you go in and you find the gas and you bring it on stream. That is when the cash flow develops. Let me ask Mr. Cleary to respond a little more to that.

Mr. CLEARY. We are talking about new gas that comes into the marketplace, not cash flow generated. The gas contracts that exist now do expire over time, but it is a phased-out time and the recontracting would be phased in at a higher price but immediate deregulation would not create cash flow.

Mr. STOCKMAN. As long as it was for new production?

Mr. CLEARY. Production after a certain point of time generates its own cash.

Mr. STOCKMAN. It would be phased enough that you would not have this enormous demand on input supplies to create dissipation of capital.

Governor BOREN. That is right. While that cash flow is being developed you are also taking action to depress demand at the same time.

Mr. STOCKMAN. Demand for the inputs.

Governor BOREN. I think the whole picture on deregulation would naturally come through the mechanism.

Mr. STOCKMAN. One other question I would like to ask. During this past winter in my State 20 percent of our gas was coming from supplementary sources. We have an SNG plant that cost about $4; we used feedstocks in order to produce that, we had to buy some imported gas from Canada.

Do you think you can produce quite a bit of gas from natural resources for three or four dollars?

Governor BOREN. There is no doubt about that.

Mr. CLEARY. In time.

Mr. STOCKMAN. I know you agree with me. I am trying to point out an inconsistency. When you look at the actual supply of gas available in the consuming States, a large percentage of it is comprised of supplementary sources which are at very high prices. It seems to me irrational to say we are only going to pay $1.79 for the natural sources that are there but still go ahead in order to meet our short-run needs and produce very high-priced synthetic or other supplemental sources from feedstocks we need for other purposes.

I appreciate your testimony but I just offer as friendly advice, let's deal more with practicalities of the problem and a little less with the rhetoric because I do not think it has a great deal of credibility because of the history.

Mr. OTTINGER. The time of the gentleman has expired. I recognize Mr. Gammage.

Mr. GAMMAGE. Thank you, Mr. Chairman.

Gentlemen, yesterday Dr. Schlesinger and Mr. O'Leary appeared before the subcommittee and Dr. Schlesinger in response to my question regarding the allocation authority proposed in the President's energy plan responded that they never intended to use it except in cases of extreme emergency.

I reminded him during consideration of the emergency natural gas bill a provision had not been considered by either the House or the Senate was included in the conference report calling for the allocation of intrastate gas which traveled in interstate pipelines, basically what is known in the trade as Hinshaw gas, which was the first step ever made by the Federal Government in the direction of intrastate allocation.

During that debate Senator Bentsen raised some objections about the possible use of this allocation authority and Dr. Schlesinger's response as spokesman for the White House was: They didn't ask for it, they didn't want it, they didn't need it, and they had no intention of exercising this allocation authority.

Yet, in the President's energy plan there is that same allocation authority for intrastate gas, broader than what was included in the emergency natural gas bill.

He said yesterday they were to utilize it only in cases of great emergency. I take small comfort in that, having seen the President's energy plan as opposed to the promises that were made and commitments made prior to the general election last October, as far as any consistence in behavior pattern is concerned.

In addition to that, I would like to ask your response to some other things also. As far as the continued regulation, not just continued regulation but expanded regulation of the market, both intrastate and interstate that would be included in the President's plan, I am stealing someone's story I was told this morning before I came to the committee meeting.

A constituent said word going around in his neighborhood is this expanded regulation with no end in sight is akin to the young

couple who decided to practice the new morality and cohabit for awhile to determine whether they were compatible. After a period of time of cohabiting they discovered they were totally incompatible, that they could not find joy and love – and they decided the solution to their problem was to get married!

It seems much akin to that because I think we have seen the results of the regulated program. We were given to believe there would be some systematic deregulation coming down the road. Dr. Schlesinger alluded to such a proposal yesterday. In four or five years then we can probably move towards some systematic deregulation.

I take small comfort in that statement also.

What disturbs me as much as anything else, however, is what appears to be a schizophrenic approach to the whole energy question, a total lack of coordination. He assured me there was further coordination at the executive level as far as the whole energy program was concerned. The President's plan includes encouragement for the extensive use of coal, coal reserves being the greatest basic source of fossil fuel energy this country has.

In my home State of Texas we have vast stores of lignite coal. Yet under the strip-mining bill that has been proposed, it would be vastly more expensive to mine that coal for utilization than it is now. The tax burden imposed on tonnage takes absolutely no consideration of the fact that lignite could be mined and used domestically within my home community; it has a lower Btu output than most other types of coal available, and it would be subject to the same tonnage tax, making it economically more feasible for us to import coal rather than use our own domestic coal.

The energy plan encourages and virtually would tax one into a program of both regulation and taxes of converting from gas and in some cases from fuel oil to coal, and yet in our area where we are very dependent on energy or gas consumption as far as public utilities, or any other form of industry are concerned, we are basically in non-attainment areas. The clean air amendments would virtually prohibit us from making this conversion. We can not mine our coal and we can not burn our coal, but we have to convert to coal.

There is no coordination apparently in these three proposals. I think they must be considered as a whole in addition to the regulatory questions, both as to allocation of the potential here for allocating away the basic fuel source which 94 percent of the industry in my State is dependent upon for continued operation, salaries, wages, what have you, community support.

The lack of coordination between these three programs and the control mechanism as far as pricing is concerned.

I would like to get your response to what have been very broad questions. I appreciate the problem you may have in responding.

Mr. OTTINGER. He will have to make the answer very short.

Governor BRISCOE. I think you have summed it up very, very well, Mr. Gammage. I agree completely with your statements. One thing that I think is real important, the lack of activity, lack of development on the Federal land, the land under Federal control, the Outer Continental Shelf and other land that contains the oil shale,

tar sands, some 40 percent of the oil and gas, 45 percent of the coal, and 55 percent of uranium, producing only 10 percent of our energy supply. I think this is one thing that we need to direct attention to.

I think your point there is no coordination is exemplified by the fact that the Federal lands are not producing.

Mr. OTTINGER The time of the gentleman has expired.

I am going to keep myself under the time limit as well. I am very concerned about the economic impact of deregulation if we were to go that way. I am worried about the President's plan, as a matter of fact, because ours is so energy intensive an economy. Every State manufacturing and processing goods uses gas and oil.

Do you have any figures that would show the inflationary impact deregulation would have?

Governor BRISCOE. I do not have any with me. We will be able to supply the committee by Monday of next week.

Mr. OTTINGER. I would like to have your figures on that. We do not want to kill the goose that laid the golden egg either with respect to oil and gas production or with respect to the economy.

Governor BRISCOE. Your question is a very good one. We will have that from the University of Texas.

[The information referred to follows:]

EXTRACTS FROM

PRELIMINARY ASSESSMENT

OF THE

PRESIDENT'S

NATIONAL ENERGY PLAN

May 11, 1977

This report represents the independent and individual work of the faculty and the staff identified and is not intended to represent an official position of The University of Texas at Austin.

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OIL PRICING POLICY

by Stephen L. McDonald, Professor of Economics

Under the Carter program the price of new oil would be permitted to rise over three years to the 1977 world level, adjusted for inflation, old oil prices would remain regulated, and a tax on the two tiers of old oil would raise their prices to consumers to the level of new oil. The purpose of continued regulation of old oil prices is to prevent large windfalls to producers, in the belief that the new oil price will provide adequate incentive to exploration. This belief is not entirely justified for the following reasons: regulation of old oil prices reduces the financial ability of the industry to explore, may discourage development of some discoveries, may preclude some secondary recovery projects, may distort maintenance decisions and encourage early abandonment, and may increase uncertainty about future prices. Furthermore, one may question whether the 1977 world price adjusted for inflation is an adequate incentive to produce an efficient allocation of domestic resources and reduce our dependence on insecure foreign supplies. It is likely that the world price will rise faster than the rate of U. S. inflation, and on efficiency grounds one can argue for a tariff to raise the U. S. price above the world price. That the incentive of price is vigorously responded to by the domestic industry is indicated by the fifty percent rise in well drilling from 1973 to 1976, the full effect of which on reserves and capacity is yet to be felt.

OIL PRICING POLICY

The basic approach to oil pricing in the Carter program is to allow the effective price to consumers to rise to the 1977 world price level (adjusted for inflation), while preventing windfalls to producers and partially compensating consumers as a group for the rise in effective price. The higher effective price of oil to consumers would presumably encourage conservation and conversion to other sources of energy, and the world price available to finders of new oil would presumably encourage domestic exploration.

More specifically, the program would:

1. allow the price of newly discovered oil to rise over a three year period to the 1977 world price adjusted for inflation, and thereafter permit further adjustments for inflation;

2. continue indefinitely the regulated effective prices to producers of $5.25 for old oil and $11.28 for old "new" oil (1973-77 vintage), with adjustments for inflation;

3. by means of a tax on $5.25 and $11.28 oil, bring their market prices (including tax) to the world price level by 1980, and thereafter adjust the tax upward for inflation;

4. use the proceeds of the tax to compensate the public, by means of tax credits or direct payments on a per capita basis, for the increased price of oil.

(Incremental tertiary recovery from old fields and stripper oil would be free of price controls. Old Alaskan oil would be controlled

at $11.28, and oil from new discoveries in Alaska would sell at the adjusted world price. Shale oil would be entitled to receive the adjusted world price.)

Questions may be raised about the implications of continued price regulations to producers, and about the adequacy of the 1977 world prices, adjusted for inflation, as an incentive to domestic exploration.

Price regulation. The continued regulation of prices as described above is intended, of course, to prevent largely functionless transfers from consumers to producers (and from consuming regions to producing regions). How significant is the qualifier "largely"?

The producers of "old" oil presumably made outlays to find and develop such oil when actual and expected prices were much lower than at present. These prices promised, on the whole, a normal return on investment. If higher prices are now received, above normal returns on investment are realized. Such returns, however, provide no necessary incentive for new exploration and development; for what is relevant to such investments is expected future rates of return, hence expected future costs and prices. If the world price is allowed on new finds, then the incentive to new exploration and development is not impaired by regulation of prices on old production. This is the basic rationale for a dual price system.

However, with respect to it several qualifying points may be made:

1. While higher prices on old oil may have no incentive effect, they may have a significant permissive financial effect. Smaller firms in the oil industry, of which there are several thousand, must depend largely on retained earnings for risk capital. They cannot compete successfully with larger companies in equity capital markets. Thus even with adequate incentive to invest in exploration, they may lack the financial means. (Higher retained earnings lower the cost of capital and increase the credit worthiness of all firms, large or small.) Persistent price controls to prevent windfalls may thus check exploration in the short run, and in the long run reduce the role of independent operators relative to the major corporations, with adverse effects on competition.

2. In cases of oil recently discovered (say, in 1976) but nonetheless falling into one of the regulated categories, development investments may be discouraged or distorted by price controls. Some fields may be abandoned as uneconomical to develop; some may be developed on artificially wide spacing and hence have less current capacity.

3. Price controls may very well preclude otherwise profitable secondary recovery operations, denying the country significant increases in recoverable reserves. (The Carter program exempts only incremental tertiary recovery from price controls; it is not clear where the line is drawn between secondary and tertiary recovery.)

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4. Price controls may distort maintenance decisions. With stripper wells exempt from controls, operators with old wells may deliberately allow them to sink into stripper status by failing to make outlays for workovers, fracturing, equipment repair and the like.

5. Price controls on old oil may adversely affect recoverable reserves by accelerating artificially the decision to abandon. While it is true that the Carter program exempts stripper wells from price controls, wells that are expensive to operate and maintain (e. g., offshore) may have to be abandoned under controls long before they reach stripper status (usually defined as capacity to produce no more than 10 barrels per day). The case-by-case examination of such instances promised by the Carter program would obviously involve expense and long delays.

6. The presence of price controls on old oil as a matter of policy may reduce incentives to explore for new oil by suggesting the possibility of future controls on what is now new but will be old oil then. In other words, a policy of controls under some circumstances creates some uncertainty regarding future rates of return and may thus dampen current investment.

Thus it is not entirely true that controls on old oil merely prevent windfalls to producers. Such controls may have significant adverse effects on current capacity, recoverable reserves and the competitive structure of the domestic industry. These adverse effects could be minimized, while still guarding against massive windfalls, by gradually phasing out controls on a definite schedule,

exempting secondary recovery and more broadly defining stripper wells.

Adequacy of the 1977 world price. The price of new oil would be permitted to rise over a three year period to the 1977 world price, with adjustment for inflation. Thereafter it would be permitted to rise at a rate equal to the rate of domestic inflation. Is such a rise adequate or appropriate?

1. Such a policy implies that the price of oil relevant to domestic exploration decisions will be below the actual world price for at least three more years. It holds out the possibility that the domestic price will be below the world price for the indefinite future, depending on OPEC price policy. We have no reason to be confident that the OPEC price will rise only at the rate of U. S. inflation. In the first place, the U. S. rate of inflation is below the world rate, the latter being the most relevant to OPEC decisions; and in the second place, it is to be expected that the price of a rapidly depleting exhaustible resource will rise relatively to other prices, the moreso as definite exhaustion approaches. If the usual forecasts of oil supply and demand are anywhere near correct, we must expect the world price of oil to rise faster than prices generally in the United States. Thus the world price in 1977 adjusted for inflation is not appropriate to an efficient allocation between imports and domestic production and probably not adequate to check the growing dependence of the country on imports from the Middle East. The objective by, say, 1980 should be completely free domestic oil prices (new oil) and not some specific target price based on the year 1977.

2. It can be argued that for national security reasons imported oil, particularly from the Middle East, carries an extra cost not fully reflected in its price. There is, in other words, an external diseconomy associated with imported oil. If this view be accepted, then we may be seen to import too much, and to produce too little domestically, when the domestic new oil price is only equal to the world price. We could reduce or eliminate this distortion by imposing a suitable tariff on imported oil, at least until an acceptable emergency reserve of oil can be accumulated. With a tariff, the U. S. new oil price would be above the world price, but not necessarily above the actual marginal cost of imports. Hence with a tariff, we might have a more efficient allocation of domestic resources as well as less dependence on insecure sources of supply. The higher price of domestic oil would encourage still more oil conservation in use, and most of the additional cost to consumers could be returned to them as tax credits or direct payments per capita as in the Carter proposals. The problem of windfalls to domestic producers would be greater, but might be handled with a gradually disappearing tax on old oil associated with steady phasing out of price controls.

In general, the Carter program seems to place too little emphasis on incentives to domestic exploration relative to conservation and protection of consumers from additional burden. The program would be more balanced if it looked to the eventual freeing of all domestic prices from regulation and perhaps contemplated a significant tariff on imported oil.

Response to incentives. It would be useless to provide additional incentives to domestic exploration if the observed response to such incentives were nil. It is, however, unreasonable to expect it to be nil, and recent evidence suggests that the response is significant. Thus after declining steadily from 1956 to 1973, the number of new wells drilled in the U. S. rose from 26,081 in 1973 to 40,529 in 1976, an increase of over 50 percent.* Such an increase cannot fail at least to check the decline in domestic reserves and production. Moreover, the full results of the rise in drilling are yet to be realized, for the following reasons. First, with a limited inventory of prospects at a given time, a sharp rise in drilling must be expected to be associated with a rise in the dry hole ratio as the average quality of prospects declines. With time to replenish the inventory of prospects through pre-drilling exploration, the industry should realize better results from a given level of drilling. Second, there is a lag of several years of development behind discovery; hence production responds only gradually to a burst of new discoveries. Third, initial reserve estimates in new discoveries are usually very conservative. As development and production proceeds, reserve estimates usually rise significantly. These considerations in association with the sharp rise in drilling in response to prices after 1973 lead us to believe that continued incentives in the form of world prices will produce significant results in new reserves and production.

*World Oil, Feb. 15, 1977, p. 74.

THE EFFECTS OF THE PROPOSALS FOR NATURAL GAS PRICING IN THE NATIONAL ENERGY PLAN ON THE ENERGY ECONOMY OF TEXAS

by

James W. McKie
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SUMMARY

The NEP proposes price ceilings of $1.75 (on "new" gas and all intrastate gas) and $1.42 (on "old" interstate gas becoming available on the market), escalated for price inflation. These prices will be insufficient to balance demand and supply for natural gas in the future. Current prices for incremental supply in intrastate markets are already above those levels, and are increasing. Very little gas is going to interstate markets. The ceilings will fail to stimulate sufficient conversions to other fuels in low-value uses in the future and will not elicit as much supply of gas from Texas sources as would be forthcoming at deregulated prices. The proposed $1.75 ceiling does not reflect true replacement cost of gas. The alleged "equivalent BTU value" basis for it is spurious. The chief effect of the ceilings would be to perpetuate shortages and to spread them into intrastate markets, thus apparently making continuous end-use allocations by the government necessary.

The industrial systems of Texas and Louisiana are heavily dependent on natural gas -- considerably more so than in other regions of the country, as our data demonstrate. Some of the industrial use, as well as use in electric power generation, is for boiler fuel, which is already scheduled to be phased out over time. But a significant part of industrial consumption is in high-value uses, where gas is a premium fuel. Allocation of gas away from these uses would be extremely damaging to the Texas industrial economy and to the jobs and taxes dependent on it.

Decontrol of interstate prices is the key to optimum allocation. It is recognized that Texas industries would have to compete on equal terms with other high-value uses for the national supply, but a free market price is the best means of finding what uses should be served in the long run. It is also the best way of assuring that gas prices will move toward the cost of replacement.

THE EFFECTS OF THE PROPOSALS FOR NATURAL GAS PRICING IN THE NATIONAL ENERGY PLAN ON THE ENERGY ECONOMY OF TEXAS

The National Energy Plan of April 29, 1977, proposes a number of new Federal regulatory policies for natural gas. The main object of these proposals, according to the "Fact Sheet" issued in connection with the President's energy message of April 20, is to "bring natural gas supply and demand back into balance" (p. 16). The Fact Sheet further observes "If the oil and gas pricing and taxing initiatives in this Plan succeed, it may be possible to return to a market determined price for new natural gas. . . . The new gas pricing policy provides prices for new gas that will reflect future costs and risks associated with finding new supplies, recognizes that the United States constitutes a single market for natural gas, and continues control on the old."

In our opinion, the policies proposed fail to make use of the one mechanism that can actually produce success, bring demand and supply back into balance, reflect future costs and risks, and recognize a single U.S. market for gas: a market free from Federal price ceilings and allocation controls. Some aspects of the proposals will do needless damage to the economies of Texas and other producing states.

Use of Natural Gas in Texas and in P.A.D. District III

Total production of natural gas in Texas in 1975-76 (fiscal year) was 7.56 trillion cubic feet. Of this total, 2.46 TCF (33%) was sold in interstate markets and 5.1 TCF (67%) was sold intrastate.[1]

Newly discovered or developed gas has been going even more predominantly into intrastate use than total production has. For the U.S. as a whole, the trend in recent years toward intrastate is shown in Table 1. The main reason for this shift toward intrastate use is that the value of natural gas could find its appropriate level in intrastate markets, while in interstate markets it could not; but meanwhile the economies of the major producing states have developed large industrial complexes based on this higher-cost natural gas.

For illustration of the industrial use of gas we shall take a somewhat broader focus than Texas alone and consider patterns of use of natural gas in P.A.D. District III, which currently provides over three-fourths of the gas produced in the Lower 48 states. Most of this consumption is in the two leading producing states of Texas and Louisiana, which would be similarly affected by the President's proposals.

Table 2 compares use of natural gas in several major categories in the United States and in P.A.D. Districts I, II, III, and V. District III used about 40 percent of all gas used for industrial purposes in the whole country, but a much smaller fraction of gas in the Residential

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[1] "Texas Natural Gas Prices, FY 1976," Office of the Comptroller, State of Texas, Analysis No. 9, February 1977.

Table 1

New U.S. Gas Reserves and Dedication
of New Reserves to Interstate Pipelines
1966-75

Year	Newly listed reserves (trillion cu. ft.)	Dedicated to interstate pipelines (trillion cu. ft.)	Percent Interstate
1966	14.8	10.0	68
1967	14.8	9.9	67
1968	9.8	6.4	65
1969	9.6	6.2	64
1970	11.3	3.5	31
1971	11.1	2.2	20
1972	10.7	5.0	47
1973	10.1	1.7	17
1974	9.7	2.4	25
1975	10.0	1.3	13

Source: American Gas Association; Federal Power Commission

Table 2

Use of Natural Gas in the United States and in P.A.D. Districts I, II, III, and V, in Five Categories, 1974[1]
(Trillion BTU Basis)

	Residential	Commercial	Industrial	Raw Material	Power Plants
U.S. Total	5,016	2,640	8,166	710	3,356
District I	1,295	618	1,282	74	282
% of U.S.	26	23	16	10	8
District II	2,316	1,273	2,560	143	706
% of U.S.	46	48	31	20	21
District III*	500	339	3,230	418	1,792
% of U.S.	10	13	40	59	53
District V	720	292	833	70	519
% of U.S.	14	11	10	10	15

[1] Other categories such as military use, transportation, etc., not shown.

* Includes Alabama, Mississippi, Arkansas, Louisiana, and Texas

Source: S. H. Clark Associates, SEADOCK Report, Project 7519, July 1975, Appendix A.

and Commercial categories. District III also accounted for a high proportion of the gas used for electric power generation in 1974. Table 3 indicates that natural gas accounted for a significantly higher fraction of industrial fuel input (excluding electric power plants) in District III than in the United States generally or in Districts I, II, and V individually.[1] Almost three-fourths of the industrial fuel used in District III in 1974 was natural gas.

Industries Using Natural Gas on the Gulf Coast

The industrial economy of District III, and by inference that of Texas, is based on natural gas. Most of the rest of the industrial fuel used in District III in 1974 came from refinery gas, petroleum coke and fuel oil. Only seven percent was non-petroleum based.

Some detail on the types of industrial use in a recent year in the Gulf Coast states is given in Table 4. (The region in this Table is the same as P.A.D. District III except for Alabama; again, Texas and Louisiana are the major industrial users.) If this region's figures are representative of Texas alone, they indicate that Texas industrial gas consumption is heavily skewed toward chemical and non-ferrous metal industries -- and petroleum products, as would be expected -- and away from iron and steel, glass, and transportation equipment, by comparison to nationwide patterns.

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[1] District III includes the Gulf Coast states except Florida. District I is, roughly, the Eastern seaboard; District II the Middle West and Plains States including the important gas-producing states of Kansas and Oklahoma; District V is the West Coast and Arizona. District IV, the Rocky Mountain area, has a much smaller total of consumption that the other districts.

Table 3

Natural Gas as Percentage of Total Industrial Fuels, 1974
U. S. and P.A.D. Districts I, II, III, and V
(Trillion BTU Basis)

	Total Industrial Fuels (TBTU)*	Natural Gas*	Natural Gas as Percent of Total
U. S.	14,681	8,166	56
District I (Eastern Seaboard)	3,748	1,282	34
District II (Midwest & Plains)	4,559	2,560	56
District III (Gulf Coast)	4,374	3,230	74
District V (West Coast)	1,550	832	54

* Does not include electric power generation nor direct use as raw material.

Source: See Table 1.

Table 3A

Natural Gas as a Source of Primary Energy, all Uses, in the U.S. and in P.A.D. Districts I-V, 1974

(Trillion Btu Basis)

	Total Primary Energy	From Gas	Percent Gas
U.S.	74,210	22,533	30
District I (Eastern Seaboard)	23,162	3,710	16
Percent of U.S.	31	16	
District II (Midwest & Plains)	24,331	7,573	31
Percent of U.S.	33	34	
District III (Gulf Coast)	15,261	7,930	52
Percent of U.S.	21	35	
District IV (Rocky Mountains)	2,194	697	32
Percent of U.S.	3	3	
District V (West Coast)	9,262	2,623	28
Percent of U.S.	12	12	

Source: See Table 2.

Table 4

Industrial Gas Consumption in the U.S. and in the Gulf Coast Region, 1973
by Type of Industry (MMCF)

Industry	U. S.	Four-State Region[1]	Percent Regional Use of U.S. Total
Mining	166,438	60,203	36.2
Food and Kindred Products	423,937	39,957	9.4
Textile Mill Products	87,275	6,145	7.0
Paper and Allied Products	372,944	76,267	20.4
Chemicals and Allied Products	2,038,346	1,457,698	71.5
Petroleum and Coal Products	1,057,705	623,194	58.9
Rubber and Misc. Plastics	105,377	46,063	43.7
Stone, Clay, Glass, Concrete	642,670	80,253	12.5
Primary Iron and Steel	773,039	48,534	6.3
Primary Non-Ferrous Metals	424,170	218,538	51.6
Fabricated Metal Products	167,054	6,197	3.7
Machinery, except Electrical	93,217	2,495	2.7
Electrical and Electronic Eq.	78,681	3,201	4.0
Transportation Equipment	192,308	5,392	2.8
Other Manufacturing	310,133	97,272	31.3
Non-Manufacturing or Mining	702,720	566,125	80.7
Total Reported	7,636,014	3,337,536	43.7
Not classified or unreported	1,357,949	270,304	19.9
Total industrial*	8,993,963	3,607,840	40.1

[1] Mississippi, Arkansas, Louisiana, Texas.

*Does not include power plants.

Source: Future Requirements Committee and Future Requirements Agency, "United States Gas Consumption, 1973" (Denver, Colorado: Denver Research Institute, 1974)

Some industrial use is for boiler fuel. Some of the rest is burned in space heaters and prime movers -- medium-value uses for which substitutes can be developed. Even in the chemical industry, for example, less than half of the gas is consumed as feedstocks or in non-substitutable uses.[1] But that fraction is extremely important to the industrial development of the Gulf states. The premium industrial uses of gas in Texas and Louisiana support a complex of industry both directly and indirectly dependent on it -- a complex unique in the United States. In no sense can these uses by regarded as expendable or unessential.

Texas, like other Gulf Coast states, is attempting to phase out the consumption that occurs in power plants, as well as other use of gas for boiler fuel, as rapidly as possible. We should not overlook the fact, however, that alternative fuels are not immediately available even for this type of use; ahd where gas is used in industrial processes, it is an essential mainstay of Texas and Louisiana industry -- production, incomes, and jobs. Conversion of such industry to other fuels, where possible, will take time.

The $1.75 Ceiling

The proposed "initial" price ceiling of $1.75 per MCF is supposed to bring new gas to parity with the "BTU equivalent of the average refiner acquisition cost (before tax) of all domestic crude oil." The

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[1] See James T. Jensen and Thomas R. Stauffer, Implications of Natural Gas Consumption Patterns for the Implementation of End-Use Priority Programs (Cambridge, Mass.: Arthur D. Little, Inc., 1972), p. 109.

latter "cost" is itself an illogical synthesis of different levels of controlled prices. The price ceiling for new gas would not be equated to the price ceiling for new oil, nor to actual acquisition cost of imported oil. Differences in transportation costs and conversion costs are ignored.

But the most telling criticism of the BTU-equivalent price is that it fails to recognize the fact that natural gas is a premium fuel. The market for energy does not determine an equal value for a BTU of gas and a BTU of crude oil, which may end up as gasoline. Gas BTUs used to have lower value but now they are rapidly becoming more valuable than BTUs of crude oil or of fuel oil. As the demand grows (partly because of the superiority of gas for environmental protection) the price rises, gradually pushing gas out of those uses in which it has relatively low value, such as boiler fuel, and stimulating those users to turn to alternative fuels. As the price continues to rise, industrial consumption of gas will increasingly be in those uses in which gas has very high value, such as glass manufacture or direct heat treatment requiring low sulfur contamination, etc. In these uses, the "replacement cost" of gas is not the cost of alternative fuels, under presently available technology. There is no reason whatever to impose a ceiling based on oil prices; the comparative use value of gas may be considerably higher, and that value should be reflected in the market price.

We must observe in this connection that the proposal to put an increasingly heavy tax on "high volume" industrial users of natural gas, beginning in 1979 (The National Energy Plan, p. 65) fails to

distinguish between low value uses such as boiler fuel and high value essential industrial uses which may also be "high volume." It simply raises costs across the board. If the object is to stimulate conversion to alternative fuels, as claimed, a higher market price would do the same job more efficiently, and would also stimulate more supply, which a tax will not. To hold prices down with a ceiling and then to get them up with a tax to discourage consumption is a very odd policy, almost self-defeating.

The Effects of the Price Ceiling Over Time

The effects of a $1.75/MCF ceiling, escalated for inflation, on Texas gas markets would develop over an extended period. The immediate impact would be chiefly on intrastate gas, of course. The accompanying Tables 5A, B, and C from a recent report of the Office of the Comptroller, State of Texas, show that less than 12 percent of the gas produced in Texas in fiscal 1976 moved at prices over $1.75/MCF. Almost all of this was used intrastate. The highest price that has ever been allowed for interstate gas sales under long-term contracts is $1.45.

We do not know whether that gas would have been sold if prices had been held to a ceiling of $1.75. Perhaps some, but probably not all, would have been withheld. What the market price is telling us is that this gas had a value of more than $1.75, and that prices of $2.00 and up were necessary on some incremental new supply in order to

Table 5

Percentage Distribution of Natural Gas Sales in Texas at Various Prices, FY 1976

A. PERCENTAGE DISTRIBUTION OF TOTAL TEXAS NATURAL GAS PRICES, FY 1976*

Price per MCF	Sept. 1- Nov. 30	Dec. 1- Feb. 29	March 1- May 31	June 1- August 31	Total	Cumulative Total
$0.01 - 0.10	3.39%	3.94%	4.57%	2.47%	3.34%	3.34%
0.11 - 0.20	19.37	17.40	14.66	10.44	15.54	18.88
0.21 - 0.30	18.57	18.23	17.50	16.00	17.59	36.47
0.31 - 0.40	18.55	16.30	10.02	11.67	14.20	50.67
0.41 - 0.50	6.96	8.53	15.39	16.85	11.84	62.51
0.51 - 0.60	6.02	6.38	6.30	7.10	6.44	68.95
0.61 - 0.70	3.08	3.05	3.45	3.87	3.36	72.31
0.71 - 0.80	1.95	2.18	2.57	2.54	2.31	74.62
0.81 - 0.90	1.87	1.71	1.17	1.62	1.60	76.22
0.91 - 1.00	1.64	1.24	1.59	1.46	1.48	77.70
1.01 - 1.10	1.18	1.14	1.23	1.07	1.16	78.86
1.11 - 1.20	0.85	0.91	0.54	0.57	0.72	79.58
1.21 - 1.30	0.84	0.78	0.71	0.85	0.80	80.38
1.31 - 1.40	2.60	2.02	1.58	1.47	1.90	82.28
1.41 - 1.50	1.71	1.48	1.43	1.34	1.49	83.77
1.51 - 1.60	1.42	0.96	0.85	0.82	1.02	84.79
1.61 - 1.70	0.78	1.07	1.33	1.31	1.12	85.91
1.71 - 1.80	0.90	1.22	1.57	1.96	1.40	87.31
1.81 - 1.90	2.28	3.08	3.65	3.45	3.11	90.42
1.91 - 2.00	2.45	2.54	2.93	3.41	2.82	93.24
2.01 - 2.25	3.31	5.22	6.49	7.83	5.68	98.92
2.26 - 2.50	0.16	0.33	0.46	0.79	0.43	99.35
2.50 and above	0.10	0.29	0.09	0.11	0.15	100.00
TOTAL	100.00	100.00	100.00	100.00	100.00	

*Based on a sample of major natural gas producers. This represents 80 percent of total FY 1976 production and sales.

Source: Texas Natural Gas Prices, FY 1976, Office of the Comptroller, State of Texas, Analysis No. 9, February, 1977

B. PERCENTAGE DISTRIBUTION OF TEXAS INTERSTATE NATURAL GAS PRICES, FY 1976*

Price per MCF	Sept. 1- Nov. 30	Dec. 1- Feb. 29	March 1- May 31	June 1- August 31	Total	Cumulative Total
$0.01 - 0.10	1.49%	1.69%	1.47%	1.20%	1.47%	1.47%
0.11 - 0.20	31.87	31.07	27.24	14.71	26.60	28.07
0.21 - 0.30	32.22	32.46	34.13	34.07	33.18	61.25
0.31 - 0.40	9.75	9.99	9.89	18.59	11.87	73.12
0.41 - 0.50	4.92	4.48	4.85	6.12	5.06	78.18
0.51 - 0.60	10.50	10.94	10.51	10.67	10.66	88.84
0.61 - 0.70	4.06	3.95	5.37	5.53	4.69	93.53
0.71 - 0.80	2.24	2.20	2.01	2.62	2.26	95.79
0.81 - 0.90	1.01	1.26	1.57	1.60	1.35	97.14
0.91 - 1.00	0.24	0.32	0.70	0.97	0.54	97.68
1.01 - 1.10	0.12	0.24	0.31	0.44	0.27	97.95
1.11 - 1.20	0.07	0.10	0.21	0.27	0.16	98.11
1.21 - 1.30	0.50	0.21	0.10	0.21	0.28	98.39
1.31 - 1.40	0.06	0.02	0.04	0.18	0.07	98.46
1.41 - 1.50	0.23	0.10	0.05	0.13	0.13	98.59
1.51 - 1.60	0.01	0.01	0.01	0.11	0.03	98.62
1.61 - 1.70	0.02	0.04	0.05	0.19	0.07	98.69
1.71 - 1.80	0.10	0.12	0.16	0.22	0.15	98.84
1.81 - 1.90	0.05	0.27	0.42	0.67	0.34	99.18
1.91 - 2.00	0.19	0.33	0.70	1.13	0.57	99.75
2.01 - 2.25	0.14	0.14	0.14	0.20	0.15	99.90
2.26 - 2.50	0.01	0.01	0.03	0.08	0.03	99.93
2.50 and above	0.11	0.05	0.04	0.09	0.07	100.00
TOTAL	100.00	100.00	100.00	100.00	100.00	

*Based on a sample of major natural gas producers. This represents 77 percent of FY 1976 interstate sales.

C. PERCENTAGE DISTRIBUTION OF TEXAS INTRASTATE NATURAL GAS PRICES, FY 1976*

Price per MCF	Sept. 1- Nov. 30	Dec. 1- Feb. 29	March 1- May 31	June 1- August 31	Total	Cumulative Total
$0.01 - 0.10	4.30%	4.98%	5.99%	4.42%	4.92%	4.92%
0.11 - 0.20	13.41	11.07	8.92	8.66	10.52	15.44
0.21 - 0.30	12.05	11.64	9.91	8.44	10.52	25.96
0.31 - 0.40	22.74	19.22	10.07	8.77	15.25	41.21
0.41 - 0.50	7.93	10.40	20.20	21.34	14.91	56.12
0.51 - 0.60	3.88	4.27	4.38	5.61	4.53	60.65
0.61 - 0.70	2.62	2.63	2.58	3.18	2.75	63.40
0.71 - 0.80	1.81	2.17	2.93	2.50	2.33	65.73
0.81 - 0.90	2.28	1.92	0.98	1.63	1.71	67.44
0.91 - 1.00	2.31	1.67	2.00	1.67	1.91	69.35
1.01 - 1.10	1.69	1.55	1.65	1.34	1.56	70.91
1.11 - 1.20	1.23	1.29	0.68	0.70	0.98	71.89
1.21 - 1.30	0.96	1.05	0.99	1.12	1.03	72.92
1.31 - 1.40	3.80	2.95	2.17	2.01	2.74	75.66
1.31 - 1.50	2.42	2.12	2.06	1.84	2.11	77.77
1.51 - 1.60	2.09	1.40	1.24	1.12	1.46	79.23
1.61 - 1.70	1.14	1.55	1.91	1.77	1.59	80.82
1.71 - 1.80	1.29	1.72	2.21	2.68	1.97	82.79
1.81 - 1.90	3.34	4.38	5.13	4.61	4.36	87.15
1.91 - 2.00	3.52	3.56	3.94	4.36	3.84	90.99
2.01 - 2.25	4.83	7.58	9.39	11.03	8.20	99.19
2.26 - 2.50	0.27	0.48	0.65	1.08	0.62	99.81
2.50 and above	0.09	0.40	0.12	0.12	0.19	100.00
TOTAL	100.00	100.00	100.00	100.00	100.00	

*Based on a sample of major natural gas producers. This represents 82 percent of FY 1976 intrastate sales.

balance demand and supply and channel the new gas to the most important uses. (Under the circumstances, with price controls on interstate sales, this mechanism worked effectively only for intrastate uses.)

What will happen to demand and supply over time? It is not necessary to make precise forecasts of demand, since virtually all authorities agree that demand for gas will increase during the next couple of decades, though it may not be possible to find the supply to meet that increase. As for supply: appended to this paper is a chart derived by the Bureau of Economic Geology at the University of Texas showing projected gas production in Texas under the policies stipulated in the National Energy Plan -- including the ceiling of $1.75 plus escalation. (The assumptions and conditions of that projection are explained in another section of this report.) The chart illustrates the finding that the replacement cost of natural gas in Texas is well above the proposed $1.75 ceiling.

Other studies indicate that the replacement costs elsewhere in the country are equally high if not higher, and that we could expect no major new supply breakthroughs in the country at large to offset the projected decline in Texas gas output. For example, the accompanying "Figure III - 7" is borrowed from the Federal Energy Administration's report, National Energy Outlook, February 1976. It shows projected non-associated gas production from the U.S. excluding Alaska. The same publication estimates associated gas production at between 4.0 (at low oil prices) and 4.9 (at deregulated high oil prices) trillion cubic feet during the period 1976-85. Even at projected real gas

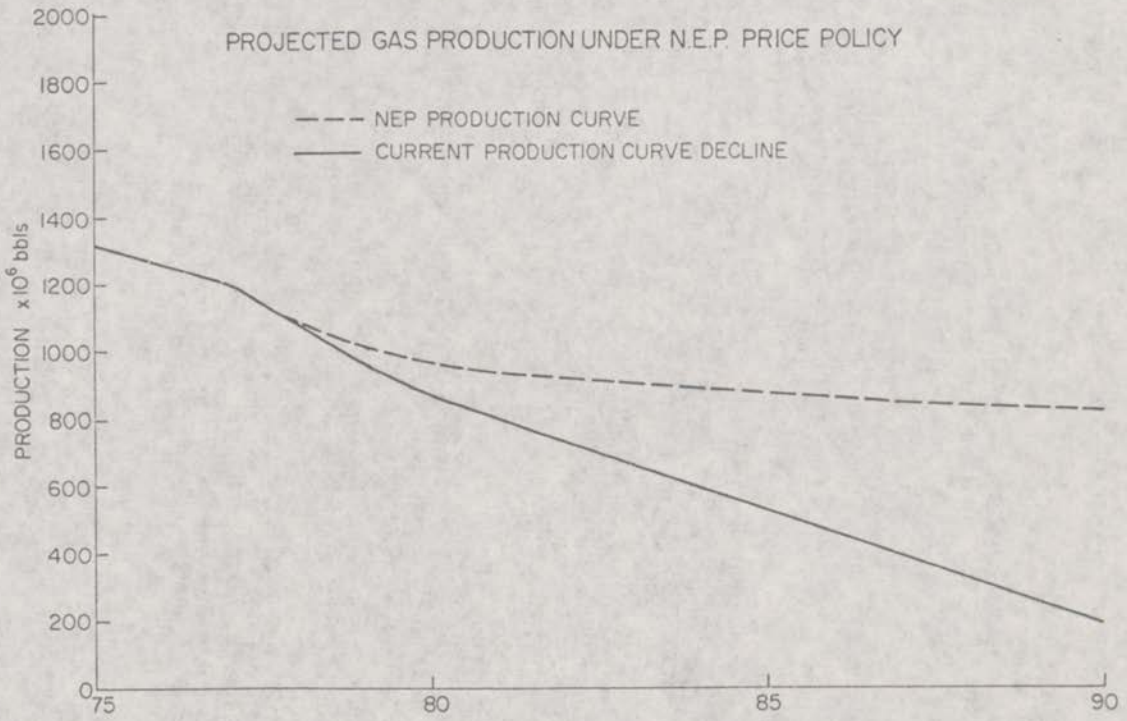
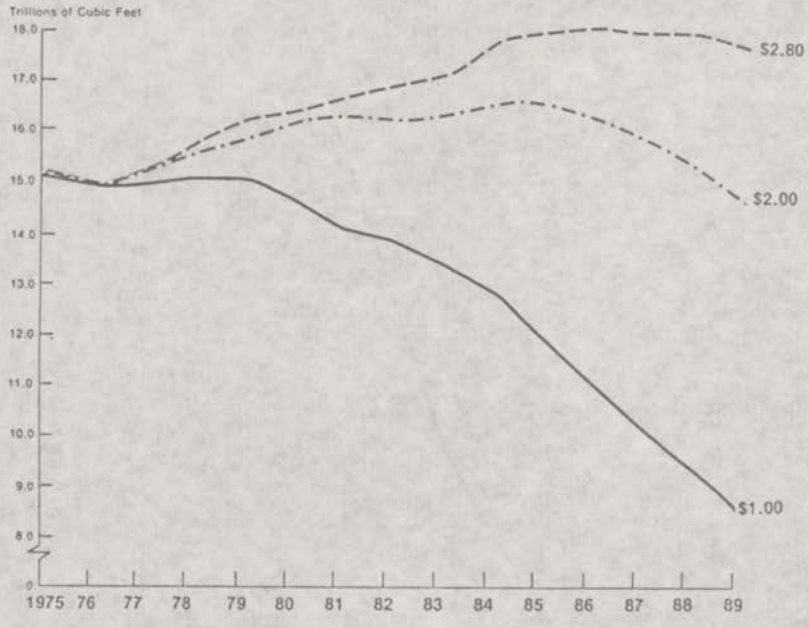


Figure 6. Gas production, historic and projected under NEP pricing policy.

From: Federal Energy Administration, National Energy Outlook, February 1976.

Figure III-7

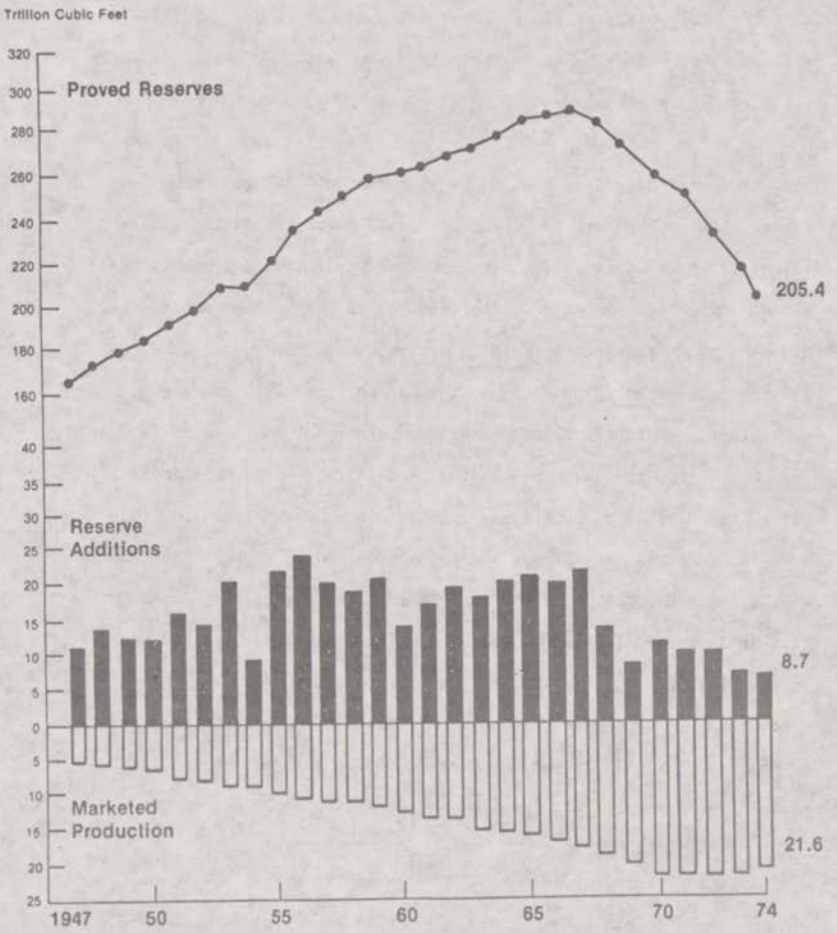
Non-Associated Natural Gas Production from the Lower-48 States and the O.C.S. at Three Wellhead Price Levels



NOTE: These quantities include gas used for repressurization of wells, excludes tight gas.

Figure III-4

U.S. Natural Gas Reserves
(Excluding Alaska)



Source: American Gas Association.

prices of $2.00 per MCF and more, the total forthcoming supply would not exceed 21 trillion cubic feet before 1985. Demand had already reached that level by 1974, and potential demand (unconstrained by actually available supply) was expected to climb toward 24 trillion cubic feet by 1985 even at higher prices than $2.00/MCF escalated for inflation.[1]

We infer that the "equilibrium" price, a price which would have some chance of balancing demand and supply of natural gas in the future, has to be above $2.00/MCF in "real" terms, probably well above it, and that it will increase further over time. Since we are already experiencing national shortages of gas, and since demand is expected to increase and supply to decrease over time under the NEP policies, we can only conclude that those policies will produce an ever-widening shortage or gap between demand and supply in the future.

Or, to put the same proposition in different terms, the present price for incremental supplies currently becoming available in the unregulated market is already above the proposed $1.75 ceiling. Demand will grow, and supply will not for the next few years; even under optimistic assumptions and increasing prices, the annually produced supply will only reverse its decline and gradually begin to recover. Thus in the absence of a ceiling the volume of sales at prices over $1.75 (adjusted), or over $2.00 for that matter, would steadily grow as contracts expired and newly available gas sought

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[1] Actual production for 1976 and 1977 is running well below the amounts shown on Figure III - 7. For background, Figure III - 4 shows what happened to gas reserves and production from 1947 through 1974 in the U. S. excluding Alaska.

more valuable current and future uses. Concurrently, the demand would be adjusted to the available supply by higher prices which, as already noted, would cause the less valuable uses to turn to alternative fuels over time.

Shortages have been visible for some time in interstate markets. The proposed policy would extend the shortages increasingly into the intrastate gas market -- without of course doing anything much to alleviate them in interstate markets, since true (but suppressed) incremental values of new gas supply are above $1.75 there also. From the Texas point of view, the important question on the supply side of the gas market is whether incentives based on the actual market value of gas will be allowed to work, to elicit the supply that Texas can produce at those prices. On the demand side, the important question is whether industries and other consumers in Texas are going to secure their gas supplies by an open process of bidding and purchasing at prices that, again, reflect value in use, or whether they are going to receive rations allocated by decisions of the Federal government under perpetually prolonged shortages and penalty taxes. The National Energy Plan is not reassuring on either of these points.

"Old" Gas and "Price Certainty"

In brief, the NEP guarantees maintenance of existing prices on existing contracts, escalated for general price inflation. "Old" gas reentering the market from non-contracted production at expiration of contracts would be subject to FPC control if it were "interstate"

production, with a maximum ceiling of $1.42/MCF plus inflation. "Intrastate production," on the other hand, would qualify for the new gas price of $1.75 plus inflation. (The National Energy Plan, p. 53.)

It is not clear how we can tell the difference between interstate gas and intrastate gas in the absence of a contract, unless the report means that certain fields are to be in permanent peonage to the interstate market.

The strangest thing about this part of the program is that it seems to restore a two-price system between the interstate and intrastate markets, notwithstanding the announced intention to have a single national (one-price) market. A lot of gas is going to become available in "old" fields in the future. Is this gas going to be permitted to move toward the $1.75 price or will it be confined to the $1.42 market? A very elaborate control system would be necessary to maintain such an anomaly, which in any event would perpetuate an unduly low price in interstate markets in contravention of the announced goal of economical conservation. In other words, we are back to the same old stand on interstate price controls.

Emergency Allocation Authority

The NEP calls for extension of the current emergency gas allocation authority for three years.

Without dwelling on the policies that during the years since 1954 have gradually cumulated to produce the emergency of 1976-77, we must point out that the program does not correct the fundamental

difficulty. Quite the contrary: it perpetuates shortages by maintaining price controls on both old and new gas. It is true that a $1.75 or $1.42 ceiling is better than a 25 cent or 56 cent ceiling, but shortages will not be eliminated. Admittedly, once we are in a national emergency we may have to invoke emergency controls to get through it, but that should not be mistaken for a policy; the ship is still sinking even though we may be able to launch life rafts.

The essential thing is to restore supply, demand, and stocks (inventories) to a condition of balance and to reconstitute the industry's flexibility to deal with emergency situations. Government controls almost guarantee that these results won't be achieved. In fact, the controls proposed in the National Energy Plan almost guarantee that emergencies will continue to happen, justifying the indefinite continuation of allocation controls. As the emergency becomes permanent, the government substitutes allocation by fiat for allocation by market; and political virtue rather than economic value becomes the principal criterion for allocation. Moreover, the government soon finds that it is politically impossible to let go. (This is familiarly known as the "tar baby effect.")

It seems transparently obvious that the principal losers in a system of end-use allocations will be the industries of Texas and other major producing states, and the jobs and taxes dependent on them. As shown in Table 3 above, industries in other regions are proportionally much less dependent on gas.

The Alternative

To reiterate what has been said already: the best way to limit demand for an exhaustible resource and to stimulate supply as costs rise is to let the market price increase accordingly. That policy will prevent artificial shortages of the kind that regulation has created. It will preclude creation of a gigantic bureaucracy of regulation which has to keep extending its controls as new side-effects appear.

If price ceilings are removed from interstate gas and kept off intrastate, incremental prices will probably rise above $1.75/MCF in both markets, affording a strong incentive to economize. Average prices will rise to incremental levels much more slowly, as contracts expire. This should afford more time to make the transition to other fuels, which many users will have to make whether there are price controls or not.

The National Energy Plan (p. 52) says that the interstate-intrastate distinction has become "unworkable, indeed intolerable, as the limited amount of new gas increasingly flows to the unregulated intrastate market at the expense of interstate consumers." This effect was produced by regulation, and the remedy for it is to deregulate interstate prices. We recognize that the industries of Texas and other intrastate users would then have to meet interstate users in the market on equal terms; the result should be that the uses of highest value everywhere will get the gas, and others will be compelled to convert.

A word may be said about residential consumers: in many areas,

space heating will be one of the high-value uses, so gas will continue to flow to residences; in others, conversion will ultimately be necessary. It need not happen overnight. Meanwhile, governments can best deal with the impact of higher prices on poor consumers by programs of income maintenance, not by arbitrarily and permanently allocating supply to any particular group under price ceilings. The question of whether industrial, commercial, and residential consumers should pay the same price per MCF of gas sold by local public utilities is best answered by state public utility commissions who are closest to the problem. The Federal government should not use specific taxes or price discrimination against particular classes of gas consumers to implement its (non-market) judgment of the relative worthiness of various uses.

Finally: the "windfall" profits referred to in the NEP, occasioned by selling "yesterday's discoveries at tomorrow's prices," will in fact be mostly absorbed in replacement costs. The NEP is to be commended for recognizing that "the pricing of oil and natural gas should reflect the economic fact that the true value of a depleting resource is the cost of replacing it." (Plan, p. xi.) That value can be found in the free market.

Mr. OTTINGER. Even recycling the monies back, just giving the money back to the people is not going to make up for the prices rising throughout the economy as a result of any sudden impact.

If we were to deregulate and have a windfall profit tax, we could take up the difference, say, in the price increase over some base level and then have a plowback. The producers would profit from considerable increased sales, I assume, from their increased production that might result, assuming there was increased production to be had, which is what your assumption is.

Are you in favor – if you say you do not want the producers to make windfall profits out of this – of an increased tax on producers?

Governor BOREN. Yes, except for the part, of course, that they would plow back into increased supply, and this goes along with your question a minute ago. The tragedy is really going to be if the consumer gets hit with a higher price and nothing is done to improve the consumer's position with increased supply.

Mr. OTTINGER. I understand your point on that. But I am told by the FPC as of today that the average price in Oklahoma, at which these new supplies in intrastate market have been produced, is $1.66. If we provide $1.75, it would seem to me we are providing plenty of incentive.

Dr. TALLEY. An average over what time frame? Current market price in Oklahoma is approximately $2.

Mr. OTTINGER. That is last quarter, and we are told for this quarter it is a few cents less, first quarter of '77. Those figures are not published yet.

Dr. TALLEY. We are talking about the price of new contracts, and based on tax commission records, our latest figures show that is $2 based on the taxes paid at the wellhead.

Mr. OTTINGER. Would you supply those prices for us?

Governor BOREN. I think you are getting figures that have the averages thrown in rather than the incremental price. We will get those figures to you.

[The material requested had not been received at the time the record was closed.]

Mr. OTTINGER. It is my understanding that in the 1960's gas was selling about 17 cents per thousand cubic feet. I just did some calculations here based on your figures that had nothing to do with inflation as a whole, but you have some figures in your statement that the prices have been escalating for drilling at 19 percent a year. I added all that up and on a cost basis that would increase to about $1.26. So it does seem there have been some reaping of unusual profits. The figures being given have been inflated much more than the inflation rate the gas exploration has been increasing.

Governor BOREN. Mr. Cleary developed some of those figures.

Mr. CLEARY. At virtually any price there will be certain wells that will make a profit. The question is not the average price. At 17 cents a few wells were built in the 1960's and the cash flow is derived from over investment opportunities. What we are trying to do is to increase the number of wells. It is very dangerous to deal with averages.

Mr. OTTINGER. The thing which is so concerning are the prices that are being asked. If we were to deregulate, that price is going to, presumably, go up. We have OPEC dictating the prices we pay for energy, and it would seem the price has no relationship whatsoever to the actual cost to bring in new wells.

Mr. CLEARY. It does have. The process that must be realized over life to achieve a certain rate of return are reflected in the finding cost. Let's say oil costs $5 a barrel to find. Over life we must get $12 to get a 15 percent rate of return. The price you must realize is reflected in the finding and developing cost. The cost the Governor referred to is the finding and developing cost.

Mr. ECKHARDT. I have looked into this question of price of oil and using 1972 as a base index figure of 100, oil prices increased to 241.3 for 1976, that is both old and new, whereas the oil field machinery cost rose to 170.9 in 1976; oil well casing 173.7; oil field wages 147.6; drilling cost per foot 192.9. So even the average cost of both old and new oil has run up at a much higher percentage than the per-foot cost. It would be like this graph. Price is running well ahead of drilling costs.

Governor BOREN. That is correct. I think our estimate, as I said in my statement, is very conservative, but beyond that, you are not looking at the cost per foot and equipment, but the fact that the target yuou are aiming for is much harder, harder to get at, so this is going to cause even further inflation of finding costs.

You have to consider the target you are aiming at as well as the cost per foot.

Mr. ECKHARDT. But that is already being reflected in present additional costs.

Mr. OTTINGER. I will yield to the gentleman from Texas.

Mr. KRUEGER. I would like to observe there is a difference between oil and gas in terms of drilling costs in that until the 1970's basically there was virtually no drilling for gas. The drilling was for oil and gas as a byproduct found. Therefore, since it is a byproduct, it was undersold both by Btu costs and drilling costs.

I thank the gentleman for yielding.

Mr. GAMMAGE. Would the gentleman yield?

I request unanimous consent that all of the records and figures requested of these gentlemen be included in the record.

Mr. OTTINGER. Absolutely. Without objection, that request is certainly granted.

What many of us are concerned about is there not be an unjust enrichment. There seems to us there has been a taking advantage of the public already by the producers. It is hard to know where that is distributed because there are many different people involved in this business along the way. I address this to the gentleman to my right. If we are going to do any kind of equity and even consider a deregulation and plow back costs, we probably ought to go well beyond the current price in order to do equity.

Mr. ECKHARDT. Just one matter I would like to clarify with Governor Boren with respect to his chart. He was talking mostly about this issue of this horizontal distance of a well from an existing well. Do you also take into account in this the new gas alternate criteria of the 1,000-foot vertical distance?

Governor BOREN. Yes. Including both. Only 6.2 qualifies. Only 2.4 percent under distance, 3.2 or something like that, on the depth, so using both definitions, taking advantage of both, this causes me to question the credibility of those who have been working on this aspect.

Mr. OTTINGER. I wish we could go further. I am sure all of us would like to ask more questions. I want to thank both of you for your patience. We will appreciate receiving the additional information that is requested. If members have additional questions, I assume you will be willing to address those as well.

Governor BOREN. Absolutely.

Mr. OTTINGER. Those will be included in the record.

Mr. OTTINGER. Our next panel consists of members of various regulatory producing States.

Mr. Morris.

STATEMENTS OF GARRETT MORRIS, CHAIRMAN, PUBLIC UTILITY COMMISSION OF TEXAS; CHARLES C. WILLIS, JR., DEPUTY ADMINISTRATOR, ENERGY RESOURCES BOARD, STATE OF NEW MEXICO, ACCOMPANIED BY PIERRE L. NYS, STAFF MEMBER; AND MACK WALLACE, CHAIRMAN, RAILROAD COMMISSION OF TEXAS

Mr. MORRIS. Mr. Chairman, I am Garrett Morris, Chairman of the Public Utility Commission of Texas, and I am pleased to have the opportunity to appear before your committee. Though the agency which I represent does not regulate the price of gas or the rates of any gas utilities, it certainly will be affected by what is proposed here.

The bill is critical of the movement of gas to the intrastate market where the price is higher; however, such criticism is inconsistent with the purpose of this act, which is to increase the cost of gas, and therefore encourage the conversion to facilities which will operate on more abundant fuels, and thus bring about conservation.

During the past five years, the price of natural gas in the Texas intrastate market has risen so as to be generally the true value of production. In other words, generally through effective State conservation regulation and a market pricing policy, the Texas intrastate natural gas market price is already supplying adequate returns on investment and incentives for further exploration and production.

This overall energy related economic policy has had a twofold effect. First, as I previously stated, the State of Texas has begun to and is currently reaping the benefits of an adequate natural gas supply. Secondly, the increasing price of natural gas which is market based has had the effect of discouraging its use in the less efficient forms such as the generation of electric power.

Thus, we presently have an electric utility industry which has made substantial progress in converting from natural gas and oil as a main boiler fuel to that of more abundant fuels such as lignite, coal, and nuclear energy. Such alternate fuels are presently significantly less costly on an MMBtu basis than Texas intrastate natural gas. Even when considered with the relatively higher base cost of plants using lignite, coal, or nuclear generation, the overall cost of

electricity to consumers is and will be relatively the same when considered with the offsetting reduction in fuel cost.

Now certainly this Nation needs to conserve gas and it needs to convert its facilities so as to use lignite, coal, and other more abundant fuels. This is being done with increasing speed in Texas.

Our commission has adopted a policy of not certifying any additional gas-fired electric generating facilities. We are doing everything possible to encourage the construction of new generating facilities which will operate on more abundant fuels. This includes allowing massive amounts of construction work in progress on new generation facilities in the rate base and accelerated depreciation. If Congress is interested in encouraging such conversion, it would be a great help if they would convert the Federal income tax deferrals allowed for accelerated depreciation into actual tax credits so that the gas-fired plants could be written off and retired in half the normal time. This would increase the cash available for new construction, and at the same time would not increase the burden on the rate payer, who is already paying heavily for conversion.

We have not only eliminated the declining block rate structure for electric utilities, but as a further means of conserving fuel, our agency requires all customers to be charged the actual cost for fuel required to generate each kilowatt hour of electricity used, and such charge to be shown separately on the bill.

Additionally, we have established a flat rate structure for electric utilities based primarily on service costs, capacity costs, risk and peak load use, which further encourages conservation of energy and therefore fuels. Our agency by interim order last week ordered the interconnection of the major electric utilities in our State. This connection vehicle not only increases the reliability of all systems but results in considerable savings in fuels, enhances the potential for increased cogeneration, and establishes a basis for wheeling, and bulk power transfers.

The President in his energy message asks for the cooperation of the American people. I firmly believe that, if they are given a chance, they will respond, personally and through their local agencies. I am concerned about the 2-tiered regulatory structure proposed here. By the time the Federal agency establishes rules and guidelines and the State agency proposes rules and gets them approved by the Federal agency all flexibility is lost.

If the gas industry is to be fairly regulated, then they must have quick access to relief for changing cost conditions, otherwise they must have wider operating margins.

In rate matters, our agency has established a pattern of responding within 90 days from the initial filing. As a consequence, we can reasonably give a narrower operating margin which is beneficial to the rate payer and yet not injurious to the utility. This ability to respond quickly would be limited by the double layer regulation proposed here, and I am afraid it will cause great harm to the utility and its customer. The only other place that I know of where such double layer of regulation is used is in the supervision of the welfare program of this Nation, and it has resulted in an administrative disaster. Certainly, Mr. Chairman, we can not afford to so burden this program with regulation to the point where there is no alternative to failure.

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I firmly believe that we need a national energy plan, but having a plan is not enough; we must have a plan that will work. It seems to me that the present plan fails both as to content and structure, and unless it is drastically altered has little chance of success.

Thank you.

Mr. OTTINGER. Thank you very much.

We will hear next from Mr. Charles Willis, Deputy Administrator, Energy Resources Board, State of New Mexico.

STATEMENT OF CHARLES WILLIS

Mr. WILLIS. Thank you, Mr. Chairman. I would like to submit, if I could, my prepared testimony for the record.

Mr. OTTINGER. We will be glad to receive that, and, without objection, that will be included in full in the record.

Mr. WILLIS. I would like to read parts of it as well as parts of Governor Jerry Apodaca's statement and insert parts of his statement as well because he is not here.

Mr. OTTINGER. You are most welcome to proceed.

Mr. WILLIS. Thank you, Mr. Chairman.

Mr. Chairman and members of the subcommittee:

My name is Charles Willis and I am the Washington representative and Deputy Administrator for the Energy Resources Board of the State of New Mexico. With me today is Mr. Pierre Nys, a staff member in our Washington office. The Energy Resources Board is an executive agency responsible, in part, for formulating and implementing energy policy for the State of New Mexico.

I would like to thank the subcommittee for inviting us to participate in these panel discussions on the natural gas section of H.R. 6831, the National Energy Act of 1977. As the fourth largest supplier of natural gas, New Mexico is extremely interested in this aspect of the energy plan and currently has in effect a State energy plan that addresses a number of similar problems. As a consumer State, New Mexico must also ensure that the impact on our consumers will be minimal.

New Mexico has an unusual inter/intrastate natural gas market structure which gives the State a unique complexion. Even though we are a producing State, only 12 percent of our natural gas is utilized within our State boundaries. The other approximately 88 percent is dedicated through long-term contracts to the interstate market. Because of these long-term contractual agreements and an inadequate intrastate pipeline system, less than 25 percent of this 12 percent used within the State is supplied by interstate pipelines, the remaining 75 percent flows through the intrastate system.

On one hand, we are sensitive to the problems of the producers, and on the other, we are acutely aware of the problems of our consumers who were faced with price increases, curtailments, and moratoriums on new hookups during the winter of 1976-77.

As the subcommittee may know, the State of New Mexico recently enacted natural gas legislation to answer consumer concerns and established a price ceiling on intrastate natural gas sold under existing and expiring contracts. The State took this step to establish price parity between the inter and intrastate markets. Now with

the introduction of this new Federal legislation, our legislation may be preempted. The following is a description of the act, and our projections of the interaction between the proposed Federal legislation and the State act.

This price ceiling legislation was passed only because of the frustration of New Mexicans in paying an average wellhead price for intrastate gas which averages more than double the interstate prices. The intrastate wellhead price of natural gas has risen sharply in the past two years and without some sort of ceiling would have continued to rise substantially. This trend has already caused severe hardship for many New Mexicans, especially farmers, low-income families and certain industries in addition to the hard-pressed middle class.

New Mexico recently became the first State to pass such a measure controlling intrastate gas prices. The legislation imposes a $1.44/Mcf price ceiling on all pre-1975 intrastate production and also requires that a certificate of abandonment be obtained from the Public Service Commission for the sale to the interstate market of any gas previously dedicated to the intrastate market under an expiring contract.

The purpose of the legislation is first, to protect New Mexico consumers against rapidly spiraling prices due to the triggering of most favored nation clauses in existing contracts, and two, to insure that current amounts of gas will remain dedicated to the intrastate market. The act terminates on June 30, 1979, or 30 days after total deregulation of the unadjusted wellhead price of all natural gas produced in New Mexico, whichever comes first.

This legislation establishes parity between the intra and interstate markets for the natural gas that is affected and therefore, prevents any price advantage to either market to influence sales decisions.

It is also important to note, especially for Federal purposes, that no ceilings have been placed on "new" gas, which is defined in the act as gas drilled or the first intrastate sale of which commenced on or after January 1, 1975.

The Governor's statement gets specific in some of the objections to the natural gas aspect of the bill as follows:

First, New Mexico would be hard-pressed to keep the gas flowing from existing intrastate contracts for consumption within the State. This is because this gas, when contracts expire, would command a $1.75 per Mcf price in the interstate market, while it would command a maximum of $1.44 per Mcf in our intrastate market under New Mexico's Natural Gas Pricing Act.

It should be emphasized that the State of New Mexico implemented this price control ceiling only after the Federal Power Commission refused to protect us from skyrocketing prices and, in effect, told us to protect ourselves. So we did act to protect ourselves, and now we find the rules of the game are being changed.

Second, all "new gas" would be subject to a ceiling of approximately $1.75 per Mcf at the beginning of 1978 whether the gas is intrastate or interstate. Under New Mexico's Natural Gas Pricing Act, the intrastate part of this gas would be free of controls. This provision was included in the law in an effort to provide incentives for exploration and production of new gas. The President's program would eliminate this incentive to a large degree. As a result, New Mexico could be expected to experience a decrease in drilling activity, gas supplies and tax revenues to the State.

Finally, New Mexico is very concerned about the effect the provisions of the President's plan would have on New Mexico's natural gas load factor. New Mexico's intrastate system is characterized by a much poorer load factor than that of

interstate pipelines. As a result, the State's intrastate suppliers have been forced to pay a higher price for gas than interstate suppliers which have better load factors. This situation leaves the intrastate suppliers at a disadvantage compared to interstate supplier when bidding for gas.

It should be noted that the average load factor New Mexico's intrastate system does have, has been achieved and maintained by an extensive use of natural gas for electrical generation and boiler fuel. In 1976, about 36 percent of the gas the state consumed was used for electrical generation, and about 24 percent was used for industrial purposes.

The President's program contains provisions which would eventually stop the use of gas for these purposes. As a result, the State's load factor can be expected to deteriorate even further in the future. Although other States will experience the same problem, the problem will be much worse in New Mexico because there is relatively little industry in the State. This situation poses further problems for New Mexico's intrastate suppliers because of the average load factor, and forces these suppliers to pay producers more for gas than interstate suppliers which tend to have better load factors.

My specific observations about the portion of the National Energy Plan that relates to natural gas include the following:

With respect to section 402, "Definitions," first of all, there is subsection (4), which includes in the definition of "person" all States and political subdivisions. By broadening the definition of "person" from that which has prevailed in the Natural Gas Act, New Mexico might no longer be able to act directly to purchase State-owned or royalty gas and arrange for its transportation through interstate pipelines for the benefit of communities in the State which are suffering from inadequate supplies of natural gas. This result would not seem to be in the public interest.

Secondly, the definition of "new natural gas" in subsection (5) would seem to exclude so-called "in-fill" wells, which account for a very substantial proportion of newly-produced natural gas in New Mexico. Thus utilizing such a restrictive definition would not seem to be consistent with the administration's goal of "increasing the supply" of natural gas.

In reviewing the proposed provisions and relying on the intent of the legislation as well as the actual language, the State of New Mexico believes there are three major problem areas which need to be corrected and clarified.

First, allowing expiring intrastate contracts to jump to the maximum lawful Btu equivalent price will undercut our current state statute. It is our understanding this price would be approximately $1.75/Mcf. If the gas from these expiring contracts fits our definition of "old" gas, the maximum intrastate price in New Mexico would be $1.44/Mcf. This price discrepancy between the two markets which we did alleviate in our legislation could possibly be recreated. We believe jurisdiction over all "old" intrastate gas should remain with the states. Local State governments can better assess the current intrastate situation and implement corrective State legislation, should the need arise, than the Federal Government. Furthermore, States have traditionally exerted a limited jurisdiction over their own natural resources. We would like to see this traditional jurisdiction preserved.

Secondly, distribution of the State's intrastate gas is inadequate because of the lack of an effective intrastate pipeline system. Using royalty gas and other supplies, problems such as curtailments and moratoriums could have been eased if an adequate transmission system existed. Meanwhile, various interstate pipelines were crossing New Mexico and most were running at one half to one fourth capacity. To alleviate this intrastate problem, intrastate gas should be allowed to flow in interstate pipelines. The current proposal maintains the status quo, and makes no mention of commingling. If this were allowed, the State of New Mexico would not have to build

a separate intrastate pipeline paralleling an underused interstate one—saving the State approximately $8 miiilion—and during times of acute shortages, excess intrastate gas could be utilized to ease the emergency.

Finally, the extent to which the Federal Government will preempt State law must be made clear. There are other drafting and technical errors that must be clarified before we can clearly and fully express our position on the proposed Federal legislation. It is hoped that these hearings will more fully resolve this type of error. For instance, in section 405 the legislation reads "any first sale by a producer of old natural gas. . .". There is no distinction between inter/intrastate gas under this existing contract section. But the administration clearly states in its briefing book, The National Energy Plan, "Existing intrastate contracts would not be affected" when discussing existing contracts. These contradictory statements must be clarified.

It is generally recognized that a revision of Federal regulatory policy is long overdue. We commend the administration's efforts in attempting to formulate a consistent and fair pricing structure. However, we believe any revision should include the provisions outlined earlier which would sufficiently protect the traditional jurisdictional rights of States, such as New Mexico. New Mexico has in effect a State energy plan and has implemented legislation to adequately remedy and enforce pricing disparities in its own intrastate market. It is argued that this area should be reserved to the states.

In conclusion, it is imperative that during consideration of this legislation, the subcommittee clearly state the legislative intent of the proposed bill, H.R. 6831. We can no longer afford to further complicate an already complex issue.

I think that basically concludes our prepared remarks.

Mr. OTTINGER. Thank you very much, Mr. Willis.

We will now hear from Mr. Mack Wallace, chairman of the Texas Railroad Commission.

STATEMENT OF MACK WALLACE

Mr. WALLACE. Mr. Chairman and members of the committee:

My name is Mack Wallace. I serve as chairman of the Railroad Commission of Texas. The commission consists of three members, each elected in a statewide election. Our statutory responsibilities include among other things the regulation of the drilling and production of oil and gas, and the transportation and sale of natural gas to the consumers of Texas. This responsibility has been exercised by the commission from 1920 to date.

I appreciate the opportunity to appear before your committee to testify regarding what to me is one of the gravest problems facing our Nation and my State today—whether or not the Federal Government will permit itself to regulate with the power to allocate intrastate natural gas—which has already been paid for by the consumers of Texas in the form of utility rates that reflect the true value of natural gas. You have three options. You can maintain the status quo and preside over the decline of the financial stability, industrial strength and position of this Nation in world affairs.

Your second option is to implement the historical regulatory policies of the major producing States at the national level, thereby providing the maximum incentive for the full development of this Nation's existing natural gas resource base, whatever it may be, and also providing the maximum incentive for industrial conversion to alternate fuels.

Your third option is to act favorably on the proposed legislation now before you which, if fully implemented, will slow the decline of this Nation's natural gas reserve but will fail significantly to achieve the goals of the National Energy Plan.

Perhaps we should look at ourselves as others see us. On April 23, the London Economist observed that President Carter's

> hope to extend Federal price controls on natural gas from gas traded interstate (that is between States) to gas traded intrastate (within its State of origin) is folly. The intrastate free market has provided a good barometer to the price that should be paid for gas. By eliminating it Mr. Carter will not merely lose a useful indicator, he will insure that the same old bad habit of price control recurs, only more widely, when the natural gas price starts jumping up against its new high ceiling in a few years' time.

It is important to note that in 1920 the Texas Legislature mandated the Railroad Commission of Texas to provide an adequate supply of natural gas at reasonable prices for the intrastate market. In 1938 the Congress of the United States mandated the Federal Power Commission to provide an adequate supply of natural gas at reasonable prices for the interstate market. The relative success of State regulation, as opposed to the failure of Federal regulation, has never been more eloquently expressed than by the passage of the Federal Emergency Natural Gas Act of 1977. It is appropriate and indeed mandatory that I call the committee's attention to a portion of an article published in the Houston Post, Sunday, January 30, 1955, wherein the question was proposed:

> Will Federal controls achieve the desired end of assuring consumers of a continuing adequate supply of natural gas at reasonable prices?

At this point I would like to suggest the word 'consumers' was invented sometime prior to 1955, because we found it in this article. It was not patented by some of our current popular gentlemen who claim credit for that word.

> The answer to this question is an emphatic no! Prevailing field prices for gas are the result of the operation of the laws of supply and demand. Federal interference, attempting to decrease those prices, will at first stimulate demand: There will, however, be no corresponding increase in supply, because the incentive to find and develop new sources is dependent upon receiving a fair price for the product. Further, such new supplies as are found incident to the search for oil, will be diverted to intrastate sale outside the jurisdiction of the FPC. The inevitable result will be further imbalance between demand and supply. Supplies of gas for interstate sale will dwindle, and the costs of moving each Mcf of gas to market will skyrocket, because the transmission lines must operate near capacity to keep unit costs within reason. The predictable end to the cycle

—and this is what haunts me—

> will be inadequate supplies and much too high prices to the ultimate consumer, who will then be forced to use other, and less desirable sources of energy. It is needless to state that the economy of the entire country will suffer from such an unfortunate succession of events.

Now, that article, I suppose, was inspired by the 1954 Supreme Court decision allowing the FPC to regulate the price of gas.

This proposed legislation suffers from the same vice as the existing Federal policy in that it provides for an artificial price mechanism that bears no relationship to the true value of natural gas. You must act to assure immediate nationwide development not only of natural gas but of crude oil, coal, nuclear energy, geothermal energy, and solar energy. This problem cannot be solved by debate, sectional trade-offs and bureaucratic rulemaking. It can be solved with the drilling rig, the drag line, the shovel, the roustabout, the roughneck, the tool pusher, and the best scientific and technical minds we have, not with endless reams of regulations and countless visits of level upon level upon level of Federal regulatory enforcers. This should not be a sectional issue. You cannot consider the economy, you cannot consider the production of energy and you cannot consider national security separately, for to do so is to invite disaster for all three.

Thank you.

Mr. OTTINGER. The Chair recognizes Mr. Krueger.

Mr. KRUEGER. Thank you, Mr. Chairman. As I was out part of the time I would appreciate it if you would return to me for questioning.

Mr. OTTINGER. I will be glad to do so.

Mr. MOORE. I thank the chairman.

I would like to ask the gentleman from New Mexico a question, if I may.

Mr. Willis, you mentioned in your statement, near the end, I believe on page 4, about the commingling of natural gas. Do we have any Hinshaw-type pipelines in New Mexico?

Mr. WILLIS. Yes.

Mr. MOORE. You realize this bill does carry a way for the government to come in and regulate that gas?

Mr. WILLIS. We wanted to more or less approach that on a status quo basis.

Mr. MOORE. When you say you want to see the status quo you want to go back before the Emergency Natural Gas Act? You don't want to see any powers over the Hinshaw Gas Act.

Mr. WILLIS. Yes.

Mr. MOORE. What I am trying to point out to you is that this bill is not a status quo.

Mr. WILLIS. Yes; we had a wrong choice of words in the statement.

Mr. MOORE. When does your pricing mechanism in intrastate gas become effective?

Mr. WILLIS. It became effective about three weeks ago.

Mr. MOORE. It is far too early to tell what effect that will have on production or exploration in New Mexico?

Mr. WILLIS. Yes.

Mr. MOORE. What is the average cost of production? Is your gas usually coming from deep sand?

Mr. WILLIS. I can't tell you exactly.

Mr. MOORE. I would like to ask all three of the gentlemen who testified here, we have the Krueger-Brown substitute to this which calls for the slow deregulation of natural gas.

Would the three of you comment as to whether you would favor that approach as opposed to the administration's approach?

Mr. WALLACE. I would favor that approach.

Mr. MORRIS. I would, also.

Mr. WILLIS. Yes, sir.

Mr. MOORE. Let me ask you a question about utility rates in Texas. I am from Louisiana. We are not as far along as you are on that. Do you foresee an increase in the electric utility rates of your consumers in Texas in connection with the cost of conversion in an existing power plant to get away from the gas-fired boiler? Do you see any increase in electricity work by forcing electric utilities off gas and onto coal.

Mr. MORRIS. As you know, the cost of coal-fired generating units is about twice or three times the cost of gas-fired generating units. So, as far as the investment involved, you have a tremendous investment over what you currently have. Even though with that increased investment and as long as the current price of gas didn't go above $2, it just about equals out because the cost of lignite currently in Texas is about the equivalent of 25 cents per Mcf in gas.

Mr. MOORE. Will you have to use the scrubbers on these coal-fired burners?

Mr. MORRIS. Yes.

Mr. MOORE. Have you figured that into your cost?

Mr. MORRIS. Yes, that was somewhere between 7 and 10 percent of the cost of a plant. If you have to put scrubbers on every plant, regardless of the sulfur content of the coal, it really is going to cost the consumer a lot of money. That is one of the things this bill, as it is currently written, requires. It requires scrubbers regardless of the amount of sulfur in the coal and the lignite and that is a very, very costly thing as far as the consumer is concerned.

Mr. MOORE. Can you look into the storage of the sludge? I understood somebody to say it will take as much as two acres a year to store the sludge.

Mr. MORRIS. We have not gotten any scrubbers in production as yet. The first scrubber put on a lignite-fired plant in our State, I believe, will come on line early this year or later this year or next year.

Mr. OTTINGER. The gentleman from Texas, Mr. Krueger.

Mr. KRUEGER. Mr. Morris, at what rate—and perhaps Mr. Wallace might also have comments—at what rate is the State of Texas converting from natural gas to coal and other sources? By what time do we expect the conversion to be complete? Just give the present law.

Mr. MORRIS. By 1990. I would guess on the present projection we would be almost completely converted with the exception of the use of gas for peaking purposes. I suppose as long as there is any gas available, it will be available for peaking purposes. They tell me to pull a big coal or lignite plant down to 20 percent capacity for peaking purposes. It takes as much gas to stabilize the flame under that type of unit as it does to do the peaking itself with a gas-fired unit.

Mr. OTTINGER. Will the gentleman yield for a moment?

Mr. KRUEGER. Yes.

Mr. OTTINGER. I did not understand the date.

Mr. MORRIS. 1990.

If I might add, Mr. Chairman, we really are making tracks, though, towards conversion.

To give you just an example of one company we just had in for a rate increase, which is Texas Power and Light, they had 250 million of construction work in process for generation facilities only at the time we brought them in. Of course, I can get the transmission lines that go with it. You are talking about 400 or 435 million dollars worth of construction work in progress related to the conversion to other types of energy.

Mr. KRUEGER. I will, in a moment, go back to other questions on coal. One of the things I would like to do for the record is get a sense of some of the prices now paid for gas in our State, particularly for the production of electricity.

I wonder, for example, whether this panel would know what, say, the August price for gas purchased was, in Texas.

Mr. WALLACE. For 1976?

Mr. KRUEGER. Yes.

Mr. WALLACE. We can provide the committee with those figures. Those things change rather rapidly

Mr. KRUEGER. Would you know what the average price for new gas is in Texas now?

Mr. WALLACE. About $2.05.

Mr. KRUEGER. What would be the average price for all gas purchased in Texas?

Mr. WALLACE. Sixty-nine to 70 cents.

Mr. KRUEGER. About 70 cents is the average price for gas purchased in Texas now. The old gas, because of contracts, is still 69 and 70 cents.

How much has the new price escalated of late, say within the last three or four months?

Mr. WALLACE. There is a softening, Congressman.

Mr. KRUEGER. The price has dropped? About how much?

Mr. WALLACE. About a nickel.

Mr. KRUEGER. About a nickel per Mcf. At what price do some of the utilities begin converting to gas or oil for their use?

Mr. MORRIS. Basically, it is in the range of $2 because until you get roughly to that price, you don't end up with any cheaper electricity because of the investment required. When you get into oil you run into delivery problems. Very few of the facilities in Texas are designed to operate on oil for any great length of time. It takes significant modification for them to operate on oil for any extended period of time.

Mr. KRUEGER. So what we are hearing, then, is that the price for new gas in Texas is a little bit above $2, the average price for all gas delivered in Texas is 69 to 70 cents per Mcf, recently the price for natural gas has softened somewhat from what it was before and utilities tend to switch if they do, when the price comes to about $2 per Mcf, but they can only shift for a short time because of the pollution problems involved.

What effect did the emergency bill this last winter have on the State of Texas?

Mr. MORRIS. Are you talking about the furnishing of gas by the various utilities?

Mr. KRUEGER. I am interested in knowing what happened to the intrastate market in Texas and I would like also to know what quantities of gas were drawn out from Texas into the intrastate market.

Mr. MORRIS. A lot more gas was made available and offered than was taken by the various utilities within the State of Texas.

Mr. KRUEGER. More gas was offered to utilities in the intrastate market than was taken?

Mr. MORRIS. Yes.

And as far as I know and as far as it has affected the utility market, it did not have any effect on the utility rates, to my knowledge.

Mr. KRUEGER. If I might I would like to ask one more question related to lignite in particular. It is my understanding Texas is trying to convert from gas to lignite in order to save the more precious fuel.

Am I correct the new bill proposed by the administration would impose a tax on lignite by the ton rather than by Btu output? If I am correct, it means instead of being encouraged to use the lignite available on the spot and to save the cost of transportation to consumers and also to save the the energy being transported in from other distances the proposed tax would encourage the State of Texas not to burn its own coal because it will be put on a low Btu fuel.

Mr. WALLACE. The original cost was 35 cents. I have heard recently it has been reduced to 25 cents. You pay twice as much on lignite as anthracite on a Btu basis.

Mr. KRUEGER. Thank you, Mr. Chairman.

Mr. OTTINGER. The gentleman from Texas, Mr. Gammage.

Mr. GAMMAGE. I presume most of you gentlemen were in the room a moment ago when I addressed my rather lengthy question to the Governors. If you recall the inconsistencies I would be happy to hear you respond to that at this time. Mr. Krueger alluded to one of those inconsistencies, the tonnage tax as opposed to the Btu tax. Also, the amendments to the Clean Air Act, how they would affect our domestic utility market. In particular, Mr. Morris, I am apprised that Houston Light and Power, for instance, burns mostly gas, converts some of its gas- burning facilities to oil, with one nuclear plant under construction and another on the drawing board. But there is about an eleven- or eleven-and-a-half-year lag time with respect to those facilities.

Any new facilities will be coal but the trade-off proposals don't permit them to utilize coal-fired plants. At the same time the population impaction in that area being something like five to seven thousand people per month with new demands for construction of utilities, will not permit them to serve the population, much less the industries unless they do something.

Will you speak to that, please?

Mr. MORRIS. I am not sure I can speak to that whole subject with any great authority because I am not too familiar with what problems they have with the Clean Air Act. I do know they have serious problems, of course, in the Houston Metro area but I am not sure how many problems they have out in the area where the lignite plants would be located.

If there have been any plants not allowed to go into effect because of the Clean Air Act, I was not aware of it.

Mr. GAMMAGE. For instance, in my particular district which runs from the innercity to the seashore, we have two rural areas; one being more suburbanized, the other commercial. In order to provide the utility service to those in the suburbanized area, they intend, or plan, to construct a coal-fired facility. Because of the nondegradation standards of the Clean Air Act in an area not industrialized, they have difficulty finding anybody to trade off with on the one-on-one basis. At the same time, the need and the demand is there. The utilities must be constructed. They have another nuclear facility being constructed now, with another on the drawing boards. They are switching from gas to oil, but under the Clean Air Act, it makes it impossible to provide services for those people.

This points up the lack of coordination in terms of the whole package when you have a supply of resources lined up against demand for consumption.

Mr. MORRIS. Of course, even with all the lignite which we have in the State of Texas, it is going to be necessary now for us to start importing western coal because it is not economically feasible to build a lignite plant unless you can stake out enough lignite around that plant to run it for its natural life.

All of the lignite that you have, of course, could't be put to the burner tomorrow. So, it is necessary, even at this point, and contracts are being made right now and some of them are in effect, for the importation of western coal from Colorado, Wyoming and from New Mexico.

If we are to convert, we not only are going to have to be able to build the plants that will use the lignite but we will have to be able to build additional plants which will import western coal and we really need to get on with it.

Mr. GAMMAGE. If the strip-mining proposals are adopted we may not be able to mine it anyway.

Mr. Wallace, do you have any response to any of these inconsistencies?

Mr. WALLACE. I have a great deal of problem with consideration of deregulation without a corresponding consideration of environmental restraints. If you don't review those, then you only have additional drilling in picked-over territory.

I am concerned about Judge Weinstein's ruling in New York when he voided the offshore lease sale even though 4,043 pages of environmental paperwork had been done.

We have a lead-time here in the production of energy. The Federal Government will have to go through the sale again. I assume if they do 6,000 pages of paperwork they may be able to get it through. The order was signed some few days after we were up here on the Emergency Natural Gas Act.

The Governor very eloquently said the people in New York were cold; they needed gas and they needed it very badly. Of course, the county of Suffolk, New York, was one of the counties which stopped exploration for oil and gas off the coast there.

If you set a priority for oil and gas production or energy production, you have to consider whether the Secretary of Interior should have withdrawn the sale of oil and gas leases in the lower Cook Inlet of Alaska, so he could review the sale.

You can also be concerned with Cincinnati, Ohio, where a Federal judge there stopped the completion of a $116 million TVA hydroelectric project on the Little Tennessee River, on the grounds it threatened the health and safety of the snail darter.

New Hampshire had a project shelved because it interfered with the clam larvae.

Maine has a problem: A planned $700 million hydroelectric project on the upper St. John River was stalled because it might threaten 30 specimens of a plant called the furbish louse wort.

Utah has its cause: A utility proposed an electric plant. After 13 years the project was scrapped. During this time the costs escalated seven times to $3.5 billion. Five million dollars was spent on paperwork. Supposedly, the blackfooted ferret and the kangaroo rat were in danger.

I am simply trying to say this Nation is in bad shape when you spend $36 billion on imported fuel. The Governors of New York and Pennsylvania sat on the far end of this table and described pain and suffering in those States and they say they need gas and yet somewhere we set the priorities for the caribou. There have been tons of environmental paperwork on the Tennessee snail darter and these other things.

I think, when these people are cold and jobless, they ought to be reminded that the clam, the snail darter and that sort of thing is comfortable. It is a matter of priority with me.

I want to say one other thing. I may never have the opportunity to say it again and I want to say it: If my family becomes hungry and a caribou comes by and my little girl needs something to eat, that caribou is going to come in second best.

Mr. OTTINGER. The gentleman from Texas, Mr. Eckhardt.

Mr. ECKHARDT. Thank you.

Chairman Morris and Chairman Wallace, I am not directing this to you but I feel sometimes some of my Texas compatriots are more like Fannin than Houston, more known for brashness than prudence and flexibility. I would hope you would be like Houston on this proposition.

I would like to start out by saying I feel that the proposed tax, in order to encourage persons not to use electricity created by gas or not to use gas for creation of electricity, is unnecessary and undesirable because I feel it would be passed on to consumers, largely. But there is another point I would like to ask you in this respect.

Do you think that to place the additional tax on gas for use in generating electricity or a tax on gas for other industrial purposes would in any way hasten the switch from gas to other fuels in Texas?

Mr. WALLACE. Not in my opinion.

Mr. ECKHARDT. What about you, Mr. Willis, with respect to New Mexico?

Mr. WILLIS. I don't think so, either.

Mr. ECKHARDT. It would seem to me that any prudent businessman would see the writing on the wall with respect to the availability of gas for the purpose of boiler fuel and isn't it true, Mr. Wallace, that you presently have very complete plans and programs, and you, Mr. Morris, too, for phasing out gas for the use of boiler fuel?

Mr. WALLACE. That is our Docket 600–

Mr. ECKHARDT. That was done a good while ago and it is now beginning to bear some fruit, is it not?

Mr. WALLACE. Yes, sir. It was done in December of 1975. I was trying to give you a quick figure as to the amount of gas which would be freed up within the next two or three years but I can't do that.

Mr. ECKHARDT. In addition to that Texas has tried to obtain new sources of coal from other sources?

Mr. WALLACE. Yes. We have contracted. Contracts were signed for low sulfur coal and it occurs the President's proposed national energy plan requires a scubber on all plants. So, really, they changed the rules after the game was completed and the contract was signed.

Mr. ECKHARDT. Now, we have been able by exercising some degree of flexibility, to persuade Mr. Schlesinger to favor our proposal to grant a right of eminent domain for coal slurry pipelines. I would suppose that would be helpful in the future.

Mr. WALLACE. I think that is the most important consumer legislation considered by the Texas Legislature in the last session and the Congress in this session.

Mr. ECKHARDT. We are close to the stage of markup in the House Interior Committee. We will have a field hearing in Wyoming and after that the bill will be set down for markup.

But insofar as some other phases of this bill are concerned, I think there are some problems which you, yourself, have recognized with respect to the question of gas pricing. You heard the discussion I had with the Governor a moment ago. I understand that a year or so ago the intrastate price for gas was around $1.50, wasn't it?

Mr. WALLACE. Yes, sir.

Mr. ECKHARDT. And in the second quarter of 1976, which I imagine would be pretty representative of the whole year, it was around $1.75.

Mr. WALLACE. We think higher, Congressman.

Mr. ECKHARDT. Maybe higher, but I think that is what our statistical figures indicate.

I understand in the last quarter, October, November, December quarter, it was $1.97 which is pretty close to what you say it is now, $2.05.

We have had testimony that under the National Energy Act, new gas would start at $1.75. Following the Btu equivalent of oil which would constantly go up because of additional oil coming into the mix and certain other uncontrolled factors, it is estimated the price

would be enough to yield an equivalent gas price of around $2.14 somewhere in the 1980s. Now, that seems pretty reasonable to me. That is something like what we were talking about as to a very top ceiling when we were considering it in the Emergency Natural Gas Act. As you recall, you and I were both concerned as to what would happen if gas went into intrastate commerce at $3 or $4 which was entirely possible, wasn't it?

Mr. WALLACE. Yes, sir, on a short term.

Mr. ECKHARDT. But in the long term it would seem even more possible because of the redetermination clauses.

Given a period of time, it would seem to me without any control, gas could go up to $3 or $4 to interstate buyers.

Mr. WALLACE. I would not say it will not under that situation, Congressman. I would say that would encourage some rather rapid change.

Mr. ECKHARDT. But it would also put a terrific burden on Texas consumers, would it not, Chairman Morris?

Mr. MORRIS. Yes, it would.

Mr. ECKHARDT. And it would put a considerable stress on Texas industry, although it is attempting to rapidly convert. In the meantime it has to pay the price the market demands.

Aren't you concerned about a complete deregulation of these requirements from Exxon?

Mr. MORRIS. I do not have anything to do with the regulation of gas. I have tried to stay out of that because that is Mr. Wallace's department and I would rather leave it to him to comment.

Mr. ECKHARDT. We always say, I am not on that committee.

Mr. WALLACE. We are servants of the legislature and are prepared to follow whatever rules they set down. The Governor's attitude is whatever the cost, we must get on with the development of our natural resources and he feels that sort of thing would encourage the development of all our resources throughout the United States and stop this terrible drain on the economy. We are all going to have to pay higher prices. I don't approve it, but if we are going to wage the moral equivalent of war then we must produce. I don't know, Congressman, what the value of the dollar will be 10 or 15 years from now. I can't say whether a reasonable price we could agree on today would be reasonable next week.

Mr. ECKHARDT. But we would move up under the President's formula, as you know.

Mr. WALLACE. Yes.

Mr. OTTINGER. Thank you, Mr. Eckhardt.

As the just retired head of the Environmental Study Conference, as to the caribou, if we desire to continue the frightening rate of exploitation of our natural resources without due regard to our environment, there is considerable danger there will not be any life left to enjoy all this oil.

I don't think it should be tossed off quite so lightly. These are endangered species which form a very basic portion of our ecosystem. We are endangering both plants and and animals on earth. I do think we have to have a balanced regard for that.

I think it is a very serious problem with which we have to deal. We have to strike these balances all the time in Congress. To

ridicule the concern, I think, does the people of Congress and Texas a disservice.

You may answer if you want.

Mr. WALLACE. Spending $36 million a year on imported crude does the American people a disservice. Priorities, of course, highly recommend a balanced environment. We have drilled over 1,200 wells in the estuaries of Texas and the Gulf. I understand the fishing is better there than anywhere else. But it is a question of priority with me. Some things just have to come second best. I have often made the statement, there are really two classes of people in this thing. It is two percent on either side. Two percent would pollute the world to make a buck. I can't join them. On the other hand, there are two percent who would stop the development of this Nation and cause us to slide into an international decline. I couldn't join those, either. I want those people in New York to have a job; I want them to be warm and enjoy some of the natural resources, especially around the Great Lakes. Yet, there is a law in New York which prevents exploration of Lake Erie.

The last time I was in Galveston, I looked out the window and saw drilling rigs so close to the shore you could make out the forms of the roughnecks on the platform. We are trying.

Mr. OTTINGER. I just want to indicate there is a concern in the case of projects mentioned. There are problems other than the endangered species involved in the TVA dam and so forth.

You did a good deal of preaching to us about this free market business. Isn't the very activity of your commission the antithesis of the free market. With the Texas Railroad Commission saying how much can be produced regardless of the market forces, therefore, they are setting the prices the whole country pays.

Mr. WALLACE. No, sir; I don't understand that. The Supreme Court of the United States ruled on proration alone, I think probably before I was out of high school. They settled that proration question.

Mr. OTTINGER. I was not talking about whether what you were doing was legal or not. I was talking about whether it was the promotion or restriction of a free market.

Mr. WALLACE. If it were illegal, you would want to talk about it.

No, sir; we are not doing anything to upset the free market.

Mr. ECKHARDT. I thought everybody understood that when the East Texas Field came in, in about 1934, the price of oil went to about 10 cents a barrel. We might be talking about conservation but nobody honestly says we were not concerned about price in the Texas Railroad Commission.

Mr. WALLACE. I have not been concerned about price, we have been on 100 percent since I have been there.

Mr. ECKHARDT. That is because the Arabs have been controlling the price.

Mr. WALLACE. I did not participate in any price control. I think the Supreme Court litigated as to whether or not that was price control and the Supreme Court held it was not.

Mr. ECKHARDT. And the big dams built on the rivers were for the purpose of flood control.

Mr. WALLACE. Did they control the floods?

Mr. ECKHARDT. They produced a lot of electricity.

Mr. WALLACE. I assume they controlled the floods.

Mr. OTTINGER. I am told by the staff that the Texas Railroad Commission set the allowables at 99 percent some time ago.

Mr. WALLACE. That is within the last three or four months. It was a token thing. We felt like, and still do, that this continued 100 percent drain will cause an unwarranted damage to the reserves.

We wanted to study the activity of fields. We did it on a two month basis. We decided that that was not a proper way to go about it, so we have called the statewide maximum efficient rate hearings.

Mr. ECKHARDT. One thing should be understood. Allowables are not based on the actual capacity of wells. Since the fields had depleted about a 50 percent allowable since the definition of what a well may produce at 100 percent is substantially the same as if the allowable was 100 percent.

Mr. WALLACE. The fields are different. Let me give you the best description I can of the maximum efficient rate of production.

If you consider an oil field as an aerosol can and you press the button on top of the aerosol can as it was designed, you will get all the contents of the can as the gas is exhausted.

On the other hand, if you take an ice pick and indiscriminately punch holes in the top of that can, it will relieve the gas rather quickly but leave more in the bottom than you got out initially. That is why under present technology we leave, all of us—I think Texas will recover something like 34 percent of the oil in place. Other States, 28 to 30 percent. That is the reason you set a maximum efficient rate for the production of the field. You could open the thing rather quickly and release a lot more oil for a few months and it would water out and it is gone.

Mr. MOORE. I think you made a good point. This is conservation of the field and not price control, is that right?

Mr. WALLACE. Part of it was environmental. They had oil running out on the ground. I am serious.

Mr. ECKHARDT. Actually, allowables were determined in relationship to the amount of oil that was desired at any particular time, the amount that could be sold. That is what you actually measured on, isn't it, the market demand?

Mr. WALLACE. That is correct.

Mr. ECKHARDT. I am not saying allowables are price controls, but I am saying allowables had the effect of sustaining price.

Mr. WALLACE. It had the effect of protection of correlative rights, it had the effect of protection of the reservoirs from unreasonable drain.

Mr. OTTINGER. At any rate, it is not a free market today?

Mr. ECKHARDT. The Supreme Court says it was.

Mr. OTTINGER. Speaking to the New Mexico situation, Mr. Willis, you expressed some concern about the ability to be able to mix gas intrastate and interstate. You said you had an excess capacity in your interstate lines at the present time.

Mr. WILLIS. They are not running at maximum.

Mr. ECKHARDT. If we leave the uniform price as the President's program suggests, doesn't that alleviate a lot of the problems of mixing the gas? It seems it would take care of pricing problems.

Mr. WILLIS. I agree with you, but then it comes down to interpreting some of the legislation that we have had a problem with. The President says that he does not—and I think in the book, the national energy plan, it goes into the whole thing.

In section 406—the existing contract section, whatever it is—it does go into contracts. What has happened in my opinion is that the President has intervened in the intrastate market but not to the full extent. He has done it haphazardly.

We have 1942 and 1975 in the two areas.

Mr. OTTINGER. If the price was uniform, there would be no problem. There would be no price advantage.

Mr. WILLIS. As I read the bill, I don't see a uniform price.

Mr. ECKHARDT. That was my understanding. You have $1.44 under your controls in New Mexico. Do you discourage production in New Mexico?

Mr. WILLIS. It is recently implemented legislation and we really don't know. It would be hard to project at this time. I think we can come back in a month or a couple of months and look at it.

Mr. OTTINGER. Can you also supply for us what is the price of newly discovered gas in New Mexico?

Mr. WILLIS. I think it would be $1.82, but those are very small amounts.

Mr. OTTINGER. I want to thank all you gentlemen for being with us and giving us useful information.

Mr. ECKHARDT. I have a unanimous consent request. I ask unanimous consent to place in the record at this point the Federal Power Commission's intrastate natural gas prices of FPC jurisdictional gas companies selling more than 1 million mcf per year in interstate commerce as of May 1977.

Mr. OTTINGER. Without objection it is so ordered.

[The material referred to follows:]

92-911 O - 77 - 35

FEDERAL POWER COMMISSION

INTRASTATE NATURAL GAS PRICES OF FPC JURISDICTIONAL NATURAL GAS COMPANIES SELLING MORE THAN ONE MILLION MCF PER YEAR IN INTERSTATE COMMERCE

SUMMARY BY STATE AND FPC GAS PRICING AREA, JANUARY, FEBRUARY, MARCH 1977

BUREAU OF NATURAL GAS
STAFF REPORT

Washington, D. C.
May, 1977

On January 9, 1975, the Commission issued Order No. 521 for the purpose of establishing a data collection system designed to investigate rates charged by jurisdictional natural gas companies for intrastate sales 1/ of natural gas which were not subject to Commission jurisdiction. Order No. 521 exempts from the filing requirement all jurisdictional producers selling less than 1 million Mcf per year in interstate commerce. 2/ Producers selling in excess of 1 million Mcf but less than 10 million Mcf in interstate commerce report on a quarterly basis, while the larger producers report on a monthly basis.

A compilation of the responses to this Order as filed by 86 companies on FPC Form No. 45 representing 341 intrastate contracts executed between January 1, 1977, and March 31, 1977, is presented in this report. 3/ The summary represents data from contracts having contract terms of one year or longer and was analyzed by state and FPC pricing area. Those contracts lacking volume data and percentage sales were omitted in the computation of the average prices and price ranges.

Summary tables by month, by state, and by pricing area are provided. The summary tables show the weighted average price for new contracts was 183.66¢/Mcf for the three months period and for renegotiated or amended contracts a three months average of 177.78¢/Mcf.

1/ Producers who sell gas only to the intrastate market are not subject to FPC jurisdiction and the requirement of Order No. 521.

2/ It is estimated that the producers required to report under the provisions of Order No. 521 sell approximately 90% of the gas produced nationally.

3/ Individual responses were found by the United States Court of Appeals for the Fifth Circuit to contain proprietary information which the Court stated must be protected from public disclosure. Continental Oil Co. v. F.P.C., 519 F2d 31 (5th Circuit 1975).

Detailed data on monthly prices for each state and FPC pricing area, and an analysis of the volumes of gas sold at varying prices is also provided.

These contract prices are the sum of base price and adjustments and may be affected by various contract terms relating to delivery points, take-or-pay obligations, length of contract, renegotiation provisions, etc. Furthermore, some of the prices summarized in this report reflect prices in sales between affiliated companies.

In view of the current interest in the magnitude of new gas sales at a comparative BTU price with domestic oil ($1.75/Mcf), we have analyzed the first quarter data as to percentage of volumes contracted for at this price or higher. The results are shown in the following tabulation:

Percentage of New Contract Volumes at $1.75/Mcf or Higher	
All Contracts	64.0%
Texas	88.5%
Louisiana	13.0%
Oklahoma	11.9%

Percentage of Renegotiated or Amended Contract Volumes at $1.75/Mcf or Higher	
All Contracts	63.2%
Texas	90.3%
Louisiana	7.5%
Oklahoma	4.6%

Summary January to March
By Month

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High	235.27	198.48	239.00	239.00
Average	180.96	165.62	191.09	183.66
Low	19.41	41.50	44.43	19.41
% Contract Volumes Sold Between				
201 - 250¢	16.5		44.5	28.7
151 - 200	69.1	76.1	49.5	59.8
101 - 150	13.5	22.2	4.5	10.2
51 - 100	.8	1.3	1.5	1.3
0 - 50		.3		.1
Contract Volumes Mcf	12,866,526	8,346,420	24,956,677	46,169,623

RENEGOTIATED OR AMENDED CONTRACTS

High	231.00	231.36	235.27	235.27
Average	185.34	175.93	170.65	177.78
Low	81.70	44.76	34.23	34.23
% Contract Volumes Sold Between				
201 - 250¢	61.5	40.2	34.1	47.2
151 - 200	23.9	34.5	40.8	32.6
101 - 150	13.6	22.4	7.0	10.9
51 - 100	1.0	2.2	16.0	8.3
0 - 50		.7	2.1	1.1
Contract Volumes Mcf	64,069,572	7,571,165	65,894,604	137,535,341

ALABAMA
By States

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High			203.90	203.90
Average			201.63	201.63
Low			210.09	201.09
% Contract Volumes Sold Between 201 - 250¢			100.0	100.0
151 - 200				
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf			3,720,000	3,720,000

RENEGOTIATED OR AMENDED CONTRACTS

High	
Average	
Low	
% Contract Volumes Sold Between 201 - 250¢	
151 - 200	
101 - 150	
51 - 100	
0 - 50	
Contract Volumes Mcf	

ARKANSAS
By States

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High	50.68			50.68
Average	50.68			50.68
Low	50.68			50.68
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150				
51 - 100	100.0			100.0
0 - 50				
Contract Volumes Mcf	16,699			16,699

RENEGOTIATED OR AMENDED CONTRACTS

High			90.49	90.49
Average			90.49	90.49
Low			90.49	90.49
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150				
51 - 100			100.0	100.0
0 - 50				
Contract Volumes Mcf			10,500,000	10,500,000

CALIFORNIA
By States

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High			120.00	120.00
Average			119.79	119.79
Low			44.43	44.43
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150			99.7	99.7
51 - 100				
0 - 50			.3	.3
Contract Volumes Mcf			548,960	548,960

RENEGOTIATED OR AMENDED CONTRACTS

High	106.50	107.27	116.63	116.63
Average	105.58	107.27	116.28	105.83
Low	81.70	107.27	108.00	81.70
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150	96.6	100.0	100.0	96.7
51 - 100	3.4			3.3
0 - 50				
Contract Volumes Mcf	6,564,446	33,450	151,002	6,748,898

COLORADO
By States

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High				
Average				
Low				
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf				

RENEGOTIATED OR AMENDED CONTRACTS

High			142.92	142.92
Average			95.36	95.36
Low			86.70	86.70
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150			15.4	15.4
51 - 100			84.6	84.6
0 - 50				
Contract Volumes Mcf			5,359	5,359

KANSAS
By States

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High	167.11	121.66	149.19	167.11
Average	155.49	121.66	148.18	145.26
Low	120.66	121.66	143.00	120.66
% Contract Volumes Sold Between				
201 - 250¢				
151 - 200	75.0			17.4
101 - 150	25.0	100.0	100.0	82.6
51 - 100				
0 - 50				
Contract Volumes Mcf	60,000	45,000	153,860	258,860

RENEGOTIATED OR AMENDED CONTRACTS

High	
Average	
Low	
% Contract Volumes Sold Between	
201 - 250¢	
151 - 200	
101 - 150	
51 - 100	
0 - 50	
Contract Volumes Mcf	

LOUISIANA
By States

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High	204.00	156.86	219.43	219.43
Average	155.82	141.33	219.43	154.90
Low	88.23	58.82	219.43	58.82
% Contract Volumes Sold Between				
201 - 250¢	12.1		100.0	13.0
151 - 200	29.4	84.6		43.1
101 - 150	58.2	4		39.7
51 - 100	.3	15.0		4.3
0 - 50				
Contract Volumes Mcf	1,858,500	745,429	130,564	2,734,493

RENEGOTIATED OR AMENDED CONTRACTS

High	165.39	161.32	219.43	219.43
Average	137.65	120.84	208.97	137.87
Low	84.80	99.02	126.00	84.80
% Contract Volumes Sold Between				
201 - 250¢			88.8	7.5
151 - 200	46.8	24.1		35.0
101 - 150	40.3	69.0	11.2	47.8
51 - 100	12.9	6.9		9.7
0 - 50				
Contract Volumes Mcf	3,236,715	1,974,199	482,413	5,692,827

MICHIGAN
By States

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High				
Average				
Low				
% Contract Volumes Sold Between				
201 - 250¢				
151 - 200				
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf				

RENEGOTIATED OR AMENDED CONTRACTS

High			128.75	128.75
Average			128.75	128.75
Low			128.75	128.75
% Contract Volumes Sold Between				
201 - 250¢				
151 - 200				
101 - 150			100.0	100.0
51 - 100				
0 - 50				
Contract Volumes Mcf			93,000	93,000

MONTANA
By States

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High	73.53			73.53
Average	73.53			73.53
Low	73.53			73.53
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150				
51 - 100	100.0			100.0
0 - 50				
Contract Volumes Mcf	23,000			23,000

RENEGOTIATED OR AMENDED CONTRACTS

High				
Average				
Low				
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf				

NEW MEXICO
By States

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High				
Average				
Low				
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf				
	RENEGOTIATED OR AMENDED CONTRACTS			
High	144.79		144.79	144.79
Average	144.79		132.46	137.85
Low	144.79		125.00	125.00
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150	100.00		100.0	100.0
51 - 100				
0 - 50				
Contract Volumes Mcf	711,400		914,398	1,625,798

OKLAHOMA
By States

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High	193.99	175.80	207.77	207.77
Average	172.35	147.86	168.57	163.62
Low	19.41	102.60	125.68	19.41
% Contract Volumes Sold Between				
201 - 250¢			1.3	.5
151 - 200	97.9	53.8	89.4	81.5
101 - 150	.7	46.2	9.2	17.4
51 - 100	1.3			.5
0 - 50	.1			.1
Contract Volumes Mcf	3,909,317	3,433,864	4,046,432	11,389,613

RENEGOTIATED OR AMENDED CONTRACTS

High	172.00	219.59	203.33	219.59
Average	167.49	131.27	168.28	166.86
Low	120.71	44.76	143.00	44.76
% Contract Volumes Sold Between				
201 - 250¢		7.9	.1	.3
151 - 200	95.8	24.6	96.8	94.3
101 - 150	4.2	57.2	3.1	5.2
51 - 100				
0 - 50		10.4		.3
Contract Volumes Mcf	8,102,566	524,891	9,455,010	18,082,467

TEXAS
By States

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High	235.27	198.48	239.00	239.00
Average	193.36	185.55	197.14	194.43
Low	52.71	41.50	87.00	41.50
% Contract Volumes Sold Between				
201 - 250¢	27.2		44.6	33.4
151 - 200	63.9	93.9	52.9	61.9
101 - 150	8.8	5.5	.2	3.2
51 - 100	.1		2.3	1.4
0 - 50		.6		.1
Contract Volumes Mcf	6,995,506	4,083,127	16,176,861	27,255,494

RENEGOTIATED OR AMENDED CONTRACTS

High	231.00	231.36	235.27	235.27
Average	204.06	203.22	190.83	197.85
Low	138.00	177.52	34.23	34.23
% Contract Volumes Sold Between				
201 - 250¢	86.7	59.9	50.0	68.2
151 - 200	13.3	40.1	39.7	27.0
101 - 150			7.0	3.3
51 - 100			.1	
0 - 50			3.2	1.5
Contract Volumes Mcf	45,454,945	5,010,725	44,066,072	94,531,742

WEST VIRGINIA
By States

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High	125.00			125.00
Average	125.00			125.00
Low	125.00			125.00
% Contract Volumes Sold Between				
201 - 250¢				
151 - 200				
101 - 150	100.0			100.0
51 - 100				
0 - 50				
Contract Volumes Mcf	3,504			3,504

RENEGOTIATED OR AMENDED CONTRACTS

High				
Average				
Low				
% Contract Volumes Sold Between				
201 - 250¢				
151 - 200				
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf				

WYOMING
By States

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High		158.00	169.00	169.00
Average		158.00	169.00	167.04
Low		158.00	169.00	158.00
% Contract Volumes Sold Between 201 - 250¢				
151 - 200		100.0	100.0	100.0
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf		39,000	180,000	219,000

RENEGOTIATED OR AMENDED CONTRACTS

High		95.14	189.22	189.22
Average		95.14	186.90	176.87
Low		95.14	184.31	95.14
% Contract Volumes Sold Between 201 - 250¢				
151 - 200			100.0	89.1
101 - 150				
51 - 100		100.0		10.9
0 - 50				
Contract Volumes Mcf		27,900	227,350	255,250

AREA 1 APPALACHIAN-ILLINOIS
By Areas

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High	125.00			125.00
Average	125.00			125.00
Low	125.00			125.00
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150	100.0			100.0
51 - 100				
0 - 50				
Contract Volumes Mcf	3,504			3,504

RENEGOTIATED OR AMENDED CONTRACTS

High				
Average				
Low				
% Contract Volumes Sold Between 201 - 250¢				
151 - 200				
101 - 150				
51 - 100				
0 - 50				
Contract Volumes Mcf				

AREA 2 OTHER SOUTHWEST
By Areas

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High	160.87	181.99	130.71	181.99
Average	125.84	130.57	130.71	130.20
Low	50.68	109.04	130.71	50.68
% Contract Volumes Sold Between 201 - 250¢				
151 - 200	62.3	19.3		22.2
101 - 150		80.7	100.0	74.8
51 - 100	37.7			3.0
0 - 50				
Contract Volumes Mcf	176,699	1,996,302	50,000	2,223,001

RENEGOTIATED OR AMENDED CONTRACTS

High	198.28	177.52	196.25	198.28
Average	198.28	154.72	117.39	121.82
Low	198,28	99.02	90.49	90.49
% Contract Volumes Sold Between 201 - 250¢				
151 - 200	100.0	72.7	31.0	35.7
101 - 150		18.8		1.8
51 - 100		8.6	69.0	62.5
0 - 50				
Contract Volumes Mcf	194,580	1,598,075	15,214,635	17,007,290

AREA 3 SOUTHERN LOUISIANA
By Areas

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High	204.00	156.86	219.43	219.43
Average	155.82	136.25	219.43	154.98
Low	88.23	58.82	219.43	58.82
% Contract Volumes Sold Between				
201 - 250¢	12.1		100.0	14.1
151 - 200	29.4	78.5		38.3
101 - 150	58.2	.5		43.0
51 - 100	.3	21.0		4.6
0 - 50				
Contract Volumes Mcf	1,858,500	532,429	130,564	2,521,493

RENEGOTIATED OR AMENDED CONTRACTS

High	165.39	109.42	219.43	219.43
Average	137.65	108.92	208.97	136.72
Low	84.80	104.90	126.00	84.80
% Contract Volumes Sold Between				
201 - 250¢			88.8	8.4
151 - 200	46.8			29.8
101 - 150	40.3	100.0	11.2	53.6
51 - 100	12.9			8.2
0 - 50				
Contract Volumes Mcf	3,236,215	1,362,199	482,413	5,080,827

AREA 4 TEXAS GULF COAST
By Areas

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High	197.30	198.48	212.50	212.50
Average	194.42	187.41	200.50	196.98
Low	175.96	125.00	165.00	125.00
% Contract Volumes Sold Between				
201 - 250¢			53.6	34.8
151 - 200	100.0	96.1	46.4	64.5
101 - 150		3.9		.8
51 - 100				
0 - 50				
Contract Volumes Mcf	3,076,200	3,877,625	12,792,161	19,745,986

RENEGOTIATED OR AMENDED CONTRACTS

High	231.00	230.72	229.31	231.00
Average	204.54	204.91	199.37	202.53
Low	176.20	194.36	34.23	34.23
% Contract Volumes Sold Between				
201 - 250¢	91.0	61.1	74.3	83.7
151 - 200	9.0	38.9	20.6	14.3
101 - 150				
51 - 100				
0 - 50			5.1	2.0
Contract Volumes Mcf	40,946,652	1,822,550	27,433,628	70,252,830

AREA 5 PERMIAN BASIN
By Areas

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High	235.27	197.17	239.00	239.00
Average	196.62	163.03	185.70	190.88
Low	52.71	41.50	87.00	41.50
% Contract Volumes Sold Between				
201 - 250¢	56.0		10.6	33.3
151 - 200	27.1	78.1	77.8	52.3
101 - 150	16.6			8.4
51 - 100	.3		11.6	5.8
0 - 50		21.9		.3
Contract Volumes Mcf	3,395,990	93,500	3,258,000	6,747,490

RENEGOTIATED OR AMENDED CONTRACTS

High	206.00	231.36	235.27	235.27
Average	191.99	209.12	175.69	184.08
Low	138.00	196.43	74.59	74.59
% Contract Volumes Sold Between				
201 - 250¢	42.1	75.7	13.8	28.8
151 - 200	43.5	24.3	59.0	50.7
101 - 150	14.4		26.8	20.3
51 - 100			.4	.2
0 - 50				
Contract Volumes Mcf	5,025,113	2,452,100	12,052,809	19,530,022

AREA 6 HUGOTON-ANADARKO
By Areas

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High	193.99	175.80	207.77	207.77
Average	172.78	166.53	167.79	169.65
Low	19.41	46.25	115.63	19.41
% Contract Volumes Sold Between				
201 - 250¢			1.3	.5
151 - 200	97.7	94.8	86.7	92.7
101 - 150	2.1	5.0	12.0	6.7
51 - 100	.1			
0 - 50	.1	.2		.1
Contract Volumes Mcf	4,332,633	1,807,564	4,276,992	10,417,189

RENEGOTIATED OR AMENDED CONTRACTS

High	172.00	219.59	203.33	219.59
Average	167.49	149.51	167.63	167.34
Low	120.71	44.76	142.78	44.76
% Contract Volumes Sold Between				
201 - 250¢		18.5	.1	.3
151 - 200	95.8	57.3	94.3	94.5
101 - 150	4.2		5.6	4.9
51 - 100				
0 - 50		24.2		.3
Contract Volumes Mcf	8,102,566	224,891	9,705,010	18,032,467

AREA 7 ROCKY MOUNTAIN
By Areas

NEW CONTRACTS
¢/Mcf

	January	February	March	January-March
High	73.53	158.00	169.00	169.00
Average	73.53	158.00	169.00	158.15
Low	73.53	158.00	169.00	73.53
% Contract Volumes Sold Between 201 - 250¢				
151 - 200		100.0	100.0	90.5
101 - 150				
51 - 100	100.0			9.5
0 - 50				
Contract Volumes Mcf	23,000	39,000	180,000	242,000

RENEGOTIATED OR AMENDED CONTRACTS

High		95.14	189.22	189.22
Average		95.14	150.78	148.82
Low		95.14	86.70	86.70
% Contract Volumes Sold Between 201 - 250¢				
151 - 200			29.8	28.8
101 - 150			69.6	67.1
51 - 100		100.0	.6	4.1
0 - 50				
Contract Volumes Mcf		27,900	762,107	790,007

AREA 8 OTHER AREAS
By Areas

NEW CONTRACTS
C/Mcf

	January	February	March	January-March
High			203.90	203.90
Average			191.11	191.11
Low			44.43	44.43
% Contract Volumes Sold Between				
201 - 250¢			87.1	87.1
151 - 200				
101 - 150			12.8	12.8
51 - 100				
0 - 50				.1
Contract Volumes Mcf			4,268,960	4,268,960
RENEGOTIATED OR AMENDED CONTRACTS				
High	106.50	107.27	128.75	128.75
Average	105.58	107.27	121.03	106.14
Low	81.70	107.27	108.00	81.70
% Contract Volumes Sold Between				
201 - 250¢				
151 - 200				
101 - 150	96.6	100.0	100.0	96.7
51 - 100	3.4			3.3
0 - 50				
Contract Volumes Mcf	6,564,446	33,450	244,002	6,841,898

Mr. OTTINGER. We will stand adjourned until 2 o'clock this afternoon.

[The following material was received for the record:]

DATA REQUESTED FROM ENERGY RESOURCES BOARD, STATE OF NEW MEXICO

Question - What was the average price of natural gas in the intrastate market in New Mexico on August 1, 1976?

Answer - Approximately 84 cents per Mcf

Source - New Mexico Oil and Gas Accounting Commission

Question - What was the average price of natural gas in the intrastate market in New Mexico on May 1, 1977?

Answer - Approximately $1.15 per Mcf

Source - New Mexico Oil and Gas Accounting Commission

Question - What are the average depths and drilling costs of natural gas wells in New Mexico?

Answer - There are three major producing districts in the depths and drilling costs of wells in each of these districts. Here is a list of them:

District One (Lea and Roosevelt Counties in southeastern New Mexico) - Average depth is 6,700 feet; average drilling cost is approximately $310,800.

District Two (Chaves and Eddy Counties in southeastern New Mexico) - Average depth is 10,500 feet; average drilling cost is approximately $550,800.

District Three (San Juan, Sandoval and Rio Arriba Counties in northwestern New Mexico) - Average depth is 5,600 feet; average drilling cost is approximately $190,000.

Source - New Mexico Oil Conservation Commission

[Whereupon, at 1:05 p.m., the subcommittee recessed, to reconvene at 2 p.m. the same day.]

AFTER RECESS

[The subcommittee reconvened at 2 p.m., Hon. Robert Krueger presiding.]

Mr. KRUEGER. The committee will come to order.

We will continue with our hearings relating to natural gas. Our witnesses this afternoon will be Edwin Faust, Mayor, Grey Forest, Texas; Lane Denton, Legislative Director, Texas Farmer's Union, and Ralph W. Kienker, Energy Affairs Director, Monsanto Company.

Mr. Faust, I am particularly glad to welcome you here. Again, I would like to ask for any summary of your testimony you wish to make at this time.

STATEMENTS OF HON. EDWIN L. FAUST, MAYOR, GREY FOREST, TEXAS; LANE DENTON, LEGISLATIVE DIRECTOR, TEXAS FARMER'S UNION; AND RALPH W. KIENKER, ENERGY AFFAIRS DIRECTOR, MONSANTO COMPANY, ON BEHALF OF THE PETROCHEMICAL ENERGY GROUP

Mr. FAUST. I would like to say first I am delighted to have the opportunity to participate in these proceedings. I would like to make it quite clear that I am speaking on behalf of the consumers of natural gas in our area of Texas.

I will read my comments, if I may.

Mr. Chairman, distinguished members, my name is Edwin L. Faust and I am speaking today of the effects of a deregulated market of natural gas within our city, our county and the South Texas area in general. I speak as a consumer in my home and in my small business.

I am also the Mayor of a small South Texas city, Grey Forest, which owns and operates a retail natural gas utility distribution system. In my capacity as Mayor I am Chairman of the Board of Directors for operation of the gas utility. I am also Chairman of the Utility Committee for the Bexar County Council of Mayors (consisting of mayors from 21 cities within Bexar County.)

At the outset I will state that I am a believer in the free enterprise system and except in monopolistic situations, the free enterprise system works very well. In South Texas we have operated within the unregulated free enterprise system at the producer level only, for the purchase of natural gas, for the past four years.

Of course, we have had a supposed shortage of natural gas. In that period of time the cost of natural gas has risen from .23 per Mcf to as high as 2.06 per Mcf and currently is selling for 2.02 per Mcf. This is approximately an 800 percent increase. This has had a devastating effect on the homeowner and businessman. All of this has happened in spite of the fact that most of our cities had long-term contracts for .23 per Mcf.

Can these increases in cost be justified by production costs? Nobody will sit down and talk about it. The consumer on the end of this situation can do nothing to help themselves. I will tell you that if the consumer had a free enterprise choice for a reasonable alternative energy source, they would have made that alternate choice long ago.

I have personally talked to the Texas Railroad Commission, State legislators, our congressional representative, the local news media, and I have corresponded with our Texas Governor about the continuing problem of rising costs of natural gas. I have testified at the State and national legislative levels, all in an attempt to help the plight of the consumer.

I am convinced that the only relief the consumer can expect is at the national congressional level. The consumer is helpless in this situation, therefore, the consumer must look to some strong legislative source for relief.

I don't know exactly what a fair price of natural gas should be. But it should bear a relation to the actual cost of production plus a fair rate of return to the producers. Somebody should be able to determine what this fair price should be for the protection of the consumer as well as the industry—and it should be controlled at this price. Currently there is no protection for the consumer in the present natural gas system.

There are two factors that affect the price of gas in Texas that I think should be investigated on behalf of the consumer. Redetermination clauses and take or pay provisions in gas contracts have greatly increased the cost of natural gas in Texas and as far as I can tell neither of these contract requirements have anything to do with production costs. In my opinion they are gimmicks to increase the cost of natural gas to what the traffic will bear.

Everytime the price of natural gas is discussed at any level we always hear that higher prices will bring new sources of supply. Look at the history of the situation on the national level. Gas prices have increased from 13 to 16 cents per Mcf to 52 cents to $1.42 per Mcf on the interstate market and each time the industry has

promised new supplies. The consumer has been required to pay the price but there is no guarantee that the monies will be spent for new sources of energy. In fact, a look at the record shows the oil and gas industry, while doing some drilling, are also buying other businesses to diversify their holdings. This will not help the consumer's energy situation unless somebody controls the revenues involved and makes it happen.

If the energy sources are as short of supply as is claimed, and there is no competitive energy source for the consumer, then you do not have a free enterprise system and the energy supplier has evolved to become a noncompetitive industry, a monopoly at the consumer level. It should be closely controlled until a competitive source is available to the general public.

It scares me to think what might happen if controls are not established. In a recent conversation with the Texas Railroad Commission people, I learned that a contract for gas was negotiated in the interstate market for $3.29 per Mcf for Texas gas. This contract occurred because of the declared national emergency situation during the past winter.

Therefore, the normal interstate prices were not in effect. If this condition is allowed to go unchecked or uncontrolled, the consumer will be paying 25 to 30 percent of take-home pay for utilities alone. It should be obvious as to what this will do to the rest of the economy. Either inflation will gain momentum or the consumer will have very little monies to spend for anything else.

Yes, gentlemen, there is little doubt in my mind that the price of interstate and intrastate natural gas should be regulated.

If you in the Congress determine on the basis of actual costs, independently verified, plus a fair rate of return, that the price of natural gas should be $1.75, then I think the people of South Texas would accept this and perhaps so would the whole Nation.

But it is my understanding that in late 1975 the FPC staff, based on industry data, determined that the actual cost of producing natural gas in this country plus a fair rate of return was between 56 cents and 62 cents per Mcf.

I would agree that over the last two years that this price would have inflated somewhat. However, I find it difficult to believe that that just and reasonable price could have tripled over the last two years to $1.75. Must we force on the general public a price of $1.75 just to appease certain segments of the oil industry and our legislative leaders? In Texas we call this a rip-off.

Gentlemen, may I add that from all I read in the newspapers, the Texas gas consumers are not represented at the various energy committee hearings. It seems as if our political leaders from Texas speak for the oil and gas industry only. Let me assure you there are a large number of gas-consuming Texans who are just upset and frustrated over the high price of gas.

In closing, I would like to extend an invitation to members of this committee to visit our area and learn, firsthand, what the consumer is faced with and how they feel about the utility situation as it exists today.

I thank you.

Mr. KRUEGER. Thank you, Mr. Faust.

We will hear next from Lane Denton, the Texas Farmer's Union.

STATEMENT OF LANE DENTON

Mr. DENTON. Mr. Chairman, our good mayor has extended an invitation and I am sure Grey Forest, Texas, would be glad to serve as host city. If time permits, I hope you will accept his invitation.

My experience is working with family farms and families in the State of Texas, approximately 10,000, with the vast majority from the high plains in the State of Texas, a group of people who have been hard hit and deprived of natural gas for irrigation purposes.

I also have the privilege of serving as president of one of the State's largest and most active consumer associations. Our association has just completed meeting with the Utility Commission and Texas Power and Light in the recent case.

I also served during my last term in the Texas House of Representatives as chairman of the Social Services Committee. We held extensive hearings all over the State of Texas, primarily hearing from the elderly population and I can assure you that one of their No. 1 concerns is income and whether or not they are going to be able to make it from one month to the next.

Just like most States, Texas has a large percentage of its population that are 60 and they are just barely getting by. Across Texas from 1973 on, the skyrocketing costs of utility bills has placed a significant burden on these people. That is the kind of testimony and information you should be concerned about and you should have an opportunity to hear from these people.

I will tell you right now, Mr. Chairman and members of this committee, listening to some of the witnesses this morning, it is my feeling that they are trying to pull the wool over your eyes. You didn't hear some of the correct concerns as to how the impact of unregulated prices of natural gas is affecting the people in the State of Texas.

I would like to share with you information on those concerns. I have outlined as a part of my testimony an expansion of some of my personal concerns on the utility and energy crises facing ths session.

Let me say as far as intrastate commerce is concerned for natural gas, it is virtually unregulated but even with agricultural use, and one that has some very long range and very signficant impact in this State, whether or not we are going to be able to produce the food and fiber for this Nation is questionable.

The irrigation farmers of the high plains of Texas not only are concerned about their products, but they are very concerned about whether they are going to get any natural gas. Gas companies in West Texas have threatened if the price is placed under regulation, they are even going to cut the farmers off. These farmers, very typical Texans, have appealed to the State legislature. I can assure you that on every single time, beginning in 1975 and in this legislative session now going on in 1977, they have been turned down.

The utility companies have indicated if this is an extremely hot summer in Texas, the utility bills for an average three-bedroom home will reach as high as $200 a month. You can imagine a family,

particularly a fixed income family, living on Social Security income, paying a price of $100 or $150 a month.

I believe it is time that we finally seek some answers to these very difficult questions.

We should have learned a great deal from the crisis in 1973. We did not. I am of the opinion that we must keep two central questions in mind throughout our deliberations on these proposals. We must make sure that we have leveled with the people in this country. Have we really completed extensive research and documentation of what really are the facts? Why is it some of the regulatory commissioners can't really give us specifics, the facts on what the exact producing costs are?

We have got to do what I think President Carter has, we have got to lay the cards on the table. We have to convince ourselves that we are talking about a very important resource and once you have used a barrel of oil, a cubic foot of gas, it is not going to return.

We still have, for instance, too much flaming of gas in the oil fields of the State of Texas. They have received permission to do that. We have to make sure we provide the kind of conservation policies that really make good sense.

The second thing is, we have to remember—and I know the committee will—who will be helped and who will be hurt by the various proposals.

This committee and the public will hear from oil company officials and even some Texas government officials that regulation of gas prices will be disastrous to the oil business and to the overall economic climate in oil-producing States.

What we have not heard very much about is the side that shows the disastrous effects of unregulated prices and the skyrocketing prices for the poor and elderly. There are a lot of people in oil-producing States rather than just those in the oil industry.

It seems to me it will be difficult, but it is absolutely essential for this committee to dig deeply into the records and information.

The Texas Railroad Commission, for instance, over a long number of years have had a cozy relationship with private in-house reporting companies who have provided all kinds of information and statistics to the various oil companies. The Texas auditors in 1975 called attention to this and indicated it was a very serious arrangement in providing this information that oil companies usually say is confidential.

Early in the spring of 1972, more than a year prior to the Arab embargo, the petroleum industry was aware of the shortages which would occur regardless of the action of these foreign oil-producing companies. These confidential production and inventory statistics, and in some cases even the future desires concerning inventories, were known and are known within the industry, through certain monthly reports of the Texas Railroad Commission.

Yet out of all of this, nothing has been done and we seem to be in some directions paying more attention to the industry and making sure that they receive excess profits, and receive this great capital investment, and not paying enough attention to the people of Texas.

There are some concerns on the part of the people of Texas as to why they should be paying an enormous price for gas while people

in other States are paying less. The prices for the farmers in West Texas have gone up 300 percent over three years ago. An elderly couple in one city in Texas asks why their utility bill in one month last winter was more than their house payment. A woman in Texas has complained about the fact she was in the hospital and still received a $60 gas bill.

It is really a national disgrace that we don't have lifeline rates in this country that really make some sense in conservation, that help those who want to conserve and use a small amount of electricity and gas.

You have got to consider controlling the price of intrastate gas. The people of Texas deserve safeguards to make sure the undedicated Texas natural gas that goes out of State be at the same price that is paid in Texas and that it doesn't cause an increase in price to the Texas consumers, that it doesn't result in a loss of jobs.

When you are presented with the usual objections of the companies, with their dire warnings of disaster, I urge you to remember the effect that nonregulation has and the disaster coming therefrom.

I again ask you to be frank with the public and to ask yourselves and everyone involved who will be benefitting from the policy you decide.

[Mr. Denton's prepared statement follows:]

STATEMENT OF LANE DENTON

As Chairman of the Texas House Social Services Committee, the Committee held public hearings all over Texas. I assure you Texans living on fixed incomes, especially the elderly, are having serious difficulty paying their utility bills. Our Committee heard sad story after sad story.

Currently, I am Legislative Director of the Texas Farmer's Union, a general farm organization representing approximately 10,000 farm and ranch families in Texas. Most of our members are from the High Plans region of Texas.

The natural gas industry in Texas, as far as intrastate commerce is concerned, is, as you know, virtually unregulated, but this is even more true as far as agricultural use goes. The newly passed Public Utility Commission law specifically excludes the transportation,delivery or sale of natural gas for fuel for irrigation as well as for any other direct use in agricultural activities. As President of a local consumer assocation, I have heard from a number of people expressing concern that they may not be able to pay utility bills this summer. Texas Power and Light Company officials have indicated electricity bills for a three bedroom home may hit $200.00 a month.

It is time that we finally ask, and seek answers for, some of the very serious and difficult questions facing our Nation relating to energy sources, energy resources, and energy shortages. We should have learned a great deal from the crisis of 1973; we did not.

We had better learn a great deal from the extreme winter and ensuring critical natural gas shortages that we just experienced.

I am of the opinion that we must always keep two questions in mind throughout our deliberations on energy proposals. Let me expand those questions.

The first question that we must repeatedly ask ourselves is, "Are we really leveling with the public in our considerations of this matter?" We owe the public candor, openness, and honesty in discussing government policies and their effect on energy shortages. We must level with people--let them know that there are no secret solutions, no cure-all solutions, no solutions at all without sacrifices.

There is no point in kidding people that we are not up against tough times; we are. President Carter has admirably laid these cards on the table already. We must not allow the fantasy that oil is a renewable or long-term energy source. We must convince ourselves that there are certain things that do not come back; that once a barrel of oil is used, it is gone forever and the amount of oil has been reduced forever by that much. Every cubic foot of natural gas use is reduced forever by that much. Everybody believes no flaring of natural gas exist in oilfields -- wrong -- too much is being flared. For example, last month one producer in an East Texas field flared a considerable amount of natural gas. So we must remind ourselves that the public has a right to be told the truth.

The second question that we must keep in mind is "Who will benefit and who will be hurt by any proposal being considered?" This Committee and the public will hear from the oil company officials and even from some Texas government officials, that regulation of gas prices would be disastrous to the oil business and to the overall economic climate in oil producing states. What we have not heard from so much is the side that shows disastrous effects of unregulated prices and skyrocketing utility bills on the consumers, farmers, the poor, and the elderly.

If we constantly keep in mind these two general questions, then we can better answer the more specific questions.

What, then have we learned from the past few years on energy uncertainty?

1. We need reliable facts about the natural gas supply picture, present and prospective. Who determines how much will be stored for peak winter days? Who really consumes how much natural gas and when? Information on reserves?
2. We need to prepare a national emergency plan which addresses, before a crisis, the key questions and issues of allocation among types of users. If we do not, we will find ourselves stumbling around, after the declaration of an emergency, trying to set priorities and finally defaulting to the gas companies.
3. Mandatory conversion both for utilities and industry

from natural gas to coal and other sources of energy. For example, it makes no sense either for the consumer or certainly not for the farmer, to use natural gas to produce synthetic fibers. It takes only approximately one-fifth the energy to produce a pound of cotton as is required to produce a pound of synthetic fiber.

4. Incentives for coal, solar, wind, qeothermal, nuclear, and other new sources of energy should be limited to independent operators, thus discouraqinq giant oil companies dominance of these alternative sources.
5. We need to stimulate a national "Manhattan" type urgency and efforts on the part of both private and public qroups toward energy related research and development.
6. A workable energy conservation program is a must.
7. There should be equitable pricing between inter-and intra-state. We've had two markets too long. I believe legislation can be drafted that will be fair to producing states and consuming states. The people of Texas should not have to suffer runaway prices for gas produced in their own backyard. Unregulated prices in Texas have not provided adequate supply -- curtailments have occurred.
8. A national energy program must include mass transit. Maximize use of buses and make bicycle traffic more attractive by creating special lanes. This will provide needed jobs and a transportation program that prepares for the future.
9. A national energy policy should advocate making neighborhoods more self-sufficient and cohesive. We must encourage the redevelopment of small scale enterpise such as neighborhood stores, neighborhood repair shops -- where do you take your broken toaster these days? Neighborhood food co-ops (where members contribute to the processing and distributing of in-season foods that are not done up in bright -- enhancing packages of styrofoam and plastic).
10. Develop an oil storage program and a program of "standby capacity." We should maintain at least a six-month supply of oil. The cost would be modest compared to what we spend yearly on national defense.

It seems to me that one of your most important, and I might add most difficult, tasks will be to determine what the true facts are. For too long we have relied solely on information supplied by the industry--and there has been a very close and cozy relationship between the industry and some regulatory bodies. Particularly, we have seen the close relationship between the oil companies and the Texas Railroad Commission.

The Federal Energy Administration and other appropriate Federal agencies should be required, on a regular and permanent basis, to compile data relating to the petroleum industry, including statistics of inventories, production, known reserves, and profits and losses on individual components of energy production. Such statistics should be gathered from all available sources, including transporters and minor distributors of petroleum products. In order to afford a complete picture of the petroleum situation at any given time, these statistics should be independently verified by the Federal Energy Administration.

Let me expand on the relationship between the industry and regulatory agencies, as well as intra-industry relations. As early as the Spring of 1972, more than a year prior to the Arab embargo, the petroleum industry was aware that shortages would occur regardless of the actions of the Arab producing countries. The confidential production and inventory statistics of most large oil companies and in some cases even their future desires concerning inventories were known and are made known within the industry by certain monthly reports of the Texas Railroad Commission. Those reports--which list such information on a company-by-company basis--were and are available to all participating parties and are received by the oil companies. The Commission regulates production of crude oil in Texas oil fields and gathers detailed statistics from oil companies in order to enable it to perform its functions. The Commission reports may well be utilized by the petroleum industry as a clearinghouse of information which many oil companies claim is confidential.

From these reports industry-wide trends can readily be ascertained on a current basis. The Commission acts as a government-sanctioned public service commission, enabling the petroleum industry to possess the advantages of a public utility, yet without the regulations normally accorded such a vitally important commodity. Thus, many of the major oil companies may have been fully aware of the actions and intentions of their competitors during the critical first six months of 1972.

An important part of a comprehensive energy program must include strenuous enforcement of anti-trust laws. The Federal government should also participate in price negotiations between oil companies and foreign oil-producing countries; for how can we possibly claim that we have a national energy policy if the government plays second fiddle to the oil giants in these crucial negotiations? Supplies of crude oil and petroleum products, domestic and imported, must be assured, both to independent marketers and others in the industry. Without such assurance, independent marketers are likely to disappear within the next few years, thus further weakening the competitive

structure of an industry already characterized by a substantial lack of competition. I would like to voice the specific concerns of Texans. They are asking why the people of New Jersey should be paying $1.42 cents per thousand cubic feet for gas when the people of Texas are paying $2.25 for the same amount. I believe that it is time that you heard from some Texans who do not support the deregulation efforts of the oil companies and who do not support the higher prices of uncontrolled intrastate gas supplies. The last few years natural gas prices have jumped from .30¢ to .40¢ per thousand cubic feet to $2.25. West Texas farmers are paying 300% more for natural gas now than they did three years ago; they have appealed to the State legislature to assist in controlling gas prices. The elderly couple in Troup, Texas, are asking why their utility bills were higher this past winter than their house payments. The woman in Burnet, Texas, who was in the hospital all last month is asking why she should be faced with a $60 gas bill for that same month. It is a national disgrace that we do not have "life line" utility rates that assist law users, especially the poor and elderly. Many of these same situations have occurred all over Texas. The consumers of Texas for whom utilities have become a substantial part of the cost of living, want a justification for the over two billion-dollars extra utility charges they have faced as a result of unregulated intrastate prices since 1973.

I think that all these effects of the industry policies, as sanctioned by the Railroad Commission, lead to one conclusion: control of intrastate prices must be considered. For if we continue nonregulation, or if we were to face across the board deregulation, the oil industry would certainly receive windfall profits, but our citizens and even our economy would not. The Subcommittee on Oversight heard testimony last year to the effect that natural gas is an integral part of the agriculture industry in Texas. Texas happens to be the fourth largest producer of agricultural products in the nation. The unbelievable increases in fuel prices are dangerously weakening this vital Texas industry. When the cost of food production increases enormously due to fuel increases, the effects are felt not just on the farms of Texas, but nationwide. It is this set of facts that has been ignored.

I believe that this committee would be surprised at the reaction of many Texans and others in this nation when they have a chance to really view and consider the effects of nonregulation; of use of questionable

industry figures; of continued "cozy" relations between the industry and the regulators. Regulation of intrastate prices is an option that I would urge you to consider. The people of Texas from a producing state do deserve certain safeguards. If undedicated Texas natural gas goes out of state the price should be precisely what is paid for gas in Texas. That it not cause an increase in prices to the producing state customers. That as a result of sharing undedicated gas there will be no loss of jobs. And when you are presented with the usual objections of the companies and their dire warnings of disaster, I would urge you to remember the effects that nonregulation has, and the disasters caused due to this policy. I would again urge you to be frank with the public, and to ask yourself and everyone involved who will really be benefitting from the policies that you decide on.

Mr. KRUEGER. At this time the committee will recess to go over for a vote and we will resume as soon as we can get back which will probably be about 15 minutes.

[Brief recess.]

Mr. KRUEGER. The committee will resume receiving testimony, at this time from Mr. Ralph W. Kienker, Director of Energy Affairs for Monsanto and representative of the Petrochemical Energy Group.

STATEMENT OF RALPH W. KIENKER

Mr. KIENKER. Mr. Chairman, members of the subcommittee: My name is Ralph W. Kienker. I am Energy Affairs Director of Monsanto Company. Today, I am speaking on behalf of the Petrochemical Energy Group (PEG) whose companies use oil and gas to produce the major portion of the petrochemical intermediates in the United States. Virtually all petrochemicals are derived from the hydrocarbon molecules of crude oil, natural gas, or natural gas liquids. These are our raw materials which we call feedstocks.

At the outset we would like to applaud the dedication and effort on the part of the President and his staff in seeking to devise a comprehensive national energy program. While we may not agree with some of the approaches advocated by the administration, we do believe this contribution will focus the attention of the entire country on the need for a rational energy strategy.

We understand that the focus today is exclusively on the provisions of the National Energy Act which would extend Federal price and allocation controls to the many States which have intrastate natural gas resources serving consumers. These include not just Texas and Louisiana, but California, Colorado, New York, Ohio and Michigan among others. We will address other aspects of the National Energy Act at the appropriate hearings.

My company is a consumer of gas in several States, but I wish to talk abut Texas today, as an example. We, the petrochemical industry, located plants in Texas and Louisiana because our raw

materials are natural gas, natural gas liquids, and petroleum. Our products from these and other plants end up in Detroit and Akron in the form of tires and other components of autos, in Virginia, the Carolinas and other States in the form of textiles, in New England in the form of plastics, in California, Texas and other agricultural States as fertilizers, pesticides, and herbicides, in all States as medicines, as hospital equipment, as home insulation. In short, Texas is a first step on a process of upgrading a raw material to consumer goods. Affect the supply of these raw materials, and you hurt the Nation. We believe that the actions proposed will adversely affect, not only gas supply in Texas, but gas supply in the Nation.

PRICES, SUPPLY AND THE CONSUMER

We believe that Federal price controls on natural gas will adversely affect the supply of natural gas and gas liquids, as review of the Federal experience should demonstrate to all. It can't help the Nation as a whole to diminish gas production in Texas.

Is it to help some consumers in Texas by rolling back all gas prices? Even if this were to inure to our benefit in the short run, in the long run total gas supply to the nation would be diminished. Of course, under this bill, our gas price would be increased through a combination of taxes and incremental pricing which would obviate the rollback to us as consumers. Indeed, a rollback would fly in the face of the President's call for recognition of the replacement value of gas which is already accounted for in the intrastate market.

EMERGENCY ALLOCATIONS OF INTRASTATE GAS

This brings me to my second point: Why confiscate the supplies of natural gas that are not dedicated to interstate commerce?

Last winter, when the Emergency Natural Gas Act (ENGA) was passed, it had a provision for voluntary emergency sales which supplemented existing FPC emergency sale regulations. Great cooperation was given the administration in locating supplies and transferring them to the interstate market from the intrastate market. More emergency gas was available under ENGA than the interstate pipelines could take.[1] Undoubtedly the Administration is and should be pleased with the success of its legislation. Thus, we do not understand why the bill now before you eliminates the ENGA voluntary sales provision and, instead, extends mandatory allocation to the very people who voluntarily helped last winter.

Equally telling, of course, is that the mandatory allocation provisions of ENGA—those dealing with interstate gas—were never used.

Third, the committee should realize that there was more gas burned as electric utility boiler fuel[2] between October and Decem-

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[1] Transcript, Meeting of Emergency Gas Requirements Group (industry and consumer representatives appointed to advise ENGA Administrator Dunham on administration of ENGA) March 30, 1977, pp. 255-256, 261.

[2] We do not mean to single out electric utility boiler fuel for use. It is cited here because data on utility fuel use is collected and published by the Federal Power Commission.

ber of this winter[3] in the States who are the net importers of gas than the entire amount of emergency gas injected into the interstate system under ENGA through early April of this year.[4] Vast quantities of this gas were sold under interruptible contracts—meaning that alternate fuel capability was installed.

Finally, if distributors and interstate pipelines are led to believe that the Federal Government will simply confiscate gas supplies from the intrastate market if "needed," then what is the incentive to husband supplies, to fill storage to capacity, to enforce curtailment priorities? If ENGA is extended to the intrastate market, next year there will be many pipelines who will follow a burn now, worry later philosophy. We would only recommend that, if ENGA is to be extended at all, the provisions of section 6 be extended. This is the best, most productive short-term solution while the objectives of the National Energy Act are being attained.

Thank you for this opportunity to address these issues of importance to our industry and the Nation.

Mr. KRUEGER. Thank you very much, Mr. Kienker.

At this time the Chair will begin recognizing members in the order of their appearance here today. We will recognize members for five minutes, and then if there should be time remaining, we will go back.

The Chair first recognizes the gentleman from Louisiana, Mr. Moore.

Mr. MOORE. Thank you, Mr. Chairman.

Mr. Denton, may I first address my questions to you? Let me say that everybody that comes from a producing State as I do have the same concerns you do. I have seen the same people in my district. I have no oil or gas production in my district whatsoever, and I am a firm advocate of decontrol.

The problem we ran into in Louisiana is the fact we had people this year who could not get gas for new homes, and they are willing to pay $2 per Mcf as opposed to paying a higher electric utility bill to heat their homes and in some cases cool their homes. So it is a matter of, I guess pay now or pay later for the energy has gone up until we develop solar or something to take care of our ultimate needs. This is going to be a problem.

Let me ask you, do you think the majority of citizens in your State favor your position of maintaining strict controls on gas and extending t to intrastate natural gas?

Mr. DENTON. So far as I can tell, I do not believe there have been any extensive public opinion polls, and I am not sure how accurate they would be. I can simply go on the basis of the contacts that I have, which would represent a general kind of citizen, elderly people, basic consumers, family farmers, who feel very strongly that it is important to have some restraint and some control on the prices, and even at the high prices in Texas, Congressman Moore, there have been curtailments in Texas, so it has not guaranteed a supply.

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[3] FPC, "Monthly Fuel Cost and Quality Information," April 8, 1977, pp. 16-17.

[4] Statement of Richard L. Dunham, Chairman, Federal Power Commission, before the Subcommittee on Energy and Power, Committee on Interstate and Foreign Commerce, United States House of Representatives, April 5, 1977, p. 3.

Mr. MOORE. I am not sure I understood your answer. Do you think that, as far as you can tell, a majority of the people that you talk to and see——

Mr. DENTON. Definitely.

Mr. MOORE. Favorably?

Mr. DENTON. Yes, sir.

Mr. MOORE. You ran for the Texas Railroad Commission last year. Did you run on that platform?

Mr. DENTON. Yes, sir, I advocated that we should over an interim period of time have some control on the price of intrastate gas, and that Texas should not be paying three times more than people out of State. Taking the position of public interest and the position of the average Texan denied me receiving the kind of contributions that the oil industry put into the race. As a result, I was unable to have a single television spot or a single billboard in the State, and yet the oil companies' candidate only received some five percent more of the vote than I did.

Mr. MOORE. It could be argued the majority of the people disagreed with you.

Mr. DENTON. No, I think if I had had the opportunity to be on television and on the billboards like the oil companies' candidate, I would have won by a significant majority. I did receive, I might add, 243,000 votes, which is quite significant when you have not a single TV or a single billboard spot, but if you look at the groups, AFL-CIO, the teacher and the student groups and consumer groups and senior citizen groups, every one of them, they all endorsed my campaign.

Mr. MOORE. Mayor Faust, I think I had the pleasure of hearing you testify last year before the Oversight and Investigations Subcommittee of this same committee. Did we not learn last year from your testimony—who is your basic supplier of natural gas to your town?

Mr. FAUST. Lo-Vaca.

Mr. MOORE. I think we all agree, as a result of those hearings we held, Lo-Vaca is not a typical supply company. It has had all sorts of troubles and problems which I think maybe a good supply company should not have had. Have they not recanted on your contracts, for instance, and not supplied you with the goods that you had a contract price for?

Mr. FAUST. That is true, but the price of gas to us is higher because of some of those problems, but I heard earlier testimony that the average price of gas in Texas is say 70 or 75 cents.

I have a graph here that I have had since 1973 and it is constantly on the rise, and it is what I am paying every month, with all of the Lo-Vaca problems. These prices and the interim order rate by the Railroad Commission says we pay to Lo-Vaca whatever they pay to the producer plus five cents for transportation.

Mr. MOORE. The problem has been in Lo-Vaca getting its supplies. As I understand it, that company has had a great deal of problems in selling off its gas and not maintaining its supply contracts. They have not operated as a supply company should.

Mr. FAUST. That is true, but I think on the problem it was an unregulated situation and look what has happened.

Mr. MOORE. I do not think that your situation has been repeated all over Texas, and certainly not in Louisiana.

Mr. FAUST. But it is getting closer.

Mr. MOORE. You made the comment that you did not feel that the unregulated market or that increased supply in the case of the interstate market would produce any more supplies. Would you make that same argument for Texas in the intrastate market, that increased price has not produced more natural gas for Texas?

Mr. FAUST. I want to tell you that we did have some curtailments a couple of years ago, but the record shows I think, if you go back and look at it, not one of those curtailments was attributed to a shortage of gas. It was pipeline trouble, acts of God, things like that. Never once did I see——

Mr. MOORE. It is hard to regulate God, is it not?

Mr. FAUST. Yes, but never once did I see that we were curtailed gas for any use for a shortage of gas.

Mr. MOORE. I think the testimony from your State has been, and I am just a small town country Congressman like you, and I am finding that those facts are available and they show in your State that production has gone up, every time you have had an increase in price, and the reason why it has not gone up in the interstate market, the record shows, is because there have not been significant increases in price. I guess they can be interpreted in two different ways.

Mr. KRUEGER. I apologize. The gentleman's time has expired. We will try to return, but at this time I believe the next person present on the committee is Mr. Stockman. Mr. Stockman is recognized for five minutes.

Mr. STOCKMAN. I would like to ask a question of Mayor Faust and Mr. Denton.

You expressed a great concern regarding the impact of the rising intrastate price on your residential consumers, particularly the elderly, those with low income, the poor and so forth. Can you give me a statistic which would indicate the general or average delivered price for natural gas for residential heating purposes that prevails in Texas? I know you should know because you run a utility.

Mr. FAUST. You are saying the average utility cost at residences?

Mr. STOCKMAN. Yes, the bill per Mcf for residences.

Mr. FAUST. It is running for my utility about $3.42. That is the retail price to the consumer.

Mr. STOCKMAN. Is that representative of the entire intrastate situation or is that because of some unusual problems?

Mr. FAUST. This is intrastate.

Mr. STOCKMAN. Yes. Do you think that is representative of Texas?

Mr. FAUST. No, sir, it is not. The prices are different all over the State.

Mr. STOCKMAN. Right.

Here is the point I want to make to you. We all can get a very parochial perspective because we have to operate within our own range of experience. As I understand it, the average in Texas of retail delivery for residential usage is about $2.30 or $2.40, somewhere in that range.

I come from Michigan, and we have a lot more severe winters than you do, and do you know what our retail users are paying for heat, fuel, whether it is natural gas or any other? If they are on fuel oil they are paying the equivalent of about $3.30 or $3.40 per Mcf. If they are on electric heat, and a lot of them had to go to that because gas has not been available, we have no new hook-ups in Michigan for gas in the last four or five years, they are paying the equivalent of about $9.

I think the point that needs to be made here is that we have moved out of an era in which we had cheap energy and you could get natural gas for 30, 50, or 60 cents and what you are experiencing in your area is no different than what people are experiencing all over the country. They are paying more for energy, so I think you really misconceive the problem in some ways.

Another point, you said if this escalation continues, people are going to end up paying 25 to 30 percent of their take-home pay for their utility bill, and I presume you are talking about heating, and if they cook with gas and so forth.

I do not have a hand calculator here with me, but I did some quick figures, and if we assume a delivered price of about $2.30 or $2.40, you are talking about someone given the median income of the country which is about $11,000 or $12,000 a year, you are talking about someone purchasing and consuming 1.8 million cubic feet of gas a year. Now you would have to have a pretty large house or you would have to have no windows, no insulation, no ceiling, or you would have to have a pretty large array of ranges, refrigerators, air-conditioners, and everything else to even come close to using that much gas, so I think that we have to be a little careful here about how fast and loose we become with our statistics and with charges and issues that we are raising.

Mr. FAUST. Mr. Stockman, I am not fast and loose. You have people coming to me every day. I am at that retail level. Every month I would say about the first 10 days of the month I get a regular parade of customers coming by asking me what has happened to the price of gas. That is all we sell is natural gas.

We are a very small operation. I know them all by their first names. They are not kidding me. I can tell you I have about five or six people that are already paying 25 percent of their income. They are low-income people.

Mr. STOCKMAN. Okay.

Mr. FAUST. But they are already paying 25 percent, and if it went up another $1.25, as this interstate price indicated it could, there is no doubt in my mind that a lot of them are going to be paying 25 percent of their income to utilities, and you add electricity and gas—

Mr. STOCKMAN. Okay, fine.

Now the point here I want to make though is that you cannot establish the price of the fuel on the basis of what you or anyone else would consider to be the cost. In your state most utilities are running their boilers, their generators, on natural gas. That is not true in most states. If they had to use an alternative fuel because natural gas production continues to decline as it has for the last three or four years and will likely, especially under the kind of

system that you have recommended, if they have to go to coal, and if they have to protect the environment in the same process by using stack scrubbers and precipitators and delivering their sludge 200 miles away and so forth, how much do you think it will be per Mcf to produce electricity?

You do not have to answer because it is going to be in the range of $4 to $10, so the point is, it is nice to say, it is permissible to say we have a serious situation where people's standard of living is being affected. I think you have to remember that at the same time we have a very serious situation with the supply of energy, and whether it is coal, gas, or any other alternative sources that we might develop, we are not going to ever go back to the days of 25 cents or 80 cents.

I think that you have to recognize that, and I think the committees of the Congress have to recognize that, that we are never going to work our way out of some of the situations that you have been talking about in the testimony.

Mr. FAUST. I understand what you say, sir. I only say this committee should look to protect the consumer. I have heard an awful lot of comments here on the other side. Very few people are looking out for the consumer, and I am asking that the committee please consider what their plight is. Some of them are far more serious than the average.

Mr. KRUEGER. The time of the gentleman has expired.

The Chair recognizes now the gentleman from Texas, Mr. Gammage.

Mr. GAMMAGE. Thank you, Mr. Chairman.

I have questions I would like to address to the panel generally.

It was interesting to hear the testimony on the petroleum chemical complex in Texas in particular, and I would say in Oklahoma, Texas, and Louisiana generally.

In general, as I understand it, that area, just Texas and Louisiana, would contain probably two-thirds of the petrochemical complex that exists in the United States today: is that correct, sir?

Mr. KIENKER. That is correct. Our estimates are about 69 percent in Texas and Louisiana alone.

Mr. GAMMAGE. These industries utilize natural gas for boiler fuel, processed steam, feed stock?

Mr. KIENKER. Yes, sir, that is correct.

Mr. GAMMAGE. It seems to me that the President's plan insofar as it imposes a use tax on natural gas, and I understand it as an incentive to convert to other fuel sources, talking about a basic industry that really could not have the option of conversion in the near future, and that even during the interim period to impose such a tax on thse basic industries would substantially raise the price of further refined goods and consumer goods around the entire nation, would it not?

Mr. KIENKER. That is correct, Mr. Gammage. There would be nothing to do but to pass that along, if we stayed competitive with firms in the outside world who might not have some of those taxes.

Now we are making efforts to reduce our usage of gases as fuels, but we cannot reduce our usage of gas as a feed stock because we do not have the technology, and we cannot reduce our usage of certain fuel applications at this point for lack of technology.

Mr. GAMMAGE. The tax that would be imposed on the use of natural gas, as I understand the President's plan, however, would not be a plow-back tax. It would not go into additional exploration, discovery, or into the industry at any level necessarily.

Mr. KIENKER. That is our understanding, that the tax goes to purposes unrelated to increasing production.

Mr. GAMMAGE. It could be extremely inflationary as far as the cost of consumer goods is concerned.

Mr. KIENKER. There is no place to hide it. It would have to be passed along.

Mr. GAMMAGE. Another question, and you can speak to this, because you alluded to it a few moments ago as far as fertilizers produced in this chemical complex are concerned, and I am sure Mr. Denton would be interested in responding to it also.

As I understand it, all of the fertilizer plants that have been constructed in about the last 10 years have been constructed generally in the Texas-Oklahoma-Louisiana area, the anhydrous ammonia plants.

Mr. KIENKER. That is correct, and those in other areas of the country have shut down in some cases.

Mr. GAMMAGE. They moved closer to their source?

Mr. KINKER. Correct.

Mr. GAMMAGE. For each ton of fertilizer that is produced, it is my understanding it requires about 40 Mcf gas.

Mr. KIENKER. I believe in the more modern plants that figure is lower, approximately 26 to 16 Mcf.

Mr. GAMMAGE. 26 as opposed to 40?

Mr. KIENKER. Yes

Mr. GAMMAGE. So natural gas is selling for a rounded $2 per Mcf and you multiply that by 26 or 40 and you get the multiple of what it costs in gas alone to produce a ton of fertilizer right now.

Since we do have many plants operating at 40, if you do not mind people can reduce it down who are interested in doing the calculations, but for purposes of discussion let's just say that the fuel costs for producing a ton of fertilizer right now is about $80.

Mr. KIENKER. Correct.

Mr. GAMMAGE. Plus the operating cost plus any capital cost, interest, what have you, transportation, so right now a ton of fertilizer runs about $140?

Mr. KIENKER. Correct.

Mr. GAMMAGE. If the administration puts these use taxes on the gas, it is going to I would think impose even a greater hardship on our agricultural consumers as far as fertilizer is concerned. That is going to pass through some additional cost to the consumers at the supermarket, is it not?

They are going to have to absorb that increased cost of fertilizer somehow. None of it is going to be plowed back into them, their industries, whether it is petrochemical industry or the agricultural industry or what have you.

Mr. KIENKER. Correct. These downstream effects will flow through.

Mr. GAMMAGE. It seems to me that what we have here is a tremendous inflationary device, that it is going to produce what for whom I am not sure.

Mr. Denton would like to respond to that.

Mr. DENTON. Congressman, of course as you know, the use of fertilizer has made a tremendous difference in the kind of production in the State of Texas. In 1973 the cost of a ton of fertilizer was $80. As you say, now it is at least $140. The farmers of Texas, and I might add that the overall cost, particularly to the irrigation farmers—and that happens to be the ones that the vast majority of our members are—irrigation farmers on the high plains have had significant concern, and pointed out that their total cost in investment in the very small farm reaches almost $50,000. Yet their final net income is less than $6,000 or $7,000, so there is just very little margin, and the increased cost of fertilizer will not only add to their cost, but it seems at times I think the farmers are willing to reduce.

If I might digress a moment, and point out that the farmers and ranchers of Texas, even though they have lost money and have had to produce under some very difficult circumstances, and have not become wealthy, have still maintained that great American tradition, and they have gone out there and plowed their land and planted their seeds and produced food and fiber for the people in this country.

You know the whole industry in oil and gas needs to take some lessons from the American farmers about willingness to stick it out and do what the right thing is for the country.

Mr. GAMMAGE. I am not sure whether you are for or against the action by that response.

Mr. KRUEGER. I am sure the time of the gentleman has expired.

Mr. DENTON. It is the increased cost of fertilizer.

Mr. KRUEGER. This time the Chair will be recognized for five minutes of questions

Mayor Faust, I would like to first refer back to your testimony. I notice that you have referred to one $3.29 price for gas negotiated, on page 3 of your testimony.

Mr. FAUST. Yes, sir.

Mr. KRUEGER. It is my understanding that this price was negotiated, the particular company that negotiated it was allowing gas to be sold from Texas into the interstate market in order to meet emergency sales.

Mr. FAUST. That is right.

Mr. KRUEGER. That price was negotiated in order to cover the cost of oil to be used for a substitute fuel, that oil being basically foreign oil, and that the substitute fuel was brought in, and by the time that the cost for the great expense to burners and the pollution that additionally resulted, they felt that the appropriate price was $3.29. So you are not suggesting that that was a normal sale of natural gas, but were recognizing that it was an emergency sale and that they were looking not at a deregulated price for natural gas to substitute for what they are selling but, rather, they were substituting for oil; is that correct?

Mr. FAUST. Yes, sir, that is true, but I was trying to indicate what could happen if they went cross——

Mr. KRUEGER. Thank you very much.

I do not think that that is a normal circumstance. We were told earlier today, although I will hope to verify this figure, that the average price for gas sold in Texas at this time is 69 to 70 cents. That is what we were told by the Railroad Commission.

Mr. FAUST. Yes.

Mr. KRUEGER. Now those of us who deal as you and I have to do with Lo-Vaca have a certain special circumstance, and I am always reminded by my district administrative assistant, who is Italian, that I am not to confuse the Italians and the Mafia and I am also reminded that I am not to confuse Lo-Vaca and all other gas companies.

I think we have a special circumstance when we deal with that particular company.

Mr. FAUST. My consumers ask the question, why is that allowed to happen to anybody?

Mr. KRUEGER. I am glad that they asked that, because it was locally-elected government officials in San Antonio, Texas, who made the determination that they wished to deal with Lo-Vaca, a gas company, instead of with another company, and I think that local government officials should indeed have concern about why they choose to deal with Lo-Vaca. I am not sure that the Congress of the United States could have forewarned them that to deal with that particular company would be to deal with a company that would not be able to deliver on its contracts, although the law does allow our city, as we are doing, to take those people to court for failure to deliver, but I certainly concur that they need to ask the question of the people who were their locally elected officials at that time. I believe neither you nor I were.

Mr. FAUST. No, sir.

Mr. KRUEGER. But the locally elected officials made that determination.

Mr. FAUST. May I, Mr. Krueger, make one other comment?

Mr. KRUEGER. Yes.

Mr. FAUST. About nine months ago we attended a National Association of American Gas Producers meeting in Alabama. In talking to the people in the other States, they have indicated that if the gas were available, they would have paid as high as $4 and $4.50 a thousand for the gas, so the unregulated market across the State lines, if it were to be released tomorrow——

Mr. KRUEGER. I understand that. I am pretty sure what is going to happen to our gas.

Mr. KRUEGER. I understand that. They are talking about $4 prices and El Paso Natural Gas has very heavy investment in some tankers which it would like to bring in to bring some gas from Algeria and other sources, and we are talking in one instance about emergencies. I did want to get that correction into the record about that $3.29 figure.

I observed that on page 4 of your testimony you referred to your understanding of FPC figures in 1975. For the record, I would wish to indicate the most recent information —that was the Bureau of Economics, by the way; it was not accepted by the Federal Power Commission itself—that we have from them as of yesterday was that the price should be a bit above $1.75. You indicate you do not

feel comfortable in setting a price—I do not either—but there are a variety of prices that various people have proposed.

I observe that in testimony earlier, Mr. Denton, you indicate Texans pay an enormous price for gas. I am concerned, as others, that we pay more for what we receive than people in other areas. Would you care to compare the price we pay against what people in other countries outside the U.S.A. pay?

Mr. DENTON. I am not familiar with what people outside the United States are paying.

Mr. KRUEGER. I think it is important to recognize that when we compare the prices Americans pay with any other country, possibly with the exception of Saudi Arabia, the average price is lower for energy than any of the other industrialized countries with whom we compare ourselves.

Mr. DENTON. What I tried to point out is we should try to have a balanced viewpoint. I do not know why the consumer should be hit the hardest in the first line.

Mr. KRUEGER. Thank you. I certainly concur that we should not be having to pay more than people in other areas and will work hard to deal with that.

I wish to ask unanimous consent to insert in the record, since I have not had the opportunity to ask any agricultural questions, testimony of John R. Dorr given before the Subcommittee on Oversight and Investigations on August 30, September 8 and 10, perhaps 16 to 20, so I will have testimony on the agricultural question. Then I will hope to come back to ask questions on that later.

Without objection, it is so ordered.

[The testimony referred to follows:]

92-911 O - 77 - 38

UNREGULATED NATURAL GAS MARKET IN TEXAS

HEARINGS

BEFORE THE

SUBCOMMITTEE ON OVERSIGHT AND INVESTIGATIONS

OF THE

COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE HOUSE OF REPRESENTATIVES

NINETY-FOURTH CONGRESS

SECOND SESSION

AUGUST 30; SEPTEMBER 8 AND 10, 1976

Serial No. 94–152

EXTRACT

TESTIMONY OF JOHN R. DORR, OIL AND GAS EXPLORATION AND PRODUCTION

Mr. Moss. Will you identify yourself to the Clerk for the hearing record.

Mr. DORR. My name is John R. Dorr of Pecos, Tex.

I want to thank the chairman and members of the committee for allowing me the opportunity to appear here today.

I am a graduate of the University of Oklahoma (1961) with a B.B.A. degree in petroleum land management. Between 1953 and graduation, I worked as a swamper-pumper, roustabout, roughneck, landman, and farmer. Following graduation, I farmed full time in the Pecos area, until 1969, when I went back into the oil business. Since that time I have devoted all my activities to oil and gas exploration and production. I did well farming and even better in the oil business. And having done well at both, I feel qualified to discuss the problems in both areas.

I got out of the farming business when I did, because it was easy to see that the water table of the Trans-Pecos region was falling far more quickly than hydrologists had predicted, and that costs for everything needed to farm were escalating on the same scale. Fertilizers, insecticides, energy, equipment, seed, labor (with the loss of

braceros), land, and water supplies continued to increase the cost of operations beyond recoverable margins. In the words of Frank Fulk, chairman, Natural Resources Committee of the Texas Sheep and Goat Raisers Association, "It is a classic example of what happens when irrigation is overdeveloped in a closed underground water basin. The water accumulated over thousands of years was pumped out in just a few (years), to a point that the lifting of it became prohibitive." Possibly water should be conserved for human consumption, which is more precious than natural gas.

"When natural gas costs $.40 M ft^3," according to Gary D. Condra, Texas A. & M. University area economist—management, in his 1975 study of the "Impact of An Increasing Natural Gas Price on Irrigated Crop Production in the Trans-Pecos Region of Texas," "it should be noted that all crop enterprises, except winter wheat, are currently returning less than cost of production." So don't let anyone tell you that the Trans-Pecos Region of Texas has become a barren oasis, with thousands of farmers broke and ghost towns everywhere, simply because of long overdue increased natural gas prices.

In the first place, few alert farmers have gone broke, and what ghost towns there are, are there because both crude oil and natural gas prices were too low. While farming activities, much of which was being done on land which was, at best, marginal, have been greatly reduced, melon, grazing and ensilage crops, along with alfalfa, have shown an increase in recent years.

Most of the problems confronting the West Texas economy are created by the excessive cost of Government controls and red tape. The alert operators foresaw possible shortages and signed long-term gas contracts. Others, looking for a big brother to take one more step towards socialism, by taking over control of intrastate production, and further hampering the domestic petroleum industry, suddenly found that the only gas they could buy was almost non-existent, at any price.

Thanks to the increased prices for crude oil and natural gas, activity in the Permian Basin, employment, housing bank deposits, new car sales (all economic indicators) show the Trans-Pecos Region in better shape than we were during the heyday of King Cotton.

Our own area has induced new industry to come our way because we have natural gas available for their use. Those already operating have come to realize that there will never again be any cheap energy sources, and are willing to pay the necessary price to stay in business. The interstate natural gas market is in deep trouble, not because Texas, New Mexico, Oklahoma, and Louisiana gas producers don't want to sell in this market, but because artificially low, Government required, wellhead prices are far less than the intrastate market. They can sell their product at a better price and without the interference, redtape and uncertainty of Government controls.

The sooner the Congress, the so-called consumer advocates and the public. with the help of the national news media, realize that until there is a 5-cent cup of coffee, 25-cent-per-hour minimum wage, a 35-cent blue plate special, a 25-cent haircut, a 25-cent theater ticket, a 50-cent football game ticket, et cetera, there is not going to be any cheap energy source from anywhere in the world again.

These are prices which would be comparable to natural gas costs, held at artificially low levels until recently. Someone said that if the price of a Chevrolet had increased as much as the price of gas, we would be paying $40,000 for a Chevy. He also said we would be paying $4.80 for a hamburger; $24 for a haircut; $240 for a pair of shoes and $12.80 for a six pack of beer.

The fallacy in this proposition is, he is comparing the natural gas price increase from 1 year, 1974 to the next, 1975, when for 20 years, prior to that time, there had been practically no wellhead increased. Go back to 1936 and check the price of a Chevy then and in 1956. Now compare that to 1976. It has increased 700 percent. Check the cost of labor, 800 percent; a hamburger, 1,000 percent; a pair of shoes, 700 percent; a haircut, 800 percent. A six pack of beer is the only thing he mentioned that has not increased more than natural gas.

The question has also been asked: What caused natural gas to go from 24 cents to $1.85 per mcf? Why use the 24-cent average price against the $1.85 top price? Some gas still sells at 5-cents per mcf. As we mentioned earlier, the demand did increase to a remarkable extent. Also, some people realized that they were going to have to pay a reasonable price for natural gas if they were to have a supply, and were willing to do so. Only those who refused to sign new long-term gas contracts—when their old ones ran out—but tried shopping for more cheap supplies and short-term contracts, ended up having to pay anything like $1.85 per mcf. We heard no complaints, so long as the interstate price was set at an artificially low wellhead price, which also helped hold down exploration and development. Only when natural gas started drawing near the market clearing price did the complaints begin.

Another thing, the petroleum industry is being charged with monopoly. Thirty companies control 90 percent of the business. Has anyone compared this with some real monopolies, like Western Union, 100 percent control; AFL–CIO and UMW labor unions, 90 percent control; ABC, CBS, and NBC, 96 percent control; AMC, Chrysler, Ford, and General Motors, 99 percent control? We could go on and on—tires, stell, appliances, computers, but it is obvious that the monopoly charge is purely a red herring.

Monopoly. unless you consider the Federal Power Commission as such, and we do, has little bearing on the 52 cents per mcf—New York, Arizona, $1.85 per mcf Texas. The market of Texas gas in Texas is the real reason for the difference. What some folks fail to mention, or perhaps they don't realize, is the fact that, when those interstate, 52-cents per mcf contracts run out, there won't be any replacements, at any price. And you can't get alternative energy, even imported gas, at anywhere close to the much talked of $2 per mcf.

The automotive industry, the labor unions, clothing, food, medicine, tires, appliances, furniture, manufacturers, in fact, no business we know of, unless required to do so by Government edict, will voluntarily sell their products at a loss, or can stay in business if they do. Certainly, as a farmer I couldn't and as an oil operator I wouldn't.

Thank you.

Mr. Moss. Mr. Wunder.

Mr. WUNDER. Thank you, Mr. Chairman.

Mr. Dorr, in your statement you say few alert farmers go broke. How would an alert farmer have been able to have foreseen the rapid increase in natural gas prices?

Mr. DORR. I was farming at the time and I could see these prices coming on. I changed my mode of operation. A number of farmers in our area that are still in business have the better land, they are not farming the marginal lands that are put in for the purpose of raising cotton when it was 52 cents during the Korean war prices, when we had 300,000 acres and people were coming from Arizona, California, to the Pecos region. These farms never would have been put in in the first place because there was not a sufficient amount of water.

The good farms are still in good production, raising onions, cantaloupes, raising ensilage for the five feedlots in the area. Our area is not good for raising grain because we have the high salt tolerance in the soil and we don't get the production that they have in the high plains.

I think these people will stay in business that have the good farms and good lands. They have the better water tables in the area. Exterior areas are going to go out like the outside areas of an oilfield.

Mr. WUNDER. Would it be a fair statement then that the farmers are having difficulty on marginal land that but for low gas prices would not be suitable for farming?

Mr. DORR. I think that is partly a fair statement. We have been wasting a lot of our natural gas from this standpoint because electricity used on a farm running a water pump is a direct drive system. Taking an engine using natural gas and going to a turbine, you have a 90 degree turn going from a drive shaft down to the well, you lose a third of your horsepower. This is a waste of energy. By doing this you increase the cost of producing water.

By going to electricity you have direct drive. Electricity uses only enough energy to pump that well for the water you are making. You don't have abundance of waste and excess energy that you do in a combustion engine. I think this is probably more conservative of the power source. The natural gas would be used for making electricity and coal might be a cheaper way. Natural gas might be used for making fertilizer and chemicals even better than burning in engines.

Mr. WUNDER. Thank you, Mr. Chairman.

Mr. Moss. Mr. Krueger, do you know how much time you will require?

Mr. KRUEGER. That depends on how much time is available.

Mr. Moss. We are having a quorum call. We are trying to determine whether to recess and return. Mr. Collins says he has a question.

Mr. COLLINS. I have only one question.

Mr. KRUEGER. I won't take over 4 or 5 minutes.

Mr. Moss. Mr. Collins.

Mr. COLLINS. I want to know what the price of gas is at this time in Pecos.

Mr. DORR. For the farmers?

Mr. COLLINS. Yes, and I want to know what alternate fuels are more comparable or more attractive in price.

Mr. DORR. I believe as I understand it at the present time the farmers have gas offered to them at $1.82.

Mr. COLLINS. Is there any alternate fuel that they are being offered or the cost of it that is any more attractive?

Mr. DORR. No, sir, unless the man was to go to the electric power where he has a shallow water source and he has a minimum he must pay during the winter months when he is not using the power. I would say it is still attractive when fully priced.

Mr. COLLINS. Thank you.

Mr. Moss. Mr. Krueger.

Mr. KRUEGER. I have questions on two points.

You were talking about the waste of power and I missed part of what you said when you were talking about a 90 degree turn in the pipe. Would you run that by again?

Mr. DORR. Congressman, according to engineering I have read, not being an engineer, myself, but when you make a 90 degree turn through the use of a drive shaft you lose 33 percent of the power coming from the power source by making this 90 degree turn. By having a direct drive, as coming from your automobile engine to the transmission, you are losing 90 degrees going to both wheels. This is my understanding. I am not an expert on this by any means.

By using electricity you have a direct drive that goes straight down the hole and turns the turbine at the bottom of the hole, raising the water to the surface. You don't have the power loss.

Mr. KRUEGER. It is your suggestion that the land in the Trans-Pecos region was perhaps, because of its salinity, best suited for raising onions and vegetables; is that correct?

Mr. DORR. Not because of the salinity but because of the naturally fine weather that we have, because of the ability to irrigate it, and this is a more profitable crop, it is a more risky crop but the area has done well on cantaloupes and onions, bell peppers and alfalfa as a good secondary crop, wheat, ensilage for the cattle feed yards.

Taking the marginal lands out of production I think you will find most of the farms in the Pecos area stay.

Mr. KRUEGER. Do you know what the price range is for a sack of onions in that area?

Mr. DORR. Today onions are very low because our crops came off late. We had a bad year this year. I bought a sack of onions the other day at $3 for 50 pounds. They put them on the truck for about $2.50 I believe.

Mr. KRUEGER. It must go through some pretty extraordinary cycles then because I thought that I remembered them telling me out in Reeves County something like $7 a sack a year or so ago.

Mr. DORR. Last year they had a very good year and the beginning of the crop year they received $7 a sack.

Mr. KRUEGER. Is that a 50 pound bag?

Mr. DORR. Yes, sir.

Mr. KRUEGER. How many sacks do they get per acre average?

Mr. DORR. On a very good crop you get between 800 and 1,000 sacks. On an average crop it is five to six hundred.

Mr. KRUEGER. A thousand sacks per acre?

Mr. DORR. Yes, sir.

Mr. KRUEGER. At anywhere from $2.50 to $7 a sack?

Mr. DORR. Yes, sir.

Mr. KRUEGER. $2,500 to $7,000 an acre?

Mr. DORR. Yes, sir. Realize you have a very high labor cost in this because of the harvesting of this is all done by hand.

Mr. KRUEGER. Did you ever engage in that kind of farming, yourself?

Mr. DORR. No, sir. I was not astute enough to get in the truck farming business. I had some background in the oil business. I did not want to take these kinds of risks. I thought maybe the oil business was even less risky than this.

Mr. KRUEGER. You were not smart enough to be a farmer and chose to go in the oil business.

Thank you very much.

Mr. MOSS. The Chair wants to express the appreciation of the subcommittee for your appearance here this morning.

The subcommittee will now stand adjourned to convene again at 10 o'clock in this room on Friday when we will have Dr. Russell G. Thompson, professor of economics, University of Houston, and Jack Hopper, economist from Austin, Texas.

The subcommittee will stand adjourned.

[Whereupon, at 12:20 p.m., the subcommittee adjourned, to reconvene at 10 a.m., Thursday, September 10, 1976.]

(End of extract)

Mr. KRUEGER. Mr. Madigan has arrived. He has not had an opportunity for questioning. I will recognize Mr. Madigan for five minutes.

Mr. MADIGAN. Mr. Chairman, I just sat down and I do not even know who the witnesses are.

Mr. KRUEGER. I will pass over and ask the gentleman from Louisiana, Mr. Moore, if he has any further questions.

Mr. MOORE. No further questions.

Mr. KRUEGER. The gentleman from Michigan.

The gentleman from Texas.

We have one question from counsel, Mr. Demarest.

Mr. DEMAREST. Mr. Kienker, as I understand it, many intrastate industrial natural gas consumers are presently paying higher prices for natural gas than some interstate industrial consumers. I wonder if, in the context of the removal of Federal price ceilings from interstate gas supplies, whether intrastate users would support the notion of incrementally pricing new gas supplies to industrial interstate customers so that the interstate industrial user who has access to cheap rolled-in interstate gas plus an incremental amount of more expensive new gas, would not enjoy a competitive advantage over the intrastate industrial consumer who does not have the benefit of rolling in new gas supplies with cheaper old gas supplies.

Mr. KIENKER. Mr. Demarest, I believe for incremental pricing provisions we certainly lean toward provisions that have been proposed by Congressman Krueger to make people quite thoughtful of their use of gas at all times and especially gas that might move

from the intrastate market into the interstate market. So I would say, yes, we would be quite interested that there be some consideration of that type of provision.

Mr. DEMAREST. For purposes of the record I should observe that to my knowledge the natural gas legislation introduced by Mr. Krueger does not contain an incremental provision.

Thank you, Mr. Chairman.

Mr. KRUEGER. We wish to thank the panel at this time,and we will recess for about two minutes as we prepare for the next panel, if those members will please come forward at this time.

We thank the panel very much.

[Brief recess.]

Mr. KREUGER. The committee will come to order.

At this time we have before us a panel of people dealing with intrastate pipelines, local distribution companies and utilities. At this time I shall ask each member of our panel to identify himself for the record. Following that identification we will insert the full written testimony of each panelist into the record, but I would ask each panelist, if he might, to try to summarize his testimony in five minutes.

We also recognize the problems of living under the 5-minute rule because in House debate we normally have to do that. It is not the ideal circumstance but if each member could summarize in five minutes we will then have about half an hour for initial testimony and at that time it would be open for the committee to ask the panel questions, and I think probably that is the best way to try to facilitate our gathering of information this afternoon.

With that request I would ask the panelists to identify themselves for the record.

STATEMENTS OF C. C. INGRAM, CHAIRMAN OF THE BOARD, OKLAHOMA NATURAL GAS CO.; CAROL L. NEAVES, EXECUTIVE VICE PRESIDENT, OPERATIONS, LONE STAR GAS CO.; ROBERT P. McCANTS, SENIOR VICE PRESIDENT, ENTEX, INC.; JOE H. FOY, PRESIDENT AND CHIEF OPERATING OFFICER, HOUSTON NATURAL GAS CORP.; WILLIAM McCOLLAM, JR., PRESIDENT, NEW ORLEANS PUBLIC SERVICE, INC., REPRESENTING EDISON ELECTRIC INSTITUTE; AND GEORGE L. DONKIN, J. W. WILSON & ASSOCIATES, INC.

Mr. INGRAM. C. C. Ingram, Chairman of the Board of Oklahoma Natural Gas Company.

Mr. NEAVES. Carol Neaves, Executive Vice President, Lone Star Gas, Dallas, Texas.

Mr. MCCANTS. R. P. McCants, Senior Vice President, Entex, Inc., Houston, Texas.

Mr. FOY. Joe H. Foy, President and Chief Operating Officer, Houston Natural Gas Corporation, Houston, Texas.

Mr. MCCOLLAM. William McCollam, Jr., President of New Orleans Public Service, Inc., New Orleans, Louisiana.

Mr. DONKIN. My name is George L. Donkin. I am with J. W. Wilson & Associates, Inc., Washington, D.C.

Mr. KRUEGER. Thank you very much.

At this time perhaps we can proceed in the same sequence in which the panelists identified themselves and begin with Mr. Ingram.

STATEMENT OF C. C. INGRAM

Mr. INGRAM. Thank you, sir. We believe it is unfortunate and misleading to polarize discussions of energy issues along geographic lines between producer and our consumer interests. We think this energy shortage is nationwide and we are all in the problem together.

Addressing natural gas pricing, we support deregulation of new onshore gas. We do think that if we have deregulation we should have some protection from the redetermination and favored-nation clauses in intrastate contracts.

Mr. KRUEGER. I will interrupt this one time to say I agree.

Mr. INGRAM. We think if there are concerns that deregulation would result in excessive revenues, those concerns could be met by a windfall profits tax that would put the money back into exploration to find new gas supplies. This approach is the best way to achieve what we are all after, to increase the supply of natural gas.

I think it would be a great mistake to regulate the intrastate market. This market has kept the industry alive the last several years., The people in these States have paid more for gas and I think it is wrong to devise a program that would take their gas away from them. However, this does not mean we want to hoard gas; we have been cooperating to alleviate shortages by selling all the gas we could in the interstate market through emergency sales. We sold 36 billion cubic feet in 1975. We sold about 59 billion cubic feet in 1976. And we have already sold this fiscal year about 57 billion cubic feet.

During the cold winter we sold 27 billion cubic feet to the interstate market.

We think that there are several aspects of this bill that discriminate against the intrastate market. One of the most glaring ones is that if the intrastate contracts expire, they become new gas and will be up for bid by the interstate pipeline companies. On the other hand, if the interstate pipeline contracts expire, they are not new gas and will remain subject to FPC abandonment jurisdiction and we in the intrastate market do not have a right to bid on them. If this condition is allowed to prevail, the interstate pipelines will keep the gas they have and will bid for the gas that we have now under contract as such contracts expire.

You may say, "So what, because you may both be allowed the same price."

That is not exactly true, because price alone is not the only governing factor in a gas purchase contract. One of the most significant factors in a gas purchase contract is the ability to take gas at a fast rate. Interstate pipeline companies, with much larger markets, normally can take gas much faster than intrastate.

So if they pay the same price we pay to take the gas and do so in 10 years instead of 15 or 20 years, they will be able to bid for gas supply from a stronger position. In addition, we feel that producers

in the future will only sell intrastate gas under very short-term contracts because they will want to have the gas bid on every year as new gas. It would be impossible under this bill for us to buy new gas in any quantity or to retain the gas we already have.

We also oppose incremental pricing. We think the incremental pricing does not reflect the cost of service and that it will not promote conservation. We think all customers should carry part of the burden of higher prices because if all the price increase are placed on big users, small users would not be encouraged to conserve to the same degree as they would if they carry their proper load of the increase.

We are very much in favor of eliminating boiler fuel use of gas. We think that should be done. Our only admonition is that we do it in an orderly manner because there are certain areas of the country which have become much more dependent than others on natural gas for boiler fuel use, and they will certainly need a longer period of time for an orderly phaseout so that the people in that area are not subjected to the sudden adverse economic impact that would occur if boiler fuel use were phased out too fast.

With respect to gas utility rate reform, we think such programs should be designed by the people in the State and local regulatory commissions. We do not think the Federal law should set local utility rates. We do suggest in our prepared testimony that the National Association of Regulatory Utility Commissioners might work out a national guideline and that the State commissioners could then develop specific rate designs.

We are very much in favor of conservation. We now in Oklahoma are making surveys free of charge to our customers for conservation but we really think that the financing and the contract installations should be done by people with experience in that business.

Finally, we believe that the allocation authority under the Emergency Natural Gas Act should not be extended to the intrastate market because such an extension is unnecessary. We have done, we think, an outstanding job in a voluntary way, we wish to continue to operate in that same way, and we believe we can best provide emergency gas on a voluntary basis.

[Mr. Ingram's prepared statement follows:]

STATEMENT OF C. C. INGRAM,

CHAIRMAN OF THE BOARD, OKLAHOMA NATURAL GAS COMPANY

My name is C. C. Ingram and I am Chairman of the Board of Oklahoma Natural Gas Company ("ONG"), an intrastate natural gas pipeline and distribution company serving 528,000 customers within the state of Oklahoma. ONG supports fully the need for a comprehensive long-range energy program. We believe it is unfortunate and misleading to polarize discussions of energy issues along geographic lines between "producer" and "consumer" interests. The energy shortage is nationwide and we are all in it together. Accordingly, the program adopted by the Congress should be one that recognizes the problems of energy consumers in all geographic regions and which also takes into account differences in the amount of dependence on various energy sources that have developed in each region over the years.

I will now deal with the specific elements of the Administration's energy program of greatest concern to ONG and other natural gas suppliers.

Natural gas pricing. Price controls on new onshore gas should be eliminated so that such gas can be sold on a basis reflecting its true replacement cost. However, such deregulation should be accompanied by a statutory ban on the triggering of favored nation or price redetermination clauses in existing

intrastate gas contracts by the increase of wellhead prices for new gas. This would insure that only new gas discoveries--the discoveries where maximum production incentives are appropriate--would have the benefit of the deregulated price. ONG believes that this approach is far more desirable than price increases to the consumer through an arbitrary ceiling price and imposition of user taxes that create no new production incentives. Concerns that deregulation would result in excessive revenues to gas producers can be remedied by taxes on any "windfall profits" which are not used directly in additional energy exploration and development.

The intrastate gas market. ONG supports deregulation of new onshore gas, despite the fact that it would remove any competitive advantage enjoyed by intrastate gas purchasers. But extension of price control to the intrastate market would be a serious error in any event. President Carter has supported pricing of energy at its true replacement cost and the unregulated intrastate market provides the only yardstick available to show the market value of natural gas in an unregulated environment. Gas consumers in Oklahoma and other producing states over the years have paid a higher gas price to insure a stable supply. It would be most unfair to substitute price controls that have spawned nationwide shortage for a system that has worked well for consumers. This does not mean that we want to "hoard" gas for our area;

indeed, ONG was a major supplier of gas to the interstate market through emergency sales last winter.

Discriminatory aspects of intrastate regulation. If regulation is extended to the intrastate market, as the proposed legislation would bring about, such intrastate gas purchasers would be subjected to the following extremely discriminatory disadvantages:

(a) Upon the expiration of intrastate contracts, interstate purchasers would be able to contract for and thereby take such reserves away from the previous intrastate purchaser. However, the intrastate purchaser would not be able to compete for reserves under expired interstate contracts because of the requirement of FPC abandonment approval. Even if the same price ceiling applies to both interstate and intrastate purchasers, the ability of the interstate pipeline to offer much larger take-or-pay provisions would result in the interstate purchaser's obtaining an inordinate share of both newly-developed reserves and those previously committed under expired intrastate contracts.

(b) Gas purchased under intrastate contracts, upon expiration of the contract, would command the new ceiling price when sold under a roll-over contract, while gas under expired interstate contracts would only command the national area ceiling of $1.45 plus the "inflation adjustment". Thus,

intrastate buyers would have to pay more for contract extensions than interstate buyers.

(c) Producers selling intrastate would only sell under short-term contracts in order to get the new ceiling prices at frequent intervals upon contract termination, whereas sales under interstate contracts could only be terminated after abandonment approval by the FPC or the successor body.

(d) Without the ban on the effectiveness of most favored nation and price redetermination provisions in all existing gas purchase contracts, the intrastate gas customers would be subjected to large increases in their average cost of gas with the interstate customers continuing to be insulated from such increases through FPC or successor body regulation.

Incremental pricing for industrial gas. Incremental pricing is contrary to energy conservation efforts. If the residential gas consumer is subsidized by paying less than his proportionate share of the total utility cost of service and cost of gas, the incentive to avoid waste and to conserve gas is diminished. Furthermore, the added cost burden to the customer of the particular industry is subsequently reflected in the price of the products and services he purchases. Consequently, the consumer of that product is the individual ultimately bearing the incremental cost--with no assurance that the price increase will result in conservation of energy or

increased supplies.

Restrictions on customer use. Given the severe and deepening natural gas shortage, it is apparent that gas for boiler fuel must be phased out. In doing so, however, it must be recognized that some areas are historically more dependent on gas for boiler fuel--both for generation of electricity and other industrial use--so that the phaseout period must be flexible enough to permit facilities to be constructed and other fuel sources obtained in an orderly manner. In ONG's view, this phaseout of boiler fuel is a far better way of eliminating low-priority use than gas user tax provisions. For example, the proposed user tax for natural gas is designed to offset the differential between the price paid by the industrial user and the prevailing fuel oil price. This creates the anomalous situation that more natural gas might be sold to industrial customers at higher prices since the industrial customer--who would pay the higher price in any event through imposition of the tax--would lack any incentive to bargain for better terms from his supplier. Also, it should be recognized that a too-rapid phaseout of large industrial sales would severely reduce the load factors of many utilities and result in a much larger share of their costs of service being imposed on their remaining residential, commercial, and small industrial customers. This would cause sharp increases in small-user rates.

If increased gas prices for industrial users are regarded as necessary to discourage such use and encourage conservation, higher industrial rates should be set by state regulatory

commissions at a level that would enable utilities to offset the decline in their earnings from curtailed industrial sales. The utilities would than be able to postpone or reduce rate increases which would otherwise be required for residential and small commercial customers because of reductions in industrial sales.

Gas utility rate reform. ONG supports the effort to reform utility rate designs so as to maximize incentives to conserve. However, it is a mistake to require establishment of inflexible uniform rate structures on a national basis. There are legitimate reasons for differences in rate structures based on local needs, and this is the reason why rate design has traditionally been a function of state regulatory commissions. One sound way to augment state regulation would be the creation of a National Association of Regulatory Utility Commissioners (NARUC) committee to adopt energy conservation rate design standards to be applied by state regulatory bodies. This would permit a group with expertise in the application of energy conservation techniques to rate design to bring about uniformity to the maximum extent feasible without disrupting the state function of applying those standards to the needs of particular areas.

Home insulation and conservation programs. ONG is already conducting an energy-saver service in which we offer home owners an inspection and recommendation on ways that they can save in the home. We believe it would be practical to expand this service so that the gas utility has responsibility for (a) surveying and inspecting individual homes,

(b) recommending insulation and other conservation measures, (c) furnishing lists of contractors, (d) encouraging local financial institutions such as banks and savings and loan associations to make home improvement loans to finance conservation work, and working with local FHA offices to assure adequate guarantees as the basis for such loans. We believe it would be a mistake for the utilities to assume the function of being the contractor or to act as the collection agent by amortizing the cost of improvements through utility bills over a relatively short period of time. Such a function would force the utility to impose additional administrative costs on the home owner since, unlike contractors and financial institutions, utilities presently do not have the experience or administrative capability to provide these services. Furthermore, it is desirable whenever possible that the home owner finance the improvements on a mortgage loan basis because this would permit a longer amortization program and lower monthly costs. We do believe that the utility has a responsibility to coordinate energy conservation activities within its service area and that it can serve as the catalyst for a community effort by all concerned--the utility, insulation supplier, contractors, financing sources, and the FHA--to see that the program is active and effective.

Extension of Emergency Natural Gas Act. ONG believes that the authority given by the present ENGA, used in conjunction with the existing FPC short-term emergency sales mechanism, is adequate to meet crisis situations such as that experienced last winter. ONG does not believe that the

existing legislative authority should be altered to confer on any agency the power to allocate intrastate gas supplies. This would deprive intrastate gas utilities and their customers of gas reserves which these utilities have contracted for in good faith at prices high enough to encourage additional drilling and development, and have connected by the construction of expensive new facilities.

These are the areas of greatest concern to ONG. We hope that the Congress will take these views into consideration as it shapes an energy program that must be enduring and responsive to the needs of all energy consumers.

Mr. KRUEGER. Thank you very much.
Mr. Neaves.

STATEMENT OF CAROL L. NEAVES

Mr. NEAVES. I am Carol Neaves, Executive Vice President, Operations, Lone Star Gas Company, Dallas, Texas.

Lone Star Gas Company gathers, transports and distributes natural gas to over one million residential, commercial and industrial customers. We are among those who appreciate the fact that the President and Congress have focused attention on our current energy situation, and we give full recognition to the dilemma you face in attempting to find socially, economically, and politically acceptable ways to assure an energy supply without damaging the Nation's industrialized economy, while industry attempts to meet the challenge of developing even greater energy supply.

The presently proposed "National Energy Act" with its heavy conservation option, and with its weak supply side, appears to be less than an adequate program needed by our country. We also feel that conservation, important as it is, can tend to become a substitute for facing the harsh reality that no tenable self-denial will provide the energy needs of our country.

NATURAL GAS PRICING

We still hold the view that deregulation of wellhead prices of natural gas is a most important step in our national energy policy. Lone Star has historically supported deregulation of new natural gas at the wellhead for the interstate market. This premium fuel while more expensive on our Texas intrastate system than on the federally regulated interstate market, is for this reason more plentiful. We do not agree with the administration's position that

deregulation would be disastrous. The free market system must be permitted to function nationwide if natural gas exploration and development drilling are to be sufficiently stimulated. And we need this stimulation to insure adequate energy during the time that will be necessary to fully develop other viable sources of energy.

PRICE CONTROLS SHOULD NOT BE EXTENDED TO THE INTRASTATE MARKET

Lone Star Gas Company feels that regulation of the intrastate market would do nothing to contribute to increased gas production. But the intrastate market can provide an important yardstick for the value of natural gas as a commodity and the effects of higher prices on conservation.

Maintenance of artificially low wellhead prices where they now exist or extending price controls to the unregulated intrastate market would be counterproductive. Such regulation would only allocate existing shortages.

Permitting the free market system to function can also assist in conservation and conversion. Eight of 11 cement plants located on Lone Star's system in Texas have already converted to coal because the price of natural gas has risen to the point that conversion was economically feasible, and not because it was mandated by Federal regulation.

BOILER FUEL USE OF NATURAL GAS

We support a phase out of new large industrial boiler-fuel use of natural gas except possibly in areas where clean air standards prevent the use of any other fuel or in the rare case where no other fuel is available.

Concern must also be expressed about forced fuel conversion within a too restrictive timeframe. This can cause undue hardships on many industries, affect employment, and the the demise of some businesses. We consider the Texas Railroad Commission Order 600, which is currently phasing out natural gas as boiler fuel for electric power generation, as an appropriate approach. We are attaching a copy of this order to our testimony for your information.

INCREMENTAL PRICING

We believe proposals such as incremental pricing and tax penalties such as the excise tax on industrial use of natural gas are punitive in nature and only drain money away that could be used for conversion as well as being costly to the general public in the end. It also sends the wrong signals to the residential customer by saying that his gas bill will continue to remain about the same for awhile, thereby providing no incentive for him to conserve.

UTILITY RATE DESIGN PROPOSALS

On the matter of utility rates, it is felt the public's best interest would be served by leaving rate jurisdiction within the individual States, as fuel usage, availability and weather conditions vary from region to region.

The "National Energy Act" proposes a single-step flat price rate to all customers. In the interest of conservation Lone Star has had two-step gas rates for almost two years. But Congress needs to be aware that a single or two-step price rate causes the larger customers to pay for more than their cost of service while the smaller customer pays less than his cost of service.

Interruptible rates included in this proposal have been used by Lone Star for over 30 years, and we consider them advantageous in protecting our high-priority customers during peak periods and permitting lower costs.

However, this whole rate design question is too technical, complex and regional to be adequately addressed by Congress in the timeframe under which the House of Representatives is currently working.

AMENDMENTS TO THE EMERGENCY NATURAL GAS ACT OF 1977

On the proposed amendments to the Emergency Natural Gas Act of 1977, I could only second Chairman Dunham's statement that I am convinced we were able to alleviate the critical shortages more promptly and efficiently by voluntary arrangements, than would have been possible through the use of compulsory authority. Therefore, Lone Star Gas Company opposes the amendments to the Emergency Natural Gas Act of 1977 which permit allocation from the intrastate market.

The allocation section (sec. 4) was never used. If allocation occurred, a greater demand would be placed on imported fuel oil as it is the only incremental substitute fuel for those forced off natural gas because of allocation. This will make the United States more dependent on OPEC and further erode our balance of payments.

In summary, Lone Star Gas Company feels more incentive should be given to encourage development of new energy supplies, especially in areas where there have been severe shortages.

We advocate immediate additional usage of coal and nuclear energy sources. We feel delays should be minimized in developing the Atlantic Outer Continental Shelf and other frontier areas. Research and development need to continue to make other alternate energy sources available as soon as possible. However, other potential energy supplies will not be available overnight. If the natural gas industry is not repressed, it can measurably assist while other energy forms are developed to supplement our future needs.

We feel this Nation is gambling with its energy destiny and quality of life if we fail to lift restrictions on new natural gas. We think all need to realize that inordinate delays and extensive requirements placed on the energy industry are, in the end, not nearly so detrimental to industry as they are to the vast population of the United States.

Mr. KRUEGER. Thank you very much.

We now hear from our next witness, Mr. McCants.

STATEMENT OF ROBERT P. McCANTS

Mr. MCCANTS. I certainly do appreciate the opportunity to talk with you this afternoon.

My name is Robert P. McCants. I am a senior vice president of Entex, Inc., in Houston, Texas. Entex, Inc. is a natural gas distribution company serving approximately 6 million people living in 486 communities in Texas, Louisiana and Mississippi. We have about 1,100,000 active meters. We do not own intrastate or interstate pipelines but purchase our gas from 27 different suppliers. We furnish interstate gas to approximately 2 million people and intrastate gas to approximately 4 million people. For further clarification, let me say that over 99 percent of our customers are in the high priority residential and small commercial classification. On behalf of our customers we are vitally concerned about the long-range reliability of both intrastate and interstate natural gas supplies.

While Entex has strong views on many aspects of the proposed energy policy, I would like to discuss one particular point in the proposed bill which other speakers may not cover in their remarks today – that is, the distinction between large and small natural gas consumers. This is particularly important in both the prohibition of new installations and the forced conversion of natural gas consumers to another fuel. Entex does not support these proposals; but if a bill is ultimately passed by Congress including such provisions, a different level of annual consumption should be utilized.

I would propose that small customers include annual average usage of less than 3,000 Mcf per day. Large fuel-burning installations should include those using in excess of an average of 3,000 Mcf per day.

The total gas used by all small customers under this definition is a relatively small percent of the total natural gas consumed in the United States. In 1975 less than 14 percent of the total gas used in the States of Texas, Arkansas, Louisiana, Mississippi and Oklahoma was utilized by residential and commercial customers. The remaining 86 percent was consumed by large users such as electric utilities, industrial plants and chemical manufacturers. Bear in mind that among customers included in the 14 percent gas usage were commercial customers such as office buildings, hospitals and schools. Few, if any, of such customers consumed as much as 3,000 Mcf per day.

In the industrial area, we estimate that only about 3.5 percent of the total gas used is used by industrial customers with requirements of less than 3,000 Mcf per day. Thus, if we add this usage to the 14 percent used by the residential and commercial customers, we find that the millions of customers in this 5-State area using less than 3,000 Mcf per day accounted for only 17.5 percent of the total gas consumed in 1975. This pattern is confirmed by the total base requirements data for the customers of one of the major interstate pipeline suppliers serving three of these States. An analysis shows that 86 percent of that pipeline's total industrial sales were to consumers using over 3,000 Mcf per day.

Thus, if we utilize the level of 3,000 Mcf per day as the dividing point between large and small customers in this 5-state area, we would include only about 17.5 percent of the total gas consumed but about 99 percent of the total customers in the small customer classification.

In 1975 the Railroad Commission of Texas instituted a statewide hearing to determine the reasonableness of reducing or eliminating natural gas as a boiler fuel and to develop a reasonable schedule for phasing out the use of natural gas as a boiler fuel in Texas. In my testimony to the Railroad Commission in this docket I reported the results of a study made by Entex on gas sales in Texas. This study revealed that large boiler fuel consumers using over 3,000 Mcf per day accounted for 96 percent of the boiler fuel consumed in the State. Yet in total they comprised less than 5 percent of the boiler fuel consumers.

This analysis showed the 3,000 Mcf per day to be a logical point of division between large and small customers. After extensive hearings on the merits of many alternate proposals, the Commission established usage of 3,000 Mcf per day as the division point between customers who would be required to convert to other fuels and those who would not. This corresponds generally to the priority of service categories 1, 2, 3 and 4 established by the Federal Power Commission in their General Policy Statement.

I believe that any consideration of the conservation of natural gas should take into account the ultimate cost to the consumer for such conservation or for the conversion to another fuel. Studies of boiler conversion cost show that the conversion of small boilers costs substantially more on a per Mcf conserved basis than the conversion of large boilers. Thus, the ultimate cost to the consumers for conversion of small boilers would be disproportionate to the actual conservation results achieved.

In addition to the cost factor, consideration must be given to other aspects of forced conversion. A substantial number of office buildings, hospitals, hotels and other commercial buildings utilizing between 1,500 and 3,000 Mcf per day were so constructed that they can be served only by natural gas. There are seven such customers just in Houston. Available space will not allow for the substitution of coal. When you consider that 1,500 Mcf per day is equivalent to 22,000 tons of coal, the problems of delivery of coal by truck into Washington are enormous. One alternative for these buildings would be the use of electricity if they are denied natural gas. They could be converted to electricity, but this would require the consumption of three times as many Btu's of basic fuels and would completely negate any conservation effort.

The use of 3,000 Mcf per day as a point of division between large and small customers is logical. It has been utilized by the Federal Power Commission, the Texas Railroad Commission and other regulatory bodies. Of course, the 3,000 Mcf per day is an arbitrary level, but it is close to the maximum size of most small urban customers and is substantially less than most large customers. In section 102(7)(A) of the proposed bill the reference to size is "design capable of consuming fuel at a fuel heat input rate of 100 million British thermal units per hour or greater." This is equivalent to 2,400 Mcf per day. In section 4992(e)(1), "taxable use" is defined as consumption in excess of 500 billion Btu's per year. For comparison, 3,000 Mcf per day is equal to 1,100 billion Btu's per year. I would recommend that throughout the proposed bill that definitions such as these should be revised to an annual average use of 3,000 Mcf per day.

Any forced conversion of natural gas consumers to another fuel will have a dramatic impact on the rates charged the ordinary residential customers. At the present time a substantial portion of the cost of service of both intrastate and interstate pipelines is borne by the large consumers. If they are forced to stop using natural gas within a short period of time, it will result in a dramatic increase in rates to the domestic consumers.

As I pointed out before, the small consumers, as I define them, used only 17.5 percent of the total gas in Texas, Arkansas, Louisiana, Mississippi and Oklahoma. It is reasonable to assume that the remaining 82.5 percent of the gas sold to the large customers carried a substantial portion of the cost of service of the pipeline companies moving the gas to the market. Thus, if these large volume sales were stopped, the small consumers would have to pick up the full burden of the cost of service rather than the fractional part they are now carrying. For example, a November 1976 analysis prepared by S. William Yost, Chief of the Bureau of Natural Gas, Federal Power Commission, showed that if the delivery of gas by interstate pipelines declined by 55 percent, that the unit fixed cost per Mcf delivered to the consumer would increase by 119 percent.

To summarize what I have said:

1. Any forced conversion, prohibition on new installations, or tax on the annual use of natural gas in the proposed bill should be limited to the relatively few larger customers, most of whom use substantially more than 3,000 Mcf per day.

2. The conversion of the large number of office buildings, hospitals, laundries and other small industries located predominately in urban areas does not make sense from either an economic or conservation standpoint. The amount of natural gas conserved by forced conversion by these users is de minimis and is greatly exceeded by the energy required to replace any such natural gas conserved.

3. The emphasis for the small user should be on conservation rather than on forced conversion. This will result in the lowest long-range cost to the consumers.

Thank you.

Mr. KRUEGER. Thank you very much.

Mr. Foy.

STATEMENT OF JOE H. FOY

Mr. FOY. Mr. Chairman and members of the subcommittee: My name is Joe H. Foy. I am president and chief operating officer of Houston Natural Gas Corporation, Houston, Texas, a corporation which operates, through subsidiaries, an intrastate natural gas transmission business. I appreciate this opportunity to appear before you and express my views on the natural gas legislation proposed by the administration.

We are entirely in sympathy with the general objectives of the administration's proposed energy policy. We believe, however, that there are some inconsistencies and inadequacies in the details of the program and that there are technical errors which unduly confuse the objectives and effects of the proposed legislation.

And we believe that one major policy change in the bill is a serious mistake. The mandatory allocation of intratate natural gas under section 416 of the bill should be eliminated.

Our company supported the adoption of the Emergency Natural Gas Act of 1977. By virtue of that act and the 60-day emergency sale provisions of the Federal Power Commission's rules, we were able to make available a total of 23.7 billion cubic feet of gas to interstate customers during the four months which ended February 28, 1977. Cooperation from gas suppliers like our subsidiary, Houston Pipe Line Company, enabled a crisis to be confronted and disaster to be avoided. Our ability to meet the crisis was possible largely because of the flexible voluntary arrangements that could be quickly entered into under the provisions of the Emergency Natural Gas Act.

It would be a mistake to depart from this structure, which worked so well last winter. A mandatory system of controls cannot operate nearly as efficiently or quickly as pipeline companies voluntarily cooperated under section 6 of the Emergency Natural Gas Act. We recommend, therefore, that the legislation simply authorize voluntary sales by intrastate pipeline companies in interstate commerce, without jurisdictional consequences, for periods not to exceed 6 months and at prices which do not exceed the seller's weighted average cost of gas plus a 15 percent markup which would attract sales and make them compensatory.

The balance of my remarks will relate to pricing of natural gas. The administration was wise not to propose an immediate, total deregulation of new natural gas. Because of redetermination clauses in most intrastate supply contracts that would be triggered by unrestrained bidding for new gas supply, immediate deregulation of new gas would result in severe economic dislocations in the intrastate markets.

The gas legislation adopted by this Congress should provide certainty as to the price levels at which old gas can be sold, with safety from potential refunds, a fair price for new gas, with flexible adjustment provisions for the future, and an ultimate deregulation of new gas, based upon appropriate findings by the President after a reasonable period of time, but subject to a veto by either House of Congress.

The proposed bill does not meet all of these criteria.

With respect to old interstate gas, the proposed legislation would apparently carry forward the ceilings heretofore fixed by the Federal Power Commission; however, it fails to protect producers who charge no more than the ceiling price against refund obligations which could arise out of pending litigation.

With crude oil pricing policy not yet formally settled, the ceiling price for new gas under the proposed legislation is not clearly ascertainable. It would be preferable to use the standard of the Btu equivalent of upper-tier domestic crude. That standard would produce a price close to $2 per MMBtu, which is the approximate level that had been attained for intrastate gas at the wellhead through the operation of a free market. It is a clear and simple standard and it would not have an undue effect on overall price levels in either interstate or intrastate commerce.

What has happened to this country demonstrates well the prescience of the eloquent dissent of Justice Jackson in the *Hope Natural Gas* case in which he pointed out that in order to prevent the undue stimulation of demand to natural gas by industrial consumers and in order to stimulate the exploration and production of natural gas, prices had to be allowed which would attract the natural gas and pull it from the ground.

But we must base our policies of today upon the situation as we find it today. We are concerned that there are simply too many dollars that will be chasing the limited supply of natural gas that is available for an immediate total deregulation to occur. Therefore we think the administration was wise not to propose that.

We propose instead a phased deregulation which would impose some limits on the price of natural gas during the phaseout period with an ultimate authority in the President subject to a one House veto and upon appropriate findings by the President that regulation is no longer necessary to terminate the regulation of natural gas.

We think the gas legislation adopted by this Congress therefore should apply a ceiling price to new gas during a phase-out period.

Apparently no one is satisfied with the definition of "new natural gas," as provided in the proposed bill. It is arbitrary and it is unrelated to any relevant geological criteria. As an alternative, it would be entirely sensible and practical to define new natural gas as that which is produced from a reservoir discovered after April 20, 1977, or after the effective date of the act or some other date certain.

The same techniques could be used in applying the definition to new production as were applied with success for many years by the Texas Railroad Commission in the application of its discovery allowable provisions. The administration of this proposed definition, which is based on a sound geological principle, would be no more difficult than the ascertainment of the arbitrary distances fixed by the proposed definition. It would add a great deal of credibility to the regulatory process among explorers and producers if the definition were based on a sound geological concept rather than upon arbitrary distance or depth measurements.

I am unable to determine from the language of the proposed bill what price should be paid to producers for old intrastate gas. The term "contract price" in section 405 could mean the original contract price, the price in effect by redetermination as of the effective date of the bill, or the price which may become effective through redetermination from time to time hereafter. Section 412(c) does not clarify the situation, since it does not reach redeterminations which, under existing contract clauses, would cause gas prices to rise as the price of fuel oil increases.

Section 408(d) of the proposed bill does not clearly state the apparent intention of the draftsman. The provision would allow the President to "establish maximum lawful prices applicable to new sales of natural gas by any ther person other than a producer if he determines that such orders are necessary to prevent circumvention of the pricing policies prescribed in sections 404 through 408."

If it is meant by this language to prevent the operation of any artifice, scheme or deceptive contractual arrangement to avoid the

limitation imposed on wellhead prices, the legislation should clearly so state. If some other objective is intended, that objective should be laid out clearly for congressional debate. The scope and meaning of such a broad grant of power should not be left to speculative administrative or judicial interpretation.

Like my brethren here, I do not believe that the incremental pricing provisions of section 414 should be adopted. If there were to be no ceiling on new gas, it would be arguable that incremental pricing is necessary to protect domestic customers against excessively high price levels. Where ceilings are provided for new gas, presumably at reasonable levels, it is a useless burden for pipelines and distributors to be forced to allocate any increase in cost to the low priority customers. The same protection that was formerly sought by incremental pricing is afforded by the imposition of a reasonable ceiling on the price of new gas.

The effect of section 414 on intrastate pricing is unclear. In most cases, new intrastate gas would be priced lower than the previous, unregulated level. However, as I pointed out earlier, old intrastate gas could – and probably would – rise in cost as a result of redeterminations triggered by increases in fuel oil price levels. Imposing an incremental pricing burden as a result of increases in the cost of old gas, which the pipeline is powerless to prevent, would seem to be the result of an oversight.

I will close with a brief reference to the end-use tax on industrial customers and its relationship to pricing. Low priority sales of natural gas began principally as a load balancing device for the pipelines. Large fixed costs are incurred in permitting pipelines to meet the peak demand of domestic customers who will use much less gas on an average day than on a peak day. In our system it is about five times as much on a peak day as on an average day for the domestic customer.

In order to achieve a more even distribution of pipeline usage throughout the year, low priority customers, with relatively constant demands, were added. The addition of these low priority customers for this purpose received the universal approval and encouragement of State and Federal regulatory commissions.

There is adequate incentive for a low priority customer to begin the process of converting to other fuels. Curtailments on the interstate lines and State regulation of intrastate companies, coupled with higher gas prices, will accomplish the desired result as rapidly as it can feasibly be achieved. When a pipeline loses a part of the industrial sales revenue that formerly assisted it to recoup a portion of its fixed costs throughout the year, the fixed costs will remain. The pipelines will need to collect more revenue from industrial customers who do not convert in order to recoup those fixed costs. The imposition of the industrial user tax would foreclose, to an undesirable extent, the ability to collect those additional revenues. As a result, pipelines would suffer an unfair burden with no benefit to anyone.

There are industrial users which should not be classified as low priority for any purpose. These include heat treating, glassmaking, can manufacturing and petrochemical manufacture, all industries which cannot practicably use another fuel or feedstock. To lump

these indiscriminately with boiler fuel customers in the imposition of a user tax would needlessly increase the cost of their products to the consumer without accomplishing the cessation of a wasteful use.

We intend these comments to be helpful and constructive, and are ready to offer, at the appropriate time, more detailed suggestions in the effort to achieve a sound, consistent and clear legislative product.

Mr. KRUEGER. Thank you, Mr. Foy. The Chair at this time recognizes Mr. McCollam.

STATEMENT OF WILLIAM McCOLLAM, JR.

Mr. MCCOLLAM. Mr. Chairman, my name is William McCollam, Jr., and I am president of New Orleans Public Service Inc. I am appearing here today on behalf of the Edison Electric Institute.

The institute is the principal national association of investor-owned electric light and power companies in the United States. Its members serve 99 percent of the investor-owned segment of the industry and over 77 percent of all users of electricity in the country. The Institute appreciates the opportunity of presenting this statement to the Subcommittee on Energy and Power. I might add, however, my company is one of those companies in the membership that is also a combination electric and gas company.

Gentlemen, my remarks will be brief and restricted to the natural gas pricing provisions in part D, sections 401-416 of H.R. 6831. What you have before you is a proposal which, as others have said, attempts to cure the regulatory sickness that has so long afflicted the interstate gas market merely by allowing the regulated price to rise slightly. Further, this proposal would infect the intrastate market, the only remaining healthy market, with the same disease of overregulation based on unsound economic assumptions that plagues the interstate market.

One of the purposes of part D of the National Energy Act is stated to be a reduction in the demand for natural gas and an increase in the supply. It is true that there is a level at which increased prices of natural gas will effect a reduction in demand because available alternatives are more economical; however, the price levels proposed in this legislation do not even fully match the price of oil, therefore there is very little likelihood of their achieving much, if any, reduction in demand. What is needed to achieve the maximum reduction in demand is to remove price regulation entirely and permit prices to seek their market level. Such action should not cause a major disruption to the domestic economy since the price of gas under existing contracts would not be affected.

Insofar as the purpose of increasing the supply is concerned, that can only be achieved through adequate incentives to explore for and produce natural gas. Except for the fact that the proposed prices for gas are permitted to increase slightly above those which are presently authorized, there is nothing to justify the assumption that these prices will provide the incentives to do what is necessary to increase the supply to the maximum level sought. At the same time by proposing extension of Federal price regulation to the intrastate gas market, particularly below current market levels, the proposed

act would in effect discourage production of additional supplies of natural gas.

Gentlemen, we believe that it is imperative that two principles be carried forth in this proposed legislation:

1. Allow field prices of natural gas to reach their competitive market level; and

2. Do not extend Federal regulation to the intrastate market.

With regard to field prices, despite the superior characteristics of natural gas, domestic prices of this fuel have been held by the Federal Power Commission to a fraction of the price of substitute fuels. This resulted in a paradoxical situation in that while the government engages in this supply-limiting action, serious consideration is given to the importation of natural gas at substantially higher prices, thus illustrating the contradictions in current and proposed regulatory prices.

Natural gas prices and the prices of gas manufactured from petroleum liquids or coal and liquefied gas imported from abroad should be freed to reach market clearing levels, thereby encouraging exploration for new reserves and stimulating development of new sources of supply. Permitting market forces to work is certainly a better solution than to continue the counterproductive regulation of gas prices and thereby the arbitrary allocation of supplies.

With regard to the extension of Federal regulation to the intrastate market, intrastate gas purchasers earnestly believe that an extension of Federal regulation to the intrastate market would serve no useful purpose and would have a damaging effect on total efforts to deal with the deepening energy crisis.

The extension of Federal regulation to the intrastate market would not add a single Mcf of new gas supply at this time of severe shortage. Rather, such regulation would dampen the enthusiasm of producers in gas-producing States to find the expensive new supplies which would provide a badly needed increment to domestic reserves. Higher intrastate prices are stimulating new exploratory activity and resultant new reserve development at the present, and any regulation which makes such activity less attractive could not come at a worse time for meeting the Nation's total energy needs.

It is recognized that there is considerable concern that deregulation of natural gas prices will result in excessive profits for producers. The way to guard against this, after price deregulation, is to require the reinvestment in exploration and production of all earnings considered to be excessive or the payment of such excess earnings in taxation.

Finally, section 414 of the proposed National Energy Act would require industrial and large commercial users to bear the full burden of increased gas costs and freeze gas costs to residential and small commercial customers. It is unanimously agreed that natural gas is a premium fuel. That being the case, all users should bear the full cost of their use of such fuel. In the event it is considered necessary or desirable to assist certain users who cannot sustain such cost, that assistance should be provided through welfare programs supported by taxation and not through tortuous adjustment of the pricing structure of such fuel.

We also would call attention to the fact that existing consumers of natural gas, residential, commercial and industrial, have incurred considerable capital expense in purchasing and installing facilities to utilize that gas. To expect large commercial and industrial users to subsidize continued use of natural gas by residential and small commercial users is unjust, but to require those same large users to subsidize new residential and small commercial gas users is unconscionable.

If the incremental pricing contemplated in this proposed legislation drives large commercial and industrial customers out of the natural gas market, then the resulting load factor imbalance will drive up the price of natural gas to residential small commercial users unnecessarily.

There are a number of other provisions in ths proposed legislation which represent serious problems for our industry and our customers, and we hope to have the opportunity in subsequent hearings to address these matters.

Mr. KRUEGER. Thank you, Mr. McCollam. The chair now recognizes Mr. Donkin.

STATEMENT OF GEORGE L. DONKIN

Mr. DONKIN. Initially, I would like to thank the chairman and other members of the subcommittee for inviting me to appear before you today to present testimony dealing with the characteristics of the intrastate natural gas market. As you know, President Carter's energy proposal contemplates extending Federal price jurisdiction to all new gas purchase contracts entered into by independent producers subsequent to April 20, 1977. In my view, this represents a far superior option to the alternative—which has been suggested by others—of permitting new gas to be sold in a totally unregulated setting. By regulating the price of all new field sales, interstate pipelines will be better able to effectively compete for new onshore reserves as they are brought onto the market, and the nation's natural gas consumers will be afforded some degree of protection against the exorbitant, monopoly price levels which currently prevail in the unregulated intrastate sector.

All that deregulation will accomplish is that the interstate market will obtain a larger slice of the existing pie, but at substantially greater and unconscionable costs.

To illustrate, deregulation has always existed in over 50 percent of the natural gas market in Texas. One would assume, therefore, that as a result of the nearly 1,000 percent increase in field prices in Texas during the 1970's, that total statewide production reflect similar significant increases. This, however, has not been the case. As shown in table 1, during the period 1971-1975, the share of Texas gas production for intrastate use rose from 53 percent to 61 percent, while total production actually declined by 13 percent.

To further illustrate the severity of the problem nationwide, in recent years, interstate pipelines have been able to acquire less than 10 percent of all new reserves additions, and the bulk of those contracted new supplies have come from the Offshore Federal Domain.

The testimony in the 1973 Permian Basin Area Rate proceeding best reflects the plight of the interstate gas pipeline industry. One witness described the situation as follows:

"Indeed, the possibility of an interstate pipeline contracting for large long-term reserves in the Permian Basin has virtually disappeared."

Similarly, a witness appearing on behalf of the Transwestern Pipeline Company testified that:

"The interstate purchaser has virtually no chance of obtaining additional reserves in competition with an intrastate purchaser."

Although during the early 1970's, intrastate purchasers in our major producing regions had begun to outbid the interstate pipelines for most new onshore supplies, the absolute price differentials observed in the two markets was not more than 2-10 cents per 1000 cubic feet (Mcf). That situation changed dramatically subsequent to the Arab oil embargo in 1973. For example, in December of 1973, the average cost of all gas purchased by the Lo-Vaca Gas Gathering Company—the largest intrastate pipeline in Texas—was 37.9 cents per Mcf. By January of last year, Lo-Vaca's total system purchases had increased to $1.658 per Mcf. Other intrastate pipelines in Texas have experienced similar purchased gas cost increases.

The impact of these recent escalations in intrastate gas costs was detailed last August in hearings before the House Subcommittee on Oversight and Investigations. One witness from Texas described the severe impact of these price increases on fixed income families (largely the elderly) and small businesses, as well as the number of bankruptcies that had occurred in his community.

Similarly, the President of the Texas Corn Growers Association testified that during a recent 29-month period, the higher cost of gas had placed the farmer in Texas at "the point of nonprofitability."

While it is clear that the immunity from Federal price controls of gas sold in the intrastate market has created severe hardships for the interstate gas pipeline companies in general and for natural gas consumers in both the producing States and elsewhere in particular, what has not been so obvious, perhaps even unknown to some, is the fact that in most States, the buyers of intrastate gas are to a large extent dominated by the natural gas producers.

Thus, the intrastate buyers have been in a unique position to manipulate the so-called intrastate "market price," which they have then used to support their pleadings for higher prices at both the FPC and in hearings such as this before the Congress.

To illustrate, in April of 1975, the Wall Street Journal reported: "An intrastate price in Texas of nearly $2 per thousand cubic feet."

This account related to a Southwest Texas sale by Consolidated Oil & Gas Inc., Southern Union Production Company and Texas Oil and Gas Corporation. The purchasers of the gas to be sold at this record price were identified as Gulf Oil, Continental Oil and the Delhi Pipeline Company, a wholly owned affiliate of Texas Oil & Gas, one of the three sellers.

The FPC, in developing its pricing policies for interstate gas sales, has often looked for guidance to comparable intrastate price levels. The producers, being rather sophisticated fellows, recognize this.

Consequently, in view of the fact that the intrastate buyers are themselves sellers, it would be naive to assume that the $2 intrastate sales price was reflective of competitive, arms' length negotiations.

I have prepared exhibit A, which I request at this time be made a part of this record, to show the extent to which natural gas producers are involved as buyers in the intrastate gas market. Schedule I of that exhibit shows that, in most instances, the intrastate buyers of new gas in 1971 and 1972 were affiliated with firms engaged in natural gas producing operations.

Schedule II of my exhibit shows that in 1973, producer affiliates operated the pipelines which accounted for 86.9 percent of the total natural gas resold to industrial consumers within Louisiana and that affiliates of Texaco, Continental Oil, Exxon, Pennzoil and Union Texas Petroleum—each of which are major producers and sellers of natural gas to interstate pipelines—accounted for nearly 81 percent of total Louisiana industrial sales.

Similarly, schedule III of the exhibit reveals that in 1973, 27 petroleum companies—whose total domestic natural gas sales accounted for 33.5 percent of all U.S. production—sold 51 percent of their intrastate gas to other petroleum companies.

As an example of the potential for abuse if intrastate gas sales are permitted to take place without price controls, in January of 1976, the Houston Pipeline Company, the third largest intrastate pipeline in Texas, purchased 40 Bcf of gas at an average cost of $1.495/Mcf. 13.2 Bcf (33 percent) of Houston Pipeline's total purchases that month were from corporate affiliates, such as HNG Oil Company, at an average cost of $1.672/Mcf. Thus, Houston Pipeline's total purchases from unaffiliated producers averaged only $1.408, or about 84 percent of the price the company paid under its gas purchase agreements with affiliates.

In marked contrast to the Houston Natural experience, the Lone Star Gas Company purchased 45.3 Bcf of intrastate gas that month at an avergae cost of $1.101/Mcf. Lone Star paid its affiliates 82.4 cents/Mcf for 4.1 Bcf (about 9 percent of Lone Star's total supply), as opposed to the 37 percent higher cost of $1.129/Mcf it paid to unaffiliated producers.

In conclusion, I would like to add that Congress clearly may direct either the FPC or the new Energy Administration to commence price regulation of these sales. This power emanates from the Constitution and has been confirmed by a history of Supreme Court decisions.

The thrust of the legal arguments may be best summarized by referral to Justice Jackson's colorful and frequently cited phrase:

"If it is interstate commerce that feels the pinch, it does not matter how remote the operation which applied the squeeze."

During the course of the Permian II Area Rate proceeding in 1973, the Presiding Law Judge concluded as follows:

"The record here shows that regulation of the intrastate aspects of producer sales of natural gas would result in more effective regulation of the natural gas industry based upon the principles of consumer protection balanced against setting a just and reasonable return to the producers . . .a better example of the adverse effect upon regulation of interstate commerce by action of an unregulated portion of the market would be difficult to find."

Had the FPC adopted Judge Litt's suggestion then and asserted price jurisdiction over intrastate gas sales, perhaps the severity of our recent supply shortages and their concomitant human and economic impacts would have been significantly reduced, if not eliminated entirely. Hopefully, the Congress will at this time accept the challenge and close the regulatory gap which has so effectively undermined the ability of the FPC to adequately regulate the natural gas producing industry in the past.

[Mr. Donkin's prepared statement follows:]

CONGRESS OF THE UNITED STATES

SUBCOMMITTEE ON ENERGY AND POWER

Of The

COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE

Testimony of

GEORGE L. DONKIN

Washington, D.C.
May 13, 1977

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Initially, I would like to thank the Chairman and other members of the Subcommittee for inviting me to appear before you today to present testimony dealing with the characteristics of the intrastate natural gas market. As you know, one of the purposes of President Carter's proposed energy legislation is --

> To bring the natural gas market back into better balance by reducing the demand for natural gas and increasing the supply through the establishment of an incentive based pricing approach for new natural gas, wherever it is used, that moderates producer revenues and protects consumers by moving toward a commodity value price ceiling (emphasis added).

The President's natural gas policy proposals are, in part, based upon the recognition that --

> Increasing amounts of higher priced gas and wasteful industrial and boiler fuel uses have moved to the intrastate market, resulting in growing critical shortages in the interstate market of the fuel which provides 30 percent of the nation's energy.

In brief, President Carter is recommending that the Congress remove the disparity that currently exists between sales by independent producers to interstate pipelines, which have been regulated by the Federal Power Commission since 1954, and sales to intrastate purchasers, which are now immune from Federal price controls. This is to be accomplished

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by extending Federal price jurisdiction to all new gas purchase contracts entered into by independent producers subsequent to April 20, 1977. In my view, this represents a far superior option to the alternative -- which has been suggested by others -- of permitting all new gas to be sold in a totally unregulated setting. By regulating the price of all new field sales, interstate pipelines will be better able to effectively compete for new onshore reserves as they are brought onto the market and the Nation's natural gas consumers will be afforded some degree of protection against the exorbitant, monopoly price levels which currently prevail in the unregulated intrastate sector.

Deregulation of both markets is simply not the answer to this nation's deteriorating gas supply situation. This is because the natural gas producing industry is not workably competitive. The real problem lies in the speculative expectations of producers that even higher price increases than those realized during the past 3 - 4 year period will be obtained in the event all new gas is deregulated -- either through Congressional action or through administrative processes at the FPC or some future energy agency. All that deregulation will accomplis is that the interstate market will obtain a larger slice of the existing pie, but at substantially greater and unscionable costs.

To illustrate, deregulation has always existed in over 50 percent of the natural gas market in Texas. One would assume, therefore, that as a result of the nearly 1,000 percent increase

in field prices in Texas during the 1970's, that total statewide production reflect similar significant increases. This, however, has not been the case. As shown in Table 1, during the period 1971 - 1975, the share of Texas gas production for intrastate use rose from 53 percent to 61 percent, while total production actually declined by 13 percent.

Table 1

TOTAL VOLUMES OF TEXAS GAS# SOLD INTRASTATE AND INTERSTATE

	Total Texas* Gas Marketed MMCF	Total Texas* Gas Exported MMCF	% Exported	Total Marketed* Texas Gas Sold In Texas MMCF
1971	7,923,707	3,734,367	47	4,189,340
1972	7,994,504	3,508,134	44	4,486,370
1973	7,811,695	3,282,821	42	4,528,874
1974	7,525,095	2,975,044	40	4,550,051
1975	6,891,907	2,656,374	39	4,235,533

* From Railroad Commission of Texas, Oil and Gas Division Annual Report.

\# Gas well gas and casinghead gas.

To further illustrate the severity of the problem nationwide, during the period 1964 - 1968, interstate pipelines obtained approximately two-thirds of all new reserves additions in the lower 48 states. More recently, however, interstate pipelines have been able to acquire less than 10 percent of all new reserves additions, and the bulk of those contracted new supplies have come from the Offshore Federal Domain, which is, by definition, subject to the jurisdiction of the FPC.

During the second Permian Basin Area Rate proceeding, which took place in 1972 and 1973, the interstate pipelines operating in that area participated as a unified group. In their initial brief to the Presiding Law Judge, the pipelines stated the following:

-- In recent years, interstate pipelines have been able to replace only a fraction of annual production from the Permian Basin with new reserves additions; and

-- The interstate and intrastate annual contracted volume ratio in the Permian Basin, has shifted dramatically from 76 percent to the interstate market in 1966 to 97 percent to the intrastate sector in the first half of 1970.

The testimony in that proceeding of the Natural Gas Pipeline Company of America witness best illustrates the plight of the interstate pipeline industry. That witness testified that:

-- Natural's attempts to purchase gas have been continually and increasingly frustrated because of Natural's inability to effectively compete with intrastate pipelines; and

-- Indeed, the possibility of an interstate pipeline contracting for large long-term reserves in the Permian Basin has virtually disappeared.

Similarly, a witness appearing on behalf of the Transwestern Pipeline Company testified that:

-- The interstate purchaser has virtually no chance of obtaining additional reserves in competition with an intrastate purchaser.

The El Paso Natural Gas Company provides an interesting case in point. Measured in terms of existing throughput

capacity, El Paso is one of the Nation's largest natural gas pipelines, serving markets throughout the Southwest and a large portion of Southern California. Between 1958 and 1967, El Paso's new reserves additions averaged 1.57 trillion cubic feet (TCF) annually, which closely approximates its annual requirements. More recently, however, El Paso has only been able to acquire, on average, 253 billion cubic feet (BCF) per year and in 1976, the Company's new reserves additions fell to 155 BCF.

Symptomatic of the problem now facing the interstate gas pipeline industry is El Paso's current proposal before the FPC to abandon and sell to Sohio a significant portion of its existing gas pipeline capacity between Texas and California. If approved, those facilities will be converted by Sohio from natural gas service to the transportation of Alaskan crude oil to Midland Texas, where it would then connect to existing crude lines supplying refineries in the Midwest. The justification for this proposal, according to El Paso, is a lack of sufficient reserves to support the existing gas pipeline, a problem which has been greatly exacerbated by El Paso's inability to compete with the intrastate market in its traditional supply areas in the Permian and Anadarko Basins of New Mexico, Texas and Oklahoma.

Although during the early 1970's, intrastate purchasers in our major producing regions had begun to outbid the interstate pipelines for most new onshore supplies, the absolute price differentials observed in the two markets was not more than 2 - 10 cents per thousand cubic feet (MCF). That situation changed dramatically subsequent to the Arab Oil embargo in 1973. For example, in December of 1973, the average cost of all gas purchased by the Lo-Vaca Gas Gathering Company -- the largest intrastate pipeline in Texas -- was 37.9 cents per MCF. By January of last year, Lo-Vaca's total system purchases had increased to $1.658 per MCF. This situation has arisen largely as a result of the increasing industrial demands in the major producing states, where natural gas is virtually a perfect substitue for fuel oil -- whose price has to a great extent been established by the OPEC cartel -- or is used as a feedstock in the manufactur of petrochemicals and fertilizers. In other words, so long as natural gas is available at a cost which is less than the price of alternative fuels, which has risen to in excess of $2.50 per million BTU in recent months, industrial firms and electric utilities in the Southwest will still prefer natural gas, regardless of the absolute magnitude of its cost. Moreover, given that the cost of new supplies is rolled in with the cost of older, lower-priced gas, the intrastate pipelines will remain able to market all of the gas they can acquire until the average cost of all gas purchased rises above the price of competitive fuels. Thus we find, for example,

during the fourth quarter of last year, the weighted average price per MCF under all new instrastate sales contracts was $1.80, with a high of $2.33 and 70.5 percent of all new intrastate sales taking place with prices ranging between $1.50 and $2.00 per MCF.

The impact of these recent escalations in intrastate gas costs was detailed last August in hearings before the House Subcommittee on Oversight and Investigations. At those hearings, Mayor Edwin L. Faust of Grey Forest, Texas described "the truly devastating effect of unregulated gas prices" on the South Texas region. Mayor Faust testified that the price of gas paid to producers by his community's gas utility had increased from 23 cents/MCF in December of 1972 to $2.06/MCF in April of last year and that during this same period, retail rates rose from $1.13 to $3.42/MCF. Mayor Faust further detailed the severe impact of these price increases on fixed-income families (largely the elderly) and small businesses, as well as the number of bankruptcies that had occurred in Grey Forest.

Similarly, the impact of greatly enhanced natural gas prices on agriculture in Texas was described by several small farmers. For example, the President of the Texas Corn Growers Association testified that during a recent 29-month period, the cost of gas to operate irrigation pumps rose 783 percent and that higher

natural gas prices had placed the farmer in Texas at "the point of nonprofitability".

While it is clear that the immunity from Federal price controls of gas sold in the intrastate market has created severe hardships for the interstate gas pipeline companies in general and for natural gas consumers in both the producing states and elsewhere in particular, what has not been so obvious, perhaps even unknown to some, is the fact that in most states, the buyers of intrastate gas are to a large extent dominated by the natural gas producers.

Therefore, the first and foremost step which must be taken in order to make the system workable is to eliminate the intrastate exemption which producers are now able to use as a leverage device in the interstate market. The typical procedure in recent years has been for gas producers to whipsaw interstate prices to higher levels on the basis of the highest prices that have been paid in unregulated intrastate markets. Thus, the intrastate buyers have been in a unique position to manipulate the so-called intrastate "market price", which they have then used to support their pleadings for higher prices at both the FPC and in hearings such as this before the Congress:

> e.g., Producer X buys gas in the intrastate market from another producer, Y, at a high price (perhaps X uses this gas as fuel in his oil refinery). Then X and Y both turn to the interstate market (and to the FPC) and say, "Look at the high price level that has been established in the intrastate market; it's only reasonable that interstate prices keep pace."

To illustrate, in April of 1975, the Wall Street Journal reported the following:

> The intrastate price for natural gas in Texas is approaching $2 a thousand cubic feet, about four times the highest price for gas sold in interstate markets.

This account related to a Southwest Texas sale at $1.89/MCF by Consolidated Oil & Gas Inc., the operator in a joint venture with Southern Union Production Co. and Texas Oil and Gas Corp. The purchasers of the gas to be sold at this record price were identified as Gulf Oil, Continental Oil and the Delhi Pipeline Co., an intrastate Texas pipeline which is wholly owned by Texas Oil & Gas, one of the three sellers.

The FPC, in developing its pricing policies for interstate gas sales, has often looked for guidance to comparable intrastate price levels. The producers, being rather sophisticated fellows, recognize this. Consequently, in view of the fact that the intrastate buyers are themselves sellers, it would be naive to assume that the $2.00 intrastate sales price

was reflective of competitive, arms-length negotiations. The three buyers of the gas in this instance -- Gulf, Conoco and Texas Oil and Gas -- account for about ten percent of all sales by domestic producers to interstate pipeline companies. Since in various area and nationwide rate proceedings, these producing companies have often attempted to justify higher regulated prices by showing that comparable rates have been paid in intrastate markets, they obviously have a vested economic interest in enhancing the so-called "free-market" price. This is particularly so when, as at present, there are other potential buyers in the same general area, to whom the producer may subsequently sell his own gas production at the new and higher price.

This example of Gulf, Continental and Texas Oil & Gas bidding up intrastate prices in concert with their hopes of obtaining greater revenues for their own natural gas production is not peculiar solely to the Southeast Texas area. In Louisiana, for example, four of the largest intrastate pipelines are owned by Exxon, Texaco, Conoco and Union Texas Petroleum. Elsewhere in Texas, Phillips, Pennzoil, Amoco, Atlantic Richfield, Coastal States Gas Producing Co. and Houston Natural Gas have all been active purchasers of new intrastate gas supplies.

I have prepared Exhibit A, which I request at this time be made a part of this record, to show the extent to which natural gas producers are involved as buyers in the intrastate gas market. Schedule I of that exhibit presents a listing of intrastate purchasers, by FPC pricing area, who entered into new gas purchase agreements in 1971 and 1972. Inspection of this listing reveals that, in most instances, the intrastate buyers were affiliated with firms engaged in natural gas producing operations.

In addition to the data collected by the FPC on intrastate sales, in 1973 the Monterey Pipeline Company (a wholly owned subsidiary of Exxon) published data on the industrial customers served by intrastate pipelines in Louisiana, including total estimated 1973 gas sales to these customers. These data are summarized in Schedule II of Exhibit A.

As in the case of the FPC data, Monterey's figures show that gas purchasers in intrastate markets are often corporate affiliates of natural gas producing companies. In 1973, producer affiliates operated the pipelines which accounted for 86.9 percent of the total natural gas resold to industrial consumers within Louisiana. Affiliates of Texaco, Continental Oil, Exxon, Pennzoil and Union Texas Petroleum -- each of which

are major producers and sellers of natural gas to interstate pipelines -- accounted for nearly 81 percent of total Louisiana industrial sales. Moreover, many of these sales were actually internal transactions between affiliated buyers and sellers or sales to other petroleum companies. To illustrate, 46.7 percent of Monterey's total industrial sales were to its parent, Exxon, and an additional 7.3 percent were made to Shell, Mobil, and Allied Chemical. The Shell pipeline delivered 100 percent of its industrial use gas to subsidiaries of its parent, Shell Oil, while the Continental pipeline delivered 27.2 percent of its total industrial sales to Continental Oil Company. Finally, of the 554.8 billion cubic feet (BCF) of gas sold through Texaco's intrastate system, 31.7 percent was sold to several corporate affiliates of natural gas producing companies.

The potential of intrastate pipelines -- specifically Monterey, Sugar Bowl (Allied Chemical) and Continental -- to exert upward pressure upon regulated prices became manifest in a 1973 producer rate case at the FPC. There, the Louisiana Land and Exploration Company requested a price of 50.0 cents per MCF under a new contract with Texas Eastern Transmission Corporation. The producer attempted to justify the higher rate by referring to offers in the same area of

50.0 cents or more by Monterey, Sugar Bowl and Louisiana Intrastate. An executive of Texas Eastern stated that in 1972, Texas Eastern offered 47 cents for new gas reserves in Louisiana but was out-bid by Continental Oil's intrastate pipeline and that Continental was currently purchasing gas in Louisiana at 50.0 cents per MCF.

To illustrate that the information and data contained in Schedules I and II of Exhibit A are reflective of the general situation in the intrastate market, Schedule III was prepared. This Schedule shows that in 1973, 27 petroleum companies -- whose total domestic natural gas sales accounted for 33.5 percent of all U.S. production -- marketed 34.6 percent of their sales in the intrastate market. Moreover, these 27 firms sold 51 percent of their intrastate gas to other petroleum companies. Thus, it is clear that the dominant purchasers of gas sold in intrastate commerce are the gas producers, who have received the greatest benefit of the dramatically increased prices we have observed and are likely to continue to experience in both interstate and intrastate field markets.

As a final example of the potential for abuse if intrastate gas sales are permitted to take place without price controls,

in January of 1976, the Houston Pipeline Company, which is a subsidiary of Houston Natural Gas Company and the third largest intrastate pipeline in Texas, purchased 40.0 BCF of gas at an average cost of $1.495/MCF. Data on file at the Texas Railroad Commission reveals that 13.2 BCF (33 percent) of Houston Pipeline's total purchases that month were from corporate affiliates, such as HNG Oil Company, at an average cost of $1.672/MCF. Thus, Houston Pipeline's total purchases from unaffiliated producers averaged only $1.408,or about 84 percent of the price the Company paid under its gas purchase agreements with affiliates.

In marked contrast to the Houston Natural experience, during that same month the Lone Star Gas Company purchased 45.3 BCF of intrastate gas in Texas at an average cost of $1.101/MCF. Lone Star paid its affiliates 82.4 cents/MCF for 4.1 BCF (about 9 percent of Lone Star's total supply), as opposed to the 37 percent higher cost of $1.129/MCF it paid to unaffiliated producers.

In conclusion, I would like to add that Congress clearly may direct either the FPC or the new Energy Administration to commence price regulation of these sales. This power emanates from the Constitution and has been confirmed by a history of Supreme Court decisions wherein Congressional powers to regulate commerce have been clearly defined. For example, in the Shreveport rate case, the Court held that:

-- Congress, in the exercise of its paramount power, may prevent the common instrumentalities of interstate and intrastate commercial intercourse from being used in their intrastate operations to the injury of interstate commerce, and

-- Congress has the power to control the intrastate rates maintained by a carrier under state authority to the extent necessary to remove the resulting unjust discrimination against interstate commerce arising out of the relation between such intrastate rates and interstate rates which are reasonable in themselves.

Thus, railroad rates which were admittedly intrastate in character and under the authority of the State might, nevertheless, be revised by the Federal government because of their economic impact upon interstate commerce.

Chief Justice Stone, in United States v. Wrightwood Dairy held that Federal Jurisdiction under the Constitution is not limited to commerce among the states, arguing, in part, that:

-- (N)o form of activity can constitutionally thwart the regulatory power granted by the commerce clause to Congress. Hence, the reach of that power extends to those intrastate activities which in a substantial way interfere with or obstruct the exercise of the granted power.

The Thrust of these arguments may be best summarized by referral to Justice Jackson's colorful and frequently cited phrase:

-- If it is interstate commerce that feels the pinch, it does not matter how remote the operation which applied the squeeze.

Congress does, therefore, possess the Constitutional power to effect Federal regulation of intrastate producer sales of natural gas. It is, of course, necessary that the Congress first determine that the exemption of these sales has substantially impeded the FPC's ability to successfully carry out its regulatory responsibilities as defined in the Natural Gas Act.

During the course of the Permian II Area Rate Proceeding in 1973, the Presiding Administrative Law Judge suggested that effective federal regulation of interstate wellhead sales was being significantly undermined by the presence of a substantial unregulated intrastate market in the same area. In his initial decision, he wrote:

-- (T)he record here shows that regulation of the intrastate aspects of producer sales of natural gas would result in more effective regulation of the natural gas industry based upon the principles of consumer protection balanced against setting a just and reasonable return to the producers . . . a better example of the adverse effect upon regulation of interstate commerce by action of an unregulated portion of the market would be difficult to find.

The Commission briefly addressed these remarks in its Permian II Opinion, which established a price of 35 cents per MCF for new gas sales in the Permian Basin. There, the FPC maintained that:

-- Any gap in our interstate jursidiction is a matter of Congressional determination.

Had the FPC adopted Judge Litt's suggestion then and asserted price jurisdiction over intrastate gas sales, perhaps the severity of our recent supply shortages and their concomitant human and economic impacts would have been significantly reduced, if not eliminated entirely. Hopefully, the Congress will at this time accept the challenge and close the regulatory gap which has so effectively undermined the ability of the FPC to adequately regulate the natural gas producing industry in the past.

Schedule I
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EXHIBIT A

Intrastate Purchasers of Natural Gas from Large Producers and their Corporate Affiliation(s) with Oil and Gas Producing Companies and/or Firms Selling to Interstate Pipelines

Federal Power Commission Pricing Area/Intrastate Purchaser	Corporate Affiliate(s) Engaged in Oil and Gas Production
South Louisiana	
(1) Continental Oil Co.	Continental Oil Co.
(2) Monterey Pipeline Co.	Exxon
(3) Allied Chemical Corp.	Union Texas Petroleum
(4) Louisiana Intrastate Gas Corp.	South Louisiana Production Co.
Texas Gulf Coast	
(1) Amoco Gas Company	Standard Oil of Indiana Midwest Oil Corp.
(2) Atlantic Richfield Co.	Atlantic Richfield Co. Hondo Oil and Gas Co.
(3) Channel Industries Gas Co.	Tenneco Oil Co. Tenneco West, Inc. Tenneco Exploration, Ltd. Tenneco Offshore Co., Inc.
(4) Coastal States Gas Prod. Co.	Coastal States Gas Prod. Co. Colorado Oil and Gas Corp. Lo-Vaca Gathering Co. Nueces Industrial Gas
(5) Texas Gas Utilities Co.	SAME AS (4) ABOVE.
(6) Texas Southeastern Gas Co.	SAME AS (4) ABOVE.
(7) Lo-Vaca Gathering Co.	SAME AS (4) ABOVE.
(8) Continental Oil Co.	Continental and Gas Corp.
(9) Delhi Gas Pipeline Corp.	Texas Oil and Gas Corp. Pecos Growers Gas Co. Pecos Growers Oil Co. The Nueces Co.
(10) Dow Chemical Co.	Dow Chemical Co.
(11) Houston Pipe Line Co.	HNG Oil Co. (Houston Natural Gas Corp.)
(12) Lone Star Gas Co.	Lone Star Producing Co.
(13) Pennzoil Pipeline Co.	Pennzoil Producing Co. Pennzoil Offshore Gas Operators, Inc. Pennzoil La. and Texas Offshore, Inc.
(14) Phillips Petroleum Co.	Phillips Petroleum Co.
(15) American Smelting and Refining Company	None
(16) Goodyear Tire and Rubber Company	None
(17) Houston Chemical Co.	None
(18) Olin Corporation	None
Permian Basin	
(1) Pecos Growers Oil Co.	Texas Oil and Gas Corporation Pecos Growers Oil Co. Pecos Growers Gas Co. The Nueces Co.

(2) Pecos Growers Oil Co.	SAME AS (1) ABOVE.
(3) Delhi Gas Pipeline Corp.	SAME AS (1) ABOVE.
(4) Intratex Gas Co.	HNG Oil Co. (Houston Natural Gas Corp.)
(5) Houston Pipeline Co.	SAME AS (4) ABOVE.
(6) Dow Chemical Co.	Dow Chemical Co.
(7) Lo-Vaca Gathering Co.	Coastal States Gas Prod. Co. Colorado Oil and Gas Corp. Nueces Industrial Gas
(8) BTA Oil Producers	BTA Oil Producers
(9) Lone Star Gas Co.	Lone Star Producing Co.
(10) Pioneer Natural Gas Co.	Pioneer Production Co.
(11) Pennzoil Pipeline Co.	Pennzoil Producing Co. Pennzoil Offshore Gas Operators, Inc. Pennzoil La. and Texas Operators, Inc.
(12) Amoco Gas Co.	Standard Oil of Indiana Midwest Oil Corp.
(13) Llano, Inc.	None
(14) Texas Utilities Fuel Co.	None
Other Southwest	
(1) Arkansas Western Gas Co.	Arkansas Western Production Co.
(2) Arkansas Louisiana Gas Co.	Arkla Exploration Co.
(3) Western Gas Corp.	Southern Gas Company Excelsior Oil Company
(4) Delhi Gas Pipeline Corp.	Texas Oil and Gas Corp. Pecos Growers Gas Co. Pecos Growers Oil Co. The Nueces Company
(5) Lone Star Gas Co.	Lone Star Producing Co.
(6) Bi-Stone Fuel Co.	None
(7) Southwestern Gas P. L., Inc.	None
(8) The LBA Co., Inc.	None
(9) Coastal Chemical Corp.	None
(10) Oklahoma Gas and Electric Company	None
(11) Transok Pipeline Co.	None
(12) Reynolds Metals Co.	None
(13) Mississippi Chemical Corp.	None
(14) Mississippi Power and Light	None
Hugoton-Anadarko	
(1) Delhi Gas Pipeline Corp.	Texas Oil and Gas Corp. Pecos Growers Oil Co. Pecos Growers Gas Co. The Nueces Company
(2) Oklahoma Natural Gas Co.	Oklahoma Natural Gas Co.
(3) Oklahoma Natural Gas Storage Company	SAME AS (2) ABOVE.
(4) Pioneer Natural Gas Co.	Pioneer Production Co.
(5) Kansas Nebraska Natural Gas Company	Excelsior Oil Company Southern Gas Company
(6) Anadarko Production Co.	Anadarko Production Co. Pan Eastern Exploration Co.
(7) Phillips Petroleum Co.	Phillips Petroleum Co.

(8) Oklahoma Gas and Electric Company	None
(9) Transok Pipeline Company	None
Rocky Mountain	
(1) Amoco Gas Co.	Standard Oil of Indiana
(2) Colorado Interstate Gas Company	Coastal States Gas Producing Co. Colorado Oil and Gas Corp. Lo-Vaca Gathering Corp. Nueces Industrial Gas
(3) Koch Industries, Inc.	Koch Oil Co.
(4) Koch Oil Co.	Koch Oil Co.
(5) McCulloch Gas Processing Corp.	McCulloch Oil Corp.
(6) Mountain Fuel Supply Co.	Mountain Fuel Supply Co.
(7) Southern Union Gas Co.	Southern Fuel Supply Co. Aztec Oil and Gas Co.
(8) Cody Gas Co.	None
(9) Texas Gas Corp.	None
(10) Thomas G. Vessels	None

SOURCE: Federal Power Commission

Schedule II
Page 1 of 1

Major Intrastate Pipelines Serving Industrial Customers in Louisiana
1973

Pipeline/(Affiliation)	Col. (1) Estimated Industrial Sales 1973 (1000 Mcf)	Col. (2) Col. (1) As Percent Of Total (%)
Texaco (Texaco)	554,800	43.4
United Gas P. L. (Pennzoil)	187,975	14.7
Monterey (Exxon)	148,555	11.6
Louisiana Intrastate	78,475	6.1
Sugar Bowl Gas Corp. (Union Texas Petr.)	75,190	5.9
Continental (Continental Oil)	67,525	5.3
Ark. La. Gas Co. (Arkla Explor. Co.)	34,310	2.7
Creole Gas P. L. Corp.	23,725	1.8
La. Gas Purchasing Co.	12,775	1.0
La. Gas Prod. Co. (La. Gas Prod. Co.)	12,045	.9
Shell (Shell Oil Co.)	10,950	.9
Cities Service Co. (Cities Svc. Oil Co.)	10,220	.8
Crown Zellerbach	10,220	.8
Miscellaneous	52,560	4.1
Totals	1,279,325	100.0

Source: Monterey Pipeline Company, Map of State of Louisiana Industrial Plant Gas Consumers, February, 1973.

Schedule III

1973 Domestic Natural Gas Sales Reported
by Responding Petroleum Companies

Producer	Total U.S. Gas Sales (1000 Mcf)	Intrastate Sales (1000 Mcf)	Intrastate Sales (% of Total)	Intrastate Sales to Petroleum Companies (1000 Mcf)	Intrastate Sales to Petroleum Companies (% of All Intrastate Sales)
American Petrofina	2,216	1,700	76.7	976	57.4
Apco Oil	9,555	-0-	-0-	-0-	-0-
Ashland Oil	99,681	8,074	8.1	4,610	57.1
Atlantic Richfield	679,104	217,313	32.0	86,491	39.8
Champlin Petroleum	117,575	18,224	15.5	14,434	79.2
Cities Service	474,541	91,112	19.2	77,992	85.6
Clark Oil	2,109	247	11.7	247	100.0
Clinton Oil	191,019	90,543	47.4	52,787	58.3
Diamond Shamrock	82,168	5,094	6.2	5,094	100.0
Exchange Oil and Gas	22,605	701	3.1	313	44.7
Exxon	1,907,280	876,775	44.5	281,446	32.1
Forest Oil	247,733	70,356	28.4	70,286	99.9
General American	46,830	5,947	12.7	3,539	59.5
General Crude	38,389	31,287	81.5	30,380	97.1
Hunt Oil	108,019	756	.7	720	95.2
Kerr-McGee	130,351	2,998	2.3	1,652	55.1
Lone Star	73,907	65,703	88.9	65,703	100.0
Louisiana Land	139,943	46,041	32.9	39,872	86.6
Murphy Oil	18,542	-0-	-0-	-0-	-0-
Occidental	45,545	44,452	97.6	21,515	48.4
Phillips	680,512	133,380	19.6	60,288	45.2
Standard Oil (Calif.)	526,576	176,930	33.6	111,112	62.8
Standard Oil (Ind.)	1,313,958	575,514	43.8	298,692	51.9
Standard Oil (Ohio)	65,998	9,042	13.7	6,166	68.2
Southwest Refining	1,700	105	6.2	105	100.0
Sun Oil	352,360	128,259	36.4	81,316	63.4
Union Texas	137,424	23,912	17.4	21,927	91.7
Totals	7,578,640	2,624,465	34.6	1,337,663	51.0

Source: Responses to Survey Data Questionnaire submitted to United States Senate, Committee On Interior And Insular Affairs, Special Subcommittee On Integrated Oil Operations.

Mr. GAMMAGE [presiding]. Thank you, Mr. Donkin. I just have one brief reaction to your closing remark.

During consideration of the natural gas bill, very early in this Congress, Mr. O'Leary was giving testimony.

One of the members of the committee pointed out to him that subsequent to deregulation of fuel oil allocation and price in his particular area, that during the winter crisis, they had adequate supplies of fuel oil but after deregulation the price had quadrupled. Mr. O'Leary responded he did have an adequate amount of fuel oil available, he said, it was his opinion that had regulatory control been maintained, he would have had an inadequate supply because they couldn't regulate the logistical demands and it would have been at a higher price than they were paying because of the unhappy past experience they had.

The chairman asked Mr. O'Leary if he felt that was analogous to other fuel services. He said he felt it was; and he would have a report forthcoming to us.

However, subsequent to that, the President's Energy Report was proposed and Mr. O'Leary has not responded.

The chair at this time will give each member five minutes for questioning.

Mr. Moore?

Mr. MOORE. I wonder if I might ask a unanimous request. It seems he made some comments as to the other various representatives at the table. I wonder if I might ask unanimous consent to let each of them reply as to some of the facts or acccusations made in Mr. Donkin's testimony.

Mr. GAMMAGE. Without objection.

Gentlemen, I suppose in the order in which you testified, if you care to respond to some of Mr. Donkin's remarks, we will give you a chance for rebuttal.

Mr. NEAVES. I really don't understand how that lessens competition. In Texas, the customer gets the benefit of that lower price. The lower price we pay our affiliates is the price used to calculate the retail gate. It is beneficial to the customer under our reporting requirements. Because of those requirements it makes us pretty tough negotiators to not let that other price get higher. We battle that price pretty hard, but the customer gets the advantage of the lower price paid either the affiliate or nonaffiliate supplier.

Mr. FOY. The witness has confused the interpretation of the facts by indiscriminately lumping together pipeline and producing subsidiaries. Sales to Houston Pipe Line from IntraTex Gas Company, a gathering subsidiary in West Texas which pays a transportation tariff to Oasis Pipeline, which was approved by Texas Railroad Commission, to go to the Katy field area some 535 miles away, where the gas is resold at IntraTex's cost in the field, plus the cost incurred in transportation, constitute about one-third of Houston Pipeline's purchases.

The lumping together of transportation costs unduly confuses the issue.

In all those cases where Houston Pipeline purchases from a producing affiliate it pays no more than it pays to the other producing affiliates in the same area.

I want to clear any insinuation of dishonest or unfair treatment on the part of our company. I am unable to understand the conspiratorial thrust. I just don't agree that there has been the kind of conspiracy between producer and others as the witness feels there has been.

Mr. GAMMAGE. Mr. Donkin?

Mr. DONKIN. Initially, with respect to Lone Star, through my work in Texas, I have often heard it said that Lone Star has always honored its contracts and that Lo-Vaca has never honored one. The example in my testimony was not put in there to be critical of Lone Star. I understand there is a lot of market power in the Texas gas market and you have to pay fairly high prices.

With respect to Houston Natural, I don't know what the breakdown is between HNG sales and IntraTex sales. I am aware that HNG is a significant producer in Texas, with approximately 70 billion cubic feet per year in 1975.

Mr. FOY. Oh, no.

Mr. DONKIN. That is the figure I received from the Railroad Commission. I doubt that it would be constructive for us to debate that for the record.

Mr. FOY. It is on the order of 7 to 8 percent of our total purchases.

Mr. DONKIN. As I say, we can't debate that particular issue here.

With respect to the issue, however, and my experience with the FPC, I can relate numerous instances where consumers came to the regulatory commission recommending higher than authorized initial contract prices. In numerous instances the purchaser was a corporate affiliate. In one instance, Southern Natural Gas submitted testimony that the intrastate market supported the requested price.

When we referred to that contract, that was a contract between Chevron and a producing affiliate of St. Regis Paper Company. As it turned out, St. Regis was one of the producer applicants in the same proceeding.

Here was an example of a producer coming before the Federal Power Commission and asking them to take a look at the prices and they also happen to be a buyer; the same applicant requesting the same higher price.

Whether it is a conspiracy or not I don't think we can prove that. It is just one of the structural situations we are faced with. The intrastate pipeline companies have producing affiliates, the major oil companies are large consumers of natural gas. Monsanto this morning produced a witness and Monsanto, itself is a very large independent producer. You can't separate who the buyers and sellers are in this industry and therein lies the problem.

Mr. STOCKMAN. May we have one thing clarified on the record?

Mr. GAMMAGE. Sure.

Mr. STOCKMAN. I think Mr. Foy has given us the answer we want, but the way it came across I don't think he is speaking to it. On the top of page 14, what you seem to be saying is that gas you purchased from the affiliates reflected the transportation costs and that very easily explains the differentials.

Mr. FOY. Yes. HNG Oil Company is a very recent acquisition, therefore, most of its gas contracts are of recent vintages as to

prices more so than some of the old contracts we had. HNG prices having been fixed at more recent times of discovery would be higher than we pay, for example, to Exxon at King Ranch.

This is the difficulty with taking a variety of different numbers and just lumping them in totals, saying, "There is something wrong with what I find here."

Mr. GAMMAGE. Mr. Moore?

Mr. MOORE. Thank you, Mr. Chairman.

Mr. McCollam, I welcome you from Louisiana. It is high time we have somebody here to protect our ox. We are glad to have all of you here.

As I understand, all the testimony, all except that of Mr. Donkin, agrees essentially we should get away from the regulation of gas. Mr. Foy indicates it would produce a bad pricing situation. Is that right?

Mr. GAMMAGE. Let the record show everybody except Mr. Donkin agrees.

Mr. FOY. We don't have the vote though.

Mr. MOORE. In addressing myself to your concern, we have heard that concern before and we get into a real problem as to the cap program. There have been econometric models run as to how many trillion feet of gas will be produced at one cap or another cap.

The bill before us doesn't have a fair Btu equivalent of new gas to new oil.

I wonder if we could do something in the range of putting a limitation on the triggering of the redetermination clauses or present it or put a cap on how much they could be triggered, would that be acceptable to you in lieu of a cap?

Mr. FOY. No, sir. I don't believe that would be an adequate answer to the problem because interstate pipeline companies today are paying from three and a half to four and a half for marginal supplies. There was a reference in the Washington Post, of $3.75 per MMBtu for LNG. In a completely deregulated situation it would have a tremendous competitive advantage in bidding against an intrastate company such as mine, 90 percent of whose sales go to industrial customers and whose cost level has already reached $1.90. In other words, $3.50 would be averaged down to substantially less than that in the case of an interstate company, but in the case of intrastate, $3.50 would bring the average up to intolerable levels. I think there should be some restraint on prices bid.

Mr. MOORE. How long would you like to see this restraint placed on the market?

Mr. FOY. About 3 or 4 years.

Mr. MOORE. The Krueger-Brown bill, are you aware of the provisions in that?

Mr. FOY. Yes.

Mr. MOORE. You are not wedded to any particular Btu figure except to see that prices don't go completely out of control in this stairstep decontrol.

Mr. FOY. I would recommend about $2.04 a million Btu—this is related to upper tier crude—then I would have some flexibility in the future allowing the President to fix higher ceilings based on a consideration of the value of competing fuels, of the need to stimulate exploration and other general economic considerations.

Mr. MOORE. With the exception of Mr. Donkin, let me ask the other representatives here, do you all agree with the testimony of Mr. Foy? You would prefer immediate decontrol.

Mr. McCollam?

Mr. MCCOLLAM. We feel the preferable situation is immediate decontrol; recognizing the realities of life, we think that would be a reasonable approach, but the best solution would be immediate deregulation.

Mr. MOORE. Do you agree with Mr. Foy as to a cap?

Mr. MCCANTS. If you have complete deregulation of interstate and intrastate, you wouldn't need a cap on the gas. If you deregulate the price of the new gas, you must have a cap on the new gas.

Mr. MOORE. What would your suggestion for a cap be?

Mr. MCCANTS. I would recommend a market clearing price close to the price of intrastate gas today or slightly higher. In general, our customers or the people we deal with–

Mr. MOORE. You do no production?

Mr. MCCANTS. No, sir. We have annual revenue of about $530 million. We do have about $15 million worth of production in Oklahoma and Texas. We are predominantly a gas distribution company. We purchase from suppliers.

Mr. MOORE. Mr. Foy, can you give us a breakdown, a similar breakdown as to your company; what percent of your company is based on production and what percent on distribution?

Mr. FOY. I will give you actual figures for 1976.

Mr. MCCANTS. While he is researching that information, may I continue?

Basically, a user of fuel can afford to pay somewhere in the neighborhood of 10 to 12 percent more for gas and use it instead of oil. You pay for natural gas after you use it; you pay for oil before you use it and you have to store oil.

Mr. MOORE. You say the Btu to oil is not fair?

Mr. MCCANTS. I think the price of natural gas should be higher.

Mr. NEAVES. We have to continue supporting complete deregulation of new natural gas.

Mr. INGRAM. We are doing the same thing.

Mr. FOY. Natural gas transmission, 27 percent of total revenues, oil and production, 6 percent; industrial gases and carbon dioxide, 14 percent; coal 7 percent.

Mr. MOORE. Thank you, Mr. Chairman.

Mr. GAMMAGE. Mr. Stockman.

Mr. STOCKMAN. I think we have had a very excellent panel of witnesses and I am very distressed to know every time we have a panel who knows something about the issue, your side of the table is absent.

Mr. GAMMAGE. I am here, Mr. Stockman.

Mr. STOCKMAN. But you don't need the light.

I want to commend Mr. Foy, in particular, because he has given us some of the most enlightened comments we have had so far.

I can see why we need deregulation. But we have so distorted the market over 20 to 30 years, we will create great disturbances if we try to get out of it overnight.

Isn't it true if you have an intrastate buyer, when they have a roll-in price structure, in the first 3 or 4 years, they will be free to bid through the ceiling for the incremental new gas which they can then inject into their existing supply and you won't have the constraint a market normally will provide?

In other words, if the users had to pay that price, that is where you would get the restraint because they would pay three, four, five dollars for natural gas. But since it is going to be rolled into their existing supplies and prices there will be no demand response. Until this new gas becomes a significant part of the pipeline, you would get some very artificial bidding because of the whole framework created from the history of this program.

Is that a correct interpretation?

Mr. FOY. Yes. I might add two points: One is that in this 23 years in which the backlog of regulated gas has been created, the government and the industry have been telling potential customers to use natural gas because it is cheap. Therefore, a great dependence on natural gas has been created which locks in these customers to natural gas even though prices may change.

The other point—I forgot.

Mr. STOCKMAN. The second question you addressed was the base for the interim ceiling. I think there is serious problems with the reference base as to the administration bill, that is the weighted average of the price of domestic oil. We don't know what that is. It is very uncertain. That is one of the most pervasive complaints we hear from industry. If you want to step up, you have to give us an idea of the price. But under the tier concept, you will have five different tiers and who knows at what given point the total amount of time those will compose? Who knows what the temporary production will be? Who knows what the real field price for Alaska will be because that will depend on the transportation cost.

The only problem I have with your suggested alternative is that we will not know what the upper tier price is because as long as they are unwilling to amend and get rid of the composite price and establish tiers, if they want it on a certain basis with price escalation, you will have the same problem. What we have learned so far has been deceptive. We have seen in the last year, what has happened to the price of upper tier oil; it has fluctuated wildly, depending on the calculations of the FEC as to composite prices.

Won't it be more stable to take the world price with some discount factor; discount 90 cents or some other factor?

Mr. FOY. It seems politically infeasible to have OPEC fixing our oil prices. I seized on upper crude because we know what that is and after all, as I see it, we are only talking about an initial price anyway.

Mr. STOCKMAN. That would be an initial benchmark, then you would escalate it in relationship to general price factors in the economy?

Mr. FOY. That is right.

Mr. STOCKMAN. The other thing I wanted to ask you about was your definition of new gas. You said basically, any new reservoir of gas after a date certain.

Do we really have a concrete enough definition? In other words, in my conversations with people in the industry, I find when you are talking about the nonassociated gas, it is not clear as to what people mean by reservoir.

Mr. FOY. I think geologists and engineers could take that definition and work with it. They did for years in Texas in determining as to when the discovery allowable would be allowed, That worked very well. In fact, it might even be possible that no Federal staff would be needed; that the determination of what is new gas or what is new oil and what is not could be made by the staff of the State's conservation commission in each case.

Mr. STOCKMAN. So you are saying there is a body of case law as to what a new reservoir is and if we used those same definitions there would be no administrative problem?

Mr. FOY. I am a lawyer, not a geologist, by training. But it has been my observation those rules worked well in the Texas Railroad Commission to everybody's satisfaction.

Mr. STOCKMAN. Thank you.

Mr. GAMMAGE. Thank you, Mr. Stockman. I am going to, at the risk of repeating myself, propose a sort of statement.

I would like to get an across-the-board response from the members of the panel. I have asked this of other panels today by way of statement.

Mr. Schlesinger appeared with Mr. O'Leary before this committee yesterday and made certain statements in response to questions of mine and other members.

It was pointed out to him that back in October of last year, when the President was a candidate, letters and telegrams were sent out to persons including Governors of Oklahoma and Louisiana, in which he pledged to work with Congress for the development of oil and natural gas.

It was also pointed out when we were discussing the Emergency Natural Gas bill in the very early session of this Congress, that there was an allocation authority which really has not been discussed in depth with this panel today, which was rather innovative. It was a whole new ball game as to the inter-intrastate markets. It was Hinshaw gas traveling in interstate pipelines from one jurisdiction to another within boundaries of a certain State. It extended the authority of the Executive to that particular gas.

We were told at the time of debate on that particular bill, that the White House neither wanted nor intended to utilize that authority; they didn't approve of that definition.

In fact, Mr. Schlesinger included a letter in the Conference Committee Report.

In view of President Carter's statements of last October and Mr. Schlesinger's statement during the emergency natural gas debate, I take small comfort in the energy plan proposed. It seems rather inconsistent with the pledges of October. The allocation authority seems inconsistent with the statements of late January and early February regarding allocation and yet this particular piece of legislation includes even broader allocation authority as far as the intrastate market is concerned.

At yesterday's hearing, Mr. Schlesinger also advised, the ultimate goal was still deregulation; supply and demand had all balanced out, it was their plan to move towards an orderly deregulation of oil and gas. I take small comfort in that statement, viewing the history of previous and very recent statements. I realize consistency is a hobgoblin but I have difficulty accepting those statements in view of recent history.

We have talked about the definition of new gas, the sensitivity of new pricing and what have you. The allocation authority is distressing to me.

Mr. Foy is very popular here today. Everybody seems to be directing questions to him. I would like to ask you, Mr. Foy, how much of the U.S. total refining capacity is located in your area.

Mr. Foy. Well, about 29 percent of it is in the State of Texas. We serve a considerable portion of that 29 percent off our own system.

Mr. Gammage. Under the allocation procedure proposed, if the Federal Government forced you to give up gas for so-called high-priority users, that is, residential and small commercial consumers, doesn't that create a potential for aggravating the problem with resulting shortages of fuel oil and propane for folks who don't get natural gas because of the shortages that might be artificially created in that refining area?

Mr. Foy. I would think so to the extent the refinery is dependent on natural gas. It would also affect diesel fuel, military jet fuel, and other types of fuel upon which our country depends.

Mr. Gammage. The allocation authority creates a danger that industries, defense operations, who are not dependent on natural gas but are dependent upon fuels and energy sources that are manufactured as a result of natural gas in this refining complex, might wind up with an artificial shortage.

Mr. Foy. It raises that possibility, and it raises the possibility that an allocation order could prevent a pipeline from cooperating with its refinery customers to provide as much gas as possible into the interstate market without shutting down the refinery and therefore depriving the country of No. 2 heating oil, which is certainly necessary in those areas who don't have gas available.

Mr. Gammage. How much of the petrochemical industry is located in your general area?

Mr. Foy. I think it is on the order of 30 or 40 percent. Probably earlier witnesses gave that.

Mr. Gammage. As I recall, my figures show something like 46 percent, and if you incorporate Louisiana and Oklahoma, you come up with more than two-thirds of the entire national petrochemical-producing complex.

Mr. Foy. That is right.

Mr. Gammage. That use natural gas as a boiler fuel for processing.

Taxes on consumption which produces dollars which don't go back into production, with those, would you not increase the price artificially of products already produced by the petrochemical community?

Mr. Foy. Not only the petrochemical community but cans, glass bottles, in which groceries and other products are sold. The cost for

heat-treating is heavily dependent on the use of natural gas. A number of industries should not be included, certainly in the overall category of industries that ought to be taxed.

Mr. GAMMAGE. What we potentially have with this proposal is an unproductive—as far as the industry is concerned, as far as additional production is concerned—an unproductive, and some might argue a needless, increase in price of oil and gas in a producing State that is going to impact on the whole United States. Particularly, if you take that 3-State area in the Southwest that has at least 29 percent of the refining capacity and 46 percent of the petrochemical industry, not counting Louisiana and Oklahoma, if you count those in, it is substantially higher.

Mr. FOY. That is right.

Mr. GAMMAGE. I would like to get the response of the panel generally from one end to the other on those statements. I am particularly concerned about the allocation authority and what it might do to local communities.

Mr. INGRAM. We stated that we opposed mandatory allocation of gas in the intrastate market, because we feel we in Oklahoma have done a very good job in supplying the interstate market with emergency gas on a voluntary basis.

Mr. GAMMAGE. I might add Dr. Schlesinger yesterday said they would use that intrastate allocation authority only in the case of extreme emergency. Two months ago, they said they did not want that authority and had no intention of exercising it.

Mr. INGRAM. We don't think they should have such authority because we don't really believe that the Federal Government can allocate from one area to the other and really determine what is high priority and what is low priority use. One of our concerns would be that the government might allocate from a high priority user in the intrastate market to a lower priority user in the interstate market. It would be very hard to administer. It certainly would have an impact—we have quite a large ammonia fertilizer business, and it would have a great impact on the food industry to have their gas supply disrupted.

Mr. NEAVES. We are opposed and are fearful of that power being there, even though we are assured it might not be used. We think the industry's cooperative efforts prove that can be done, and certainly you are going to end up with higher prices to the consumers when you take natural gas away from processors where it is necessary for products and then add a tax to it.

Mr. MCCANTS. We definitely oppose any allocation power of that sort. It would make planning for the needs of our customers that much more difficult. We purchased gas both in the interstate and intrastate market, and if you have the availability of allocation rather than the free transfer, the voluntary sort of thing we had last winter, you could run into a problem where suddenly you would have to withhold allocation of gas from the low priority market that might create tremendous problems, for example, in the high-priority market.

You might have a pipeline serving, for example, electric utilities. You say you are going to take all this gas from the electric utilities and ship it to the homeowner. The electric utility might not have

adequate standby, and you would end up with a bunch of homes in that area that couldn't use natural gas in their homes. You have to take into account all of the multitude of problems that create problems for the people using the gas and the pipeline getting it. I think that cannot be done by allocation authority. I think there has to be a free interchange between two pipelines.

Mr. McCollam. Speaking for the electric utilities who have that unique problem just referred to, I would like to point out that we are moving as rapidly as we can away from the use of natural gas as a boiler fuel. I am sure coming from the State of Texas, you recognize that the electric utilities have a tremendous investment in boilers that can burn—they were originally designed only to burn natural gas. We cannot convert those existing boilers to coal, for example, without completely scrapping the boilers and starting from scratch. We have, in many instances, been forced to convert the boilers to the use of oil. In my particular company we are almost 100 percent burning oil now as a boiler fuel. There are other companies in Louisiana and Texas that are in the process of moving in that direction. It does not make sense, to answer your question, to have an allocation authority in the Federal Government which will compound the problems we already have. We are voluntarily moving in the direction of phasing out oil and natural gas. We are heavily committing the electric utility industry, particularly in the part of the country I come from and you come from, to the use of nuclear power and coal-fired generation, but that is for new units. We are heavily committed in that direction.

We have units that must be operated in order to maintain the reliability of electric service using natural gas as a boiler fuel for some time to come. We must have in effect an orderly phase-out of the use of natural gas as a boiler fuel which, in our judgment, will not be the case if this allocation authority is reposed in the Federal Government.

Mr. Donkin. I think almost all gas supply experts would agree that under the status quo curtailments of high priority uses across the country are unavoidable within the foreseeable future.

In December of last year, Mr. Gordon Zareski, who is the leading gas supply expert at the Federal Power Commission and a well recognized gas supply expert, testified before the California Assembly Subcommittee on Energy that with an extension of Federal jurisdiction to the intrastate market and gas allocation entitlements, within the foreseeable future there would be zero curtailment of high-priority uses. I think that all reasonable policy people would agree that we cannot expect an allocation procedure to take place immediately. The economic disruptions simply would not be tolerated. On the other hand, as Mr. McCollam has just indicated, within Louisiana and across the country, natural gas for relatively low-priority uses are being voluntarily phased out. That is voluntary. It is probably the case, however, that some stimulation from the Federal Government would render that phase-out more rapid, within the context of a reasonable phase-out period with allocation procedures.

Mr. Gammage. Dr. Schlesinger assured me there were tight coordinating controls at the top, but he didn't say who they were

vested in or who was going to handle them or what was going to be done. We have 3 particular pieces of legislation before us in this session of Congress that don't seem to be related to one another as far as communication is concerned and yet they are directly related as far as the overall energy problem is concerned. One is the strip-mining bill, one being the Clean Air Act, and another being the President's energy plan. If you read the strip-mining bill very carefully, it imposes a tonnage tax not based on the Btu output per ton, but the tonnage of the coal, itself. Mr. Foy and all these other Texas people here can tell you that Texas gets about half the Btu output of anthracite coal, so you literally double the cost of energy production if you burn your local domestic coal based on that tax. In addition to that, it has provisions in it that, for practical purposes, not only would greatly increase the cost of strip mining but might eliminate it altogether in some areas.

You have the Clean Air Act, the amendments to the Clean Air Act, which virtually would prohibit in areas where there is a nondegradation standard, no one-on-one tradeoff available where you cannot burn coal, you cannot convert from natural gas to anything because natural gas is the only clean fuel available, and there doesn't seem to be any coordination between these as far as the whole energy and environmental package is concerned. Yet all of these are directly energy and industry related.

We have a situation where the Texas Railroad Commission has for some time been encouraging local industries to convert from gas to other fuels, primarily coal, and many are moving in that direction as rapidly as possible. I hope they get in under the wire.

We have a situation where the executive department is promoting incentives to move in that direction. The Congress recognizes the necessity of it, and the people of the country recognize the necessity of it, but because of lack of communication and coordination within the executive department, itself, is concerned, as far as its support for these various pieces of legislation is concerned, everybody is supposed to convert to coal. Nobody can mine coal and nobody can burn coal. Where do we go from here? This is a very perplexing situation. I am not sure exactly what we are supposed to do. Will that slurry pipeline be of any use, Mr. Foy?

Mr. McCollam. Speaking for the electric utilities, I would like to echo a loud amen to what you have been saying. We have been trying to say this for the last several years. We are doing the best job we know how to phase out, as I said earlier, the use of natural gas as a boiler fuel. I happen to be looking at some statistics in front of me and, incidentally, I happen to serve as chairman of the National Electric Reliability Council, and we have rendered a report recently which shows that in 1976, about 13 percent of all the kilowatt hours were generated on natural gas as a boiler fuel. By 1985, that is going to be down to about 3 percent. We are moving in the right direction, and yet these other constraints that you have identified, these unrealistic amendments to the Clean Air Act, these unrealistic coal mining regulations, the strip-mining bill, all of these things are going to be deterrents to our achieving the very goal that this particular legislation that we are talking about now is pushing us in the direction of. We have to be more realistic in

coordinating these various requirements under the Clean Air Act, and the strip-mining bill, and also we have got to have the pipeline to transport this coal from distances in the West. We are committed to it in our area of the country. There has got to be better coordination, and I think you have hit the nail on the head 100 percent.

Mr. GAMMAGE. That anthracite will be cheaper than our lignite even with the tonnage tax, but I wonder if we can burn it when we get it.

Mr. Moore?

Mr. MOORE. I would like to ask each of the gentlemen to basically give us the average acquisition price of their gas, the most recent figures they may happen to have.

Mr. INGRAM. I can give you the Oklahoma natural average, $1.25. The highest is $1.71.

Mr. NEAVES. Our weighted average purchase price last month was $1.42, but we have new additions at $2.10.

Mr. MOORE. New additions? What do you mean?

Mr. NEAVES. Latest acquisition.

Mr. MOORE. That is not your weighted average.

Mr. NEAVES. The weighted average was $1.42 last month.

Mr. MCCANTS. At the risk of sounding like a politician again, my prices are different. We are a distributor. The prices I am quoting are the wellhead price plus the pipeline's cost of transportation to us. This is the price delivered to the city gate. Our average cost in the last 9 months was $1.60 per Mcf. In the interstate area we are paying from 96 cents to $1.02 to interstate pipelines. We are paying $1.75 to $2.01 to the intrastate pipeline.

Mr. MOORE. Are we comparing apples with apples? Did the other comments include transportation?

Mr. INGRAM. Mine was wellhead.

Mr. NEAVES. Wellhead.

Mr. MOORE. What is your wellhead price?

Mr. MCCANTS. We have no wellhead price. We purchase from the pipeline.

Mr. MOORE. Mr. Foy?

Mr. FOY. Our cost of gas fluctuates depending on whether we are able to take some low-cost supply that is available to us under older contracts. Within the past 3 months it has fluctuated in the range of $1.80 to $1.90. Our new acquisition cost is about $2.04.

Mr. MCCOLLAM. I do not have at my fingertips the information you have asked for, but I can tell you that the newest supplemental supplies of intrastate gas that we have contracted for—when I say we, I am speaking of my company, New Orleans Public Service—have been at about $1.90 per Mcf.

Mr. MOORE. That includes transportation?

Mr. MCCOLLAM. Yes. That is delivered to one of our city gates.

Our cost of gas, our weighted average cost of gas—incidentally as far as interstate gas is concerned, the United Gas Pipeline Company is our principal supplier—is expected to be in the range of $1.40 per Mcf, for the full year 1977 for our gas supply. Last year, it was lower than that, but for this year we expect it to be about $1.40, our weighted average. The 1.90 figure is for the highest recent acquisition from intrastate sources.

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[The following information was received for the record:]

WEIGHTED AVERAGE COST OF GAS

	Houston Pipe Line Wellhead Cost	Intratex Gas Wellhead Cost	Houston Pipe Line Weighted Average Cost--All Sources*
January, 1977	$1.7807	$1.7787	$1.81627
February, 1977	1.8563	1.7764	1.87650
March, 1977	1.8958	1.8078	1.91281
April, 1977	1.9601	1.8780	1.9910

*Includes transportation costs attributable primarily to purchases from Intratex Gas Company.

Mr. MOORE. Mr. Donkin, I have questions for you now. What is the basic business or enterprise of J. W. Wilson and Associates, Inc?

Mr. DONKIN. We are an economic consulting firm specializing in public utility economics and energy economics.

Mr. MOORE. Who are your clients?

Mr. DONKIN. We have a large number of clients. I would estimate between 50 and 75 over the last 3-year period. I would be happy to tell you who my primary clients are on the projects I have worked on. They are the City of San Antonio, 8 cities in Florida, the California Assembly's Subcommittee on Energy, the New York Assembly Natural Gas Task Force. Recently, I participated for the Department of the Interior in an investigation of the offshore natural gas production capacity.

Mr. MOORE. All of these are public entities you have been working for. Is that indicative of the entire clientele of your company?

Mr. DONKIN. Yes, sir.

Mr. MOORE. Not free enterprise but public interests?

Mr. DONKIN. I think there have been a very small number of private corporations but by and large most of our work is done for Federal, State and municipal governments.

Mr. MOORE. I am not familiar with how this panel was selected. How did you come to be a member of this panel?

Mr. DONKIN. I was invited to appear here today by the subcommittee staff.

Mr. MOORE. Have you done any work for this committee or subcommittee staff professionally?

Mr. DONKIN. No, sir.

Mr. MOORE. You appeared here last year on a similar hearing before the subcommittee? A member of your company did. Was it you?

Mr. DONKIN. I don't believe I have ever appeared before this particular subcommittee. I have appeared before Chairman Dingell on another occasion.

Mr. MOORE. Thank you. That is all the questions I have.

Mr. GAMMAGE. Mr. Stockman?

Mr. STOCKMAN. Since a number of you are involved in utilities, I have a question that might shed some light on the whole gas price question. We had Dr. Schlesinger here yesterday, and he agreed with me that when we are dealing with the whole energy area one fundamental concept should be kept in mind, and that is the rule of essential equivalency. When we are looking for extra Btu's, we ought to go where we can get them the cheapest. If that is in some instances conservation, that is fine. If in other instances it is conversion from current sources to coal, that is fine. But if it is continuing to use conventional gas and oil, that is the route we ought to go.

I ask this question: In light of all the associated costs of getting a Btu of usable energy out of coal that some of you were discussing before—if you are talking about utilities and industries, you have to build coal yards, you might have to cover them, you have to put on stack scrubbers, electrostatic precipitators, you have to rent land to have a disposal area, in some cities you might have to ship 200 miles. In many cases companies are not able to put in a huge coal yard, or put something on the stacks. Do you think in view of all those costs to the economy that you can put a coal based Btu under a boiler for $1.79 in view of all those factors that have to go into the true cost of producing a Btu of energy? The reason I use $1.79 is that that is what the administration seems to be saying that is the outside cost we can have for new gas. It seems to me some of the producers in the oil and gas industry would be doing a great service if you could provide even some ballpark estimates to show what the equivalent price is of getting the Btu out of coal, in the light of going all the way upstream, to include the taxes and the costs under the strip-mining bill and everything coming under the Clean Air Act, retrofit, and so on. It seems to me it will go up to $3-$5. If you are ready to pay that for conversion energy, why can't we have the same gas coming out of the same economy?

Mr. MCCOLLAM. Congressman Stockman, I would respond that I think it is highly questionable that you could do it for that figure. We have provided some information—when I say we, now, I have to say the Middle South Utilities System of which my company is a part—it has done a horseback estimate on what the estimated conversion cost would be if we took all of our gas-fired boilers and oil-fired boilers and had to, in effect, scrap them and convert all of these boilers to coal. The estimated conversion cost in our case—and I might say the Middle South Utilities System serves the States of Arkansas, Louisiana, Mississippi and a small part of Missouri—would be about $5 billion in 1976 dollars and probably by the time this could be done, it would escalate to a lot higher figure than that, even assuming you could get it done from an engineering viewpoint and also considering the availability of the boilers. We estimate, relating that particular investment to what it would equate to on a levelized annual cost basis, we would be looking at something like $737 million a year in levelized annual cost, and if you related this cost—and I am talking now about conversion cost, not the cost of fuel.

Mr. STOCKMAN. You are talking about retrofit?

Mr. McCollam. I am talking about scrapping boilers and putting in new boilers. If you relate this levelized cost to our total actual energy sales in 1976, including sales to other utilities—I am speaking of our general business sales, our retail sales—that would represent an average incremental cost of almost 20 mills per kilowatt hour, 2 cents per kilowatt hour just in conversion cost. That would be a cost equivalent of about $11.66 per barrel of oil, if you wanted to relate that to a conversion—relate that conversion cost on an annual basis to the cost of a barrel of oil.

Mr. Stockman. What is the amortization period?

Mr. McCollam. This would be over the life of the plant. Most of our generating plants are designed for a 30- or 35-year life, something like that. This is based on about a 15 percent fixed charge rate over that period of time.

Mr. Stockman. That is going to vary with the remaining life of whatever plant you are converting?

Mr. McCollam. Yes, but for all practical purposes, we are going to have a new plant, in effect, because you can't take a natural gas boiler and convert it to coal. There is no way. You have to scrap it and build a new coal boiler. We are talking about essentially scrapping all of the existing electric utility boilers and building new boilers. I am not even addressing myself to the reliability problem, the loss of capacity as a result of this, the exposure to interruptions in service. This is just the dollar cost to which I address myself. It is just not feasible to do this.

Mr. Stockman. For a utility, it would include other costs for coal?

Mr. McCollam. And also to what extent we are going to have to use scrubbers, for example. There are present proposals—you put scrubbers on everything regardless of the sulfur content of the coal. It doesn't make sense. That is what the clean air bill is prescribing. The whole thing is simply crazy.

Mr. Stockman. I think it would be very helpful if you could have some of the basic figures and have them ready. It seems it would be possible to transform them into Btu costs so we can compare it with the natural gas price. In other words, reporting on an average basis it is hard for people to follow. If you can transform it into a fuel equivalent cost, not only your conversion cost but your higher operating cost—for one you might have to expand the size of the system because of the lower reliability, because the scrubbers must be considered. I hope you can work all that in so we can get a realistic appraisal of what the cost of the alternative source would be.

Mr. McCollam. I might mention figures I just quoted you. We have furnished them for the record in the hearings on Senate bill 977, which is the Coal Utilization Act of 1977—these figures are already a matter of record on the Senate side, and to whatever extent we can furnish additional information to this committee, modifying these figures as you would feel we should do, we will be happy to do that.

Mr. Stockman. We would appreciate that.

Mr. Gammage. Mr. McCollam, would you provide that for the record?

Mr. McCollam. Yes, we will do so.

[The following material was received for the record:]

During my appearance before the Energy and Power Subcommittee you requested certain data relative to the total estimated cost of converting existing gas/oil electric generating units to coal-burning. We have prepared estimates of these costs for your use.

In order to aid you in assessing the overall impact of a forced coal-conversion program, I thought it would be appropriate to provide you with background information on the Middle South Utilities System.

Historical Background of the Middle South Utilities System

Middle South Utilities, Inc. is a holding company registered under the Public Utility Holding Company Act of 1935 and is comprised of five operating subsidiary companies; i.e., Arkansas Power & Light Company, Arkansas-Missouri Power Company, Louisiana Power & Light Company, Mississippi Power & Light Company, and New Orleans Public Service Inc. These Middle South Utilities operating companies are operated as a single integrated electric system.

All major generating units in the Middle South Utilities System were designed for burning natural gas as the primary fuel until about 1969 when evidence of the impending shortage of natural gas became apparent. Since 1970, its expansion plans have been based on having all future base load units in the form of nuclear and coal-fired. While the System's generating units were historically designed to burn only natural gas on a continuous basis, the boilers were designed to be able to burn fuel oil intermittently for very limited periods in order to handle emergency situations involving loss of gas fuel for short periods of time.

Under orders of the Federal Power Commission, delivery of natural gas to Middle South power plants by interstate pipelines already has been greatly curtailed. The System's natural gas usage as a boiler fuel has dropped by 31% in the period from 1970 to 1976, representing a total reduction estimated at 667,000,000 MCF of boiler fuel gas for the six-year

period. Our present projections indicate an additional 6% reduction in use of natural gas as a boiler fuel by the System between now and 1986. Concurrently, the System's oil usage increased from 975,130 barrels in 1970 to 35,130,000 barrels in 1976.

Substitution of fuel oil and purchased energy for this gas (which was contracted for on a contract-price, firm-delivery basis but not delivered) has increased the fuel costs to our customers by an estimated $ 610,000,000 over this six-year period. These costs, together with associated boiler conversion costs, represent a burden already thrust upon the consumers in our service area by virtue of federal governmental action. At the same time, curtailments by United Gas Pipe Line Company, the interstate pipeline supplying the greater portion of the System's boiler fuel, have been about double those of the next largest pipeline's curtailments (Schedule 1, FPC Curtailment Report, November 1976).

Additionally, the Middle South Utilities System operating companies have expended approximately $ 180,000,000 to convert their major boilers in order to permit burning oil for extended periods. Some of these modifications were done with the contemplation of eventually converting to coal-firing; therefore, all of the modified facilities would have to be prematurely retired and replaced with new coal burning facilities. Furthermore, the System companies have experienced greatly increased operating and maintenance problems and expense as a consequence of the increased use of fuel oil in boilers not originally designed to burn oil on an extended basis.

It is anticipated that the Middle South Utilities System will consume about 40,000,000 barrels of oil in 1977 (60% more than in 1976) to supplant the natural gas shortfall and meet our customers' energy requirements. We feel that it is obvious from the foregoing facts that the Middle South Utilities System and its customers are already bearing a heavy financial burden as a result of shifting from natural gas to oil as a boiler fuel.

Estimated Cost of Coal Conversion Program

As I indicated on [illegible] the estimated capital cost for converting our existing gas and oil-fired units to permit coal-burning would be $ 4,913,825,000 (in 1976 dollars), exclusive of scrubbers. In response to your request, we have estimated the total cost of converting these units to coal-burning. Our analysis is summarized below:

	Estimated Cost in 1976 Dollars	
	$/Million BTU	Mills/KWH*
Annual Fixed Charges on Capital Expenditures for New Boilers Including Scrubbers	1.91	19.40
Operating and Maintenance Cost	.42	4.28
Capacity Loss Due to Scrubbers	.10	1.00
Minemouth Coal Cost (Powder River Basin Low Sulfur Coal)	.39	3.95
Transportation Cost	.80	8.11
	3.62	36.74

* Assuming average heat rate of 10,160 BTU/KWH

As you can see, the total cost of $ 3.67 per million BTU is considerably higher than the $ 1.79 cost for new gas suggested by the Administration. I would like to emphasize that the above-estimated costs do not include any provision for replacement capacity during the conversion period. These costs would be substantial; however, we have not attempted to quantify them because of the many uncertainties involved.

For comparison purposes, the following information should be of interest to you. Our actual 1976 cost for fossil fuel and operation and maintenance was $ 1.35 per million BTU (11.95 mills/kwh). Therefore, the net increase in cost compared to the coal conversion program would be $ 2.47 per million BTU, or 24.79 mills/kwh. The financial impact on our customers would be very significant. In 1976, our average revenue per residential customer was $ 308.56, or 30.5 mills/kwh. Adding the increase of 24.79 mills/kwh would raise the average residential customer's annual bill to about $ 560, an increase of over 80%. All these costs are in terms of 1976 usage and dollars and, of course, with inflation, the added cost at the time of completion of the conversion program would be even greater.

Practicability of Coal Conversion Program

Many technical and/or legal constraints make it impracticable to convert a number of our existing units to coal-firing. Included among these constraints are such factors as:

a. Lack of physical space for new boilers, coal storage, handling facilities, ash and sludge disposal areas. Some of our major generating stations are located in heavily populated metropolitan areas, and it would be literally impossible to acquire the necessary land, which we understand would require about 2,000 acres for a 1,000 MW plant.

b. Height limitations imposed by local, regional, state and/or federal regulations such as, proximity to commercial or private airports. Such limitations would preclude the possibility of constructing tall stacks (400 - 800 feet).

c. The lack of adequate manufacturing capability for boilers and associated equipment, which would be required if the proposed legislation were enacted.

d. The lack of adequate manufacturing capability for combustion turbines or other capacity, which would have to be constructed to provide replacement power for the existing facilities during the conversion period.

e. The problems associated with mining and transportation of the additional coal which would be required in the event of passage of such legislation. There is a serious question whether or not there are adequate mining and transportation facilities to accomodate coal units currently in the planning and/or construction period. Legislation authorizing the construction of coal slurry pipelines appears essential in order to supplement the capability of railroads for transporting coal.

The System's present plans call for substantial expenditures for electric production facilities during the period 1978 - 1985. The proposed legislation, if enacted, would approximately double these expenditures, making it impossible for our System to finance such a program when we are still burdened with financial difficulties brought about by factors beyond our control, such as inflation of recent years, the effects of inadequate rate relief, and higher fuel costs resulting from curtailments of firm contracts.

Summary

In summary, we are of the considered opinion that it is not feasible, technically or economically, to convert any of our existing gas or oil-fired boilers to permit burning coal. Conversion to coal-burning would involve (1) completely replacing the existing boilers with new boilers; (2) constructing new boilers remote from the existing boilers and reconnecting the steam lines to the new boilers; or (3) installing a coal gasification plant on the plant site and modifying the existing boilers to permit burning low BTU gas. None of these alternatives would be accomplished for a number of years because of the lead times involved in the design and construction of such facilities. The third option has not yet been proven as being viable for large scale, commercial application, with the degree of reliability required by the electric power industry. If we were forced to convert to coal-firing, the inevitable result, in our opinion, would be that electric service to our customers would be seriously jeopardized during the conversion period.

Alternative Approach

The estimated increased cost of $ 2.47 per million BTU is equivalent to about $ 15.40 per barrel of oil. Our average oil cost in 1976 was about $ 11.40 per barrel; therefore, the incremental cost represents an increase of 135%. It appears to us that, in view of the above-described constraints and other major problems concerning the national energy situation, it would be much more appropriate and logical to use the $ 15.40 per barrel equivalent for securing fuels through the use of more advanced technologies. It is possible that such a program could advance commercial development of such fuels which would be more compatible with our existing boilers.

Mr. GAMMAGE. I have one brief question I would like to address to Mr. McCants and then we will defer to committee counsel.

Mr. McCants, I am looking at page 4 of your statement, where you refer to 3,000 Mcf per day as a logical cut-off between large and small customers, as far as the tax burden is concerned. I have got in my particular district a part of the Texas Medical Center and some of those installations there. Such installations might fall into the category of large customers as far as their consumption is concerned. There are other enterprises that might well fall into the large consumer category. Do you feel the imposition of a tax on them would have a direct and heavy negative impact on some of the elements in the community that they serve? I would like for you to speak to that a little more elaborately, if you would, sir.

Mr. MCCANTS. I will be glad to. In reviewing the use of the customers, with respect to the forced conversion and whether or not new installations could be made, we made a complete review of our customers, and the one you cited is a perfect example. The Methodist Hospital would have a heavy tax burden. Of course I don't know how that would fit in with the President's plan to limit the increase in hospital costs because the cost of their services would go up. Two of the installations are owned by the City of Houston that would be directly affected there. One of the Harris County facilities would be as well as some of the downtown hotels. The University of Houston would be affected, Rice University would be affected in Houston. If you don't draw a line between these small customers and the very large customers at some logical viewpoint, you end up with the undesirable result of getting your hospitals and customers, the large schools and things of that sort paying a tax, and either being required to convert, which again is a taxpayers' cost to convert to another fuel. I don't really believe that, with the Clean Air Act and everything else, that these medical center power plants, for example, could be converted to coal or should be converted to coal. It would have a very adverse impact, and we feel strongly that customers of this sort should not be forced to convert.

Mr. GAMMAGE. Thank you very much.

Does anyone else have a comment on that at this time?

Mr. FOY. It just occurred to me, as Mr. McCants was talking, we have a facility that furnishes to the Texas Medical Center chilled and heated water and steam, and it consumes 3.1 million cubic feet of gas per day. I doubt that that facility can convert, and I think this illustrates the difficulty of using arbitrary volume limitations in the imposition of the tax or in the incentive to convert.

Mr. GAMMAGE. Thank you.

At this time I will defer to committee counsel, Mr. Demarest.

Mr. DEMAREST. Thank you, Mr. Chairman.

Gentlemen, earlier Mr. Moore asked each of you for information regarding your average acquisition cost for all gas. This morning we heard testimony from the Texas Railroad Commission that the average price of gas produced in Texas was approximately 70 cents per Mcf. That just does not square with the figures you have given us.

Were your figures the average cost of gas under existing contracts, old contracts, as well as the cost under your new contracts, or did those figures relate just to your new contracts?

Mr. FOY. I gave both. Perhaps the figures I gave you were a little confusing. On about a third of the volumes that come into the Houston pipeline system, there is the transportation cost, which I mentioned earlier from West Texas into Katy so that the wellhead cost associated with each of the figures that I gave you as weighted average cost of Houston pipeline might be as much as 5 cents to 6 cents less. I am not prepared to quantify that for you, but that would be close.

Mr. DEMAREST. That would be $1.75, approximately and $1.85 without considering the transportation cost.

Mr. FOY. In those ranges, but that is the average cost on all contracts, old and new.

Mr. INGRAM. I think that the prices we gave you were our average and our highest acquisition costs for intrastate gas. I believe—although I am from Oklahoma—that 70 cents may be the average cost of all gas, interstate and intrastate. That is probably what that 70 cents is, but the intrastate prices are what we gave you.

Mr. NEAVES. The $1.42 I gave is the weighted average purchase price of all of our gas, including the old existing contracts, the new ones. We have about 40 percent of our volume covered by contracts that now have redetermination or price escalation. About 60 percent are old, fixed price contracts, and some 20 percent of that volume is still coming into the system at 19 cents, which, of course, has the effect of pulling that $2 gas down to that $1.42.

Mr. INGRAM. I believe that about 50 percent of the Texas gas goes in interstate commerce and is still under some of the old regulated prices. About 60 percent of the Oklahoma gas goes out of the State under these old contracts, so when you take an average for the State, it is much lower than the number that we gave you.

Mr. MCCANTS. I think that the figures that I cited a little while ago may give you some insight to that problem. For example, we are buying interstate gas in Texas to serve 125,000 customers. The interstate gas that we purchase in Texas is about $1 per Mcf cheaper than the intrastate gas, because the interstate gas was purchased in these East Texas fields quite a number of years ago and they are long-term, fixed price contracts. I am sure the 70-cent price that was quoted this morning includes all inter- and intrastate purchases.

Mr. DEMAREST. Thank you.

Mr. Ingram, at the beginning of your testimony you referenced a problem that you perceive with the Carter natural gas pricing proposal, and if I could restate it, your problem was that at the same price you believed intrastate pipelines would be unable to compete with interstate pipelines for the purchase of new gas supplies, largely because the intrastate pipeline could not take the gas as rapidly as the interstate pipeline.

Mr. INGRAM. That is right.

Mr. DEMAREST. Is that same problem posed by deregulation? Won't interstate pipelines be able to match, or in fact exceed, any bid of an intrastate pipeline under new gas deregulation, and therefore the same problem would exist under deregulation as an alternative to the Carter program?

Mr. INGRAM. I think that is true, but I think that the phaseout of boiler fuel is going to make a lot of gas available that the intrastate market can't absorb right away. The intrastate market is limited to what we can use with our own customers. If we do phase out certain industrial uses and certain boiler fuel uses, that gas will be available for the interstate market. In addition, deregulation would increase overall supply for all buyeres, and at least we found in Oklahoma that if you do pay the price, you develop the reserves. In other words, we had a period of time where we had lower prices and the use of gas in Oklahoma was exceeding the new reserves developed. About 5 years ago as higher prices were paid in intrastate market, this has turned around, and for about the last 4 or 5 years we have developed more reserves than have been used in the Oklahoma market. Thus, by increasing overall supply, deregulation would help intrastate buyers compete for supply with larger interstate buyers.

Mr. DEMAREST. But until there was a supply response adquate to satisfy the demand for natural gas by customers of the interstate pipelines, the intrastate pipelines would suffer a disadvantage.

Mr. INGRAM. Yes, we would still have some problems. Incidentally, I worked in gas purchase 30 years ago before the *Phillips* decision. We had the same problem then. The only thing about it was we didn't have this large period in which people got behind in their supply.

Mr. DEMAREST. Mr. McCants, you have given us some boiler fuel statistics defining a cutoff of about 3,000 mcf per day as an appropriate standard to be used with respect to forced conversion from use of natural gas under boilers to alternative fuels.

Would you support using the same standard as the reference point for application of incremental pricing proposals that might be directed at obtaining the same result? For example, incremental pricing might be drafted so as to require the allocation of higher gas prices to certain industrial boiler fuel consumers up to, let's say, 110 percent of Btu equivalency with middle distillates, so as to create economic incentives for conversion. Would you then support a standard of 3,000 Mcf per day to define the class of boiler fuel users to which incremental pricing would apply?

Mr. MCCANTS. Although Entex opposes incremental pricing generally, if you are going to have incremental pricing that is a logical level. That is about a logical dividing point between the small customers, the hospitals, that sort of thing, and the larger customers. Yes, I would support that level.

Mr. DEMAREST. Mr. Foy, in your statement I noticed you were reading from page 2. You read the first sentence of the second full paragraph, and then you departed from your statement to give a rather detailed amplification of your position. Then you resumed with the last sentence of the second full paragraph on that page. The omitted language was: "The Administration was wise not to propose an immediate total deregulation of new natural gas. Because of redetermination clauses in most intrastate supply contracts that would be triggered by unrestrained bidding for new gas supply, immediate deregulation of new gas would result in severe economic dislocation in the intrastate markets."

Am I to understand that your amplification of that language does not indicate that you wanted to depart from that statement?

Mr. FOY. No. That still is one of the reasons why I do not feel that an immediate total deregulation of new gas would be in the best interest of anybody in the business.

Mr. DEMAREST. You have recommended to the committee that we look to the Texas Railroad Commission's definition of reservoirs for purposes of a new gas definition. You have also indicated that perhaps the experience of the Texas Railroad Commission would be useful for administering a new gas definition based upon a new reservoir concept.

Could you provide for the record both a copy of the language you are referencing and any published regulations that might exist on how that is implemented so we could have that before the committee?

Mr. FOY. Yes. We will look into that.

Now I am referring to the practice rather than the wording of any particular regulation. My contention was that it is possible with reasonable certainty to determine whether a new reservoir has in fact been discovered.

Mr. DEMAREST. Would it be possible for you to provide a brief summary of that practice for the record?

Mr. FOY. Yes, I think that can be done, and I will call on someone to have that done for you. I will also supply to you, Mr. Demarest, a more precise accounting of our cost.

Mr. DEMAREST. Thank you.

[The following material was received for the record:]

(STATEWIDE CONSERVATION RULES - Cont'd.)

(2) The provisions of this rule are not limited to the spacing and acreage determinations as set out above. If any spacing not mentioned is brought to the attention of the Commission, it will be given appropriate acreage assignment.

(3) In addition to the assignment of acreage as required above, when a tract, after full development, has remaining unassigned acreage in an amount less than one-half (1/2) the prescribed amount, no well will be authorized on such acreage unless approved as an exception to this rule after notice and hearing.

(4) The Commission, in order to prevent waste or to prevent the confiscation of property, may grant exceptions to the density provisions as stated above. Such an exception will be granted only after notice and hearing.

(C) General

(1) An Application (Form W-1) for Permit to Drill or Deepen must be accompanied by a certified plat of the basic lease or unitized tract, showing thereon the acreage dedicated to the proration unit for the proposed well, and also showing thereon the acreage previously dedicated to all Commission approved well locations on said basic lease or unitized tract. A permit to drill any well for oil, gas or geothermal resource will not be granted until such plat has been attached to and made a part of such form (Form W-1). Each operator seeking a permit to drill on a basic lease or unitized tract containing insufficient acreage must file with and as a part of the form (Form W-1) a statement of the names and addresses of all offsetting property owners, and must certify (Form W-1-A) that such basic lease or unitized tract has not been subdivided from any other tract. If further proof is desired by the Commission, a hearing may be called.

(2) On large tracts consisting of one basic lease or unitized area, if the density is not exceeded as shown on the face of the form (Form W-1), a plat will suffice that shows the acreage allocated to the well for which permit is sought, and the acreage allocated to the immediate offset wells on the lease or unitized area.

(3) If a waterflood permit has been granted by the Commission, and if density rules conflict with the orderly development necessary to control efficiently the flood fronts, the Commission may grant an exception to the order if the operator states on the appropriate form (Form W-1) the number of the order permitting the waterflood.

(4) On leases from which production is secured from more than one reservoir (or field), the operator may draw units around the proposed location and wells from the same reservoir to which a producer is projected, and also show all other wells with appropriate reservoir (or field) designation.

051.02.02.039
RULE 39. PRORATION AND DRILLING UNITS: ASSIGNMENT OF NON-CONTIGUOUS ACREAGE WHERE NON-CONTIGUITY IS CAUSED BY RIGHTS-OF-WAY TRAVERSING AN OPERATOR'S PROPERTIES

(a) Proration and drilling units established for individual wells drilled or to be drilled shall consist of acreage which is contiguous.

(b) An exception to the contiguous acreage provision may be granted at the operator's request if acreage that is to be included in the proration or drilling unit is separated by a long, narrow right-of-way tract.

051.02.02.040
RULE 40. ASSIGNMENT OF ACREAGE TO POOLED DEVELOPMENT AND PRORATION UNITS

(A) Acreage up to the amount specified in applicable field rules may be pooled into a development or proration unit, provided that an operator must file with the Commission a certified plat delineating the pooled unit, and a Certificate (Form P-12) of pooling authority wherein it is stated that the tracts are pooled by authority of an agreement between the various interest holders in the several tracts committed to the unit, with such tracts separately identified and the gross number of acres in each of said tracts shown separately, with a total gross acreage allowed not to exceed the unit size authorized by rule.

(B) If a tract to be pooled has an outstanding interest for which pooling authority does not exist, the tract may be assigned to a unit where authority exists in the remaining undivided interest, provided, that total gross acreage in the tract is included for allocation purposes, and the Certificate (Form P-12) filed with the Commission shows that a certain undivided interest is outstanding in the tract. The Commission will not allow an operator to assign only his undivided interest out of a basic tract, where a non-pooled interest exists.

(C) The non-pooled undivided interest holder retains his development rights in his basic tract, and should such rights be exercised, authority to develop the basic tract be approved by the Commission, and a well completed as a producer thereon, then the entire interest in the basic tract must be allocated to said well, and any interest insofar as it is pooled with another tract must be assigned to the well on the basic tract for allocation purposes. Splitting of undivided interest in a basic tract, between two or more wells on two or more tracts is not acceptable.

(D) Acreage assigned to a well for drilling and development, or for allocation of allowable, shall not be assigned to any other well or wells projected to or completed in the same reservoir; such duplicate assignment of acreage is not acceptable, provided, however, that this limitation shall not prevent the reformation of development or proration units so long as no duplicate assignment of acreage occurs, and further, that such reformation does not violate other conservation regulations.

051.02.02.041
RULE 41. APPLICATION FOR NEW OIL OR GAS FIELD DESIGNATION AND/OR ALLOWABLE (As Amended by Order No. 20-58,241, Effective January 30, 1968.)

(A) Evidence proving that a well is a discovery must be received in the Commission's Austin Office prior to the assignment of a new field designation and/or a discovery allowable. The evidence must prove that the new reservoir is effectively separated from any other reservoir previously shown to be productive. Evidence other than horizontal distance is required. An application (Form P-7) must include the following:

(1) An area map, scale one (1) inch equals one thousand (1000) feet, showing all oil, gas, and/or abandoned wells within at least two and one-half (2-1/2) miles in each direction from the well claimed to be a discovery well; the producing interval of surrounding oil and/or gas wells; all near-by fields, past

(STATEWIDE CONSERVATION RULES - Cont'd.)

or present, should be identified with correct field names, the producing formations, and average depth of the producing interval; also, the total depth of all dry holes that are used as evidence of separation. The map must be on white paper, with all data shown legibly.

(2) (As Amended by Order No. 20-58,241, Effective January 30, 1968.) Full-scale electrical log of the well with the subject formation and all nearby producing formations identified clearly; however, a temporary delay may be granted to the required filing of an electric log without delay of discovery allowable for good cause shown, provided that other data submitted to the Commission satisfactorily proves discovery of a new reservoir.

(3) If application is based on structural differences, attach a subsurface structure map contoured on top of the producing formation. The map must be signed by the engineer or geologist who prepared it.

(4) If the application is based on faulting, pinch-outs or vertical separation of small magnitude, attach a geological cross-section prepared from electrical logs (not tracing).

(5) If application is based on reservoir pressure differentials, submit reservoir pressure measurements or calculations other than drill-stem test pressures.

(6) If application is based on differences in fluid levels, submit detailed core data or drill-stem test data from comparable formations. Fluid level data should be of recent date.

051.02.02.042
RULE 42. OIL OR GAS DISCOVERY STATUS (As Amended by Order No. 20-56,204, Effective March 28, 1966, and Order No. 20-56,342, Effective May 31, 1966.)

(A) The Commission will permit production from all wells shown to be completed in and producing from new and separate producing oil and/or gas reservoirs without the necessity of formal notice and hearing, provided, that all the pertinent data is furnished to the Commission on the form (Form P-7) prescribed. If the data furnished are considered by the Commission to be insufficient to establish discovery status, or if any party protests the granting of an application for discovery status for any well, the Commission, on request of the applicant, will set the application for hearing, giving notice thereof.

(B) The discovery allowable rate for oil wells proven to be completed in a new and separate reservoir shall be determined from the following Discovery Allowable Schedule:

SCALE OF ALLOWABLES

INTERVAL OF DEPTH	DAILY WELL ALLOWABLE
0 - 1,000	20 barrels
1,000 - 2,000	40 barrels
2,000 - 3,000	60 barrels
3,000 - 4,000	80 barrels
4,000 - 5,000	100 barrels
5,000 - 6,000	120 barrels
6,000 - 7,000	140 barrels
7,000 - 8,000	160 barrels
8,000 - 9,000	180 barrels
9,000 - 10,000	200 barrels
10,000 - 10,500	210 barrels
10,500 - 11,000	225 barrels
11,000 - 11,500	255 barrels
11,500 - 12,000	290 barrels
12,000 - 12,500	330 barrels
12,500 - 13,000	375 barrels
13,000 - 13,500	425 barrels
13,500 - 14,000	480 barrels
14,000 - 14,500	540 barrels

(C) (As Amended by Order No. 20-56,204, Effective March 28, 1966, and Order No. 20-56,342, Effective May 31, 1966.)

(1) Each oil well drilled in a new field onshore or in a new oil producing reservoir onshore within the confines of an established field may receive, as a maximum daily, its discovery allowable, exempt from market demand limitation, for a period of twenty-four (24) months from the date of assignment of the oil allowable to such discovery well or until the eleventh (11th) oil well has been completed therein, whichever occurs first.

(2) (a) Each oil well drilled in a new field offshore or in a new oil producing reservoir offshore within the confines of an established field may receive, as a maximum daily, its discovery oil allowable, exempt from market demand limitation, for a period of eighteen (18) months from the date of assignment of the oil allowable to such discovery well or until the sixth (6th) oil well has been completed therein, whichever occurs first.

(b) This amendment will apply to all future onshore discoveries and to all onshore fields that are currently enjoying discovery allowable status.

(D) A subsurface pressure test shall be made on the discovery well in accordance with the instructions on the Commission's appropriate form (Form W-7), and the results thereof reported to the Commission within sixty (60) days after completion of the discovery well.

Mr. DEMAREST. Finally, you also referenced a fuel oil redetermination clause that exists in some of your contracts.

Could you provide the committee with a copy of that kind of redetermination clause?

Mr. FOY. Actually I was referring to someone else's contract, but since it is in our hands, I can provide it to you.

Mr. DEMAREST. Thank you.

Gentleman have discussed at some length the proposals originally supported by President Carter which I believe called for trial deregulation of natural gas for a 4- or 5-year period as an experiment, to see if it works. I wonder if such a proposal doesn't ignore your concerns that the real problems occur during this transition period. It is the 4- or 5-year period of market instability which is of concern to you rather than what happens at the end of that period when, hopefully there will be a moderation of further price increases by the establishement of supply-demand equilibrium.

Is that a fair assessment?

Mr. FOY. Yes, sir, that is a fair assessment of my position. I don't want to be hanged as an experiment to see if it will kill me.

Mr. DEMAREST. Would you support a legislative provision which provided for automatic deregulation to be triggered by the existence of a supply-demand balance? Such a provision might be cast in terms of equivalency of new gas discoveries during some period with production during, let's say, a preceding period. Or some other form of comparison might be utilized which looks to new gas discoveries

and consumption. Presumably if that balance were struck, the marketplace would be ready for deregulation.

Mr. FOY. I would not be prepared to say that any standard devised today would be entirely applicable to the circumstances that might exist 4 or 5 years from now. Therefore I would prefer to leave the determination to the President, subject perhaps to a one House veto.

Mr. DEMAREST. Would you have any suggestions as to what guidelines could be utilized to judge the President's decision?

Mr. FOY. I would think in this case that the guidelines should be extremely broad since the judgment of both the President and the Congress would be called on before the action took place.

Mr. DEMAREST. Mr. Donkin, to summarize your testimony, I believe it was your conclusion that competition is not working in the intrastate market and that it is not a free market in any real sense of the word. Is that your conclusion generally?

Mr. DONKIN. That is a general conclusion.

Would you like me to elaborate on one other aspect of it?

Mr. DEMAREST. If you desire.

Mr. DONKIN. Specifically, it is the OPEC oil cartel. The price of No. 2 and No. 6 fuel oil goes a long way towards determining the demand for natural gas in the industrial intrastate market. So many of these large industrial firms do have the ability to convert so long as natural gas is delivered to them at a price below the equivalent Btu costs. Taking into account the efficiencies between gas and No. 2 and No. 6 fuel oil, they will prefer natural gas.

To illustrate, I represent eight clients in Florida, and they generate electricity with either natural gas or oil, and they are paying about 70 cents per million Btu for the natural gas, when it is available, and anywhere from $2 to $2.50, depending on whether they burn No. 2 or No. 6, for their oil. You can see how much the price of natural gas to the pipeline that serves them could increase before they would be willing to voluntarily switch to No. 2 or No. 6. So that within the context of not only the intrastate market by itself but the natural gas producing industry not being workably competitive, the OPEC situation, and the interrelationships between all buyers and sellers within the natural gas industry, these conditions lead me as an economist to conclude that we do not have a workably competitive market at work.

Obviously, as an economist I prefer to see free markets exist in the absence of regulation. Unfortunately that is not the situation here.

Mr. DEMAREST. Mr. Foy responded to your comments in your opening statement, and I believe he referenced—correct me, Mr. Foy, if I am wrong—some of his old gas contracts, and explained that some of the purchases Houston Natural is now making from an affiliate producer would, of course, be much higher than contracts from nonaffiliated producers, which are in some cases old and at lower prices. But I believe the comparison set forth in your statement, Mr. Donkin, was a comparison between affiliated and nonaffiliated sales under new contracts; is that correct?

Mr. DONKIN. No. I was referring to what I interpret to be weighted average system purchase costs.

Mr. DEMAREST. So that one of the reasons for that disparity could be the difference in mix of old and new gas as between affiliated and unaffiliated purchasers.

Mr. DONKIN. This is correct and this is precisely why in my testimony I said as a possible example as opposed to—I really wasn't making the assertion, but I used the example to indicate the potential, and I know an awful lot more perhaps about the interstate situation since 1970, where in countless instances each new interstate price plateau was triggered by a contract wherein the purchaser was affiliated, was buying gas from a group of producers wherein an affiliate was a member.

Mr. DEMAREST. Finally, you did indicate earlier that you appeared here at the request of the staff. I don't believe you were asked, but I will ask you, was the expense of your testimony paid for by any of your clients or by the subcommittee?

Mr. DONKIN. I am appearing here today totally as an individual. All costs incurred, which are not very many, essentially the copying costs of my testimony, will be incurred by our firm. That is essentially all I have to say on that subject.

Mr. DEMAREST. Thank you.

Mr. GAMMAGE. Mr. Vlcek.

Mr. VLCEK. I have two brief follow-up questions on the question of acquisition cost. I wonder if each of the pipeline witnesses would indicate what percentage of their contracts are subject to redetermination clauses. You can do it for the record if you don't have it.

Mr. FOY. I am trying to think how to give that to you without being misleading, because some are not up for redetermination for another year. Some are redetermined every 4 years, some every year, some every 6 months, but in general I would say that 75 to 80 percent of the gas that we buy is under contracts that have some form of redetermination clause.

Mr. VLCEK. Not necessarily all of which would be triggered immediately but there is some time involved.

Mr. FOY. Right.

Mr. NEAVES. I made that statement earlier. About 40 percent of our supply contracts or 40 percent of the volume covered by contracts has redetermination or escalation provisions in it, and ours is similar to Mr. Foy, some on a 3-, 4-, or 5-year basis, some annually.

Mr. INGRAM. For Oklahoma Natural, about 63 percent of our daily deliverability is subject to contracts that contain favored nation and redetermination clauses.

Mr. VLCEK. I wonder if each of you could provide for the record an example of several of these kinds of redetermination clauses and escalation clauses.

Mr. FOY. We will be glad to.

[The following material was received for the record:]

Lone Star Gas Company
A DIVISION OF ENSERCH CORPORATION
301 S. Harwood Street • Dallas, Texas 75201

CAROL L. NEAVES
Executive Vice President

May 31, 1977

Honorable John D. Dingell, Chairman
Subcommittee on Energy and Power of the
Committee on Interstate and Foreign Commerce
Congress of the United States
House of Representatives
Room 3204
House Office Building Annex No. 2
Washington, D.C. 20515

Dear Congressman Dingell:

At the hearing before your Subcommittee on May 13, 1977, we were requested to provide an example of redetermination provisions included in gas purchase contracts by Lone Star Gas Company for the record. A typical provision presently being used is enclosed for that purpose. You will recognize that we have a number of these types of provisions in effect varying due to conditions at the time the contract was negotiated. For instance, our older redetermination procedures only required action every five years. Additionally, some provisions provide for an adjustment of the price concluded if conditions such as quality, pressure, compression or gathering obligations are not comparable. Currently, competition and the existing energy picture have necessitated our use of provisions similar to the one enclosed.

I would also like to clarify Lone Star Gas Company's situation on a point that was not completely covered during the May 13 hearing. Most of Lone Star's gas supply contracts are entered into for an initial term of 20 years and not for the relatively short terms as seem to be the impression left with the Subcommittee.

Certainly, if we can provide meaningful information for your Subcommittee during its deliberation, we would be pleased to assist.

Sincerely,

Carol L. Neaves

CLN:re
Encl.

Price Redetermination Provision

Seller or Buyer may request a redetermination of the price payable hereunder commencing _____-_____ and at twelve (12) month intervals thereafter. A redetermined price shall be in lieu of and supersede the price in effect under the preceding paragraph or any increases provided for under the preceding paragraph or any prior redetermined price. A redetermination may be initiated by Seller or Buyer giving written notice of desire for price redetermination on or before _____-_____ of the year preceding the date of _____-_____ of the year in which a redetermined price becomes effective. The redetermined price shall be the arithmetic average of prices eligible for payment under three (3) gas purchase contracts having the highest unit prices of separate and distinct bona fide intrastate gas pipeline companies entered into during the twelve (12) month period preceding _____-_____ of the year of Buyer or Seller's notice requesting a redetermination; said contracts shall only include those of which Buyer has knowledge and shall only include contracts for gas produced, delivered and sold in _____-_____ County, Texas, under terms of such gas purchase contracts covering similar quantities of gas reserves and containing similar conditions relating to quality, pressure, quantity, gathering and compression obligations, delivery point and term of contract as contained in this contract; provided that provisions contained therein relating to pre-payments, advance payments, funding arrangements and similar financial inducements shall not be considered. For the purpose of effecting a price redetermination, Seller may provide Buyer (subject to Buyer's acceptance and verification) with any of the aforesaid contracts or substance thereof to be used as a basis of determining the redetermined price; provided, however, that Seller must transmit same to Buyer postmarked no later than ninety (90) days prior to the date the redetermined price is effective. Only contracts between gas pipeline companies and producers shall be considered. Buyer shall give Seller written notice of the

redetermined price to be paid at least thirty (30) days prior to the date the redetermined price is effective. Buyer's notice shall include a statement of the contracts relied upon and an explanation of any adjustments in arriving at the redetermined price. Buyer shall pay to Seller the redetermined price for gas purchased and received hereunder during the period ensuing from the effective date of said redetermined price until the next redetermined price shall become effective; subject to and provided that, in the event a redetermined price is placed in effect, this contract shall be automatically amended or modified to give Buyer the benefit of any more favorable provisions, including increased obligations on the part of Seller, contained in any of the contracts on which such redetermined price is based, which modifications and amendments shall be accompanied by this reference thereto and may, but need not be formalized by a written agreement between the parties. Buyer shall have the right to refuse to pay the redetermined price, which decision Buyer shall make known to Seller in writing at least five (5) days prior to the date the redetermined price is effective, and Seller shall have the right at any time within a period of six (6) months following the date of notice of Buyer's decision, as aforesaid, to terminate this contract by giving Buyer sixty (60) days prior written notice thereof, provided that if Seller does not so terminate this contract, the price in effect prior to the request for a price redetermination shall remain in effect subject to the other provisions thereof. The redetermined price shall be in effect for all gas purchased and received hereunder during the period ensuing until the next price redetermination shall become effective, except that for each accounting period for which the price is not redetermined, the price shall be the same as the price for the preceding accounting period plus the increase provided for under paragraph 1 above.

IV.

PRICE

1. Base Price

The terms "one thousand (1,000) cubic feet" and "Mcf" as used interchangeably in this Article IV.1.A.,B., and C. shall be deemed to mean 1,000 cubic feet of gas which contain 1,000,000 British Thermal Units as such term is defined in Article 3.A.(10) of the General Terms of this contract.

A. Subject to the other provisions hereof, the price to be paid by Buyer to Seller for each one thousand (1,000) cubic feet of Old Gas sold by Seller to Buyer hereunder shall be as follows:

(i) 48¢ during the period commencing on January 1, 1974, and extending to April 1, 1975; and

(ii) 75¢ during the period commencing on April 1, 1975, and extending to October 1, 1975.

B. In the event New Gas is produced prior to October 1, 1975, the price for each one thousand (1,000) cubic feet to be paid for such New Gas shall be as follows:

(i) 66¢ from the date deliveries of such New Gas commence to October 1, 1975.

C. The price for each one thousand (1,000) cubic feet to be paid for all gas during the remaining term of this contract commencing on ~~October~~ August 1, 1975, shall be as follows:

(i) 90¢ during the one year period commencing on ~~October~~ August 1, 1975 and extending to ~~October~~ August 1, 1976; and

(ii) 93¢ during the one year period commencing on ~~October~~ August 1, 1976 and extending to ~~October~~ August 1, 1977, and increasing 3¢ each ~~October 1~~ August 1 thereafter for the remaining term of this contract.

The foregoing notwithstanding, beginning no later than fifty (50) days, but no earlier than one hundred twenty days prior to ~~October~~ August 1, 1975, and each October 1 thereafter during the remaining term of this contract the parties hereto shall: (i) mutually determine four (4) prices by the procedures hereinafter described; (ii) express each of the four (4) prices so determined in cents per Mcf as defined in this Article IV and (iii) select the highest price so determined in (ii) as the price payable by Buyer to Seller for all gas delivered during the annual period in question, so long as such determined price exceeds the appropriate price set forth in (i) and (ii) of this Article IV. 1.C. for such annual period.

(a) The parties shall select gas sales contracts (excluding this contract) between bona fide pipe line companies and sellers with terms of one year or longer whose terms extend into and/or through the 12-month period for which a price is to be determined and the price(s) applicable under such contracts for such 12-month period or portion thereof (contract price) shall be considered under this paragraph. Successive contracts between the same seller and buyer, each for periods of less than one year but collectively for one year or more may be used. If a contract contains a known price change which will occur during the 12-month period for which a price is to be determined, the contract price for such contract shall be determined by time weighting the prices in the contract using only that portion of the term in the contract so selected which is within the period for which a price is to be determined hereunder. Only contracts between bona fide pipeline companies and sellers covering the purchase and sale of gas within the State of Texas (including State and Federal Offshore Areas) shall be considered, however, contracts entered into for the purchase of peaking gas shall not be considered. If the bona fide pipeline company does not sell some amount of gas to unrelated third parties (other than sales of gas to be used in production, exploration, fuel for field processing of natural gas, compression or similar operations), purchases between buyers and sellers which are related (agents, subsidiaries, affiliates, etc.) may not be considered. From these contracts the parties shall determine the highest contract price and such price shall be the price determined under this paragraph.

(b) The highest price to be paid for natural gas (other than peaking gas) during the 12-month period for which a price is to be determined by a user for volumes of gas of at least 10,000 Mcf per day. Only contracts of users which consume an average of 25,000 Mcf or more of gas per day shall be considered. The 10,000 Mcf per day volume may consist of a single contract or several contracts. In the event more than one contract is involved, the prices shall be weighted based on daily volumes to be delivered, and then averaged. The contracts so used may or may not have commenced deliveries, if it can be reasonably assumed that deliveries will commence within 90 days from October 1.

If the point of delivery of the gas purchased by the user is different from the wellhead or central point in the field, then the party submitting such price under this paragraph (b) shall furnish to the other party sufficient data to establish the commodity component and the transportation component of the price and only the commodity component shall be considered in the price determination under this Article IV.1.C.

For purposes of this paragraph (b), purchases by users shall be deemed to include only purchases by users or affiliates of users from sellers other than a seller who is an affiliated company with such purchasing user or affiliate of such user. Further, only purchases which involve gas which will be purchased in Texas and physically consumed on the Gulf Coast of Texas will be considered.

(c) The highest offer for gas (except peaking gas) made by (i) Buyer or any successor thereof or (ii) any company affiliated with Buyer or successor thereof when the offer is being made for gas to be supplied to Buyer or successor thereof for use in its general pipeline system and, when the terms of such offer are known to Buyer, Buyer shall make the necessary information available to Seller each year for the price calculation provided herein.

(d) Attached hereto as Exhibit "B" is a list of eight companies which own steam electric plants in the State of Texas. Each year by ~~August~~ June 10, prior to the 12-month period for which a price is to be determined, the parties shall submit to each other all information which is available to such parties concerning the cost of and quantities received of all fuels between and including Distillate Oil (No. 2) and Residual Oil (No. 6) which are to be used in plants having individual capacities of 25 megawatts or greater and which were received by such companies during the months between ~~July~~ May 31 of the preceding year and ~~July~~ May 31 preceding the 12-month period for which a price is to be determined. The parties specifically recognize that information may not be available for all of the companies for all of the months involved but only such quantities and costs that are available shall be used for calculating a price under this paragraph. As of the effective date of ~~this~~ contract the parties agree that the individual company Form 423 reports which the company is required to file monthly with the Federal Power Commission shall be used as the data for determining quantities and amounts under this paragraph.

Should the Federal Power Commission or any successor regulatory body cease to require this report, or should there be any change in the reporting procedure then the parties hereto shall mutually agree upon another method of obtaining the information required and, in the case of reporting procedures, agree on the changes to be utilized.

The costs and volumes that are available from the data described above for the eight companies shall be used to determine the average price per MMBTU for all such fuel oil paid by such eight

companies during such prior 12-month period and such price shall be the price determined for the purpose of this paragraph.

2. Buyer's Right to Cancel

Should the price determined by the method described in Article IV. 1.C. (d) or by arbitration of Article IV.1.C.(d)) exceed the highest price determined by the other methods described in Article IV.1.C. (or by arbitration of Article IV. 1.C. (a), (b), (c)) by 30%, then Buyer shall have the option, to be exercised within 20 days from the date all prices determined under Article IV.1.C. were agreed to (or as determined by arbitration) to cancel this contract by giving written notice of such intent to cancel this contract. However, Seller shall have the right to continue the contract in full force and effect by agreeing, within 30 days of receipt of Buyer's written notice of cancellation, to accept negotiated price for the gas during the 12-month period in question but in no event shall such price be less than 10% above the highest of the prices determined in Article IV. 1.C. (a), (b) or (c). In the event Seller does not elect to accept such lower price, then Buyer shall continue receiving and purchasing such gas from Seller until such time as Seller has made arrangements to dispose of the gas, however, Buyer will not be obligated to continue taking gas for a period longer than eleven months from the date Seller advises Buyer that Seller elects not to accept such lower price. All gas so taken by Buyer during such period, including the 20-day period within which Buyer has the right to cancel and the thirty-day period which Seller has to exercise its right to refuse the lower price (to the extent that such periods are not prior to the 12-month period under consideration), shall be paid for at the appropriate price then in effect under Article IV. 1.C. (i) or (ii) for the 12-month period in question or at a price determined by multiplying

the highest of the prices determined and not in dispute as of ~~October~~ August 1 of the 12-month period in question in Article IV.1.C.(a), (b) or (c) by 110%, whichever i the greater. All appropriate provisions of this contract shall govern the purchase and sale of gas during such period.

3. Arbitration

In the event the parties hereto shall fail to reach agreement on any matter relating to the calculation of a price under this Article IV. by ~~September~~ July 10, the matter shall, at the request of either party hereto, be submitted to arbitration in accordance with provisions of Article 14. of the "General Terms," attached hereto and made a part hereof.

4. Prices Pending Determination of New Price

In the event the parties hereto have not agreed upon the price to be paid at the beginning of the 12-month period under consideration or if the price is in arbitration at the beginning of such period, Buyer shall pay to Seller for gas purchased during such period, until such new price is agreed upon or determined by arbitration, the appropriate price in effect under Article IV.1.C. (1) or (i) or a price determined by multiplying the highest of the prices not in dispute determined in Article IV.1.C. (a), (b) or (c) by 110%, whichever is the greater. After the price to be paid during the period under consideration has been agreed upon or determined by arbitration, and if Buyer does not elect to cancel this contract as hereinabove provided, retroactive adjustment (if any shall then be due by either party to the other) shall be made between the price theretofore paid for gas during such period and the price agreed upon or determined to be applicable during such period. Notwithstanding the above, if the price to be paid during such period has not been determined by the end of

the period under consideration and the parties hereto have agreed upon the price to be paid for the succeeding period, then effective at the commencement of such succeeding period, the price to be paid for gas purchased during such period shall be the price so agreed upon, subject to adjustment in the event Buyer elects to cancel this contract in accordance with the provisions of paragraph 3. above on determination of the price which has been under arbitration. In the event Buyer does so cancel this contract, no retroactive adjustment shall be made.

5. BTU Price Adjustment

In the event that the heating value of the gas purchased hereunder shall be greater than or less than 1,000 British Thermal Units per cubic foot, the price set forth above currently in effect shall be increased or decreased, as the case may be, by multiplying the same by a fraction, the denominator of which shall be 1,000 and the numerator of which shall be the British Thermal Unit heating value per cubic foot of such gas.

6. Tax Reimbursement

Buyer agrees to reimburse Seller for one hundred percent (100%) of that portion of the aggregate amount of all of the Taxes per Mcf paid by Seller with respect to gas sold hereunder which shall be in excess of seven and one-half percent (7-1/2%) of the price per Mcf paid when the sale actually occurs.

B. PRICE: Each contract shall contain the following pricing provision: The price to be paid by Buyer to Seller during each year shall be the higher of: (a) the highest price currently being paid, or contracted, for gas in Texas Railroad Commission District No. 8, or (b) the following schedule:

II

1st year - 110% of the price of fuel oil equivalents
2nd year - 113% of the price of fuel oil equivalents, but not less than 67.34¢/MMBTU
3rd year - 116% of the price of fuel oil equivalents, but not less than 69.19¢/MMBTU
4th year - 119% of the price of fuel oil equivalents, but not less than 70.98¢/MMBTU
5th year - 122% of the price of fuel oil equivalents, but not less than 72.77¢/MMBTU
6th year - 125% of the price of fuel oil equivalents, but not less than 74.56¢/MMBTU
7th year - 128% of the price of fuel oil equivalents, but not less than 76.35¢/MMBTU
8th year - 131% of the price of fuel oil equivalents, but not less than 78.14¢/MMBTU

For the purposes of each contract, the "price of fuel oil equivalents" shall refer to the low quotations of the price of Gulf Coast Bunker C fuel oil (max. 0.6% sulfur) as published in Platt's Oilgram Price Service, Houston Edition, or if such Edition is discontinued or ceases to publish such quotations, then the quotations for Gulf Coast Bunker C fuel oil (max. 0.6% sulfur) in a comparable publication. Provided, further, that if Platt's or such other comparable publication shall cease to publish quotations for Gulf Coast Bunker C fuel oil (max. 0.6% sulfur) or if for any reason the use of 0.6% maximum sulfur fuel oil in all major metropolitan areas of Texas is prohibited, there shall be used the quotations from the applicable publication for the highest sulfur content fuel oil permitted. The fuel oil price to be used in determining the applicable contract price shall be an average of the aforesaid quotations during the twelve (12) consecutive months immediately preceding the applicable contract year. A factor of 6.287 MMBTU's per barrel shall be used to convert the price of fuel oil to cents per MMBTU in determining the price of gas, subject, however, to any adjustments required from time to time or at any time to maintain an accurate conversion of the heating value of fuel oil to that of natural gas.

C. QUANTITY: Each contract shall contain the following quantity provision:

i. The average DCQ will be the allowable assigned or 85% of deliverability, whichever is lesser.

ii. Buyer will take ratable in accordance with deliverability of wells or allowables set out by the Texas Railroad Commission, whichever is applicable, to

14. The term "MCF" means one thousand (1,000) cubic feet of gas.

15. The term "psig" means pounds per square inch gauge.

II.

DELIVERY POINTS

Seller and Buyer shall by mutual agreement establish a delivery point at the inlet flange to Buyer's facilities near the outlets of the "Warren Sand Hills Plant" and the "Warren Waddell Plant", Crane County, Texas; provided that upon Seller's written request Buyer shall establish the delivery points at the inlets of the processing facilities of either or both of said Plants; herein referred to as "Delivery Points". Buyer at its expense shall construct, operate and maintain all facilities at and from the Delivery Points necessary for carrying out its obligations under this Contract.

III.

PRICE

1. Base Price

Subject to all other applicable provisions hereof, the price to be paid by Buyer to Seller for each MMBTU of gas delivered for sale by Seller to Buyer hereunder, or for which Buyer is obligated to pay whether or not received, shall be one dollar and ninety cents ($1.90) plus fixed escalations of two and five tenths cents (2.5¢) per MMBTU January 1, 1976, and each six months thereafter during the term hereof.

2. Price Redeterminations

Seller is hereby given options to cause the price to be paid by Buyer for Seller's gas to be redetermined as of July 14, 1975, and thereafter at January 1, 1976 and at the end of each six (6) months thereafter during the term hereof as provided hereinafter. Such redetermined price shall become effective at the beginning of any such six (6) month period and shall remain in

effect until adjusted by the redetermination process or by the operation of any other provision of this agreement. Thirty (30) days prior to the beginning of each new six (6) month period, Buyer shall advise Seller of the level at which Buyer has information to believe that the price would next be redetermined, and Seller shall advise Buyer of the information Seller has that would redetermine the price. If Buyer and Seller cannot agree on price, arbitration proceedings would begin as provided in Article XXII.

The redetermined price payable for such gas shall not be less than the price payable under any other provision of this Article III and shall be equal to the highest price (including all allowances for gathering, BTU content, tax reimbursement and similar pricing provisions) per MMBTU being paid a producer by a pipeline company anywhere in the State of Texas for gas committed under a long-term gas contract (two years or longer) for the purchase of gas of a pressure and quality similar (or if dissimilar as to quality and pressure, appropriate adjustments shall be made thereto), to that available hereunder at the time of such redetermination. For purposes of this Contract, a pipeline company is defined as any company whose principal business is purchasing gas from producers in the field and transporting such gas through its pipeline facilities for resale to third parties for consumption.

3. Tax Liability and Tax Reimbursement

Seller agrees to pay, or cause to be paid, all taxes and assessments imposed upon Seller with respect to the gas delivered hereunder prior to its delivery to Buyer. Buyer agrees to pay, or cause to be paid, all taxes and assessments imposed upon Buyer with respect to the gas delivered hereunder after receipt of gas by Buyer. Neither party shall be responsible or liable for any taxes or other charges levied or assessed against any of the facilities of the other party used for the purpose of carrying out the provisions of this Contract; provided, however, Seller shall be liable for all taxes levied or assessed on the sale

III. Marathon Oil Company South Hobbs

PRICE #18 56872-102 836-06 III

1. Subject to all other applicable provisions hereof, for all gas delivered by Seller to Buyer at the Delivery Point, Buyer agrees to pay Seller one dollar and ninety cents ($1.90) per MMBTU during the first Contract Year. This price, if not redetermined as provided for hereunder, shall escalate two cents (2.0¢) per MMBTU at the beginning of the second and each succeeding Contract Year.

2. Each of Seller and Buyer is hereby given the option to cause the price to be paid by Buyer for Seller's gas, for the second and each succeeding Contract Year of the term hereof, to be redetermined as hereinafter provided. Such redetermined price shall become effective at the beginning of any such Contract Year. Any request for a redetermination of prices shall be given in writing by one party to the other not less than thirty (30) nor more than ninety (90) days prior to the beginning of the Contract Year for which a price redetermination is requested. Should such request not be given within such time, said option for such respective period shall be deemed to have been waived for that period only.

3. The redetermined price shall be computed by taking the average (rounded off to the nearest one-hundredth of a cent) of the three (3) highest prices per MMBTU of gas

being paid by a pipeline company or companies to a producer or producers (including prices being paid by Buyer or prices being received by Seller, if applicable) under new gas purchase contracts executed within the twelve (12) month period immediately preceding the Contract Year for which a redetermination is being computed. To be taken into account when computing a price redetermination, a contract must have an original term of five (5) years or longer and be for the purchase, in Texas Railroad Commission Districts 8 or 7-C, of gas of a pressure and quality similar to that available hereunder (or if of a different pressure and quality, appropriate adjustments shall be made) on the first day of the Contract Year for which a redetermination is being made; provided, however, any price being paid by an interstate company will not be used under this paragraph to the extent that such price is suspended or subject to refund at the time of any such price redetermination hereunder. For purposes of this Contract, a pipeline company is defined as any company whose principal business is purchasing gas from producers in the field and transporting such gas through their pipeline facilities for resale to third parties for consumption.

4. Notwithstanding the foregoing provisions of this Article III, if from time to time and at any time after the first Contract Year, but not more often than once during any Contract Year, it is determined by Buyer (in its sole discretion) that economic conditions indicate a downward change in the value to Buyer of gas purchased from Seller, Buyer is given the option to cause the price to be paid hereunder to be renegotiated. Any request for a renegotiation of price shall be given in writing by Buyer to Seller not less than ninety (90) days prior to the date upon which such renegotiated price is to become effective. Buyer and Seller agree to negotiate in good faith to determine a renegotiated price which will reflect the economic conditions and the burden on Buyer with respect to the price in effect hereunder at the time such request for renegotiation is given. Such renegotiated sales shall be at any price and under any terms and conditions as may be mutually agreed upon by the parties; provided, however, at any date within ninety (90) days from the date the renegotiated price becomes effective, Seller may elect to terminate this Contract, and sell such gas to another pipeline company at a price higher than the renegotiated price or consume such gas in its own operations, by giving written notice of such election to Buyer. At Seller's option, deliveries may continue at the renegotiated price on a day to day basis for a period not to exceed ninety (90) days from the date Seller notifies Buyer of its intention to

terminate the Contract.

In the event the parties cannot reach a mutually agreeable price by the end of the renegotiation period, Seller may elect to continue selling gas to Buyer, at the price and under conditions as existed at the time the request for renegotiation was given, for a period of ninety (90) days after the end of the negotiation period, at which time the Contract will be terminated.

In the event Seller elects to terminate the Contract pursuant to this Section 4 by selling such gas to another pipeline company at a price higher than the renegotiated price or by consuming such gas in its own operations, then at Seller's option Buyer and Seller will enter into a transport agreement, under the terms of which Buyer will be obligated to transport the gas dedicated hereunder to a mutually agreeable point on Buyer's or its nominee's pipeline system for delivery to Seller or Seller's agent. Such transport obligation will extend through the original term of this Contract, and the initial transport fee shall correspond to the fees Buyer is charging others for similar service at the time of termination hereunder.

5. Buyer agrees to reimburse Seller for all "excess in royalty payments" which Seller may incur on any of Seller's leases with respect to gas sold and delivered to Buyer hereunder. Such payments shall be made by Buyer to Seller within ten (10) days following receipt of statement

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Atlantic Richfield Co.
Wade Ltd.
#18-04200-112

From the beginning of the First Contract Year through November 30, 1974	25.0¢
From December 1, 1974 through November 30, 1978	26.0¢
From December 1, 1978 through November 30, 1982	27.0¢
From December 1, 1982 through November 30, 1986	28.0¢
From December 1, 1986 through November 30, 1990	29.0¢

If this Contract continues in effect after the twentieth Contract Year, further escalations of one cent (1¢) per MCF shall become effective at the end of said twentieth Contract Year and at the end of each fourth Contract Year thereafter.

2. Heating Value Adjustment

If the heating value of Seller's Gas, as hereinafter determined at each delivery point, is less or greater than 1000 BTU per cubic foot, the foregoing prices shall be adjusted by multiplying the applicable price by a fraction whose numerator is the determined heating value and whose denominator is 1000.

3. Seller is hereby given the option to cause the price to be paid by Buyer for Seller's gas for the second,

Atlantic Richfield
Waha Fld.

third, fourth or fifth four-year period as set forth above to be redetermined as hereinafter provided. Such redetermined price shall become effective at the beginning of any such four (4) year period, and shall remain in effect during said four-year period in lieu of the 1¢ escalation otherwise applicable hereunder. Any request for a redetermination of prices shall be given in writing by Seller to Buyer within ninety (90) days prior to the beginning of the four (4) year period for which a price redetermination is requested. Should such request not be given within such time, Seller's said option for such four (4) year period shall be deemed to have been waived by Seller.

The redetermined price payable for such gas for any such four (4) year period shall be no higher than the highest of the following prices:

(1) The highest of the prices and other applicable and valid considerations which Buyer has agreed to pay any producer for gas delivered from lands and leases situated in the Waha Field Area, Reeves County, Texas, under terms and conditions similar in all other respects to those provided in this Contract; or

Atlantic Richfield
Waha Fld.

(ii) The highest of the prices and other valid considerations which Seller or any other producer of gas from the Waha Field Area is then legally entitled to receive from another intrastate gas pipeline company which is purchasing gas for resale wholly within intrastate commerce from gas reserves in the Waha Field Area of a similar quality and quantity to those attributable to Seller's lands and leases in the Waha Field Area; or

(iii) The price offer and other valid consideration which Seller or any other producer of gas in Railroad Commission District 8 has received for gas reserves in said District 8 from another intrastate gas pipeline company purchasing gas for resale wholly within intrastate commerce who is ready, able, and willing to purchase gas reserves of a similar quality and quantity to those attributable to Seller's lands and leases in the Waha Field Area; provided, however, Buyer may decline to agree to pay hereunder a price redetermined at the level of such higher offer in which event Seller may terminate and cancel this Contract.

The price as redetermined shall be in effect at the beginning of any such four (4) year period and shall continue in effect until the next succeeding four (4) year period when such price shall either escalate one cent (1¢) per Mcf or again be redetermined as provided above.

18-67810-101

rate proceedings he l to give consideration to any area rate higher than those provided for herein, to oppose therein any such higher area rate. Buyer shall receive hereunder any and all rights and benefits given to any pipeline company in any such proceeding, including, without limitation, refund of money paid; provided, however, the price to be paid hereunder shall never be reduced below that price otherwise provided under the other provisions of this Article VIII.

Seller is given the option to cause the price to be paid by Buyer for Seller's gas to be redetermined for the one contract year period commencing with the beginning of the second contract year, and additional such options for each succeeding contract year during the term of this Contract. Such redetermined price shall become effective as of the first day of the contract year for which it is determined and shall continue in effect unless it should be replaced by a higher price under the provisions of this Article VIII, but such redetermined price shall not be less than the fixed prices otherwise provided hereunder. Any request for a redetermination of prices shall be given in writing by Seller to Buyer not less than ninety (90) days nor more than one hundred eighty (180) days prior to the beginning of the one (1) year period for which a price redetermination is requested. Should such request not be given within such time, Seller's said option for such one (1) year period shall be deemed to have been waived by Seller for that period only.

The redetermined price payable for such gas for any such one (1) year period shall be the average (rounded off to the nearest tenth of a cent) of the two (2) highest prices (taking into account all valid pricing considerations) per MCF of gas being paid in Railroad Commission Districts 8 and 7-C under long-term gas contracts to producers by intrastate pipeline companies for the purchase of gas of a pressure and quality similar (or if dissimilar as to quality and pressure, appropriate adjustments shall be made thereto) to that available hereunder at the time of such redetermination.

ARTICLE IX

BILLING AND PAYMENT

Buyer shall render a statement to Seller on or before the 10th day of each calendar month showing the volume of gas, in terms of Btu's and MCF's, delivered to Buyer hereunder during the preceding calendar month at the point of delivery. On or before the twenty-fifth (25th) day of each calendar month after the month of first delivery hereunder, Buyer agrees to make payment to Seller for all gas received by Buyer hereunder during the preceding calendar month or such monthly billing period as is used by Buyer. Such accounting and payment shall be supported by a statement showing the total amount of gas delivered to Buyer during such prior month or billing period and the amounts due therefor as provided in this Contract.

Superior - W. Recardo

III

ARTICLE IX

PRICE

9.1 Subject to the other provisions of this Contract, Buyer agrees to pay to Seller for each one thousand (1,000) cubic feet of gas delivered by Seller to Buyer hereunder, or for which Buyer is obligated to pay for whether taken or not, as follows:

(a) From the date of first delivery of gas hereunder or thirty (30) days from the date hereof (whichever is earlier), subject, however, to the provisions of Paragraph 5.2 of Article V, and for a period of four contract years - 26.0¢ per Mcf.

(b) For the next four contract years - 27.0¢ per Mcf.

(c) For the next four contract years - 28.0¢ per Mcf.

(d) For each succeeding four year period during the term of this Contract the price shall be increased 1.0¢ per Mcf over that in effect for the preceding four year period.

9.2 If the heating value of Seller's gas is less or greater than 1,000 Btu's per cubic foot, the foregoing prices shall be adjusted by multiplying the applicable price by a fraction whose numerator is the determined heating value and whose denominator is 1,000.

9.3 Seller is given the option to cause the price to be paid by Buyer for Seller's gas to be redetermined as provided below for the second four contract year pricing period pro-

vided in Section 9.1 above and additional such options for each such succeeding four contract years pricing period during the term of this Contract. A redetermined price shall become effective as of the first day of the four year period for which it is determined, and during such period shall be subject to being replaced by a higher price under the other paragraphs of Articles IX and X. Any request for a redetermination of price shall be given in writing by Seller to Buyer not less than ninety (90) days nor more than one hundred eighty (180) days prior to the beginning of the four (4) year period for which a price redetermination is requested. Should such request not be given within such time, Seller's said option for such four (4) year period shall be deemed to have been waived by Seller for that period only. Should Buyer and Seller be unable to agree on a redetermined price prior to sixty (60) days before such price is to become effective, at the request of either Buyer or Seller the matter shall be determined by arbitration under the provisions of Article XX hereof.

The redetermined price payable for such gas for any such four (4) year period shall be the highest of the following prices:

(i) The highest price then provided by other Sections of Article IX and X;or

(ii) The average (rounded off to the nearest tenth of a cent) of the three (3) highest prices per MCF of gas being paid in Railroad Commission District 4 under long-term gas contracts to producers by intrastate pipeline companies or to independent producers (other than "small producers") as classified by the Federal Power Commission by interstate pipeline companies

for the purchase of gas of a pressure and quality similar (or if dissimilar as to quality and pressure with appropriate adjustments for such dissimilarities) to that available hereunder at the time of such redetermination; provided, however, any price being paid by an interstate company will not be used under this paragraph to the extent that such price is suspended or subject to refund at the time of any such price redetermination hereunder.

9.4 If at any time or from time to time during the term of this Contract, the Federal Power Commission, or any successor governmental authority having jurisdiction in the premises, shall allow, by final order following hearing, or by settlement, for the area in which Seller's leases are situated, higher unconditional rates for natural gas of the contract vintage and quality (including upward and downward BTU adjustment and other applicable and appropriate factors) of the gas involved herein than the price herein then provided to be paid, then the price to be paid by Buyer to Seller for gas which has been delivered under the provisions of this Contract since the date the higher rate is made effective by said order shall be retroactively increased, and thereafter continued until a further higher price is provided under this or any other paragraph of this Article. Any sum retroactively due Seller under this Paragraph 9.4 shall bear interest from the date the higher rate is made effective until paid as provided in Section 14.1 of this Agreement, shall be paid to Seller within thirty (30) days

after said order is final; provided, however, Buyer shall have the right, at its option, to intervene in any area rate proceedings held to give consideration to any area rate higher than those provided for herein, to oppose therein any such higher area rate and, in the case of any such higher area rate, to seek relief therefrom in any regulatory agency or any court having jurisdiction. Buyer shall receive hereunder any and all rights and benefits given to any pipeline company in any such proceeding, including, without limitation, refund of money paid; provided, however, the price to be paid hereunder shall never be reduced below that price otherwise provided under the other provisions of this Article. Should Buyer and Seller be unable to agree within thirty (30) days following final order of the Federal Power Commission that the price established thereby is higher or the amount by which such price is higher, at the request of either Buyer or Seller the matter shall be determined by arbitration under the provisions of Article XX hereof.

ARTICLE X

TAXES

10.1 Seller shall bear and pay all gross production or severance taxes assessed or levied upon or with respect to gas delivered hereunder at the rate existing on the date hereof. Buyer shall bear and pay all taxes levied and assessments imposed upon Buyer with respect to gas delivered hereunder after its receipt by Buyer. Neither party shall be responsible or liable for any taxes or other statutory charges levied or

5. Quality - Seller agrees that all gas delivered to Buyer at the point of delivery shall be merchantable dry gas which shall:

(a) contain not more than one-fourth (1/4th) grain of hydrogen sulphide or more than ten (10) grains of sulphur per one hundred (100) cubic feet;

(b) have a gross heating value of not less than 950 Btu's per cubic foot of gas when saturated with water vapor. Buyer shall have the right, but not the obligation, to accept deliveries of gas with a heating value less than 950 Btu's per cubic foot;

(c) not have a maximum temperature greater than 120° F. or a minimum temperature less than 40° F.;

(d) be commercially free of all gums and gum forming constituents, and all free liquids.

6. Price - For all gas purchased hereunder, subject to the Btu provisions as contained herein, Buyer agrees to pay Seller 47.5¢ per Mcf from the date of first delivery until the end of the first contract year. The price shall escalate one cent (1¢) per Mcf at the beginning of the second contract year and each contract year thereafter. The parties hereto agree that the 1.0¢ price escalations provided herein shall not continue to be applicable should Seller elect to have the above-specified price redetermined hereunder; provided, however, once the redetermined price is the same as the last highest applicable price established under this paragraph, then the 1.0¢ price escalations shall again become effective until said price is again redetermined.

If the heating value of the gas delivered by Seller to Buyer is more or less than 1,000 Btu's per cubic foot, then the price as provided for above shall be multiplied by a fraction, the numerator of which is the heating value of the gas and the denominator of which is 1,000.

Seller is given the option to cause the price to be paid by Buyer for Seller's gas to be redetermined for each contract year commencing at the end of the first contract year, and additional such options for such succeeding contract year thereafter during the term of the Agreement. Such redetermined price shall become effective as of the

first day of the contract year for which it is determined. Any request for a redetermination of prices shall be given in writing by Seller to Buyer not less than sixty (60) days nor more than one hundred eighty (180) days prior to the beginning of the contract year for which a price redetermination is requested. Should such request not be given within such time, Seller's said option for such period shall be deemed to have been waived by Seller for that period only. Seller shall not qualify for the price redetermination option for a contract year if Seller's average delivery of gas hereunder for the three month period preceding the effective date of such redetermination is less than 250 Mcf per day.

The redetermined price payable for such gas for any contract year shall be the average (rounded off to the nearest tenth of a cent) of the two (2) highest prices (taking into account all valid pricing considerations) per Mcf for gas being paid in Texas Railroad Commission District Three under long-term gas contracts (5 years or longer) to producers by intrastate pipeline companies or to independent producers (other than "small producers" as classified by the Federal Power Commission) by interstate pipeline companies, for the purchase of gas of a pressure and quality similar (or if dissimilar as to quality and pressure, appropriate adjustments shall be made thereto) to that available hereunder at the time of such redetermination; provided, however, any price being paid by an interstate company will not be used under this subparagraph to the extent that such price is suspended or subject to refund at the time of any such price redetermination hereunder. For purposes of this Contract, a "pipeline company" is defined as any company whose principal business is purchasing gas from producers in the field and transporting such gas through their pipeline facilities for resale to third parties for consumption.

7. Measurement - Buyer agrees to measure the gas purchased hereunder by means of standard type equipment and that such gas will be measured in conformance with the Texas Standard Gas Measurement Act. For the purpose of measurement, a cubic foot of gas is defined as the volume of gas contained in one cubic foot of space at a standard pressure base of fourteen and sixty-five one-hundredths (14.65) pounds per square inch absolute and a standard temperature base of sixty degrees Fahrenheit (60° F.). Temperature shall be determined by a recording thermometer continuously used and installed by Buyer so as to record properly the temperature of the gas being metered, and

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(4) be commercially free of all gums and gum forming constituents, and all free liquids; and

(5) not contain any free water.

6. Price

6.a For all gas delivered to Buyer at the Point of Delivery, subject to the Btu provisions as contained herein, Buyer agrees to pay Seller $1.85 per Mcf during the term hereof, or until such price is redetermined or renegotiated as hereinafter provided.

6.b If the heating value of the gas delivered by Seller to Buyer at the Point of Delivery is more or less than 1,000 Btu's per cubic foot, then the price as provided for above shall be adjusted by multiplying such price by a fraction, the numerator of which shall be the gross heating value of the gas at the actual conditions of delivery, as determined under Paragraph 7.c hereof, and the denominator of which shall be 1,000.

6.c Each of Seller and Buyer is hereby given the option to cause the price to be paid by Buyer for Seller's gas to be redetermined, as hereinafter provided, for the second contract year, and additional such options for each succeeding contract year during the term of this Contract. Such redetermined price shall become effective on the first day of the contract year for which it is determined and shall remain effective until again redetermined. Any request

for a redetermination of prices shall be given in writing by one party to the other not less than sixty (60) days nor more than one hundred eighty (180) days prior to the beginning of the contract year for which a price redetermination is requested. Should such request not be given within such time, said option for such contract year shall be deemed to have been waived for that period only. Seller shall not qualify for the price redetermination option for a contract year if Seller's average delivery of gas hereunder for the three month period immediately preceding the effective date of such redetermination is less than 200 Mcf per day.

6.d The redetermined price shall be computed by taking the average (rounded off to the nearest one-hundredth of a cent) of the three (3) highest prices per Mcf of gas being paid on the effective date of the redetermination by a pipeline company or companies to a producer or producers (excluding any prices being paid retroactively but including prices being paid by Buyer or prices being received by Seller, if applicable) under new gas purchase contracts executed within the six (6) month period immediately preceding the contract year for which a redetermination is being computed. To be taken into account when computing a price redetermination, a contract must have an original term of two (2) years or longer and be for the purchase, in Texas Railroad Commission District(s) Three, of gas of a

pressure and quality similar to that available hereunder on the first day of the contract year for which a redetermination is being made; provided, however, any price being paid by an interstate company will not be used under this Paragraph. ~~to the extent that such price is suspended or subject to refund at the time of any such price redetermination hereunder.~~ For purposes of this Contract, a pipeline company is defined as any company whose principal business is purchasing gas from producers in the field and transporting such gas through their pipeline facilities for resale to third parties for consumption.

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6.e Notwithstanding the foregoing provisions of this Section 6, if at any time Buyer determines that economic conditions indicate a downward change in the value to Buyer of gas purchased from Seller, Buyer is given the option to cause the price to be paid by Buyer for Seller's gas to be renegotiated. Any request for a renegotiation of price shall be given in writing by Buyer to Seller not less than ninety (90) days prior to the date upon which such renegotiated price is to become effective. Buyer and Seller agree to negotiate in good faith to determine a renegotiated price which will reflect the economic conditions and the burden on Buyer with respect to the price in effect hereunder at the time such request for renegotiation is given. Such renegotiated

sales shall be at any price and under any terms and conditions as may be mutually agreed upon by the parties; provided, however, at any date within ninety (90) days from the date the renegotiated price becomes effective, Seller may elect to terminate this Contract and sell such gas to another pipeline company at a price higher than the renegotiated price by giving written notice of such election to Buyer. At Seller's option, deliveries may continue at the renegotiated price on a day to day basis for a period not to exceed ninety (90) days from the date Seller notifies Buyer of its intention to terminate the Contract.

6.f In the event the parties cannot reach a mutually agreeable price by the end of the renegotiation period, Seller may elect to continue selling gas to Buyer, at the price and under conditions as existed at the time the request for renegotiation was given, for a period of ninety (90) days after the end of the negotiation period, at which time the Contract will be terminated.

6.g In the event Seller elects to terminate the Contract pursuant to Paragraph 6.e, by selling such gas to another pipeline company at a price higher than the renegotiated price, then at Seller's option Buyer and Seller will enter into a transport agreement under the terms of which Buyer will be obligated to transport the gas dedicated hereunder

to a mutually agreeable point on Buyer's pipeline system for redelivery to Seller or Seller's agent. Such transport obligation will extend through the original term of this Contract, and the initial transport fee shall correspond to the fees Buyer is charging others for similar service under new gas transport agreements executed within the six (6) month period immediately preceding the date of termination hereunder.

7. Measurement

7.a Buyer agrees to measure the gas purchased hereunder by means of standard type equipment and that such gas will be measured in conformance with the Texas Standard Gas Measurement Act and American Gas Association Gas Measurement Committee Report No. 3 or subsequent revisions thereof. For the purpose of measurement, a cubic foot of gas is defined as the volume of gas contained in one cubic foot of space at a standard pressure base of fourteen and sixty-five one-hundredths (14.65) pounds per square inch absolute and a standard temperature base of sixty degrees Fahrenheit (60° F.). Temperature shall be determined by a recording thermometer continuously used and installed by Buyer so as to record properly the temperature of the gas being metered, and specific gravity shall be determined by Buyer by use of the Acme gravity balance, or, at the option of Buyer, by such other tests and instruments as may be standard for such purposes in the gas industry.

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III

6. Price

6.a From the date of initial delivery of gas hereunder to November 1, 1974, for all gas delivered to Buyer at the Point of Delivery, Buyer agrees to pay Seller $1.26 per MMBtu.

6.b On November 1, 1974, and to be determined each 6 months thereafter the price shall be the highest of the following:

(1) The existing price plus an escalation of 1.0¢ per MMBtu or

(2) The highest price being paid a producer per MMBtu on the first day of the period for which the redetermination is being made for the purchase of gas of a pressure and quality similar to that available hereunder in Texas Railroad Commission District No. 3 by a pipeline company under a contract whose original term is one year or longer; provided, however, that if such highest price is being paid in compliance with any type of an "oil parity" price clause contained in such contract and Seller will not agree to be paid the next highest price provided hereunder which is not based on an "oil parity" price, then Buyer may elect to terminate this contract upon thirty (30) days' notice to Seller rather than pay such redetermined price; provided, further, that any price being paid by an interstate company will not be used under this subparagraph to the extent that such price is being collected subject to refund at the time of any such price redetermination hereunder.

For purposes of this Contract, a "pipeline company" is defined as any company whose principal business is purchasing gas from producers in the field and transporting such gas through their pipeline facilities for resale to third parties, or

(3) The average (rounded off to the nearest one-hundredth of a cent) of the three (3) highest prices per MMBtu for gas being paid by a pipeline company to a producer under a contract whose original term is one (1) year or longer, for the purchase in Texas Railroad Commission Districts 2, 3 and 4, of gas of a pressure and quality similar to that available hereunder on the first (1st) day of the period for which a redetermination is being made; provided, however, any price being paid by an interstate company will not be used under this subparagraph to the extent that such price is being collected subject to refund at the time of any such price redetermination hereunder. For purposes of this Contract, a "pipeline company" is defined as any company whose principal business is purchasing gas from producers in the field and transporting such gas through their pipeline facilities for resale to third parties, or

(4) An "oil parity" price based on a procedure to be mutually agreed upon; provided, however, in redetermining prices under this Paragraph 6.b, this subsection (4) shall not be taken into account until the redetermination on

November 1, 1976, but shall be taken into account on November 1, 1976 and at each subsequent price redetermination; and provided further, Buyer shall have the right to terminate this Contract upon thirty (30) days' written notice to Seller rather than pay such "oil parity" price unless Seller elects to redetermine the price to be paid it hereunder without taking into account the "oil parity" price agreed on under this subsection 4 of paragraph 6.b.

6.c In the event that the Federal Power Commission, or any other governmental agency having jurisdiction, shall at any time subsequent to the date of this Contract prescribe or establish by final order following hearing, or by settlement, or otherwise make effective, a ceiling rate applicable to jurisdictional sales of natural gas of the quality (including upward and downward BTU adjustment and other applicable and appropriate factors) from the area in which the properties covered hereby are located that is greater than the price provided herein, then the price hereunder shall be increased to equal said ceiling rate effective on the same date as the effective date set forth in such final action of the Federal Power Commission or other agency. It is further agreed that Buyer shall receive any and all rights and benefits hereunder, including, without limitation, refund of money paid, that is allowed to any purchaser of gas in any such rate proceeding.

Acco Oil & Gas Co.
May 8, 1973

page three

Any gas taken in any contract year in excess of the annual minimum quantity required to be taken for such contract year shall be considered make-up gas to the extent necessary to liquidate any gas take deficiency occurring in prior years in the order in which such deficiencies occurred. The term "contract year" means a period of twelve (12) consecutive months during the life of this Contract beginning at 8:00 a.m. on the first day of May of any year and ending at 8:00 a.m. on the first day of May of the next succeeding year. The first contract year shall be that period from date of first delivery of gas hereunder to May 1, 1974.

5. Quality - Seller agrees that all gas delivered to Buyer at the point of delivery shall be merchantable dry gas which shall:

(a) contain not more than one-fourth (1/4th) grain of hydrogen sulphide or more than ten (10) grains of sulphur per one hundred (100) cubic feet;

(b) have a gross heating value of not less than 1,000 Btu's per cubic foot of gas when saturated with water vapor. Buyer shall have the right, but not the obligation, to accept deliveries of gas with a heating value less than 1,000 Btu's per cubic foot;

(c) not have a maximum temperature greater than 120° F. or a minimum temperature less than 40° F.;

(d) ~~be commercially free of all gums and gum forming~~ constituents, and all free liquids. ~~The~~ gas shall not contain in ~~excess of~~ seven (7) pounds of ~~water per million cubic feet~~.

6. Price - For all gas purchased hereunder, subject to the Btu provisions as contained herein, Buyer agrees to pay Seller 45.0¢ per Mcf from the date of first delivery until the end of the first contract year. This price, if not redetermined as provided for hereunder, shall escalate 1.00¢/Mcf at the beginning of the second and each succeeding contract year.

If the heating value of the gas delivered by Seller to Buyer is more or less than 1,000 Btu's per cubic foot, then the price as provided for above shall be multiplied by a fraction, the numerator of which is the heating value of the gas and the denominator of which is 1,000.

Seller is given the option to cause the price to be paid by Buyer for Seller's gas to be redetermined for the contract year commencing May 1, 1974, and additional such options for each succeeding contract year during the term of this Contract. Such redetermined price shall become effective on the first day of the contract year for which it is determined. Any request for a redetermination of prices shall be given in writing by Seller to Buyer not less than sixty (60) days nor more than one hundred eighty (180) days prior to the beginning of the contract year for which a price redetermination is requested. Should such request not be given within such time, Seller's said option for such contract year shall be deemed to have been waived by Seller for that period only. Seller shall not qualify for the price redetermination option for a contract year if Seller's average delivery of gas hereunder for the three month period preceding the effective date of such redetermination is less than 200 Mcf per day.

The redetermined price shall be computed by taking the average (rounded off to the nearest one-hundredth of a cent) of the two (2) highest prices per Mcf for gas being paid by a pipeline company to a producer under a contract whose original term is two (2) years or longer, for the purchase in Texas Railroad Commission District Three (3), of gas of a pressure and quality similar to that available hereunder on the first (1st) day of February immediately preceding the contract year for which a redetermination is being made; provided, however, any price being paid by an interstate company will not be used under this subparagraph to the extent that such price is suspended or subject to refund at the time of any such price redetermination hereunder. For purposes of this Contract, a "pipeline company" is defined as any company whose principal business is purchasing gas from producers in the field and transporting such gas through their pipeline facilities for resale to third parties for consumption.

7. Measurement - Buyer agrees to measure the gas purchased hereunder by means of standard type equipment and that such gas will be measured in conformance with the Texas Standard Gas Measurement Act. For the purpose of measurement, a cubic foot of gas is defined as the volume of gas contained in one cubic foot of space at a standard pressure base of fourteen and sixty-five one hundredths

OKLAHOMA NATURAL GAS COMPANY

FAVORED NATIONS PROVISION
USED IN THE SOUTHEAST OKLAHOMA TYPE OF CONTRACT

13.2 If Buyer pays more than the price stipulated above for gas purchased in Haskell, Latimer, LeFlore, McIntosh, Muskogee or Sequoyah Counties, Oklahoma, under contracts of similar duration and having other terms and conditions similar to those herein provided, then during the period in which Buyer pays such higher price to others for gas produced in the above-described counties, Buyer shall pay Seller for gas produced hereunder an amount equal to the highest price so paid by Buyer for any such gas. In determining whether or not the price paid to others for such gas is higher than that specified herein, due consideration shall be given to the quality of the gas, the quantity of gas delivered at any single delivery point, flexibility with respect to obligations to take gas, cost of transportation of gas within and beyond the field in which it is produced, the size of the ultimately recoverable gas reserves dedicated to Buyer, and differences in delivery pressure which affect the cost of receiving and transporting gas. The provisions of this Paragraph 13.2 shall not apply to, and the price payable to Seller hereunder shall not be affected by, purchases of gas which prior to such purchase has been transported through a pipeline operated by a natural gas pipeline company or public utility, or such purchases and sales which are made through the same meter setting. Furthermore, the provisions of this Paragraph 13.2 shall not apply to, and the price payable to Seller hereunder shall not be affected by, purchases of gas for interstate transportation, use and/or sale.

13.2 If prior to July 1, 1979, Buyer pays more than the price stipulated above for gas purchased in Kingfisher, Blaine or Major Counties, Oklahoma, or if after July 1, 1979, Buyer pays more than the price stipulated above for gas purchased in Kingfisher, Blaine, Major, Dewey, Custer or Canadian Counties, Oklahoma, under contracts of similar duration and having other terms and conditions similar to those herein provided, then during the period in which Buyer pays such higher price to others for gas produced in the then applicable above-described counties, Buyer shall pay Seller for gas produced hereunder an amount equal to the highest price so paid by Buyer for any such gas. In determining whether or not the price paid to others for such gas is higher than that specified herein, due consideration shall be given to the quantity of gas delivered at any single delivery point, flexibility with respect to obligations to take gas, cost of transportation of gas beyond the field in which it is produced, the ultimately recoverable gas reserves dedicated to Buyer, and differences in delivery pressure which affect the cost of receiving and transporting gas. The provisions of this Paragraph 13.2 shall not apply to, and the price payable to Seller hereunder shall not be affected by, purchases of gas which prior to such purchase has been transported through a pipeline operated by a natural gas pipeline company or public utility, or such purchases and sales which are made through the same meter setting. Furthermore, the provisions of this Paragraph 13.2 shall not apply to, and the price payable to Seller hereunder shall not be affected by, purchases of gas for interstate transportation, use and/or sale, or purchases of gas made by a subsidiary company entirely or partially owned by Buyer.

PRICE REDETERMINATION PROVISION
CURRENTLY IN USE IN WESTERN OKLAHOMA CONTRACTS

C. Notwithstanding the above, it is understood and agreed that the price for gas delivered hereunder may be redetermined at the beginning of the accounting year following the normal chart changing time between December 19, 197__, and December 25, 197__, both inclusive, and at the beginning of every accounting year thereafter, with each such price redetermination to cover the gas delivered hereunder during the succeeding accounting year. Prior to the expiration of the above described accounting period Buyer shall propose by written notice a contract price for the succeeding period in accordance with the below described guideline and the information held by Buyer at that time. Upon such proposal, the price for the accounting period for which a redetermination is proposed may be agreed upon by the parties, but in the absence of an agreed redetermination the parties shall make a price redetermination for such period in the following manner:

The redetermined price shall be equal to highest price being paid during any one of the ninth (9th), tenth (10th), and eleventh (11th) accounting months of the accounting year immediately preceding the accounting period for which the redetermination is proposed for gas then being purchased in counties, Oklahoma, by any pipeline company or public utility that purchased at least an average of cubic feet of gas per day in the state of Oklahoma during the accounting year immediately preceding the accounting period for which the redetermination is proposed, which pipeline company or public utility is then purchasing gas in one or more of the aforesaid counties. In selecting such price, there shall be considered only such contract arrived at as a result of arm's length, good faith bargaining between producers which have no direct or indirect affiliation or special relationship with the purchaser being considered, and prices being paid under contract covering pipeline sales by or between transmission companies shall not be considered.

It is understood that contract price or prices being paid under bond or corporate undertaking shall be considered in determining said price. It is further understood that a contract price that a producer is temporarily restrained from accepting by executive order concerning emergency price controls or by regulatory bodies other than Federal Power Commission shall be considered. It is recognized that in making the determination herein provided for, the contract containing the price selected as herein provided will probably contain different specifications and conditions relating to the quantity, quality, pressures, deliveries, tax reimbursement, adjustment for heating value, and other circumstances regarding the gas to be delivered under the respective contract, and in such event appropriate adjustments in the unit price set out in said contract will be made to compensate for the variation in contractual terms and conditions to arrive at an adjusted price which will cover the delivery and receipt of gas under conditions comparable to those set out herein, and such adjusted price shall be used in lieu of the price set out in the respective contract in the determination of the price as herein provided, it being the intention that all variations in contractual conditions shall be converted by price adjustments to conform with the contractual conditions set out in this agreement.

D. It is further provided that should Buyer at any time be prohibited by the Corporation Commission of Oklahoma, its successor, or by any other Federal or state legislative or regulatory action, from including the full amount of the applicable contract price provided for above in computing the cost of purchased gas adjustment to be applied to the rates charged Buyer's customers, then Buyer may propose by written notice to Seller that the price to be paid to Seller hereunder shall thereafter be limited to that portion of the applicable contract price which Buyer is permitted to include for such purposes. In the event the price Buyer pays Seller for gas purchased hereunder is proposed by Buyer to be limited by the foregoing provision, Seller shall have thirty (30) days following receipt of notice from Buyer of such limited price within which to notify Buyer if it is unwilling to continue sales hereunder at such limited price; in the absence of such notice from Seller, the price as so limited shall become the contract price, effective as of the commencement of Buyer's first accounting month after the expiration of such thirty (30) day period, and shall remain in effect until such time as a higher price is permitted to be employed in the calculation of Buyer's cost of purchased gas adjustment, but in no event shall Buyer be required to pay more than the applicable contract price as provided in paragraphs A, B, and C hereof. However, if Seller is unwilling to continue sales hereunder at such limited price, then upon written notice from Seller to Buyer to that effect given within such thirty (30) day period, Buyer shall have sixty (60) days after its receipt of such notice within which to attempt to resolve the matter to Seller's and Buyer's mutual satisfaction. If such resolution has not occurred within such sixty (60) day period, then Buyer, at its election (to be communicated in writing to Seller during such 60-day period) can continue the contract in effect by continuing to pay Seller the applicable contract price as provided in paragraphs A, B, and C hereof; otherwise, this contract shall be terminated, effective upon the expiration of such sixty-day period, and neither party shall have any further obligation to the other hereunder, other than Buyer's obligation to pay for any gas taken but not paid for, provided that in the event Buyer has not fully recovered all deficiency payments made to Seller under the provisions of Article VI hereof, at the time of such contract termination, then Seller shall repay Buyer concurrently with such contract termination, an amount equal to all such unrecovered deficiency payments. During the period of negotiation provided for above, the applicable contract price as provided in paragraphs A, B, and C hereof shall be paid for all gas taken during said period.

Mr. VLCEK. A final question. To what extent have each of you made sales of natural gas to interstate pipelines in the last year under either the FPC 268 procedure or under the Emergency Natural Gas Act? What amounts were those and what prices?

Mr. INGRAM. During our last fiscal year, which ended last August 31, we sold 59 billion cubic feet of gas under the 60-day emergency sales that were authorized by the Federal Power Commission.

Mr. VLCEK. What prices were those?

Mr. INGRAM. They ranged from a low of $1.25 to a high fo $1.85.

Mr. VLCEK. Would you provide us with a list of individual sales and the price of each?

Mr. INGRAM. Yes, we can provide that for the record.

[The following information was received for the record:]

OKLAHOMA NATURAL GAS COMPANY
EMERGENCY PIPE LINE SALES
9/1/75 through 4/29 77

Purchaser	Volumes (Mcf)	Price (per MMBtu)
Arkansas Lousiana Gas Company	1,454,225	$1.85
Cities Service Gas Company	3,007,763	1.85
Columbia Gas Transmission Company	2,812,716	1.25
	1,022,667	1.80
	3,835,383 at average price of	1.40
Consolidated Gas Supply Corporation	5,771,729	1.85
East Ohio Gas Company	7,254,473	1:45
Lone Star Gas Company	1,229,662	1.25
	772,757	1.40
	2,151,504	1.65
	2,335,130	1.80
	6,489,053 at average price of	1.60
Memphis Light, Gas and Water	1,804,905	1.80
Michigan-Wisconsin Pipe Line Company	3,218,216	1.25
	2,474,360	1.35
	4,766,355	1.50
	6,301,509	1.65
	2,667,793	1.80
	19,428,233 at average price of	1.53
Natural Gas Pipeline Company of America	6,445,895	1.45
	8,682,404	1.65
	2,765,118	1.85
	17,893,417 at average price of	1.61
Northern Natural Gas Company	452,912	1.45
	2,610,191	1.80
	3,063,103 at average price of	1.75

Purchaser	Volumes (Mcf)	Price (per MMBtu)
Panhandle Eastern	3,076,389	$1.25
	5,015,000	1.35
	2,528,300	1.45
	300,000	1.70
	825,862	1.80
	11,745,551 at average price of	1.39
Trans-Continental Gas Pipe Line Co.	1,919,382	1.45
	2,920,525	1.55
	9,585,106	1.75
	4,195,972	1.85
	18,620,985 at average price of	1.71
Unied Gas Pipe Line Co.	6,507,003	1.50
	3,284,814	1.75
	9,791,817 at average price of	1.58
TOTAL	110,160,637 at average price of	1.60

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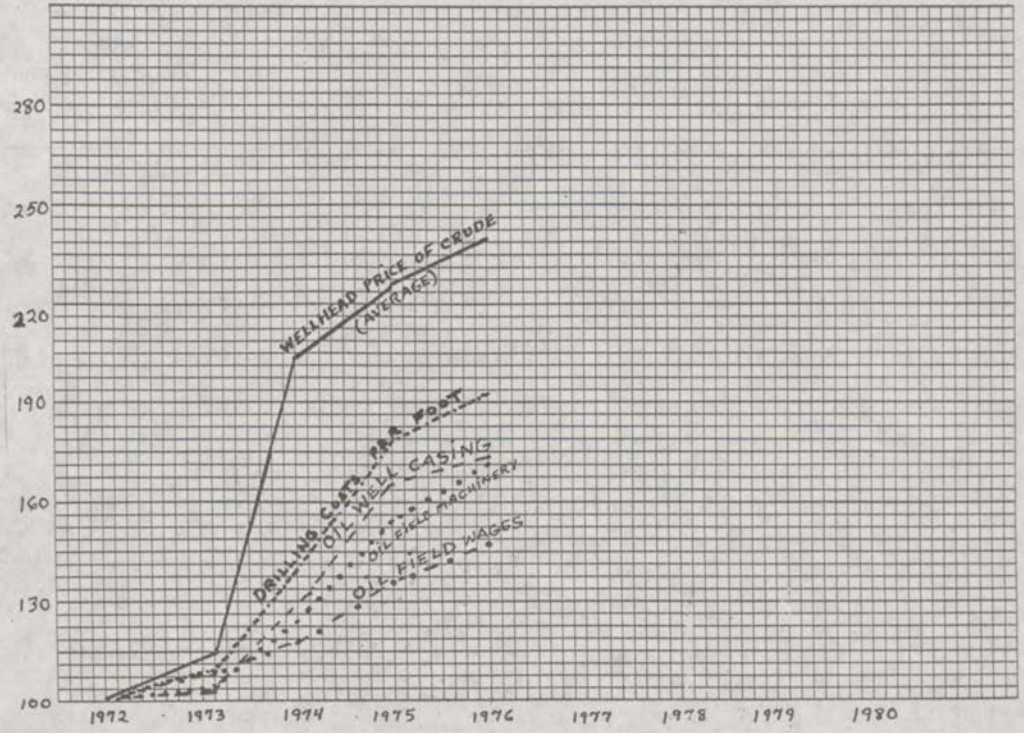
Crude Oil Prices and Cost of Production



INDICES OF CRUDE OIL PRICES
AND COSTS OF PRODUCTION,

1972 - 1976
(1972 = 100)

YEAR	WELLHEAD PRICE OF CRUDE OIL	COST			
		Oil Field Machinery	Oil Well Casing	Oil Field Wages	Drilling Cost Per Foot
1972	100.0	100.0	100.0	100.0	100.0
1973	114.8	104.6	103.7	107.7	108.4
1974	202.7	124.0	132.9	118.8	139.4
1975	226.3	154.2	164.7	135.7	178.2
1976	241.3	170.9	173.7	147.6	192.9

SOURCE: IPAA Petroleum Statistics

Mr. NEAVES. Lone Star Gas did not actually sell any. We did transport some gas for other folks under the Emergency Act. One of our subsidiary companies, Enserch Energy did make two sales, and they were made at a price of $2.25 each. They were relatively small sales. One involved 1.5 million feet a day. The other is continuing to the Texas Gas Transmission Co. They are delivering 2 million a day under that sale.

Mr. VLCEK. And what prices were those?

Mr. NEAVES. Both prices are priced at $2.25.

Mr. FOY. I will have to give you that.

Mr. VLCEK. Could you provide us a list for the record?

Mr. FOY. Yes, I will.

Mr. VLCEK. Whether it was under 268 or under the Emergency Natural Gas Act and the price?

Mr. FOY. We will provide that detail for the record.

[The following material was received for the record:]

HOUSTON NATURAL GAS SYSTEM TRANSMISSION SUBSIDIARIES

ANALYSIS OF SHORT TERM INTERSTATE SALES

FISCAL YEAR TO DATE APRIL 30, 1977

Seller / Purchaser	Sale No.	Type of Sale	Beginning Date	Ending Date	Volume MMCF	Price per MMBTU
Houston Pipe Line Company						
Transcontinental Gas Pipe Line	1	Section 2.68	11-1-76	12-30-76	6,342	
					1,260	
					351	
				Total	7,953	$2.15
	2	Section 2.68	1-17-77	3-15-77	5,036	$2.15
	3	Emergency Gas Act	3-17-77	In Progress	3,554	$2.20
Total Transco					16,543	
United Gas Pipe Line	1	Section 2.68	11-6-76	1-5-77	5,173	$2.15
	2	Section 2.68	1-17-77	3-18-77	6,596	
					1,004	
					452	
				Total	8,052	$2.15
Total United					13,225	
Texas Eastern	1	Emergency Gas Act	3-10-77	In Progress	2,599	$2.20
Total Houston Pipe Line					32,367	
Intratex Gas Company						
United Gas Pipe Line	1	Section 2.68	10-18-76	12-17-76	3,058	$2.15
Columbia Gas System	1	Section 2.68	1-28-77	3-29-77	2,355	$2.15
Total Intratex					5,413	
Grand Total					37,780	

Mr. VLCEK. Thank you, Mr. Chairman.

Mr. GAMMAGE. Mr. Demarest has one more question.

Mr. DEMAREST. Gentlemen, you all addressed the issue of extension of the Emergency Natural Gas Act, and I believe there was general opposition on the part of the panel members, other than Mr. Donkin, to continuation of the allocation provisions, but there was no opposition expressed to continuation of the emergency sale provisions.

Would you similarly support the continuation of the authority to order transportation of emergency purchase gas under which I believe Lone Star carried some emergency gas which otherwise could not have been made available to the purchaser who needed it? Would you support a continuation of that authority?

Mr. NEAVES. Yes.

Mr. INGRAM. The authority for transportation?

Mr. DEMAREST. Yes.

Mr. INGRAM. Yes, we would support that.

Mr. FOY. It causes us no concern.

Mr. GAMMAGE. If there are no further questions, I would like to thank the panel for being so patient in waiting and staying as long as you have today, and I would like to thank my colleague, Mr. Moore, for hanging in there.

Mr. FOY. Thank you.

[Whereupon, at 5:55 p.m., the subcommittee adjourned, to reconvene at 10 a.m., Monday, May 16, 1977.]

NATIONAL ENERGY ACT

TUESDAY, MAY 17, 1977

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY AND POWER,
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE,
Washington, D.C.

The subcommittee met at 10:15 a.m., pursuant to notice, in room 2123, Rayburn House Office Building, Hon. Richard L. Ottinger, presiding, Hon. John D. Dingell, chairman.

Mr. OTTINGER. The subcommittee will come to order.

The witness for today is the Honorable Richard L. Dunham, Chairman of the Federal Power Commission.

Mr. Dunham, we are glad to have you with us. We will be glad to receive any statement that you may have. The statement may be included in the record.

Without objection, you may proceed as it is convenient for you.

STATEMENT OF HON. RICHARD L. DUNHAM, CHAIRMAN, FEDERAL POWER COMMISSION, ACCOMPANIED BY DREXEL D. JOURNEY, GENERAL COUNSEL, AND KENNETH WILLIAMS, ACTING CHIEF, BUREAU OF NATURAL GAS

Mr. DUNHAM. Thank you, Mr. Chairman.

I have supplied the committee with a relatively long statement, some 18 or 19 pages with appended table.

In accordance with your time requirements, with no objection I would like to have that put into the record.

I have a few summary comments I would like to make pulling out the highlights of my more lengthy testimony which has been furnished.

Mr. OTTINGER. Without objection, your full statement will appear in the record, and you are welcome to proceed.

Mr. DUNHAM. Thank you, Mr. Chairman.

I appreciate this opportunity to discuss title I, part D of H.R 6831, the National Energy Act, which is directed primarily to the establishment of a pricing system at the wellhead for new natural gas in an effort over the long term to increase the supply of natural gas and reduce the demand. At the same time, part D would deal with short-term supply shortages by extending the mandatory allocation provisions of the Emergency Natural Gas Act of 1977. Finally, this

section would foster the conservation of natural gas by an end-use pricing system which would provide an incentive to certain industrial and other users to convert to more abundant fuels.

The purpose of my statement is to provide the subcommittee with data relative to the volumes of natural gas, both flowing and projected, which would be affected by the bill. Furthermore, my statement contains the results of an analysis regarding the overall economic impacts of proposed pricing system changes, which may be of assistance to the subcommittee.

This bill and the other bills clearly reflect an awareness by the President and the Congress that we do, in fact, face a potentially disastrous shortage of available energy and that we must act now if we are to avert significant disruptions in our economy and a profound change in our way of life. Some potentially severe disruptions were avoided through implementation of the Emergency Natural Gas Act of 1977; however, a more dependable, long-term solution to the current imbalance in natural gas supply and demand must be found.

This bill attempts to remove in part the pricing distinctions which have arisen from the existence of two separate markets for natural gas—one regulated, one essentially unregulated. Thus, the bill would establish a new pricing system, based on relation to a controlled oil price, which should put both interstate and intrastate buyers on an equal footing when shopping for new gas supplies.

During 1976, the interstate market had approximately 11.4 Tcf flowing at the following base rates:

6.4 Tcf at 29.5 cents/Mcf or less,
1.7 Tcf at 52.0 cents/Mcf,
1.2 Tcf at 93.0 cents/Mcf,
0.7 Tcf at 142.0 cents/Mcf.

The remaining 1.4 Tcf flowed at various rates, including up to $1.80 for Canadian gas.

During 1976, the intrastate market had roughly 9.0 Tcf flowing. Prices vary, and only the following general price range data are available on that market—from Form 45 reports:

New contracts averaged - $1.62/Mcf for the calendar year 1976.

Renegotiated or amended contracts averaged - $1.69/Mcf for the calendar year 1976.

Reports for the month of February 1977 show an averge price of $1.66/Mcf for new contracts and $1.88/Mcf for renegotiated or amended contracts.

We do not have reliable figures on the prices of gas flowing in the intrastate market under preexisting contracts.

Historical data based upon trends since 1968 indicate that over the next 12 months, reserves dedicated to the interstate market may total approximately 2.0 Tcf.

Our interpretation is that section 406 of H.R. 6831 would allow gas currently flowing in the interstate market under long-term dedications, and newly produced old gas, to receive higher prices upon expiration of prior interstate contracts—the so-called "rollover contracts" provision. The price for such rollover contracts may not exceed $1.45 plus the inflation adjustment as defined in section 402(a)(20) of the bill, but would be subject to Presidential

control at a lower level. The bill would also allow the oil-related higher price of about $1.75 for rollover contracts on producing intrastate reservoirs, and on gas now flowing interstate for a limited period.

While it is not possible to estimate the total dollar impact of the rollover contract provision with certainty, it is possible to estimate the volumes of natural gas now being sold in interstate commerce which might, over time, be eligible for the rollover price. In arriving at the estimate, several assumptions have necessarily been made. However, we believe that the analysis reflects the vast majority of the interstate sales affected by the rollover provisions of H.R. 6831.

In summary, the study indicates that the gas subject to the rollover provision of the bill would be about 170 billion cubic feet annually in 1977 and would reach a peak of about 1.5 trillion cubic feet annually in the late 1980s and early 1990s. The latter figure includes both production from contracts expiring in the indicated year and remaining production from all contracts that have expired in previous years. The total interstate volumes affected by the rollover provision through 1998 are estimated to be in the range of 21 trillion cubic feet. If it were assumed that all interstate contracts would escalate to $1.45 upon expiration, then the total cumulative dollar impact through 1998 would be about $19 billion, without considering the various inflation adjustments. This also assumes that flowing gas prices, in the absence of this act, could be maintained at 53 cents all the way through to 1998.

This bill recognizes that imported liquefied natural gas will be an important supply option through the mid-1980s and beyond. The bill sets no upper limits in LNG imports in total or from any one foreign source. I have included in this testimony a list of the pending LNG import applications, about 0.5 Tcf has already received FPC approval and about 1.1 Tcf is pending.

Section 415 of the National Energy Act consolidates FPC jurisidiction over synthetic gas manufacture, transport and sales with our current natural gas regulation. We believe that a coherent energy policy requires consistent economic regulation of all energy sources and section 415 is an integral part of the consolidation process.

Section 414 of the bill, while establishing a process to allocate the burden of new high cost gas supplies to industrial users and their customers, does not provide true "incremental pricing" as that concept has usually been used in FPC proceedings. Residential and small commercial users would in no case confront the increment cost of gas supplies, and industrial users would have the higher prices averaged in with whatever gas was available to them.

In conclusion, I would call your attention to section 402(a)(5) regarding the definition of "new natural gas," the so-called 2.5-mile limit and the 1,000 foot drilling depth. If I understand the intent of this definition as describing the category of gas eligible for the new gas price of $1.75 then I do not believe this is a meaningful or workable definition. I would urge the committee to consider the methodology and definitions used in the FPC's Opinion No. 770-A, particularly pages 154-156 of that opinion.

There are a number of other technical problems related to section D which we have difficulty with and have questions on. The

Commission and staff will, of course, be happy to work with this committee as you further consider the President's proposal.

That concludes my highlight attempt to summarize the total statement, Mr. Chairman. I will be happy as always to answer any questions you or members of the committee may have.

[Mr. Dunham's prepared statement follows:]

STATEMENT OF
RICHARD L. DUNHAM, CHAIRMAN
FEDERAL POWER COMMISSION
BEFORE THE
SUBCOMMITTEE ON ENERGY AND POWER
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
UNITED STATES HOUSE OF REPRESENTATIVES

May 17, 1977

Mr. Chairman and Members of the Subcommittee: I appreciate this opportunity to discuss Title I, Part D of H.R. 6831, the "National Energy Act." Part D of this bill would amend the Natural Gas Act to implement the President's National Energy Plan.

Many other portions of H.R. 6831 relate to the natural gas industry. Part D is directed primarily to the establishment of a pricing system at the wellhead for new natural gas in an effort over the long term to increase the supply of natural gas and reduce the demand. At the same time, Part D would deal with short-term supply shortages by extending the mandatory allocation provisions of the Emergency Natural Gas Act of 1977. Finally, this section would foster the conservation of natural gas by an end-use pricing system which would provide an incentive

to certain industrial and other users to convert to more abundant fuels.

The purpose of my statement is to provide the Subcommittee with data relative to the volumes of natural gas, both flowing and projected, which would be affected by the bill. Furthermore, my statement contains the results of an analysis regarding the overall economic impacts of proposed pricing system changes, which may be of assistance to the Subcommittee.

Later today, the FPC's General Counsel will provide a comparative analysis of Part D in the light of H.R. 2088, 3136, 3171 and H.R. 687. While there are important differences in these bills, generally all would attempt to increase the supply of natural gas available to higher priority users through voluntary or mandatory means.

H.R. 6831 and the other bills to which I have just referred clearly reflect an awareness by the President and the Congress that we do, in fact, face a potentially disastrous shortage of available energy and that we must act now if we are to avert significant disruptions in our

economy and a profound change in our way of life. Some potentially severe disruptions were avoided through implementation of the Emergency Natural Gas Act of 1977; however, a more dependable, long-term solution to the current imbalance in natural gas supply and demand must be found. By way of illustrating the tremendous demand for natural gas it should be noted that 50 billion cubic feet could be needed currently to meet all firm gas requirements of the interstate market on a peak day in the winter.

One of the major causes of the inability of interstate gas pipelines over the last several years to secure new gas supplies to meet the tremendous demand has been the obvious disparity between interstate and intrastate prices. The market within producing states has, quite understandably, been able to secure the lion's share of new gas supplies by offering higher prices.

H.R. 6831 attempts to remove in part the pricing distinctions which have arisen from the existence of two separate markets for natural gas--one regulated, one essentially unregulated. Thus, the bill would establish

a new pricing system, based on relation to a controlled oil price, which should put both interstate and intrastate buyers on an equal footing when shopping for new gas supplies.

During 1976, the interstate market had approximately 11.4 Tcf flowing at the following base rates:

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During 1976, the intrastate market had roughly 9.0 Tcf flowing. Prices vary, and only the following general price range data are available on that market (from Form 45 reports):

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Renegotiated or amended contracts averaged - $1.69/Mcf for the calendar year 1976.

Reports for the month of February 1977 show an average price of $1.66/Mcf for new contracts and $1.88/Mcf for renegotiated or amended contracts.

We do not have reliable figures on the prices of gas flowing in the intrastate market under preexisting contracts.

Historical data based upon trends since 1968 indicate that over the next 12 months, reserves dedicated to the interstate market may total approximately 2.0 Tcf.

The bill's pricing approach recognizes that in the economic sense, new gas prices should be determined essentially by the cost of replacing the gas, that is, the price of alternative fuels. This is much different from the regulation related to historic costs which the FPC has been required by the courts to enforce in the past.

Our interpretation is that Section 406 of H.R. 6831 would allow gas currently flowing in the interstate market under long-term dedications, and newly produced "old gas", to receive higher prices upon expiration of prior interstate contracts--the so-called "rollover contracts" provision. The price for such rollover contracts may not exceed $1.45 plus the inflation adjustment as defined in Section 402(a)(20) of the bill, but would be subject to Presidential control at a lower level. The bill would also allow the oil-related higher price of about $1.75 for rollover contracts on producing intrastate reservoirs, and on gas now flowing interstate for a limited period.

While it is not possible to estimate the total dollar impact of the rollover contract provision with certainty,

it is possible to estimate the volumes of natural gas now being sold in interstate commerce which might, over time, be eligible for the rollover price. In arriving at the estimate, several assumptions have necessarily been made. However, we believe that the analysis reflects the vast majority of the interstate sales affected by the rollover provisions of H.R. 6831.

In summary, the study indicates that the gas subject to the rollover provision of the bill would be about 150 billion cubic feet annually in 1977 and would reach a peak of about 1.5 trillion cubic feet annually in the late 1980's and early 1990's. The latter figure includes both production from contracts expiring in the indicated year and remaining production from all contracts that have expired in previous years. The total interstate volumes affected by the rollover provisions through 1998 are estimated to be in the range of 21 trillion cubic feet. If it were assumed that all interstate contracts would escalate to $1.45 upon expiration, then the total cumulative dollar impact through 1998 would be about $19

billion, without considering the various inflation adjustments. This also assumes that flowing gas prices, in the absence of this Act, could be maintained at 53¢ all the way through to 1998. 1/

The President's National Energy Plan, implemented in H.R. 6831, recognizes that imported liquefied natural gas will be an important supply option through the mid-1980's and beyond. The bill sets no upper limits on LNG imports in total or from any one foreign source.

There are currently pending before the FPC four LNG projects involving Algerian gas and one involving Indonesia gas. The FPC recently approved the El Paso I project (decided in Opinion No. 786, titled Columbia LNG) and has found that the imported LNG should be rolled-in with other supply costs. In that case, the FPC found that the LNG

1/ Two tables are attached as Appendix A; the first is based upon the year of expiration of the contract and the second upon the first full year after expiration. Since contracts expire at random times during the year, the actual would fall between the two.

would be used for base load and that its cost would approximate the cost of new supplies of domestic production. In another case, Opinion No. 796, the FPC found that LNG to be imported by Trunkline LNG Company should be incrementally priced so that the demand at $3.37 per Mcf could be tested in the market. By incrementally pricing imported LNG, customers will determine whether the imported gas is actually worth the price, and thus whether certain projects go forward. The end result of incrementally pricing imported LNG may be to discourage some LNG projects.

Following is a table presenting the estimated costs and volumes of foreign LNG by project:

Estimated Initial Costs and Volumes of Foreign LNG

Project	Docket No.	Price ($ per Mcf) Base Price FOB Algeria	FOB U.S.*	U.S. Terminal Tailgate*	Volumes (Annually) (Bcf)
APPROVED					
Distrigas	CP70-196	0.345	0.68	1.04-1.38	15
El Paso I	CP71-68	0.305	1.23 1.30	1.66 (Md.) 1.71 (Ga.)	365
Trunkline LNG	CP74-138	1.30	2.74	3.37	179
PENDING					
Distrigas	CP77-216	1.30	2.10	2.70	46
Eascogas	CP73-47	1.30	2.43	2.90	237
Pac Indonesia	CP74-160	1.25	2.83	3.16	196
El Paso II	CP73-258	1.30	2.85	3.23	365
Tapco	CP77-100	1.30	3.67**	4.57	350

* Includes escalations.

** Estimated delivered price to terminal in New Brunswick, Canada.

Synthetic Natural Gas

Section 415 of the Act would amend the Natural Gas Act to give the Federal Power Commission jurisdiction over the manufacture, transportation and sale of synthetic natural gas (SNG) by a natural gas company or its affiliate. If a natural gas company has commenced manufacture of synthetic gas prior to enactment of this Section, however, or if a company has been issued a certificate of public convenience and necessity to transport the SNG, then the Commission would certificate the continuation of service without further proof of the public convenience and necessity provided the application is made by the company within 90 days after enactment.

One of the major obstacles to the development of SNG plants in the U. S. has been the large capital investments required for the projects and the investor uncertainty over inflationary factors and government energy policy. Section 415 of the Act could, in part, resolve this problem.

Since 1972, the FPC has taken the position that synthetic gas products from a manufacturing process which converts petroleum products or coal feedstocks into synthetic gas of a high Btu content is not "natural gas" within the meaning

of the Natural Gas Act. 2/ Review of the legislative history of the Natural Gas Act indicates that the Congressional intent was to limit FPC jurisdiction so that artificial gas is not within the Commission's jurisdiction. Similarly, the Commission determined, and was affirmed by the U. S. Court of Appeals for the D. C. Circuit, 3/ that our jurisdiction did not extend to the production, transportation, or sale of unmixed synthetic gas produced from coal. Only when artificial gas (produced either from naphtha or coal) is commingled with natural gas in a jurisdictional pipeline would the Commission assume jurisdiction.

If Section 415 were incorporated into the Natural Gas Act, as proposed here, the FPC would be given the authority to certificate the production, transportation, and sale of SNG in a manner similar to that now applicable to natural gas in interstate commerce. The financial risks involved would thereby be reduced, improving investors' confidence in SNG projects. The Commission recently dealt with the issue

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2/ Opinion No. 637, 48 FPC 1216 (1972).

3/ Opinion No. 663, 50 FPC 651 (1973); and Alice Henry, et al. v. Federal Power Commission, 513 F.2d 395 (1975).

of investor risk in the Trunkline LNG Company case 4/ when we certificated the importation of LNG from Algeria. We conditioned the certification on a tariff schedule including a minimum bill provision applicable for periods of service interruptions. We believed the minimum bill, which would permit Trunkline LNG to recover its non-equity related fixed costs, was necessary to ensure the financeability of the project. The Commission expressed unwillingness to include in the minimum bill provision a recovery for the equity protion and thus have ratepayers share the risk of interruptions with investors, since it has no control over the cost of service of the project and did not establish the rate of return for the project.

With the jurisdiction contemplated by Section 415, the Commission would be able to set rates for SNG based on costs of service, including a reasonable rate of return for investors. In the event of a plant failure, the unrecovered investment in the plant that was no longer useful could be removed from the rate base. Whether the write-off

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4/ Trunkline LNG Company, Docket Nos. CP74-138 and CP74-139 and Trunkline Gas Company, Docket No. CP74-140, Opinion No. 796, issued April 29, 1977.

would be charged against consumers or stockholders would become the subject of adjudicatory proceedings.

A final point concerns the pricing of synthetic gas. Given the Commission's approval of incremental pricing in the recent Trunkline case, supra, it is possible that we would require new synthetic gas to be priced incrementally. That is, users of this gas could be charged a price equal to the cost of the resources used to produce the gas, including a fair rate of return on investment. If it is in the national interest to encourage SNG production, and if it is thought that investors are unwilling to assume the risks associated with SNG plant construction and operation, direct subsidies in the form of loan guarantees might be a superior alternative to the hidden subsidy inherent in average cost or rolled-in pricing of high-cost SNG.

In sum, we support Section 415 of the National Energy Act to consolidate FPC jurisdiction over synthetic gas manufacture, transport and sales with our current natural gas regulation. We believe that a coherent energy policy requires consistent economic regulation of all energy sources and Section 415 is an integral part of the consolidation process.

The bill contains a grandfather provision in cases where a certificate for the transportation or sale for resale of the SNG has been issued previously by the FPC. The provision raises the possibility that the FPC may be required to issue a certificate under Part D for the sale of SNG at rates which may not have been cost-based. There are three SNG projects which have been affected by past FPC actions in light of our limited certificate authority over SNG:

(1) Algonquin SNG, Inc. naphtha reforming plant is the subject of FPC Opinion Nos. 637 and 637-A. The plant produces 118,200 MMBtu per day and 17,847,200 MMBtu over the winter season, which is sold to Algonquin Gas Transmission Co. for resale under the terms of a special SNG rate schedule. Data previously filed with the FPC indicates that SNG produced from this plant costs between $5-$6/Mcf.

(2) Columbia LNG Corporation's hydrocarbon reforming plant is the subject FPC Opinion No. 669 and an order issued January 7, 1974. The plant was

designed to produce 216,000 Mcfd or 75,600,000 Mcf annually which was sold directly to the distributor customers of Columbia Gas Transmission Company. The SNG is transported by Columbia Gas Transmission. No data are available with respect to the cost of such gas.

(3) The coal gasification project of Transwestern Coal Gasification Company and Pacific Coal Gasification Company is the subject of FPC Opinion Nos. 728 and 728-A. The plant was designed to produce 250,000 Mcfd which would be sold to Pacific Lighting and Cities Service Gas Co. for $2.50/Mcf, subject to adjustment after operating data are available. Transwestern Pipeline Company would transport the gas. The plant is still not financed.

El Paso filed an application in Docket No. CP73-131 for permission to construct and operate the facilities necessary to transport SNG to be produced from the Burnham Coal Gasification Complex. In Opinion No. 663, the Commission found that coal gasification facilities were non-jurisdictional.

El Paso has requested that further processing of its transportation application be held in abeyance pending resolution of certain environmental and other problems.

Section 414 of the bill attempts to assess all gas unit costs above the average unit costs incurred in the prior 12-month period (plus inflation) against low-priority, natural gas users of each pipeline company, while simultaneously seeking to assure full cost recovery for the pipeline company. This provision in the bill does not relate exactly to the purpose of incremental pricing as now contemplated by the FPC. Also, the bill does not appear to address the incremental cost of synthetic gas.

The term "incremental pricing" is used by the FPC to mean charging a price for a specific supplemental block of gas at its cost to the pipeline. On the other hand, "rolled-in pricing" means that the supplemental gas is combined with all other system supply and priced at its average cost of total system supply. For example, as I noted earlier in my testimony, the FPC recently required LNG proposed for importation by the Trunkline LNG Company to be sold at its incremental cost of $3.37 per Mcf, instead of allowing the cost of this

higher-priced gas to be rolled-in (i.e., averaged) with lower cost domestic gas.

To achieve the maximum amount of energy conservation in the national interest, and consequently the efficient use of gas, all gas users would have to pay the incremental cost of new gas supplies for a part of their consumption. Thus, each customer would have the advantage of low cost for a share of the flowing gas supply available, but would pay the full cost of higher cost gas for any consumption of gas above this level.

In order to provide incentives for gas conservation to all customers, all must be confronted for some part of their consumption with the incremental cost, the marginal replacement cost, of increased gas supplies.

The bill would appear to create a quite different pricing method. The high-cost gas supplies would be paid for primarily by industrial, large commercial, and other low priority users --- all users other than residential and small commercial. Even the low-priority would not necessarily confront the full per-unit cost of new supplies because such costs would be averaged in with whatever old gas were available to them.

The bill would require rolling-in all of the cost of new gas supplies with the cost of the existing gas still available to serve the low-priority customers. Thus, if my understanding is correct, neither high-priority nor low-priority users would normally be faced with the marginal replacement cost of gas for any of their consumption. Low-priority users would bear all of the cost of additional supplies above the previous average cost, but they would not recognize the marginal replacement cost of gas since these costs would be disguised by the rolling-in process.

The bill, however, would put a cap on the rolled-in price to low-priority customers. The cap would be the price of substitute fuels, as established by the President. When this ceiling is reached, the excess costs of supplemental gas over and above the cap price would be paid by the high-priority users.

In general, the section does not appear to be designed to achieve fully the conservation objective, as would true incremental pricing. The effect of incremental pricing upon conservation efforts among high-priority and low-priority users, however, remains indeterminate due to the variety of factors

involved. Undoubtedly, the ability to use alternate fuels is an important factor to be considered in assessing the impact of conservation efforts upon various categories of natural gas use.

Finally, H.R. 6831 would extend the mandatory allocation provisions of the Emergency Natural Gas Act of 1977 from April 30, 1977, through April 30, 1979. In addition, Section 4 of ENGA would no longer distinguish between interstate and intrastate pipelines or between interstate and intrastate natural gas in meeting the requirements of high priority users.

As I noted in my testimony before the Subcommittee on April 5 of this year, service to customers protected under Section 4 of ENGA was not interrupted during the recent natural gas emergency. Voluntary sales and transportation by pipelines and distributors under Section 6 made it unnecessary to implement the Section 4 mandatory allocation powers to protect high priority users.

While I do not object to the extension of Section 4 power for another two years, I assume that such authority would be

used only when voluntary transactions are not sufficient to protect high priority uses. In this connection, I note that certain contractual impediments to voluntary purchase and transportation agreements--for example, intrastate contract provisions which prohibit the sale or commingling of intrastate gas with interstate natural gas--are declared by the bill to be against public policy and unenforceable.

This concludes my prepared remarks. I will be pleased to answer any questions.

APPENDIX A

TABLE I

IMPACT OF EXPIRING CONTRACTS
BASED ON YEAR OF EXPIRATION

YEAR	VOLUME		
	EXPIRING 1/ (Mcf)	100% 2/ (Mcf)	ANNUAL CUMULATIVE 3/ (Mcf)
(a)	(b)	(c)	(d)
1977	150,097,049	170,564,828	170,564,828
78	337,611,214	383,649,107	528,629,211
79	265,310,979	301,489,749	750,824,578
80	286,517,589	325,588,169	963,789,060
81	171,983,419	195,435,703	1,014,656,404
82	157,872,639	179,400,726	1,041,858,669
83	154,722,855	175,821,426	1,061,401,295
84	122,762,459	139,502,794	1,041,693,895
85	133,575,071	151,789,853	1,037,229,664
86	106,939,264	121,521,891	1,003,167,105
87	187,810,165	213,420,642	1,066,112,681
88	315,688,065	358,736,438	1,264,932,217
89	360,105,214	409,210,470	1,484,402,854
90	245,552,040	279,036,409	1,540,778,835
91	218,952,985	248,810,210	1,558,472,220
92	80,069,695	90,988,290	1,415,689,677
93	3,418,628	3,884,805	1,207,221,030
94	2,750,098	3,125,111	1,029,262,987
95	2,740,267	3,113,940	877,987,479
96	893,022	1,014,798	747,304,155
97	53,222	60,480	635,269,012
98	68,718	78,089	540,056,749

SOURCE: Reports by large producers in Docket No. R-478.

1/ 1972 volumes declined per Davis Curve.

2/ Expanded on the basis that large producers account for 88% of sales.

3/ 85% of previous year's cumulative volume plus current year's volume.

APPENDIX A

TABLE II

IMPACT OF EXPIRING CONTRACTS
BASED ON FIRST FULL YEAR OF ELIGIBILITY

YEAR	VOLUME		
	EXPIRING 1/ (Mcf)	100% 2/ (Mcf)	ANNUAL CUMULATIVE 3/ (Mcf)
(a)	(b)	(c)	(d)
1977	117,347,540	133,349,477	133,349,477
78	182,625,954	207,529,493	320,876,548
79	286,969,532	326,101,741	598,846,807
80	225,514,332	256,266,286	765,286,072
81	243,539,951	276,749,944	927,243,105
82	146,185,906	166,120,348	954,276,987
83	134,191,743	152,490,617	963,626,056
84	131,514,427	149,448,213	968,530,361
85	104,348,090	118,577,375	941,828,182
86	113,538,810	129,021,375	929,575,330
87	90,898,374	103,293,607	893,432,638
88	159,638,640	181,407,545	940,825,287
89	268,334,855	304,925,972	1,104,627,466
90	306,089,432	347,828,900	1,286,762,246
91	208,719,234	237,180,948	1,330,928,857
92	186,110,037	211,488,678	1,342,778,206
93	68,059,241	77,340,047	1,218,701,522
94	2,905,834	3,302,084	1,039,198,378
95	2,337,583	2,656,344	885,974,965
96	2,329,227	2,646,849	755,725,569
97	759,069	862,578	643,229,312
98	45,239	51,408	546,796,323
99	58,410	66,375	464,843,250

SOURCE: Reports by large producers in Docket No. R-478.

1/ 1972 volumes declined per Davis Curve.

2/ Expanded on the basis that large producers account for 88% of sales.

3/ 85% of previous year's cumulative volume plus current year's volume.

Mr. DINGELL. I commend you for a very helpful statement to the committee and I thank you for your assistance. I would observe that it would be very useful to us if you would provide, through your very able general counsel, Mr. Journey, a statement of the technical defects which you find in the bill, together with the necessary amendments to perfect the bill. Our staff is finding certain technical problems with regard to the legislation. We would be delighted to receive any substantive suggestions which you have, Mr. Chairman.

I would stress that we are interested in your views, not in the views of the Office of Management and Budget. Therefore you are expressly instructed not to clear those matters through OMB but to give us your thoughts. We have no needs of the views of the OMB until we ask for them.

The Chair will now recognize members for purposes of questions.

Mr. Journey, did you have any comments you wanted to add?

Mr. JOURNEY. Not now, sir. I will be on the panel this afternoon.

Mr. DUNHAM. We look forward to your comments at that time.

The Chair observes that my colleagues have appeared in the order that they will be recognized and we will recognize at this time the gentleman from Texas, Mr. Krueger, for 5 minutes.

Mr. KRUEGER. Thank you, Mr. Chairman.

Mr. Dunham, thank you very much for your statement. I should like first of all to cover, if we might, roughly what portion of the cost paid by a consumer of natural gas in interstate commerce comes from the cost of amortizing the pipeline, and roughly what portion of the cost actually goes to the producer.

As I just look hastily at the figures that you have given for the prices paid to producers for natural gas in existing interstate commerce, I would guess that it comes out to be about 50 cents per Mcf, or perhaps a little bit less at this time.

Now of the price actually paid by a consumer of natural gas, a normal residential consumer, about what portion of that goes for transportation and distribution costs and about what portion would go to the producer?

Mr. DUNHAM. Quite obviously it depends upon both the source of the gas and the point at which it is ultimately delivered, just a rough—and we have figures actually calculated for each particular market area, so it would be possible to get the exact figures, but for the purposes of your question the average flowing gas rate is probably somewhere around 60 cents. I think you indicated 50, but some point in that range, and that varies of course by pipeline by pipeline, depending on what particular vintages of gas they happen to have contracted with historically.

The end prices at the end of the pipeline in a market, for instance, in New York, would be somewheres between $2.50 to $3. I think that is about right, somewhere in that area, so the flowing producing rate is that proportion of that.

Mr. KRUEGER. So if a New York consumer paid about $3 for the gas that he received, of that $3, on average about 60 cents would go to the producer and the other $2.40 would go for the transportation and the distribution.

Mr. DUNHAM. Yes, the transportation, distribution and of course the operation and maintenance of both the interstate pipeline and the distributor at the end.

Mr. KRUEGER. So it is about 20 percent goes to the producer then for the interstate gas.

Secondly, as I look at your table I, in which you have given the various dates on the last page, appendix A, given the dates of expiring contracts, do I read that table correctly, and does that mean that by and large what we have is a period of contracts expiring with the major contracts for interstate natural gas covering about 15 to 16 years?

Mr. DUNHAM. That is right

Mr. KRUEGER. And are most of those contracts as far as you know contracts in which the gas can in fact be delivered, that is, are these more or less secure reserves, or is there any way of saying at this time?

Mr. DUNHAM. There is no precise way of saying, because quite obviously you would have to know the condition of the wells under the particular contract. We made a series of assumptions. One of the footnotes gave one of the assumptions which I believe relates to your question, Mr. Krueger. We declined the volumes on the basis of the Davis curve. As you know producers start producing relatively slowly, then production maximizes in a particular period and then declines, so the age of the well, quite obviously the geological conditions of the particular reservoir, would all bear on that, and that is an important qualification. These are only assumptions which we have tried to moderate and apply the best we can, but they are only dealing with averages. They are not precise.

Mr. KRUEGER. Would the average seem to be then that about, say, 7 percent or so of the existing interstate contracts for natural gas would be expiring each year? As I look at it, it seems to me that if it takes about 15 years, that would be about 7 percent a year, and I don't see all that much of a difference between various years.

Is that fair?

Mr. DUNHAM. I think that is about right. They might be bunched in particular periods as a result of particular large discoveries.

Mr. KRUEGER. What that would mean then is if we are talking about prices, for example, for new gas going into interstate commerce, we are talking for the most part about overall, a nationwide average, of about 7 percent of the gas selling at the new price, so whatever price we are looking at for new gas is likely to be in the neighborhhood of 7 percent of the gas that a consumer receives, and about 93 percent of the gas would continue to remain under contract.

Mr. DUNHAM. That is right.

Mr. KRUEGER. So if, for example, you had an average of 60 cents for 93 percent of the gas, and you had $2 for the remaining 7 percent of the gas, you would multiply $2 times 7 percent and 60 cents times 93 percent.

Would that be correct?

Mr. DUNHAM. It would be about right. Another perspective, which I think is the same point, in the first year we estimated roughly, in 1978 I believe, that the change would amount to about 3 percent.

That is in that first year, so you may be a little high, but it depends, of course quite obviously on the particular year. For next year it is about 3 percent.

Mr. KRUEGER. But one inference then that might be fair from that would be that if we talk about higher prices for new gas, whether it is a result of federally set higher prices or as a result of deregulated higher prices, we are nonetheless talking about rolling in those prices very, very slowly, because the vast majority of gas always remains under contract; is that correct?

Mr. DUNHAM. That is correct.

Mr. KRUEGER. Thank you very much.

The next question I should like to ask is roughly what was the shortfall in the interstate market this last winter, in terms of delivery, and then the other part of that, that I would like to ask, and that would complete my questioning, is what portion of that shortfall was met under the President's energy bill?

Mr. DUNHAM. The second part of your question is perhaps easier to answer than the first. As you know, the prime variable was the extraordinary temperature that we had this year. As a result, for a period of at least 6 weeks many areas of the country had very little if any gas service other than the human needs areas, the critical area which the emergency bill ws directed to confront. I don't know how to calculate the gap if all demand was to be met; it has been a number of years since we have been able to meet all demand on the interstate system, because of the operation of the curtailment systems, interruptibles and so forth.

Let me answer the second part first.

We estimate that roughly so far this year we met about 164 billion cubic feet of delivery under so-called emergency procedures.

Mr. KRUEGER. Under emergency sale procedures.

Mr. DUNHAM. Some under FPC procedures and some under the Emergency Act, and that was a relatively small proportion of the total deliveries during that period of time, but by virtue of being small does not mean that it wasn't important. It was extraordinarily important at the margin. I don't quite know how to characterize that. I could try and calculate some figures and supply them.

Mr. KRUEGER. I think my time has expired.

Mr. DINGELL. Without objection, those figures will be inserted in the record at the appropriate place.

[The following information was supplied for the record:]

1. What was the shortfall last winter between supplies and firm contract demands? How much of that shortfall was offset by emergency sources under both the Commission's Rules and the Emergency Natural Gas Act?

1976-1977 Winter
(November 1, 1976 through March 31, 1977)

Shortfall 1/	1,620 Bcf
Emergency Supplies	
Natural Gas Act 2/	126
Emergency Natural Gas Act 3/	38
Total Emergency Supplies	164
Difference	1,456 Bcf

1/ From available data submitted for the April 30, 1977, FPC Form 16 (39 reporting pipelines as of May 18, 1977).
2/ Includes volumes reported pursuant to Section 2.68 of FPC Rules of Practice and Procedure and Sections 157.22 and 157.29 of the Regulations under the Natural Gas Act.
3/ Reflects volumes reported for the months of February and March 1977.

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes the gentleman from New York, Mr. Ottinger, for 5 minutes.

Mr. OTTINGER. Thank you, Mr. Chairman.

I am concerned about the rollover provisions you describe on page 6 of your statement. What price under your present regulations is placed on gas under expiring contracts.

Mr. DUNHAM. Could you restate the last part of your question. I missed it. I couldn't hear you.

Mr. OTTINGER. What price is allowed for gas at the present time under expiring contracts?

Mr. DUNHAM. It is rolled over to the appropriate vintage. Basically the gas we are talking about as being expired in this short-term period would, under the provisions of Opinion 770-A, be eligible to roll over to 53 cents.

Mr. OTTINGER. And under the President's bill, what would the price be?

Mr. DUNHAM. As I read the bill the ceiling on that rollover would be to $1.45. There is some language in the bill which gives me the impression that the President could decide prices other than that, but it would be at a ceiling of $1.45.?

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Mr. OTTINGER. That is roughly an increase of $1. I suppose I have two questions.

What do you estimate the economic impact of that is, and what is the justification for that kind of an increase that seems totally unrelated to production?

Mr. DUNHAM. As I understand the President's proposals, the thrust of the bill is an entirely different concept than the cost based regulations and system that the Federal Power Commission has been obliged to live by under the Natural Gas Act. The concept behind the President's proposal, again as I understand it, was to set the price primarily on an alternative fuel replacement cost or commodity value, concepts other than the historical cost basis. One of the reasons for this is capital formation for exploration and development funds that are required, if we are to expand natural gas supplies.

Mr. OTTINGER. There is no requirement that the additional revenues included for the companies be used for gas exploration, is there?

Mr. DUNHAM. There is no requirement; it depends on the particular company. I would expect that independent producers would do so, since they are in that business, use the funds to reinvest. Otherwise it would be subject to taxation.

Mr. OTTINGER. Wouldn't it make much more sense to apply the incentive directly to gas production instead of to revalue old gas?

Mr. DUNHAM. I think those are policy questions. The way I could answer that is that the Federal Power Commission, in its Opinion 770-A, did feel that the incentive, the top tier, should be directed toward new gas. That is an entirely different concept, and it is very difficult to equate one with the other.

Mr. OTTINGER. My rough calculations of the cost of this particular provision, you tell me if I am in the ball park, applying it to 1.5 trillion cubic feet of gas, would be about $1.5 billion.

Mr. DUNHAM. In these tables we have made calculations year by year of what we estimate that to be under the group of assumptions. I think those are important, you have to look at them in terms of the assumptions we have made. We did the calculations two different ways, took two different periods, but we are talking about in the first year, 1977, about $157 million. Then the next year it happens to be by nature of the period that the contracts expired, about $480 million, and it varies all the way up and comes to the figure that I had. Under those assumptions on an accumulated basis, about $19 billion until 1998.

Mr. OTTINGER. $19 billion.

Mr. DUNHAM. That is over the 20-year period. It is $157 million in the first year, and it varies, and then if you accumulate all that over the 20-year period.

Mr. OTTINGER. $19 billion.

Mr. DUNHAM. But that has got to be borne in perspective of the total gas market.

Mr. OTTINGER. I am not sure that we get our money's worth for the $19 billion.

Thank you, Mr. Chairman.

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes the gentleman from Louisiana, Mr. Moore, for 5 minutes.

Mr. MOORE. Thank you, Mr. Chairman.

Mr. Dunham, on page 4 of your testimony you made a comment that under this bill as far as the price was concerned of a cap, $1.75, buyers would be on an equal footing in interstate and intrastate markets. I am wondering isn't there additional regulations issued by your agency over interstate gas in addition to merely pricing?

Mr. DUNHAM. For transportation, yes. On production, no, not on production as such, only on the transportation in interstate commerce.

Mr. MOORE. And then of course we now have allocation as well.

Mr. DUNHAM. Curtailment, yes.

Mr. MOORE. Curtailment.

Mr. DUNHAM. But again that applies to the end of the pipe, not the beginning of the pipe, if I understand your question.

Mr. MOORE. Right, so that essentially you made the comment that we had essentially an unregulated market in intrastate and a regulated market in interstate.

Now with the passage of this bill we would have the pricing being the same, but would your statement still not be true? We would still have essentially an unregulated, with the exception of a capping on the price, versus a regulated market with equal price?

Mr. DUNHAM. If I understand your question, I think you are relating to the conservation responsibilities of the States, the States in terms of production?

Mr. MOORE. No. Your statement that you made about interstate being regulated, intrastate being essentially unregulated, that would still be true, except now that the price would be the same in the two.

Mr. DUNHAM. Yes. I think your analysis is correct. As I understand the bill, it relates only to the price regulation aspects of the production, not the pipeline transportation within a State.

Mr. MOORE. One of the problems we have seen, and one of the problems I think that certainly you have seen, has been the uneven distribution of newly produced natural gas in this country as to where it goes, the intrastate market versus the interstate market.

Now in your opinion has this been strictly due to pricing or have there been other considerations that cause more gas to go to intrastate than to interstate?

Mr. DUNHAM. In my opinion, the major reason has been the price disparity. The other factor which is important and may be significant, but is essentially a value judgment, is in the case of the intrastate pipelines they have not been anxious to come under the jurisdiction of the Federal Power Commission; I think that was evident, and one of the reasons for the major provisions in the Emergency Natural Gas Act which permitted the intrastate pipelines to transport gas in interstate commerce without coming under the jurisdiction of the Federal Power Commission, so that is another factor.

Mr. MOORE. I think it is a very candid answer. It seems we heard that from producers earlier in this hearing, something about doing business with your friends if you are in the intrastate market, and

you are going to get the same price, why come under the FPC? I would like to ask you in connection with 770-A, I believe your department or your agency must have done some price elasticity studies, to lead you to raising the price of interstate gas.

Would that be correct?

Mr. DUNHAM. Yes.

Mr. MOORE. Could you make those price elasticity studies available to this committee for us to use in our deliberations?

Mr. DUNHAM. Yes, of course. We will be happy to provide that.

Mr. MOORE. Mr. Chairman, I ask that the record be kept open, and that those studies be made a part of the record when they are received.

Mr. DINGELL. Without objection, so ordered.

[The following information was received for the record:]

What were the elasticity studies that went into Opinion Nos. 770 and 770-A?

Studies of the behavior of gas supply have been undertaken, in different forms, by several groups within the FPC staff. No work completed before 1970 is included in this summary.

The earliest study was presented in the Second Southern Louisiana Area Rate Proceeding (Docket AR69-1). It also appears, in summary form in the Spring, 1971 issue of *The Bell Journal of Economics and Management Science*. Data covering the period 1961 to 1969 were used to estimate the coefficients of this econometric model. *New discoveries* were estimated to increase 20.94 billion cubic feet in response to a 1¢/Mcf increase in the average of the preceding two years' wellhead price of gas, decrease 9.69 billion cubic feet in response to a $1/barrel increase in the average of the preceding two years' wellhead price of oil, and increase 13.51 billion cubic feet in response to a 1¢/gallon increase in the average of the preceding two years' price of natural gas liquids. The response is such that an increase in the price of gas continues to increase new discoveries, but at a declining rate, over a number of years until an equilibrium level is reached. Because the elasticity depends on the initial level of new discoveries and the associate levels of the gas, oil and liquids prices, no compact summary of the elasticities can be given. Over the data period 1961-1969, gas prices displayed relatively little variation, rising at most from about 17¢/Mcf to 20¢/Mcf in any production district (it actually declined in one) and varying no more than about 6¢/Mcf among production districts. The model has not been employed for prediction using gas prices more than about 15¢/Mcf above 1969 level.

The Project Independence Blueprint *Final Task Force Report: Natural Gas* published by the FEA in November 1974 and prepared under the direction of the FPC can serve as the prototype of a number of Staff studies. It is not easy to summarize this work in elasticity terms. However, the general tenor is captured in Table VI-11 which shows *Non-Associated Gas Production* increasing very little in response to prices above 70¢/Mcf in 1977 and 1980, 80¢ in 1985 and $1.00 in 1988.

In Opinion 770 and 770-A the Commission alluded to many empirical studies indicating substantial supply elasticities, and observed that many areas, both on and offshore, remain unexplored and that there is no current shortage of drilling equipment. No explicit estimate of response to the Opinion 770 prices was given. However, an estimate of the response to Opinion 699-H prices was implicit in the assumption that new dedications, stimulated by 699-H prices, would continue in the 7/27/76-7/26/77 period at a rate equal to that experienced from 1/1/75 to 7/26/76.

In any search for, or assessment of, supply elasticity estimates several considerations should be borne in mind. First, although drilling and other costs can be estimated with precision comparable for that of other production processes, the drilling outcome in the form of new discoveries cannot. Indeed, so long as the distribution of the location, size and depth of remaining pools remains unknown, no well-understood averaging process over wells to be commenced can predict average discoveries with high confidence. Second, the historical experience has shifted from a period of relatively constant costs, prices, and discoveries to a period of rapid escalation in the former two and decline in the latter. In fact, change has occurred so rapidly that the effects of one round of increases have not been understood before another occurs.

Mr. MOORE. Mr. Dunham, I thank you for your answers.

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes the gentleman from Tennessee, Mr. Gore.

Mr. GORE. Thank you, Mr. Chairman.

Let me follow up on the questions just asked, Chairman Dunham.

What are you going to do about this remaining incentive to producers to prefer the intrastate market over the interstate market?

Mr. DUNHAM. Well, by virtue of the fact that under this bill there would be a single price element, parity; the price disparity would be eliminated under this bill.

The other factors Mr. Moore related to, of course, would not change, and it is hard for me to evaluate, there are a lot of other factors involved, too. If a field is produced in close proximity to an interstate pipeline, it is more economically advantageous, because they do not build connecting facilities to dedicate or to sell that gas to the interstate market.

Conversely, if they happen to be in close proximity to an intrastate market, or a direct use of that gas, then that is the way it would go, but I think the major factor is the single price.

Mr. GORE. I think the exploration pattern does reflect, as you just said, that the areas explored have been near interstate markets more frequently. But I am not convinced that the paperwork entry barrier is negligible, and I am wondering, if we are going to try to equalize the two markets, perhaps it might be worth exploring how useful these forms are.

One of them is form 40, if I am not mistaken, requiring those who sell in the interstate market to provide the government information on their reserves. Now it seems that if the new Department of Energy is serious about acquiring valid information that is trustworthy and can be used to better predict the energy outlook in this country, that this ought to have an effect on the paperwork burden that intrastate producers of natural gas have.

It seems to me that when we are looking at better ways to gather information, that is a perfect opportunity to eliminate the disparity there.

Mr. DUNHAM. Under this legislation the need for a great deal of information which we now collect would automatically disappear, because the primary reason for our Form 40, Form 64 and a series of other forms is to get the information, in order to make the calculation on the basis of the cost.

Now, once a single price is established, or a price is established, then the need under the present system for a lot of that information disappears. This does mean, in my opinion, that the Department of Energy or whatever agency will need some basic information-gathering authority just for policy-making purposes. But it would no longer be used in the same type of adjudicated procedures that we now have to follow on cost-based regulation.

Mr. GORE. I would just like to underscore again the need for information. Your statement here this morning again reflects this.

You say you are talking about the reserve dedicated to the interstate market, and you are forced to talk about historical data based upon trends. It is absolutely incredible that we do not have that kind of information, and it is so vital to the formulation of a

wise energy policy. I hope you will make that a very high priority as we proceed with this package.

You testified that the effect of the President's program during the natural gas emergency was to reduce the shortfall by around 400 Bcf. If we have another winter next year like we had this winter, what do you predict the shortage to be?

Mr. DUNHAM. One other factor you could speculate on is this: the Federal Power Commission recently put out a report which showed that the reserves under interstate commerce we know about declined by a further 5 percent this year, which is the ninth straight year. Now applying that figure against a winter supply-demand or demand situation like we had this last winter, you could only speculate in that case that it would be 5 percent shortfall, further shortfall, beyond the shortage we had this winter, so 5 percent more severe.

Offsetting that possibly is that many of the industries that were forced off of natural gas this last winter by lack of access to supplies, have not converted back, or have made other plans for using alternative fuels, so that factor might moderate it, but there is no question if we had a winter as severe next winter as we had this winter, I see very little that we could do but have a problem as severe as we had, of something about that dimension.

Mr. GORE. That is one of the questions which needs continuing exploration now, while the weather is warm. Dr. Schlesinger testified here last week that the proposed price of $1.75 was supply-sensitive, and was adequate to promote significant new drillings. If that does constitute a sufficient stimulus, as he testified it did, then why is this tremendous give-away on the roll-over provision proposed?

Mr. DUNHAM. I tried to answer that in Mr. Ottinger's questions, Mr. Gore. I am not knowledgeable of the reasons for selecting that particular policy option by the President. I was not party to it. I do not know.

The Federal Power Commission made a different policy judgment which is being decided in the courts, as you know, in regard to its 770-A. I do not know how to answer that question, except possibly, and it is only speculation, a determination on their part that the capital formation aspects of that were required and necessary in order to increase exploration and development, additional drilling, and thereby eliciting supplies.

Mr. GORE. That is an interesting addition to the record.

Thank you, Mr. Chairman.

Mr. DINGELL. The time of the gentleman has expired,

The Chair recognizes the gentleman from Illinois, Mr. Russo, for five minutes.

Mr. RUSSO. I have always been known to have a good voice without a mike, Mr. Chairman, so I will try it without a mike for a while.

Let me just ask you, Mr. Dunham, do you feel that the $1.75 is a sufficient incentive for the gas companies to go out and find more gas, and help them in their capital formation?

Mr. DUNHAM. It is really very difficult to speculate on that. It is certainly more of a supply incentive than the present 770 opinion of

the Federal Power Commission, which is $1.45, escalating at a cent a quarter. Whether or not $1.75 is a high enough price to elicit sufficient supplies is very speculative.

The reserves——

Mr. RUSSO. Do you think it ought to be higher?

Mr. DUNHAM. I think a case can be made, but I do not have the information on which to make that judgment because the prime determination has to be the amount of available reserves in this country onshore and offshore, which can be produced at a particular price. When you talk about reserves you have to talk about production at a price.

Mr. RUSSO. When the President's policy came out at $1.75, obviously he must have some information or some studies that he used to make that determination. Were you aware of it?

Mr. DUNHAM. I am not aware of that. I assume that he does, and the staff that developed the bill did make a group of postulates.

Mr. RUSSO. You are not personally aware of that information?

Mr. DUNHAM. I am not.

Mr. RUSSO. Do you feel that the gas companies have any shut-in wells on the onshore and offshore pending this legislation?

Mr. DUNHAM. No, I do not. It is possible to speculate there are some for obvious economic reasons. In my opinion, it is not a significant sum of gas that is not going flat out. This last winter my staff did some surveying down there and, as far as we could tell, every well was running flat out and essentially maintenance was being deferred, and a safety element could be argued, so I have no knowledge of any particular shut-in reserves.

There are a number of proceedings before the Federal Power Commission now relating to this type of a problem, and they are proceeding before our administrative law judges and in various stages, so I do not reflect or comment on those particular proceedings.

Mr. RUSSO. Are you saying that the average price of intrastate gas was about $1.62 for this year? Is that what you are saying?

Mr. DUNHAM. No.

Mr. RUSSO. Contracts averaged $1.62?

Mr. DUNHAM. That is new contracts, $1.62.

Mr. RUSSO. Natural gas sold in the intrastate market for 1976?

Mr. DUNHAM. Yes, that is on page 4. Bear in mind that that is a limited survey relating only to the information that we have available to us and we are restricted in the information we can have.

Mr. RUSSO. Is there any other department in the executive branch that has more available information other than the Federal Power Commission?

Mr. DUNHAM. The Federal Energy Administration has legal ability to gather some information on the intrastate prices that we do not have. They may have that better information.

Mr. RUSSO. So when you say we do not have reliable figures on the prices of gas flowing in intrastate market, that is strictly the Federal Power Commission?

Mr. DUNHAM. The Federal Power Commission per se. We are limited by the authority that we have to gather information only from jurisdictional companies.

Mr. RUSSO. Is there any particular reason why the intrastate pipelines do not want to come under the jurisdiction of the Federal Power Commission?

Mr. DUNHAM. Yes, I would assume there are many reasons.

As Mr. Moore pointed out, there is a number of other, as they would see it, impediments, with dealing with the Federal Power Commission.

Mr. RUSSO. What are they?

Mr. DUNHAM. The forms filling out questions, some of the contractual requirements we have in regard to abandonment or changing sales, in addition to the price distinctions that I mentioned.

Mr. RUSSO. Did you ever think that some of those suggestions would be good suggestions and maybe that you ought to do something about it, dealing with interstate gas, because intrastate pipelines have done such a good job for so many years without your intercession?

Maybe if you cut back on the forms and other complicated procedures it would be even better for the interstate market.

Mr. DUNHAM. The question has two sides. I would not argue that.

We are required in the methodologies that we must use in calculating the prices, we must base that on evidence. This is a long history, it has been built over some 20 years, 23 or 24 years. The courts require us to base our determinations on facts and figures subject to cross-examination, evidentiary rules and that type of thing. If you are asking me if I feel some of it is surplusage, that may be, but in the view of the courts I am not sure that they would agree with that.

Mr. RUSSO. Thank you very much.

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes the gentleman from Texas, Mr. Collins, for five minutes.

Mr. COLLINS. Thank you, Mr. Chairman.

Mr. Dunham, you have had extensive regulatory experience. In the United States today what other products, other than oil and gas, are under price control; raw materials? What other tangible goods are under price control besides oil and gas today?

Mr. DUNHAM. In terms of resources, none.

Mr. COLLINS. None. This is the only one. Yet Congress is talking about going into an extensive oil and gas price control program.

As a student of history and with extensive background on this, can you recall any peacetime successful program of pricing and wage control?

Mr. DUNHAM. Peacetime, I certainly would be hard-pressed; I cannot.

Mr. COLLINS. On these tiers of gas prices we have, how many tiers are there of gas prices that we have today?

Mr. DUNHAM. I believe we have eleven vintages and tiers. Is that about right?

Mr. JOURNEY. That is about right.

Mr. DUNHAM. Eleven is about right.

Mr. COLLINS. We have eleven different price structures. How many classes of ultimate users do you have for priorities?

Mr. DUNHAM. Nine steps, nine curtailment categories.

Mr. COLLINS. How do you determine which price goes to which user and all of that? Is that just done through one formula or is it extensive hearings?

Mr. DUNHAM. No, not priced to each particular element. We have operated historically on a rolled-in price, so the price and curtailment or allocation portion are really separate proceedings. They are both very complex, extensive proceedings, but they essentially are separate. Whatever gas is available is allocated, price is determined on a rolled-in basis or average cost basis and then curtailed on different proceedings, general proceedings.

Mr. COLLINS. Let me ask you—I note New Jersey has a contract with a very low price where they are buying gas on a long-term contract. It is a loser for the company to furnish this gas, but they have the company bound under contract. Under this new bill, as I understand it, will the company still be required to deliver that gas on the old contract price?

Mr. DUNHAM. Until the contract expires.

Mr. COLLINS. Which will run another 15 years?

Mr. DUNHAM. Whatever the particular contract may be.

Mr. COLLINS. I think that price may be around 19, 30 cents, somewhere down in there.

Mr. DUNHAM. We have many contracts——

Mr. COLLINS. In other words, they are going to continue to buy gas at a very, very low price if we do not change. Is there any reason why Congrss should not change those contracts if we change the intrastate constitutional question?

Mr. DUNHAM. Well, Mr. Collins, quite obviously it depends on the position you take in regard to what function you want the price to perform.

If you want the price to perform a conservation element, to give that type of a signal, then a case could certainly be made that the flowing gas, the average cost-prices should be raised in order to confront individuals with the actual replacement cost of that gas, so that perhaps they will conserve its use to a greater extent than they do by virtue of the historical low average prices. It would have to depend on what you are trying to do.

If your objective is to give the producers additional exploration and development or capital formation, funds, then that is another reason.

Mr. COLLINS. Congress might revise old contracts if we start changing the basic constitutional question of full regulation of intrastate gas, which is now protected under the Constitution in the eyes of most lawyers, as I understand it.

Mr. DUNHAM. It is my understanding that the contract provisions can be preempted by Federal legislation, but I am not a lawyer.

Mr. COLLINS. What is the cost of synthetic natural gas today as you see it?

Mr. DUNHAM. Between $5 and $6.

Mr. COLLINS. In other words, our country is supposed to produce synthetic natural gas under this bill on a cost-plus basis, based on $5 of $6?

Mr. DUNHAM. That would seem to be the case; we do now have some synthetic gas certificates which we have approved that are in that range.

Mr. COLLINS. Mr. Russo just asked a question about the government forms that are filled out by companies. A major oil company told me they fill out today about 450 government reports a year, most of those are mandated by Congress.

How many do you require within your department?

Mr. DUNHAM. Not quite that many; about 5 regular forms, but of course even that number is not significant, it depends on how many questions and blanks there are in the form. There is a great deal, as I explained earlier, that we are required to provide.

Mr. COLLINS. Thank you, Mr. Chairman.

Mr. DINGELL. The time of the gentleman from Texas has expired.

The Chair recognizes the gentleman from Michigan, Mr. Stockman, for five minutes.

Mr. STOCKMAN. Thank you, Mr. Chairman.

Mr. Dunham, you pointed out in response to a previous question that this proposal really changes the whole basis for pricing from the historic cost base to an interstate fuel equivalency concept. It would seem to me that implicit in that would be also an intrastate fuel equivalency concept, in other words, within one fuel, natural gas that we are talking about here.

As I look at your data on page 9 regarding LNG imports it seems to me there is a great contradiction in the bill, because we have domestically produced gas being capped at $1.75, but as I look at most of the landed prices for some of your pending applications, they are beginning to range up in the area of $2.80. It seems to me the landed price is roughly equivalent to the field price of domestically produced. So you have a great spread there, plus, as I read the bill, I see no volumetric limits on LNG imports, and I see no pricing concept based on the intrafuel equivalency notion.

I cannot really understand that, because what that price is is a very strong incentive to meet incremental demand for natural gas through very, very high-cost imports and that assumes or involves a number of things.

It involves increased supply in security because you never know when it is going to be cut off; it involves a balance of payments drain; it involves the export from this country of our productive exploration and drilling and seismic crew capacity; it involves high cost to the economy because you are talking about field equivalent prices of about $2 or $3 per thousand cubic feet. It seems to me the whole idea of interfuel equivalency is that you want to get incremental supplies at the least cost, so can you see any justification for this open-ended approach toward imported LNG and the very tight ceiling of $1.79? Either we are going to have to do something on the import side or we ought to relax the ceiling we are placing on the domestically produced side.

Can you rationalize or discuss or elaborate on that inconsistency?

Mr. DUNHAM. I think the first thing——

Mr. STOCKMAN. Let me say, before you give your answer, that I added up your annual volumes for currently approved and pending requests, and you see we are not talking about a marginal phenom-

enon. I add it up to 1.7 trillion cubic feet. It seems to me that will continue if the conversion programs in the next four, five or six years do not work as expected. So you are going to have that continued natural gas demand there.

Mr. DUNHAM. The column you refer to, as I think you did, is the United States terminal tailgate column, the third one in, that is the most comparable?

Mr. STOCKMAN. That is the most comparable?

Mr. DUNHAM. Most comparable to wellhead. That would not include the transportation and product prices. So quite obviously there is a larger figure, at least $1, added to all of those prices when it gets down to the cookstove or whatever.

The problem it seems to me is one of course in theory and in trying to apply the theory to the actual situation. Most logically, I think economists would say that the price ought to be set at replacement cost. The dilemma you have is what replacement cost do you take?

LNG has one price, SNG has another, oil import and export, or imported and domestic have two different prices. Some people would argue that electricity is an alternative fuel, which it is in certain cases. So which one do you select? How do you calculate this amount?

It is a very difficult thing.

As I understand the President's proposal, he did not particularly choose replacement cost in that theoretical sense. He picked a cost of the $1.75 equivalent to an average of domestic oil. So from that array he selected a particular category.

I assume there was, I can only assume that the reason for choosing that price in a ceiling price is to overcome what some would argue would be a disorder or an interruption in the market, in view of the short supply.

These are a lot of policy questions and I wish I could come up with a simple single answer. I have some of the same problems you do.

Mr. STOCKMAN. You are familiar with this business as it is written, would you not say there is a strong incentive in this bill for drastically increased reliance on LNG imports.

Mr. DUNHAM. LNG or SNG. No, I think there is another element in, particularly on liquefied natural gas importation. The public interest considerations are in my opinion very important there, dependency upon a particular country, a particular source, the possibility or threat of interruption, and the impact that would have on a particular system if a very significant amount of their gas supplies came from that source.

There are a number of other factors: qualitative, diplomatic, if you will, international relations. As you pointed out, balance of payments questions would need to be entered into the final decision.

I believe the President's proposals are that these ought to be reviewed on a case-by-case basis, instead of saying, as his predecessor did, a two-trillion-cubic-feet limit and no more than one trillion cubic feet from a particular country. If they were done so in an integrated-department type of situation, which he would have available to him, either the Secretary of the Department of Energy or

the President, these other considerations would be included. As you pointed out, LNG is of course a very expensive increment of gas.

Another determination which would be or must be made probably at each element of subsequent approvals is whether that portion of the energy equation cannot be filled by some other source.

Mr. STOCKMAN. That is right.

Mr. DUNHAM. We need so much energy and if there is no alternative, then what obviously—a case-by-case basis, he would look at it.

[The following letter and attachment were received for the record:]

FEDERAL POWER COMMISSION
WASHINGTON, D.C.
May 26, 1977.

Hon. JOHN D. DINGELL,
CHAIRMAN,
Subcommittee on Energy and Power,
House of Representatives,
Washington, D.C.

DEAR CONGRESSMAN DINGELL: This is in response to Congressman David A. Stockman's request of May 17, 1977, for information concerning natural gas supplies.

The enclosed Appendix provides a summary of imported liquefied natural gas applications. The term "permitted prices at the terminal gate" is a misnomer in that no prices for LNG have actually been permitted as yet, rather they are "proposed" prices. In all cases, the indicated price is estimated.

With regard to the second question, involving systems that have been most active arranging for the importation of LNG, all applicants with LNG projects seek the supplemental supply on the assumption it will be needed in the future to meet high-priority needs. Some distributors may show modest growth in residential hookups, in the short run. Details as to each distributor's situation are not available due to difficulty in projecting four or five years into the future.

* * * * * * *

I hope this information is helpful to you. If I may be of further assistance, please do not hesitate to contact me.

Sincerely,

RICHARD L. DUNHAM,
Chairman.

Enclosure: Summary of Import Project Filings

Source: FPC Section of Records and Dockets

Summary of Filings

Import Project Docket No.	Applicant	Type of Filing (Section)	Date Filed	Description of Filing
I Distrigas Project 1/				
A. CP70-196	Distrigas Corp.	3	3-17-70	Importation of 15.4 million MMBtu/yr for 20 years authorized by Opinion No. 613.
CP73-135	DOMAC	7	11-20-72	Sale of imported volumes in interstate commerce (Opinion No. 613).
CP74-137	DOMAC	7	11-13-73	Construction and operation of the Everett, Mass., terminal.
CP74-227	Distrigas Corp.	7	3-4-74	Sale of imported volumes by Distrigas to its affiliate DOMAC.
B. CP76-9	Distrigas Corp.	3	7-8-75	Short-term importation of 21 million MMBtu during the 18 month period 7-1-76 to 12-31-77.
CP76-280	Distrigas Corp.	7	2-23-76	Sale of short-term imported volumes by Distrigas to DOMAC.
CP76-386	DOMAC	7	3-28-76	Sale of short-term imported volumes to distributor customers.
II Eascogas Project 2/				
A. CP73-47	Eascogas LNG Inc.	3	8-16-72	Import. of 238 million MMBtu/yr for 20 yrs. (Total import. 4.8 billion MMBtu over 20 yrs).
CP73-88	Eascogas LNG Inc.	7	9-29-72	Sale of up to 238 million MMBtu/yr for a 20 year period.
CP73-148	Energy P/L Corp.	7	11-29-72	Constr. and oper. of 6,000 feet of 24-inch p/l with a looped river crossing under the Arthur Kill.
B. CP73-139	Algonquin LNG Inc.	7	11-22-72	Constr. and oper. of the Providence, R.I. Terminal and 3.8 miles of p/l across the Providence River.
CP73-197	Algonquin Gas Trans.	7	1-26-73	Constr. and oper. of 1.2 miles of 30-inch and 2 miles of 16" p/l.
CP73-199	New England LNG	7	1-26-73	Sale of 7 to 14 million MMBtu per year.
III El Paso I Project				
CP71-68	Columbia LNG	3	9-22-70	Import of 500,000 Mcf/d of LNG at the Savannah, Ga. LNG terminal
CP71-153	Consolid. Syst. LNG Co.	3	11-25-70	Import. of 500,000 Mcf/d of LNG at the Cove Point, Md. LNG terminal.
CP71-151	Southern Energy Co.	3	11-25-70	Import. of 350,000 Mcf/d of LNG at Savannah, Ga. terminal for a term of 25 yrs.
CP71-264	Southern Energy Co.	7	5-4-71	Constr. and oper. of the Savannah, Ga. LNG terminal.
CP71-276	Southern Nat. Gas Co.	7	5-19-71	Constr. and oper. of p/l connection between Savannah terminal and Southern's p/l.
CP71-289	Columbia & Consolidated	7	6-4-71	Transportation and sale of imported volumes on the U. S. East Coast.
CP71-290	Consolidated Systems	7	6-4-71	Constr. and oper. of 190.2 miles of 30-inch p/l from Loudon Cty. Va. to Clinton Cty. Pa.
IV El Paso II Project 3/				
A. CP73-258	El Paso Eastern Co.	3	10-15-76	Import. of 1,000,000 Mcf/d for 20 years at LaSalle, Texas terminal.
CP73-259	El Paso Eastern Co.	7	3-1-77	Exchange and sale of imported volumes in interstate commerce.
CP73-260	El Paso Nat. Gas Co.	7	3-1-77	Constr. and oper. of facilities and transportation of gas.
B. CP77-269	El Paso LNG Terminal	7	3-1077	Constr. and oper. of LaSalle, Texas LNG terminal.
CP77-270	El Paso Eastern Co.	7	3-1-77	Sale of natural gas to United LNG Company.
CP77-271	United Gas P/L Co.	7	3-2-77	Constr. and oper. of appurtenant facilities.
CP77-272	United LNG Co.	7	3-3-77	Sale of natural gas to United Gas Pipe Line Company
V Trunkline Project				
CP74-138	Trunkline LNG Co.	7	11-15-73	Constr. and oper. of Lake Charles, La. LNG terminal
CP74-139	Trunkline LNG Co.	3	11-15-73	Importation of 178,571,428 Mcf per year for a term of 20 years.
CP74-140	Trunkline Gas Co.	7	11-15-73	Constr. and oper. 45.8 miles of 30-inch p/l.
VI Pacific Indonesia Project				
CP74-160	Pacific Indonesia LNG Co.	3	3-31-75	Importation of 346,000 Mcfd of LNG from Republic of Indonesia
CP74-207	Pacific Indonesia LNG Co.	7	3-31-75	Sale of natural gas to Southern California Gas Company and Pacific Gas & Electric Co.
CP75-83-3	Western LNG Terminal Associates	7	3-31-75	Construction and operation of LNG storage and vaporization terminal in Oxnard, Ca.
VII Tepco Project 3/				
CP77-100	Tenneco Atlantic Pipeline Company	7	12-20-76	Construction and operation of pipeline in Maine, Ny., Mb., Mass. and Pa. & sale of gas.
CP77-101	Tenneco Atlantic Pipeline Company	3	12-20-76	Importation of maximum daily volume of 1,140,000 Mcf per day of Algerian natural gas from Canada for 20 years.
CP77-102	Tenneco Atlantic Pipeline Company	4/	12-20-76	Authorization to construct and operate border facilities on Maine - New Brunswick International Border.
CP77-103	Tennessee Gas Pipeline Company	7	12-20-76	Authorization to construct and operate minor pipeline facilities in Mb., Ny., and Pa. to deliver gas to resale customers.

Summary of Filings

Footnotes:

1/ On 2-11-77 Distrigas and DOMAC in Docket Nos. CP77-216, CP77-217 and CP77-218 filed applications covering the importation and sale of some 46 million MMBtu per year for 20 years from the Everett, Mass., terminal. This program is proposed to supersede Distrigas import programs in Docket Nos. CP70-196 and CP76-9 as of 1-1-1978. Also pending are Distrigas & DOMAC's tariff filings in Docket Nos. RP76-102 and RP76-73 respectively.

2/ Original Eascogas project proposed importation into the terminals at Providence, R. I., and Staten Island, N. Y. Eascogas is currently in the process of restructuring their project to import LNG into the terminals at Cove Point, Md. and Staten Island, N. Y. No application to this effect have been filed to date, but are anticipated. Therefore the applications involving the Providence, R.I., terminal, i.e. CP73-139, CP73-197 and CP73-199 referenced above may become moot.

3/ Original El Paso II project proposed importation into the terminals at Raccoon Island, N. J., Cove Point, Md., and Savannah, Ga. Pursuant to El Paso Eastern's amendment to its application in Docket No. CP73-258, El Paso Atlantic Co. was substituted for El Paso Algeria Corp., as purchaser. In the contract with Sonatrach executed on October 28, 1975, the Algerian delivery point is not specified. The application filed by Southern Energy Co., in Docket Nos. CP73-271 and CP73-272 and by Southern Natural Gas Co., in Docket No. CP73-273 pertaining to construction and operation of Savannah, Ga., terminal were withdrawn. Currently, El Paso Eastern Co., proposed in Docket No. CP73-253 to receive the imported volumes in the LaSalle, Texas, LNG terminal.

4/ Filing pursuant to Executive Order No. 10485.

5/ LNG import terminal will be constructed in New Brunswick, Canada.

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes the gentleman from Illinois, Mr. Madigan.

Mr. MADIGAN. Thank you, Mr. Chairman.

Mr. Dunham, I would like to discuss briefly with you your testimony as it relates to section 415 of the proposed bill. Your statement says that the Trans-Western coal gasification plant, which is proposed to produce some 250,000 cubic feet of synthetic gas a day at $2.50 a thousand cubic feet still is not financed. Could you tell me why it is still not financed? Do you know?

Mr. DUNHAM. I know of no communication to us on why it has not been financed. I can speculate as to the reason.

It is my understanding that at those prices and absent a guarantee from the Federal Power Commission of essentially what we call an all-events tariff, to cover all of the costs, either their calculations and or the financial community's calculations did not believe that that plant was economically viable at the price that we permitted. In other words, the financial community wants absolute certainty that the cost will be recovered in order to perform this banking function of providing the funds under debt or equity. There may very well be other reasons.

The technology and such may not have been developed in such a way that they believed they could economically produce gas at the price that we provided in that certificate, which was $2.50.

Mr. MADIGAN. I am a little bit confused by that. Are you saying that you presently have the authority to regulate the synthetic natural gas?

Mr. DUNHAM. We do not have the authority to regulate the plant. However, the significant factor is that we do regulate the gas when it comes out of the plant and is commingled in the interstate gas stream. We determine the price that the synthetic gas company or plant can sell in interstate commerce.

Originally we said when they came in with an application that we do not have plant certificate jurisdiction and they said, "Well, we understand that, but we must in order to get it financed, we must go and explain to the investors the price at which you will allow us to sell that gas."

So we do, indirectly, have jurisdiction, not directly.

Because it is the price at which the pipeline can sell the gas—can transport the gas, purchase it, and transport it in their system. So it is a critical factor.

Mr. MADIGAN. I assume if you have that authority or that responsibility to regulate prices, it moves into interstate commerce, then the FPC must have done some studies of the economic feasibility of these coal gasification plants, and also what the end price of the product ought to be.

Mr. DUNHAM. Yes.

In the hearing—do you recall that case? Maybe Mr. Williams can answer more specifically on that case.

Mr. WILLIAMS. I believe that in that case the price that ultimately the Commission permitted Pacific Lighting et al. to pay was the price which the company came in with studies and indicated that the project at least would be viable in the initial stages at that price. The Commission approved, or issued an opinion permitting

Pacific Lighting et al. to pay, and guaranteeing that Transco et al. could charge that initial price and permitted adjustments after there was operating experience.

Mr. MADIGAN. Does the FPC have studies of different kinds of processes and what the cost for manufacturing synthetic gas and different kinds of processes would be or do you study these things as they are presented to you?

Mr. DUNHAM. No. The only information we would have is when specific applications come before us. I would assume that the Energy Research and Development Agency may have information and do look at particular areas. We do not, until an application comes before us.

Mr. MADIGAN. In the case of El Paso, buying from the Burnham coal gasification complex, you indicate in your testimony that this was delayed because of, and I quote you, "certain environmental problems." Are those problems with the manufacturing process?

Mr. DUNHAM. No. I am informed they dealt primarily with the acquisition of water rights and movement of coal, transportation or strip mining, those types of environmental problems, to the production of the plant per se.

Mr. MADIGAN. Finally, you suggest the desirability of a loan guarantee program for coal gasification plants. Have you any recommendations as to the amount of money that should be included in such a program?

Mr. DUNHAM. I do not believe——

Mr. DINGELL. The witness may continue his answer. The Chair observes the time of the gentleman from Illinois has expired.

Mr. DUNHAM. I will supply that.

[The following information was received for the record:]

Do you have any recommendations as to the amount of money that should be included in a loan guarantee program for coal gasification plants?

The Federal Power Commission has no way to independently estimate the budget authority needed to fund a loan guarantee program or is qualified to comment on the merits of such a program. However, it is to be noted that, ERDA has compiled a fact book [1] on a Synthetic Fuels Commercial Demonstration Program. In this publication ERDA cites the following figures needed in the first five years of such a program.

Funding Authorization for Loan Guarantees $6 billion, New Borrowing Authority $1.5 billion.

Mr. DINGELL. The Chair recognizes the gentleman from Indiana, Mr. Sharp, for 5 minutes.

Mr. SHARP. Thank you, Mr. Chairman.

Mr. Dunham, one of the things it seems to me we have to unravel and perhaps you can help us, is the interrelationship of some of the parts of this proposal.

We have incremental pricing, we have a user's tax, we are going to get rid of the declining block in the rate structure and we are possibly going to change the load factor for many of the gas and electric companies and pipelines.

Those elements—just my rough guess—add up to men that increasing costs will have to be charged to the residential sector even though it appears that the intent of the program is to try to stabilize the residential sector, and shift costs on to the industrial sector.

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[1] Proposed Synthetic Fuels Commercial Demonstration Program, Fact Book. United States Energy Research and Development Administration, Washington, D.C., March, 1976.

Can you give me any help in understanding what the potential impacts are?

Mr. DUNHAM. Yes. We have tried to make some calculations because of what these costs would be. I think there is a number of things which you pointed out, and, if I may, I would like to comment on each one.

Essentially in my opinion the incremental pricing provisions in the bill do not run, at least in my understanding of what incremental pricing is, at least the way the FPC has done. They are essentially, as I interpret it, directive; in other words a disincentive to industries and utilities to using natural gas, thereby preserving this finite supply of gas transported in interstate commerce for residential use.

Now that does change, that would change the nature of the market because the amortization of the pipeline and of the distributors would then have to be spread and distributed to the retail customers, 365 days a year, at least those costs would have to be covered 365 days a year. Now whether or not there is an increased cost to consumers depends fundamentally upon the amount of supplies that are available.

If the supplies stay the same, in other words interstate commerce now would continue to have about 11 trillion feet of gas distributed to residences, and if that volume stays the same, then the cost of service, the demand charge would be the same. That would require, in effect, more hook-ups for residences because to take up the burden of that gas use that is now supplied to either utilities or industries so that if the supply stayed at the same volume there would be no change, except for this: Because of the nature of the residential market, particularly up in the Northeast and Midwest and other areas like that in the colder climates, the peak load demand is spread over a shorter period of time.

It essentially would be over a four- or five-month period and during the summer and spring there would be relatively little demand. There is no air-conditioning demand, particularly up in the colder areas.

So it would require in my opinion the acquisition and development of additional storage facilities up in those areas. That would require an additional cost and could spread it on and would be an added cost to consumers. But the critical factor that would govern that cost is really the estimate of the amount of supplies that would be dedicated.

Mr. MADIGAN. Sure, but I do not understand the purpose of the various proposals combined is precisely to reduce reliance. What you are saying——

Mr. DUNHAM. It is directing it more to residential, off of utilities, off of boiler fuel and essentially off of industry that can use alternative fuels. It is a redirecting of the market.

Mr. MADIGAN. Right. So not even discussing the change in the price of the gas itself—clearly the unit costs are going to increase.

Mr. DUNHAM. Yes.

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Mr. MADIGAN. It would appear to me that the whole thing working will obviously vary dramatically from one gas company to another. So I do not think we should kid anybody that we are somehow relieving one sector over another. They are both going to have to go up. Inevitably they will, the question is how well we manage it here.

Do you have any written analysis on this?

Mr. DUNHAM. I do not know. We have not put it together quite that way. We have some studies that we have done that relate to it.

For instance, one study was done by the Bureau of Natural Gas with regard to the additional cost to users, gas users, as a result of declining volumes; in other words, to carrying the amortization of the pipelines and distribution systems over a smaller volume. Some of these pieces, some speculations or postulates could be made; they would only be that type of a judgment, not very precise.

We have some hearing records on that, I have been informed. We could supply them to the committee.

Mr. MADIGAN. Are you talking about volumes?

Mr. JOURNEY. That has come up in some of our cases, administrative hearings record develop some of this.

Mr. MADIGAN. Would it be easy for you to identify by index for us so we could find that information without delving into it, without putting into our record volumes?

Mr. DUNHAM. Why we do not try to identify particular things and talk to your staff?

Mr. DINGELL. I think that would be helpful. Without objection that will be inserted in the record at this point.

[The following material was received for the record:]

Supply for the record studies which the Commission staff may have made regarding the impact of price changes and shortfalls by class of customer.

The staff has not made any formal study on the impact of price changes and shortfalls by class of customer.

However, a simple study has now been put together to illustrate the impact of decreasing throughput on the average unit cost of providing service. This study covers ten large pipelines and is based on the cost in the most current rate case for each pipeline and the projected gas deliverability as shown for each in its most current Form No. 15. The cost of gas purchased was deducted from total claimed cost of service in order to approximate the annual fixed costs of each pipeline. The remainder was divided by the annual gas deliverability to obtain an average unit cost for each of the years 1977 through 1981. While not precise, this study shows the dramatic impact of changes in throughput on the average unit cost.

The data needed to spread this impact among the classes of customers served by each pipeline is not presently available. An attempt by the staff to superimpose this data upon the annual deliverability for the years 1977 through 1981 would require extensive staff time. We believe the study we have provided gives an over-view of the potential impact on residential consumers as supply declines. We wish to emphasize that this study does not reflect the potential impact of increases in the cost of supply on residential consumers.

COMPANY	TOTAL COST OF SERVICE ABSENT PURCHASED GAS COSTS		PROJECTED ANNUAL DELIVERABILITY FROM 1976 FORM 15 VOLUMES IN MILLION MCF (MMMcf)				
			1977	1978	1979	1980	1981
	$	1					
Columbia Gas Transmission	522 247 301	2	1146	1099	1077	1049	1008
Average Unit Cost		3	45.57 ¢	47.52 ¢	43.49 ¢	49.79 ¢	51.81 ¢
Consolidated Gas Supply	227 994 832	4	634	633	679	645	607
Average Unit Cost		5	35.96 ¢	36.02 ¢	33.58 ¢	35.13 ¢	37.53 ¢
El Paso Natural Gas	517 356 628	6	1121	984	882	780	706
Average Unit Cost		7	46.15 ¢	52.53 ¢	58.66 ¢	66.33 ¢	73.28 ¢
Michigan-Wisc P/L	498 676 415	8	783	740	657	598	533
Average Unit Cost		9	63.69 ¢	67.39 ¢	75.90 ¢	87.29 ¢	93.56 ¢
Natural Gas P/L Co	758 342 259	10	1047	960	858	789	683
Average Unit Cost		11	72.43 ¢	78.99 ¢	87.37 ¢	96.11 ¢	111.03 ¢
Northern Natural Gas	457 093 175	12	732	656	603	533	482
Average Unit Cost		13	62.44 ¢	69.68 ¢	75.80 ¢	85.76 ¢	93.86 ¢
Tennessee Gas P/L	344 153 965	14	1137	938	874	803	718
Average Unit Cost		15	49.62 ¢	60.16 ¢	64.55 ¢	70.71 ¢	78.57 ¢
Transcontinental Gas P/L	414 404 077	16	584	496	420	367	323
Average Unit Cost		17	70.96 ¢	83.55 ¢	98.67 ¢	112.92 ¢	128.30 ¢
Transwestern P/L	149 431 753	18	235	194	163	137	116
Average Unit Cost		19	63.59 ¢	77.03 ¢	91.68 ¢	109.08 ¢	128.62 ¢
United Gas P/L	193 675 000	20	687	508	377	299	259
Average Unit Cost		21	28.19 ¢	38.13 ¢	49.41 ¢	64.77 ¢	74.78 ¢
		22					
		23					
		24					
		25					
		26					
		27					

Mr. DINGELL. The time of the gentleman has expired. The Chair thanks him for his questions.

The Chair recognizes the gentleman from Ohio, Mr. Brown.

Mr. BROWN. Thank you very much for your testimony thus far and for your response to questions, which I gather have indicated to us that there is a supply response to price. We seem to have that evidence historically on page 46 of your testimony.

I wonder if you could supply for the record, not necessarily now, what the time frames of those various base rate prices are.

[The following information was received for the record:]

What were the time frames of the various base rate prices listed on page 4?

The base rates reflected on page 4 of the testimony referred to sales made by independent producers during calendar year 1976 under the various price vintages adopted by the Commission in Opinion Nos. 749, 699, and 770, as amended.

Mr. BROWN. Who is covered by the form 45 reports which you mention on page 4 which yielded the average new contract for 1976 intrastate gas at $1.62, and average renegotiated contracts of $1.69?

Mr. DUNHAM. Only those companies which are now jurisdictional to the Federal Power Commission.

Mr. BROWN. Which means those companies that sell interstate?

Mr. DUNHAM. Sell some gas.

Mr. BROWN. And are supplying you information on the gas that they also sell intrastate.

Mr. DUNHAM. That is right.

Mr. BROWN. What percentage of the intrastate market is covered by those form 45 reports?

Mr. DUNHAM. We would estimate that those producers covered by our form 45 reports amount to about 80 or 90 percent of the gas produced, large producers.

Mr. BROWN. That seems to be high to me.

Mr. DUNHAM. Of interstate gas.

Mr. JOURNEY. I am not sure that——

Mr. BROWN. What percentage of the intrastate gas consumption is covered by those reports?

Mr. DUNHAM. We would have no way of knowing.

Mr. BROWN. Could you supply it?

Mr. DUNHAM. I do not believe we would have any way to get that, since we cannot get that information from——

Mr. BROWN. What is the volume supplied by that gas?

Mr. DUNHAM. We could make a calculation, an assumption based on what we know of total volumes of intrastate gas transported but I do not know how good it would be.

[The following information was supplied for the record:]

How much interstate gas is covered by the FPC Form 45 reports? What percent of the intrastate market is covered by producers filing the FPC Form 45 reports?

We have no direct information concerning how much of the intrastate market is supplied by producers filing the FPC Form 45 reports, which collect data on new and renegotiated contracts for nonjurisdictional companies. We do know, however, that the 178 producers which have reported data on FPC Form No. 45 represent over 93 percent of all jurisdictional natural gas sales. Moreover, the summary data which has been published by the FPC for 1975 and 1976, represent 2,000 contracts newly executed or renegotiated during that time.

The respondents to FPC Form No. 45 during 1976 reported *new* and *renegotiated* contracts representing 704.5 billion cubic feet. This volume represents about 7.8 percent of *total* intrastate sales of about 9.0 trillion cubic feet for the same year.

Mr. BROWN. If you could supply that for the record so as to give us some range. My information is it is somewhere between 25 and 30 percent of the intrastate market is covered by reports which you are referring to.

Mr. DUNHAM. I see.

Mr. BROWN. The unreported contracts, would you guess, would be higher or lower in terms of the average price they yield?

Mr. DUNHAM. The most recent contracts are likely to be higher than—are higher than the $1.62.

Mr. BROWN. That confirms what we have been told by three pipelines who have testified before this subcommittee so far, intrastate pipelines that say their average for all contracts is $1.75 to $1.90, which would indicate that the figures which you make reference to here may be low for the average price.

Mr. DURHAM. Because we do not have the whole——

Mr. BROWN. Now was that not the original cost of finding and producing gas from wells drilled after January 1, 1975, determined by the FPC in 1976 in opinion 770(a) to be $1.61?

Mr. DURHAM. $1.61 is the level price. We use the discounted cash flow method to bring it back down and average it back up. So it started at $1.42, escalates a penny a quarter, it is now $1.45.

Mr. BROWN. It was lowered to $1.42 on a trend line study. I wonder if you could supply for the record some brief description of the methodology by which you got that trend line study?

Mr. DUNHAM. Yes.

Mr. DINGELL. Without objection the document referred to will be inserted in the record at the appropriate place.

[The following material was received for the record:]

What were the concepts that went into the DCF methodology utilized in Opinion 770? Also, what were the trending of costs and producer materials utilized in that same decision?

A.) DCF Methodology

A detailed explanation of the concepts that went into the DCF methodology are set forth in Opinion No. 770-A at pages 29 through 32. (Copies attached)

B.) Trending of Costs

In Opinion No. 699-H, the Commission adopted a least squares method for trending actual drilling cost. In Opinion No. 770, the Commission found that drilling cost indicies published by the IPAA (Independent Petroleum Association of America) would logically be nearer actual costs than the results of other statistical methods. A thorough description of the use of the IPAA indicies is set forth in Opinion No. 770 at pages 45 through 48. (Copies attached)

C.) Producer Materials Utilized in the Decision (Opinion 770 & 770-A)

The significant data used by the Commission in its costing methodology are published by various gas and oil industry associations as follows:

1) Joint Association Survey (JAS) publishes drilling costs and exploration and development expenditures.
2) American Gas Association (AGA) publishes natural gas and liquid reserves and production.

3) Independent Petroleum Association of America (IPAA) publishes drilling cost indicies.

4) American Petroleum Institute (API) publishes gas, oil, dry hole drilling data.

Insofar as establishing reasonable costing methodology, the Commission employed the Opinion No. 699-H method with its own modifications as well as a method presented by its Office of Economics. It is also noteworthy that the Commission has been attempting to obtain Court approval of Rulemaking which issued FPC Forms 40 and 64. These FPC Forms would provide an independent source of data.

The Commission found that the present value of the revenues resulting from the $1.42 rate escalating at one cent per quarter is equal to the present value of the revenues at a level rate or constant annual rate of $1.61 over the projected 15-year life of a well. Moreover, rather than allowing a constant rate of $1.61, which might appear too high in 1976 and too low in 1991, the Commission determined that a lower initial rate with proper escalation is in the public interest. Escalation of 4 cents per annum on the initial $1.42 rate would track an approximate 3 percent annual rate of inflation in future exploration and development costs. It is also significant to understand that either $1.42 with 4 cents per annum or the level rate of $1.61 will yield the 14.16 percent computational rate of return found reasonable by the Commission.

II. DISCOUNTED CASH FLOW METHODOLOGY

In its application for rehearing, APGA criticizes the Commission's use of the discounted cash flow (DCF) methodology in Opinion No. 770 in lieu of the Permian costing methodology 30/ used in various area rate proceedings. This criticism was expressly rejected by the Court in Shell Oil Co. v. F.P.C., supra, when APGA attacked the DCF analysis used in Opinion No. 699-H.

Once again APGA fails to understand that the Permian methodology was a point of departure for the DCF cost analysis used herein. 31/ The Permian methodology was not "abandoned" but was supplemented by the DCF format. This was made clear in Opinion No. 699-H where the Commission stated:

> We find that supplementary (DCF) cost analysis necessary to assure that the rate allowed for new gas supplies adequately reflects the true cost of those supplies. We believe that the Permian methodology adjusted by applying a DCF analysis to produce a true yield of 15 percent over the life of the investment and further tested by the use of trended drilling costs will establish a more reliable foundation for a predictive just and reasonable rate than will the exclusive use of the Permian methodology standing alone. 32/

30/ Area Rate Proceeding (Permian Basin Area), 34 FPC 159 (1965).

31/ See, Opinion No. 770, ___ FPC ___, mimeo p. 17.

32/ See, Opinion No. 699-H, ___ FPC ___, mimeo p. 14.

The DCF methodology focuses on anticipated cash flows over the life history of a well rather than on revenues and costs in any one year. Since the time value of money is one of the crucial factors in this analysis, judgments must be made concerning the timing of costs and revenues. The principal costs (or negative cash flows) were assumed to occur in the three-year pre-production period (denominated years -1, -2, and -3) 33/, while negative cash flows (or cash expenditures) in the productive period (operating expenses, etc.) were assumed to vary proportionally with production. Projected revenues or positive cash flows were assumed to occur during the 15-year productive period (denominated years 0 through 14). 34/

The present value of all positive and negative cash flows over the 18 year pre-production and production period was computed at the first year of production (year 0). Net investments (cash outflow) made during the three years prior to production were compounded annually at a 15 percent rate of return. Similarly, future revenues less annual expenses (cash inflow) were discounted by the same 15 percent rate of return. These computations based on the stated assumptions yielded the present value of investment as of the first year of production.

The DCF methodology is designed to determine the price required to yield a given rate of return over the life of the project. It recognizes the fact that there is a time value which can be placed upon capital and that cash flow must be at a level necessary to produce the required return. The DCF methodology also reflects the cost of capital by allowing a return on all invested funds. This was pointed out in Opinion No. 699-H as one of the reasons for this departure from the Permian methodology. There the Commission stated:

33/ See, Opinion No. 770, ___ FPC ___, Exhibits 15 and 17, mimeo pp. 90 and 93.

34/ Ibid.

> The Permian costing format requires that dry hole and exploration expenditures be expensed and recovered through production. The Permian formula is explicable only by an assumption that the dry hole allowance in the price of existing production in each year is in the aggregate sufficient to pay for or "expense" the total dry hole costs for that year. This assumption may or may not have ever been correct for a given producer. However, such an assumption today is contrary to the public interest in two related respects. First, it provides a disincentive to existing producers to increase investment in exploration and development and to incur the concomitant dry hole expense. The perpetuation of such disincentives would frustrate the fundamental national goal of achieving a greater degree of energy self-sufficiency. Second, the assumption and, consequently, the methodology is discriminatory to new market entrants who have no flowing gas against which to "expense" the dry hole costs. Today, the price of each Mcf of new gas must fully reflect the cost of finding and producing that gas and we find that the Permian formula does not adequately achieve that goal. If the recovery of such funds is to be permitted only over the depletable life of the project, then a return must be allowed on these costs just as it is allowed for successful wells.

We believe that the record as a whole permits us to make reasonable assumptions as to the timing of expenditures. We also believe that the DCF analysis is necessary to make reasonably certain that the end result of a 15 percent return will be attained without the attrition inherent in the Permian methodology. We, therefore, find that the Permian methodology adjusted by the DCF analysis is the most reliable basis for determining a reasonable rate structure. Accordingly, the criticism of APGA with respect to the use of a DCF analysis is hereby rejected.

C. Drilling Cost

The second major factor in the cost of gas production is drilling costs. The basic data from the Joint Association Survey is presented below as Exhibit 6.

Exhibit 6. Drilling Costs Per Foot
(Excluding Alaska)

Year	Successful Well Cost	Dry Hole Cost
1967	22.90	12.14
1968	23.69	12.60
1969	24.35	12.78
1970	26.62	14.33
1971	27.63	15.83
1972	27.53	16.94
1973	27.43	18.93
1974	34.00	26.27

Source: Joint Association Surveys

In Opinion No. 699-H, the Commission adopted a least squares method for trending actual drilling cost to the 1973 test year. Subsequently, actual data for 1973 revealed that the linear regression line predicted dry hole costs too low and successful well costs too high by equally significant amounts.

Of the three staff studies in this proceeding, all based on data through 1973, two used least squares trending to arrive at a 1976 cost figure for successful and dry hole drilling while the third chose the most recent (1973) figures at the time of the submission. Their estimated drilling costs were:

	Successful	Dry Hole
BNG I 95/	$32.61	$18.78
BNG II 96/	27.43	18.93
OEC 97/	32.61	19.78

95/ BNG Recommendations, August 4, 1975.

96/ BNG Recommendations, March 23, 1976.

97/ OEC Recommendations, August 4, 1975.

IPR approved of updating available data, but chided the Commission for being deficient in prescience and advocated the use of more judgment and a curvilinear regression line to provide a more reliable estimate. 98/ Utilizing such method, Witness Auten for IPR estimated successful well cost for 1974 of $28.07 per foot and for 1975 of $28.08 per foot. 99

Witness Ogden for UDC estimated that 1974 drilling costs would be 40% greater than 1973. 100/

The actual 1974 successful well cost reported by JAS was $34.00 per foot, an increase of approximately 24% over 1973, $5.93 greater than Witness Auten's estimate and $3.75 greater than would be indicated by a 1973-1974 linear regression line. Dry hole cost has increased similarly. A linear regression line would predict 1974 costs between approximately $18.00 and $22.00, varying with the length of the series used to fit the line. Witness Auten, relying upon curvilinear regression analysis, estimated the 1974 dry hole cost at $20.49. Witness Ogden applied his estimated 40% increase in drilling to dry holes. The actual 1974 dry hole cost reported by JAS was $26.27, an increase over the 1973 level of approximately 39%.

The extraordinary inflation of recent years suddenly has affected drilling costs to a degree that no submitted statistical trending method would yield an accurate prediction. We are, however, again confronted with a "test" year for drilling, 1975, that is one year ahead of the available JAS cost data. The continuing general inflation requires that the task of updating actual data be once again undertaken. There is no comprehensive, long-term price index for petroleum industry drilling. The IPAA for several years published only quintennially a comprehensive oil and gas drilling cost survey and index, but in 1973, the IPAA commenced issuing the reports annually. 101/ Between 1969 and 1973, the IPAA

98/ IPR Comments, May 30, 1975, Appendix L, p. 5.

99/ Ibid. Chart 2.

100/ UDC, May 14, 1975, Statement 7, p. 5.

101/ Independent Petroleum Association of America, Report of Cost Study Committee, May 1976.

index tracked actual experience as reported by JAS reasonably closely. While the 1969 index was 100 and the 1973 index was 131.5, 102/ the average increase in successful well and dry hole costs as reported by JAS between 1969 and 1973 was approximately 24%. Furthermore, the extraordinary increases from 1973 to 1974 provide a rigorous test of accuracy. The 1973 IPAA cost per foot index is 83.0, 1974 is 100.0, and 1975 is 114.9. If the 1973 and 1974 IPAA indices had been used to estimate 1974 JAS costs, the indicated costs per foot would have been $33.05 (compared to $34.00 actual) for successful gas wells, and $22.81 (compared to $26.27 actual) for dry holes. 103/ For that period, the accuracy of the IPAA index substantially exceeds the accuracy of any submitted form of regression analysis.

The IPAA index shows a further 14.9% increase from 1974 to 1975. 104/ The continued upward pressure upon oil and gas-well drilling costs is borne out by the Bureau of Labor Statistics (BLS) index for drilling machinery which increased 24% between 1974 and 1975, and 14% from February 1975, to February 1976. 105/ Also the BLS shows similarly escalating wage costs; average hourly earnings rose 14.6 and 12.2 percent between February 1974-75 and 1975-76, respectively. 106/ Thus, the IPAA appears to be a reasonably accurate reflection of actual experience, and we here adopt it in preference to regression analysis for the purpose of trending the 1974 JAS data to the 1975 test year.

To obtain the 1975 drilling costs per foot we converted the 1973 and 1974 JAS costs to constant dollars, using the IPAA index for drilling costs per foot. The averages of the 1973 and 1974 constant dollar costs for successful wells and dry holes of $33.53 and $24.56 per foot, respectively, were adjusted to 1975 dollars by applying the 14.9% increase indicated by the IPAA index. The 1975 projected costs are:

102/ IPAA, Report of Cost Study Committee, June 1975.

103/ Exhibit 6, supra.

104/ Exhibit 6, infra.

105/ Wholesale Prices and Price Indexes, Bureau of Labor Statistics, selected volumes; Oil Field Machinery and Tools (Code No. 1191).

106/ Employment and Earnings, Bureau of Labor Statistics, selected volumes; Crude Petroleum and Natural Gas Fields (SIC 131-2), average hourly earnings.

Exhibit 7. Well Costs ($/ft)
(Excluding Alaska)

Year	(1) Current Dollars Successful	(2) Current Dollars Dry Hole	(3) Index*	(4) Constant Dollars Successful	(5) Constant Dollars Dry Hole
1973	27.43	18.93	83.0	33.05	22.81
1974	34.00	26.27	100.0	34.00	26.27
1975	38.53(p)	28.20(p)	114.9	33.53(a)	24.54(a

Sources: (1) and (2): Joint Association Survey.
(3) : IPAA Report of the Cost Study Committee, Summary of Committee Activities, May 1976. Adjusted index.
(4) and (5): (1) and (2) ÷ (3) for 1973 and 1974.

(a) Average 1973-74.

(p) projected = 1973-74 average x 114.9.

Mr. BROWN. Have there been any motions filed with the Federal Power in the last two months for a new interim rate for natural gas produced from wells drilled after January 1, 1975, or for wells drilled after January 1, 1977?

Mr. DUNHAM. Yes, sir, there have. We have a rulemaking pending with regard to the next biennial determination and there have been some filings made in that proceeding.

Mr. BROWN. What have those filings requested as a price for new natural gas wells?

Mr. DUNHAM. I have not read those and I have not seen an analysis.

Mr. BROWN. Anyone with you who could tell us?

Mr. DUNHAM. No, I do not believe so.

Mr. BROWN. I have information, Mr. Chairman, that would indicate that the prices are——

Mr. DINGELL. If the gentleman will yield, the Chair will not take it from his time. The Chair simply wants to have a brief colloquy about matters that concern us both substantially. I am sure the gentleman from Ohio seeks in no fashion to intrude into the decisionmaking process at the Federal Power Commission.

Mr. BROWN. Indeed not, Mr. Chairman. I am only asking what the filings have been, as a matter of fact, not as a matter of opinion of the Chairman, as to what they should have been or anything else and I asked for the process by which the previous decisions had been made. It is a common process, as I understand; is that not correct?

Mr. DINGELL. If the gentleman will yield further, I understand this is his intention and the Chair speaks in all courtesy and respect to the gentleman on this point.

Mr. BROWN. Indeed I have not asked——

Mr. DINGELL. The *Pillsbury* case troubles me, as you know.

Mr. BROWN. I am fully familiar with that. I have not asked the Chairman to justify the decision of the Federal Power Commission, but merely to provide a description of what is, I understand, a common process which has been used previously in the past and not with reference to figures but with reference to how the information is arrived at.

Mr. DUNHAM. Yes. As I pointed out, I have heard and I have seen calculations that some people have made with regard to particular prices, but I would not want to rely on my recollection of that. We would be happy to supply you with some of the basic figures and perhaps speculate on the calculations.

Mr. BROWN. Well, if I may I would be happy to insert into the record at this point with unanimous consent, I understand there have been at least two filings and that one of these filings was for $1.9082 or $1.91 for gas drilled after January 1, 1975, and for gas drilled after January 1, 1977, that the request is for $2.3978 or $2.40, which would indicate, Mr. Chairman, that the $1.75 for gas in the future might be somewhat lower than necessary to elicit a supply response.

Now, Mr. Chairman, on page 7 you make a reference that I do not understand and I wish you would submit some information for the record to clarify it. You are talking about roll-over gas and you say this also assumes that flowing gas prices in the absence of this act could be maintained at 53 cents, all the way through to 1998. Would you elaborate on that?

Mr. DINGELL. The time of the gentleman from Ohio has expired. The Chair will permit the witness to respond.

Without objection the material referred to will be inserted into the record at the appropriate place.

[The following information was received for the record:]

List the filings that were made in the new National Biennium Rate Review. Included in these filings is there at least one response filed, that proposes prices for post-January 1, 1975 gas of $1.98 and for post-January 1, 1977 of $2.40?

SUMMARY OF FILINGS MADE THUS FAR IN DOCKET NO. RM 77-13

Comments are due in RM77-13 on August 1, 1977. However, a few petitions have been filed.

Associated Gas Distributors has petitioned to expand the proceeding to elicit and consider evidence as to whether additional revenues from renewal contracts and higher rates for new gas sales in general actually produce additional gas supplies or increase exploration and development; to consider whether new wells in developed fields should receive the newest vintage rate; and to determine the extent to which higher rates gotten by producers through transportation by interstate pipelines of non-jurisdictional direct industrial sale gas and reservations of portions of offshore gas to producers' own uses, should be considered.

Amoco Production Company and Indicated Producer Respondents answered this motion to the general effect that (1) the proceeding already includes all areas covered by AGD, and (2) AGD is attempting to impose evidentiary burdens which cannot be met because quantification of incremental supplies elicited by higher rates is impossible.

In addition to the foregoing, certain producers have petitioned seeking immediate rate increases subject to refund during the pendency of RM77-13, because of alleged cost increases. $1.75 is sought for gas wells commenced after January 1, 1975, and $2.21 per Mcf for wells commenced after January 1, 1977.

Mr. DUNHAM. Okay.

Very quickly, Mr. Brown, with regard to that there are proceedings whereby the producers could come in and maintain that the 53-cent price, in this case or any vintage, any of these 11 vintages, was no longer adequate in terms of continuing production or additional inflation with regard to production costs or some other factor like that.

So this assumption was only that the price could be maintained. Our prices have changed in the past on existing vintages, notably the so-called flowing gas at the older price of 26¢, which was subsequently, on order of the Federal Power Commission, raised somewhat.

So this is a low assumption. You would have—it could be changed.

Mr. BROWN. The 538 is the low assumption?

Mr. DUNHAM. Yes.

Mr. BROWN. That is what I thought.

Thank you.

Mr. KRUEGER. [presiding.] The gentleman's time has expired.

Mr. BROWN. My time is up. I would like to ask permission to submit a couple of written questions to the chairman for his response as soon as possible.

Mr. KRUEGER. Without objection it is so ordered.

The Chair recognizes at this time for five minutes Mr. Walgren.

Mr. WALGREN. I have no questions for the witness at this time and will yield back the balance of my time, Mr. Chairman.

Mr. KRUEGER. I thank the gentleman.

The Chair recognizes at this time the gentleman from California, Mr. Moorhead, for five minutes.

Mr. MOORHEAD. Mr. Dunham, I am interested in the portion of your testimony dealing with synthetic natural gas and LNG. In your testimony on pages 10 and 11 you refer to the difficulty of providing large capital investments for development of synthetic natural gas. You state that some of these problems can be handled in this legislation by giving the FPC the authority to certificate the production transportation and sale of SNG in a manner similar to natural gas in interstate commerce.

How would this work in that manner?

Mr. DUNHAM. In essence, under that bill it would make the entire process jurisdictional in the sense of the President's proposals; as opposed to the situation we now have where we have jurisdiction only over the gas, once it is produced, and then transported in interstate commerce. It is the question of certitude, certainty of price.

If we had the opportunity to a greater extent than we now do to look at or ascertain the costs of production, we could make the public interest decision on that broader base, as opposed to when the gas comes out of the plant and goes into the pipe.

Mr. MOORHEAD. How could you assure them that they could sell their product at a profitable price or sell a large enough amount of it to make the total enterprise worthwhile?

Mr. DUNHAM. In one of the cases referred to in the testimony, what the producer requested was an all-events tariff. That means

essentially all costs, whatever they are. Of course, if you give a producing plant that type of a guarantee, it would in my opinion be financeable; in other words, all costs.

In this latter case we talked about, we said $2.50 and we will look at additional increments later on if necessary.

Mr. MOORHEAD. When Mr. O'Leary spoke to this committee, he said it was the policy of the administration to keep the total amount of synthetic natural gas and LNG that we might be receiving from overseas down to a very low level so that it would not hike up the total price the consumer was paying for the product. Would that not defeat the attempt to make the enterprise profitable and would it not discourage the people fromn putting their money into the project from thinking they would be able to have enough production to get their money back?

Mr. DUNHAM. Of course it would have a different result, I think it is a difference. I did not read Mr. O'Leary's testimony, but it is quite a different proposition, it seems to me, from our national perspective in regard to synthetic natural gas introduced from the coal gasification process, as opposed to LNG.

I would think whoever had that responsibility would look at those differently. I happen to believe there are great potentials in terms of coal gasification or certainly hope there are. LNG raises different questions of dependence, possibility of interruption, and so forth.

I really do not know the assumptions the President and Mr. O'Leary and Mr. Schlesinger have put into the energy equations, the amounts from either coal gasification or LNG.

Mr. BROWN. Will the gentleman yield?

Mr. MOORHEAD. Yes.

Mr. BROWN. I was fascinated by that comment because the second time you said you do not know what went into the formation of the $1.75 price and you do not know what assumptions have been made here.

Did not Mr. Schlesinger and the administration in any way consult the Federal Power Commission on these issues?

Mr. DUNHAM. The answer to that is no. I saw drafts of the bill at very, very short periods before they were submitted. That is the answer.

Mr. MOORHEAD. In your testimony further on on page 13 you talk about "If it is in the national interest to encourage SNG production" and "if it is thought investors are unwilling to assume the risks associated" and so forth and so on.

Do you believe it should be a part of our national policy to encourage the development of synthetic natural gas.

Mr. DUNHAM. With regard to synthetic gas produced from coal, the answer is yes. I say that for two reasons:

One, we have enormous supplies of coal, as you know.

Second, we have an enormously efficient transportation system, and I believe that should be taken advantage of.

I would think that processes, technologically, can be developed which are environmentally preferable to some of the other alternatives.

So the answer is yes, I do personally believe that coal gasification should be one of the major efforts that this country should attempt to develop and refine the technology.

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Mr. KRUEGER. The time of the gentleman from California has expired.

The Chair at this time recognizes the Chair for questions.

Mr. DINGELL. Mr. Chairman, I am much concerned about the fashion in which the Emergency Natural Gas Act enacted by this Congress has been administered.

I would like to begin by commending you. I think you have done an outstanding job. Parenthetically, I address you not as the Chairman of the Federal Power Commission but as the administrator of the Emergency Natural Gas Act, for reasons that I am sure we both fully understand.

Mr. Chairman, I would like to have you inform us if you please of the levels of contracts under that act, and the impacts of that act on the intrastate market.

Let us deal with the first, if we may. What were the price levels of the contracts under the Emergency Natural Gas Act, per thousand cubic feet?

Mr. DUNHAM. You mean price?

Mr. DINGELL. Yes.

Mr. DUNHAM. The average price was about in the $2.20 range. The most prevalent price was $2.25, that was the ceiling.

Mr. DINGELL. $2.25 was the most prevalent.

Can you tell us what was the high and what was the low?

Mr. DUNHAM. Well, the high was $2.25 MMBtu, on direct wellhead purchases.

Now there were some replacement cost purchases where we essentially replaced, took the gas and replaced the full cost for either coal or oil or something that went into the utility boiler at higher prices. There were some at $3, $3.37, is what I recall, but I am not sure about replacement oil costs, in other words, replacement oil costs plus the additional maintenance of the utility boiler and other costs attributable directly to the gas. It was an exchange type of thing. But the wellhead price purchase, the ceiling, I believe, the highest purchase was $2.25. In other words, some cases we purchased the oil and put it under the—transported it and put the oil under the boiler in order to take the gas off the boiler and send it——

Mr. DINGELL. So as to make the seller of the gas whole and leave him with a neutral price impact.

Mr. DUNHAM. Right.

Mr. DINGELL. Do you regard that as a special circumstance or do you regard that as an indication of the price at which natural gas should move?

Mr. DUNHAM. That particular type of transaction I would consider as an emergency example type of procedure, that type of exchange, oil for gas.

Mr. DINGELL. What was the highest price which was offered and accepted—two questions—for natural gas during this period of emergency sales.

Mr. DUNHAM. It was in the $3 range.

Mr. DINGELL. I heard of a $5 contract.

Is that a fact?

Mr. DUNHAM. No, I don't believe we had any—I don't recall any. There certainly were none approved at that price.

Mr. DINGELL. I know you would not approve it. As a matter of fact it was not approved.

Can you submit a list of contracts which came before you for approval, giving an indication of price, those which were approved, and those which were disapproved?

Mr. DUNHAM. Both on the so-called exchange type arrangement.

Mr. DINGELL. Yes, if you please.

Mr. DUNHAM. And direct purchase from wellhead.

Mr. DINGELL. Yes.

Mr. BROWN. Wouldn't it also be helpful—if you will yield——

Mr. DINGELL. I am glad you asked me to yield.

Mr. BROWN. Some indication as to whether those are producer or pipeline sales.

Mr. DUNHAM. Yes.

Mr. BROWN. In other words, whether it came from the producer or the pipeline. I think I know what you are after.

Mr. DINGELL. I think that would be helpful.

Mr. DUNHAM. Yes, we will.

Mr. DINGELL. Were there LNG or SNG purchases involved in this?

Mr. DUNHAM. Yes, there were at least two LNG purchases; one from Phillips plant in Alaska, another one that was an Algerian sale, a particular tanker volume. The LNG sale may be the one, that was the high $3 range, as I recall it. But I do have that information. That was approved.

Mr. DINGELL. I am advised you also rejected one contract early on in your role as Administrator, something on the order of $2.75; am I correct?

Mr. DUNHAM. Yes, there was one, yes.

Mr. DINGELL. As I understand it the next morning the same folks were back with a $2.25 contract; is that right?

Mr. DUNHAM. Yes, that is right.

Mr. DINGELL. Now I would like to get down to some questions that trouble me. The proposal before the committee involves a distance of 2-1/2 miles and a vertical distance of a thousand feet for purposes of establishing whether in fact it is new gas or old gas.

Will you give us your comments and your views on this? Is this a workable criterion for new gas or are there other criteria that should be used? Obviously, it is fairly simple to administer if you say we are going to take the 2-1/2 miles horizontal distance and 1,000 feet vertical distance. But is it necessarily a proper definition for new gas?

Mr. DUNHAM. In my opinion it is not a workable definition of new gas. We went through that process in the rehearing of 770 and the ultimate result in 770-A. I mentioned in my opening remarks and reference to pages in the 770-A opinion which would, I believe, explain to you and your staff the reasoning process that we went through in choosing a different methodology. From what I recall of that hearing and that is proper for me to talk about, because that is now out of our hands and in the courts——

Mr. DINGELL. Again I caution you as to *Pillsbury*. It is not my intention to dictate your policies to you.

Mr. DUNHAM. This would not apply, because that particular case is no longer in our hands, it is in the court's hands, so I am not restricted.

But in that rehearing process, when we ran into some of these same definitional problems, we came to a different conclusion. We did not feel that the application of a particular linear dimension was applicable in geological terms to the actual circumstances which apply under the ground. The structures are so complex and there is no commonality between them.

Mr. DINGELL. This is in 770-A that you referred to.

Mr. DUNHAM. 770-A, I refer to the page numbers in my testimony.

Mr. DINGELL. Would you submit those to us for the record?

Mr. DUNHAM. Yes, I will.

[The following material was received for the record:]

Supply a list and summary of contracts approved and disapproved under the Emergency Natural Gas Act with reference to high, low, and average prices which were proposed and approved and/or disapproved.

GENERAL ORDERS ISSUED UNDER
THE EMERGENCY NATURAL GAS ACT OF 1977

	Date Issued	Name	FR Citation
(1)	2/03/77	Order No. 1	2/08/77: 42 FR 7948
(2)	2/03/77	Order No. 2	2/08/77: 42 FR 7948
(3)	2/03/77	Order No. 3	2/08/77: 42 FR 7948
(4)	2/11/77	Order No. 4	2/15/77: 42 FR 9167
(5)	2/15/77	Order No. 5	2/17/77: 42 FR 9673
(6)	2/22/77	Order No. 6	2/28/77: 42 FR 11246
(7)	2/24/77	Order No. 6-A	2/28/77: 42 FR 11246
(8)	2/25/77	Order No. 2-A	3/03/77: 42 FR 12172
(9)	3/01/77	Order No. 4-A	3/04/77: 42 FR 12423
(10)	3/04/77	Order No. 1-A	3/09/77: 42 FR 13110
(11)	4/20/77	Order No. 7	(See E77-92)

SUMMARY OF THE GENERAL ORDERS ISSUED UNDER
THE EMERGENCY NATURAL GAS ACT OF 1977

P. L. 95-2, the Emergency Natural Gas Act of 1977 was signed into law by President Carter on February 2, 1977. This Act empowers the President to declare a Natural Gas Act emergency. Further, until April 30, he may order interstate gas pipelines to switch gas from surplus to shortage areas. And, until July 31, he may waive controls on the price interstate pipelines may pay producers for natural gas, permitting them to pay any "just" price. Finally, President Carter designated the Chairman of the Federal Power Commission, Richard Dunham to administer the Act.

The General Orders issued on February 3, 1977 by Administrator Dunham described the consultation structure necessary to administer P.L. 95-2; the general criteria followed for emergency purchases; and the conference procedure which will be followed for daily and weekly consultation.

(1) Specifically, Order No. 1 establishes the organizational structure by which personnel might assist the Administrator in his administration of the Act. The consultation group is composed of "(1) governmental representatives to be designated by the Attorney General, the Secretaries of the Interior and Agriculture, the Federal Trade Commission, the Administrator of the Federal Energy Administration, as well as staff members to be assigned by the Federal Power Commission; (2) consumer representatives designated by the Secretaries of Health, Education and Welfare and Housing and Urban Development from members of the general public; (3) representatives of state and local governments, as designated by the National Governors' Conference, the Conference of Mayors, and the National Association of Counties; (4) representatives of the natural gas industry, including interstate and intrastate natural gas pipelines and local distribution companies." However, the Administrator reserves the "decisional responsibility and the legal actions to be taken" to himself as Administrator.

(2) Order No. 2 determines the fair and equitable prices for emergency purchase of natural gas. Emergency purchases of natural gas at $2.25 per MMBtu, inclusive of all state and local taxes and other adjustments may be made without prior notification to or authorization by the Administrator. If the seller of gas will be required to use alternate fuels to replace the volumes sold, a price equal to or less than the cost of alternate fuel plus 7 percent will not have to be authorized by the Administrator. If a distribution company makes an emergency sale, it may receive its overall replacement cost plus applicable transportation and storage costs if any. Finally, no subsequent Administrator's action may require a refund of monies collected or reduction of transactional prices which comply with the Act. Purchases of natural gas at prices in excess of the levels set forth above will be permitted only with authorization of the Administrator.

(3) Order No. 3 sets up weekly meetings of the emergency gas requirements group to review the prior week's natural gas operations, natural gas flow, storage refilling plans and to assemble data reports. It also sets up the daily work group which will monitor daily requirements and supply, and propose actions appropriate to the resolution of these problems.

(4) Order No. 4, issued February 11, 1977 stated (1) that voluntary transactions and self help measures have aided in easing gas supply problems; (2) that weekly reporting of "prices and volumes of natural gas' delivered, transported or contracted for" is necessary and the specific information which must be reported to the Administrator was delineated; (3) that the actual prices and volumes of each delivery must be reported by the recipient on the Wednesday following delivery; (4) that the seller must report certain information to the Administrator on the first of each month following delivery.

(5) Emergency Order No. 5, issued February 15, 1977 authorized the Administrator to order any pipeline to transport gas or construct necessary transportation facilities when the gas is an emergency purchase under Section 6(a). Compliance with the Administrator's Order would not subject the pipeline to regulation under the Natural Gas Act or to regulation as a common carrier under any provision of state law.

(6) Emergency Order No. 6 issued February 22, 1977 stated that the term "emergency supplies" in Section 6 of the Act shall be deemed to mean natural gas that is necessary to enable the purchasing party to serve uses of natural gas other than boiler fuel uses and industrial use with alternate fuel capability specified in Priorities Four through Nine of FPC Order No. 467.

(7) Emergency Order No. 6-A, issued February 24, 1977 clarified Order No. 6. Specifically, Order No. 6 imposed on the purchaser, not the seller, the obligation to determine whether it is qualified to make such purchase. The seller may deem the purchaser's execution of a contract to purchase gas pursuant to Order No. 6 a statement that the purchaser is qualified to purchase such gas.

(8) Emergency Order No. 2-A issued February 25, 1977 stated that the price $2.25 per MMBtu "inclusive of all state and local taxes and other adjustments". With respect to wellhead sale of natural gas, $2.25 per MMBtu is the maximum consideration that may be received by the seller if the natural gas is delivered at the wellhead without prior notification to or authorization by the Administrator. The price is inclusive of any form of payment to the seller or to any affiliate of the seller for any services however denominated that are necessary to deliver the gas at the wellhead.

(9) Emergency Order No. 4-A, issued March 1, 1977 changed the abbreviation Mcf to MMBtu in subparagraph (c) of Paragraph No. (2); and inserted a new subparagraph (g) which stated "the amount and method of determination of any broker's fees, commissions or finder's fees paid in relation to the transaction;"

(10) Emergency Order No. 1-A, issued March 4, 1977 amended Order No. 1 by adding the National Association of Regulatory Utility Commission to the list of persons consulted by the Administrator.

(11) Emergency Order No. 7 - See Docket No. E77-92 issued April 22, 1977.

EMERGENCY ORDERS

	Docket Number	Date Issued	Company	Type of Order	FR Citation
1	E77-1	2/3/77	Transcontinental Gas Pipe Line Corporation	Order	2/8/77: 42 FR 7998
2	E77-1	2/3/77	LoVaca Gas Gathering Company	Supplemental Order to Transco's order	2/8/77: 42 FR 7999
3	E77-4	2/4/77	Southern Natural Gas Company	Order	2/10/77: 42 FR 8428
4	E77-5	2/4/77	Southern Natural Gas Company	Order	2/10/77: 42 FR 8428
5	E77-10	2/6/77	Columbia Gas Transmission Corporation	Order	2/10/77: 42 FR 8427
6	E77-7 E77-9	2/8/77	Pennsylvania Gas and Water Company and McCormick Oil and Gas Corporation	Order	2/14/77: 42 FR 9056
7	E77-10	2/8/77	Columbia Gas Transmission Corporation	Order	2/14/77: 42 FR 9056
8	E77-4	2/9/77	Southern Natural Gas Company	Supplemental Order	2/14/77: 42 FR 9057
8-A	--	2/10/77	Southern Natural Gas Co. Texas Utilities Co.	Notice of Conference to be held	2/11/77: 42 FR 8704
9	E77-14	2/10/77	Phillips Petroleum Company	Order	2/16/77: 42 FR 9057

EMERGENCY ORDERS

	Docket Number	Date Issued	Company	Type of Order	FR Citation
10	E77-12	2/11/77	Memphis Light, Gas and Water Division	Order	2/15/77: 42 FR 9224
11	E77-17	2/15/77	Transcontinental Gas Pipe Line Corporation	Order	2/23/77: 42 FR 10738
12	E77-18	2/16/77	City of Danville	Order	2/23/77: 42 FR 10736
13	E77-3, E77-6, E77-11, E77-15, E77-16	2/17/77	Governor of Tennessee Re: Rules in considering applications of governors	Order	2/25/77: 42 FR 11071
14	E77-14	2/17/77	Phillips Petroleum Company	Supplemental Order	2/23/77: 42 FR 10739
15	E77-17	2/17/77	Transcontinental Gas Pipe Line Corporation	Supplemental Order	2/23/77: 42 FR 10738
16	E77-19	2/18/77	Phillips Petroleum Company	Order	3/4/77: 42 FR 12480
17	E77-21	2/18/77	Columbia Gas Transmission Corporation	Order	3/4/77: 42 FR 12479
18	E77-4	2/18/77	Southern Natural Gas Company	Supplemental Order	3/4/77: 42 FR 12480
19	E77-25	2/20/77	Pelto Oil Company	Order	2/25/77: 42 FR 11073
20	E77-12	2/20/77	Memphis Light, Gas and Water Division	Supplemental Order	2/25/77: 42 FR 11072

EMERGENCY ORDERS

	Docket Number	Date Issued	Company	Type of Order	FR Citation
21	E77-5	2/20/77	Southern Natural Gas Company	Supplemental Order	2/25/77: 42 FR 11073
22	E77-10	2/20/77	Columbia Gas Transmission Corporation	Supplemental Order	2/25/77: 42 FR 11073
23	E77-22	2/20/77	Texas Gas Transmission Corporation	Order	2/25/77: 42 FR 11074
24	E77-20	2/21/77	Eastern Shore Natural Gas Company	Order	2/25/77: 42 FR 11072
25	E77-24	2/22/77	Transcontinental Gas Pipe Line Corporation	Order	2/28/77: 42 FR 11276
26	E77-26	2/23/77	Marathon Oil Company	Order	2/25/77: 42 FR 11077
27	E77-19	2/23/77	Phillips Petroleum Company	Supplemental Order	2/25/77: 42 FR 11077
28	E77-27	2/23/77	Public Conference for 2/28/77	Notice	2/25/77: 42 FR 11076
29	E77-1	2/24/77	Transcontinental Gas Pipe Line Corporation	Supplemental Order	3/2/77: 42 FR 12083
30	E77-21	2/24/77	Columbia Gas Transmission Corporation	Supplemental Order	3/2/77: 42 FR 12084
31	E77-20	2/26/77	Eastern Shore Natural Gas Company	Supplemental Order	3/3/77: 42 FR 12258

EMERGENCY ORDERS

	Docket Number	Date Issued	Company	Type of Order	FR Citation
32	E77-28	2/26/77	United Gas Pipe Line Co.	Order	3/3/77: 42 FR 12258
33	E77-30	2/26/77	Columbia Gas of Kentucky, Inc., Et al.	Order	3/3/77: 42 FR 12257
34	E77-32	2/26/77	Texas Gas Transmission Corporation	Order	3/3/77: 42 FR 12259
35	E77-34	2/26/77	Transcontinental Gas Pipe Line Corporation	Order	3/3/77: 42 FR 12257
36	E77-36	2/26/77	Columbia Gas Transmission Corporation	Order	3/3/77: 42 FR 12259
37	E77-31	2/28/77	Colorado Interstate Gas Company	Order	3/3/77: 42 FR 12261
38	E77-29	2/28/77	Eastern Shore Natural Gas Company	Order	3/3/77: 42 FR 12261
39	E77-37	3/1/77	Tennessee Gas Pipeline Company, Division of Tenneco Inc.	Order	3/4/77: 42 FR 12477
40	E77-38	3/1/77	Columbia Gas Transmission Corporation	Order	3/4/77: 42 FR 12475
41	E77-39	3/1/77	Delhi Gas Pipeline Corporation	Order	3/4/77: 42 FR 12476
42	E77-33	3/2/77	United Gas Pipe Line Company	Order	3/4/77: 42 FR 12479

EMERGENCY ORDERS

	Docket Number	Date Issued	Company	Type of Order	FR Citation
43	E77-40	3/2/77	CNG Transmission Company	Order	3/4/77: 42 FR 12478
44	E77-41	3/2/77	United Cities Gas Company	Order	3/4/77: 42 FR 12916
45	E77-42	3/2/77	United Cities Gas Company	Order	3/7/77: 42 FR 12916
46	E77-43	3/3/77	Northern Natural Gas Company Peoples Division	Order	3/7/77: 42 FR 12917
47	E77-45	3/3/77	Texas Gas Transmission Corporation	Order	3/9/77: 42 FR 13154
48	E77-44	3/3/77	Consolidated Edision Company of New York, Inc.	Order	3/9/77: 42 FR 13154
49	E77-47	3/3/77	Columbia Gas Transmission Corporation	Order	3/9/77: 42 FR 13150
50	E77-46	3/3/77	Entex, Inc.	Order	3/9/77: 42 FR 13149
51	E77-24	3/4/77	Transcontinental Gas Pipe Line Corporation	Supplemental Order	3/10/77: 42 FR 13350
52	E77-48	3/4/77	Natural Gas Pipeline Company of America	Order	3/10/77: 42 FR 13349
53	E77-49	3/7/77	Northern Natural Gas Company	Order	3/10/77: 42 FR 13349
54	E77-20	3/7/77	Eastern Shore Natural Gas Company	Supplemental Order	3/10/77: 42 FR 13349

EMERGENCY ORDERS

	Docket Number	Date Issued	Company	Type of Order	FR Citation
55	E77-50	3/7/77	Texas Eastern Transmission Corporation	Order	3/11/77: 42 FR 13591
56	E77-5	3/8/77	Southern Natural Gas Company	Supplemental Order	3/11/77: 42 FR 13600
57	E77-37	3/8/77	Tennessee Gas Pipeline Company A Division of Tenneco Inc.	Supplemental Order	3/14/77: 42 FR 13864
58	E77-49	3/9/77	Northern Natural Gas Company	Erratum	3/14/77: 42 FR 13865
59	E77-48	3/9/77	Natural Gas Pipeline Company of America	Supplemental Order	3/14/77: 42 FR 13864
60	E77-21	3/9/77	Columbia Gas Transmission Corporation & UGI Corporation	Supplemental Order	3/14/77: 42 FR 13864
61	E77-33	3/9/77	United Gas PipelLine Company	Supplemental Order	3/15/77: 42 FR 14170
62	E77-51	3/10/77	Panhandle Eastern Pipe Line Company	Order	3/16/77: 42 FR 14778
63	E77-54	3/10/77	Texas Gas Transmission Corporation	Order	3/16/77: 42 FR 14780
64	E77-52	3/10/77	Raton Natural Gas Company	Order	3/16/77: 42 FR 14779
65	E77-53	3/10/77	El Paso Natural Gas Company	Order	3/16/77: 42 FR 14780
66	E77-48	3/10/77	Natural Gas Pipeline Company of America	Supplemental Order	3/16/77: 42 FR 14778

EMERGENCY ORDERS

	Docket Number	Order Issued	Company	Type of Order	FR Citation
67	E77-52	3/11/77	Raton Natural Gas Company	Supplemental Order	3/17/77: 42 FR 14904
68	E77-55	3/14/77	Columbia Gas Transmission Corporation	Order	3/17/77: 42 FR 14903
69	E77-37	3/14/77	Tennessee Gas Pipe Line Company	Supplemental Order	3/18/77: 42 FR 15132
70	E77-1	3/15/77	Transcontinental Gas Pipe Line Corporation	Supplemental Order	3/18/77: 42 FR 15133
71	E77-33	3/15/77	United Gas Pipe Line Company	Supplemental Order	3/21/77: 42 FR 15364
72	E77-53	3/16/77	El Paso Natural Gas Company	Supplemental Order	3/22/77: 42 FR 15463
73	E77-57	3/16/77	Morris Cannan	Order	3/22/77: 42 FR 15462
74	E77-58	3/16/77	Transcontinental Gas Pipe Line Corporation	Order	3/22/77: 42 FR 15463
75	E77-59	3/17/77	Petroleum Evaluation Corporation	Order	3/22/77: 42 FR 15464
76	E77-56	3/17/77	Sumpf-Williams, Et al.	Order	3/22/77: 42 FR 15464
77	E77-48	3/17/77	Natural Gas Pipeline Company of America	Supplemental Order	3/22/77: 42 FR 15465
78	E77-60	3/17/77	Panhandle Eastern Pipe Line Company	Order	3/22/77 42 FR 15464

	Docket Number	Date Issued	Company	Type of Order	FR Citation
79	E77-61	3/21/77	Panhandle Eastern Pipe Line Co.	Order	3/22/77: 42 FR 15754
80	E77-62	3/21/77	Pennsylvania Gas and Water Co.	Order	3/23/77: 42 FR 15754
81	E77-64	3/21/77	Texas Gas Transmission Corp.	Order	3/23/77: 42 FR 15755
82	E77-65	3/21/77	Panhandle Eastern Pipe Line Co.	Order	3/23/77: 42 FR 15754
83	E77-66	3/21/77	Panhandle Eastern Pipe Line Co.	Order	3/23/77: 42 FR 15754
84	E77-58	3/21/77	Transcontinental Gas Pipe Line Corporation	Supplemental Order	3/25/77: 42 FR 16189
85	E77-67	3/21/77	Atlanta Gas Light Company	Order	3/25/77: 42 FR 16183
86	E77-68	3/23/77	Equitable Gas Company	Order	3/25/77: 42 FR 16185
87	E77-70	3/23/77	Delhi Gas Pipe Line Corporation	Order	3/25/77: 42 FR 16184
88	E77-73	3/23/77	Texas Gas Transmission Corp.	Order	3/28/77: 42 FR 16470
89	E77-5	3/24/77	Southern Natural Gas Company	Erratum	3/29/77: 42 FR 16664
90	E77-62	3/24/77	Pennsylvania Gas and Water Co.	Erratum	3/29/77: 42 FR 16664
91	E77-71	3/24/77	Columbia Gas Transmission Corp.	Order	3/29/77: 42 FR 16663
92	E77-70	3/24/77	Delhi Gas Pipeline Corporation	Supplemental Order	3/29/77: 42 FR 16663
93	E77-74	3/24/77	Panhandle Eastern Pipe Line Co.	Order	3/29/77: 42 FR 16664
94	E77-33	3/24/77	United Gas Pipe Line Company	Supplemental Order	3/29/77: 42 FR 16665
95	E77-63	3/24/77	Transcontinental Gas Pipe Line Corp.	Order	3/29/77: 42 FR 16664
96	E77-72	3/24/77	Transcontinental Gas Pipe Line Corporation	Order	3/29/77: 42 FR 16665

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	Docket Number	Date Issued	Company	Type of Order	FR Citation
97	E77-75	3/25/77	Panhandle Eastern Pipe Line Co.	Order	3/29/77: 42 FR 16664
98	E77-76	3/25/77	Texas Gas Transmission Corp.	Order	3/29/77: 42 FR 16665
99	E77-69	3/25/77	Consolidated Edison Co. of NY, Inc.	Order	3/29/77: 42 FR 16670
100	E77-77	3/25/77	Panhandle Eastern Pipe Line Co.	Order	3/30/77: 42 FR 16849
101	E77-78	3/25/77	Panhandle Eastern Pipe Line Co.	Order	3/30/77: 42 FR 16849
102	E77-79	3/28/77	Inexco Oil Company, Et al.	Order	4/1/77: 42 FR 17522
103	E77-81	3/30/77	Texas Gas Transmission Corp.	Order	4/4/77: 42 FR 17910
104	E77-38	3/30/77	Columbia Gas Transmission Corporation	Supplemental Order	4/4/77: 42 FR 17911
105	E77-80	3/30/77	Tennessee Gas Pipeline Company	Order	4/4/77: 42 FR 17911
106	E77-82	3/31/77	Panhandle Eastern Pipe L ine Co.	Order	4/5/77: 42 FR 18127
107	E77-83	4/4/77	Transcontinental Gas Pipe Line Corporation	Order	4/8/77: 42 FR 18655
108	E77-84	4/4/77	Texas Gas Transmission Corp.	Order	4/8/77: 42 FR 18655
109	E77-79	4/4/77	Transwestern Pipeline Company, Et al.	Supplemental Order	4/11/77: 42 FR 18897

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	Docket Number	Date Issued	Company	Type of Order	FR Citation
110	E77-85	4/5/77	Texas Gas Transmission Corp,	Order	4/11/77: 42 FR 18896
111	E77-86	4/6/77	Piedmont Natural Gas Co., Inc.	Order	4/11/77: 42 FR 18896
112	E77-87	4/6/77	Texas Gas Transmission Corp.	Order	4/11/77: 42 FR 18897
113	E77-89	4/6/77	Texas Gas Transmission Corp.	Order	4/11/77: 42 FR 18897
114	E77-86	4/7/77	Piedmont Natural Gas Co., Inc.	Erratum	4/11/77: 42 FR 18896
115	E77-91	4/7/77	Texas Gas Transmission Corp..	Order	4/12/77: 42 FR 19233
116	E77-92	4/7/77	Proposed Order	Notice	4/12/77: 42 FR 19154
117	E77-90	4/8/77	Piedmont Natural Gas Co., Inc.	Order	4/12/77: 42 FR 19233
118	E77-38	4/8/77	Columbia Gas Transmission Corporation	Supplemental Order	4/14/77: 42 FR 19509
119	E77-93	4/8/77	Texas Gas Transmission Corp.	Order	4/14/77: 42 FR 19509
120	E77-88	4/12/77	North Central Oil Corporation	Order	4/15/77: 42 FR 19916
121	E77-92	4/12/77	Proposed Order	Notice Ext. Time	4/15/77: 42 FR 19895
122	E77-53	4/14/77	El Paso Natural Gas Company	Supplemental Order	4/20/77: 42 FR 20499
123	E77-94	4/14/77	Columbia Gas of Ohio, Inc.	Order	4/20/77: 42 FR 20497

EMERGENCY ORDERS

	Docket Number	Date Issued	Company	Type of Order	FR Citation
124	E77-71	4/15/77	Columbia Gas Transmission Corporation	Supplemental Order	4/21/77: 42 FR 20660
125	E77-79	4/15/77	Inexco Oil Company, Et al.	Supplemental Order	4/21/77: 42 FR 20660
126	E77-94	4/19/77	Columbia Gas of Ohio, Inc.	Supplemental Order	4/25/77: 42 FR 21137
127	E77-79	4/19/77	Inexco Oil Co., Et al.	Erratum	4/25/77: 42 FR 21137
128	E77-95	4/19/77	Columbia Gas Transmission Corp.	Order	4/25/77: 42 FR 21135
129	E77-96	4/19/77	Honesdale Gas Company	Order	4/25/77: 42 FR 21136
130	E77-97	4/19/77	Larco Gas Corporation	Order	4/25/77: 42 FR 21136
131	E77-98	4/19/77	Texas Gas Transmission Corp.	Order	4/25/77: 42 FR 21136
132	E77-18	4/20/77	Texaco Inc. & City of Danville	Supplemental Order	4/27/77: 42 FR 21500
133	E77-92	4/22/77	Order #7	Order	5/2/77: 42 FR 22146
134	E77-99	4/28/77	Pennsylvania Gas and Water Co.	Order	5/4/77: 42 FR 22562
135	E77-95	4/29/77	Columbia Gas Transmission Corporation	Supplemental Order	5/6/77: 42 FR 23182
136	E77-100	4/29/77	Texas Gas Transmission Corp.	Order	5/6/77: 42 FR 23182
137	E77-53	5/2/77	El Paso Natural Gas Co.	Supplemental Order	5/6/77: 42 FR 23206

EMERGENCY ORDERS

	DOCKET NUMBER	DATE ISSUED	COMPANY	TYPE OF ORDER	FR CITATION
138	E77-101	5/5/77	Texas Gas Transmission Corp.	Order	5/10/77: 42 FR 23618
139	E77-87	5/6/77	Texas Gas Transmission Corp.	Supplemental Order	5/12/77: 42 FR 24074
140	E77-99	5/9/77	Texas Gas Transmission Corp.	Supplemental Order	5/16/77: 42 FR 24759
141	E77-103	5/16/77	Mid Louisiana Gas Company	Order	
142	E77-102	5/17/77	El Paso Natural Gas Company	Order	
143	E77-103	5/17/77	Mid Louisiana Gas Company	Errata	

SUMMARY OF THE CONTRACTS AUTHORIZED AND DENIED
UNDER THE EMERGENCY NATURAL GAS ACT OF 1977

(1) Emergency Order, Docket No. E77-1, issued February 3, 1977, authorized LoVaca Gathering Company (LoVaca) to deliver up to 150,000 Mcf per day of natural gas to Transcontinental Gas Pipeline Company (Transco) for a 60 day period at a transportation charge of 18 cents per Mcf plus 2% of the volumes for fuel. The emergency order negates any action by LoVaca's producers to terminate their existing contracts; such actions might arise since the contractual provisions prohibit the sale of natural gas in interstate commerce and commingling of LoVaca's general system gas supply with gas moving in interstate commerce. Nor does LoVaca's compliance with P.L. 95-2 subject the distributing company to regulations under the Natural Gas Act.

(2) Supplemental Emergency Order, Docket No. E77-1, issued February 3, 1977, supplemented the "LoVaca" order previously issued by allowing use of the facilities of South Texas Natural Gas Gathering Company to move such gas supplies from LoVaca to Transco.

(3) Emergency Order, Docket No. E77-4, issued February 4, 1977, allows Southern Natural Gas Company (Southern) to purchase surplus Category I natural gas from El Paso Electric Company for the first thirty days at $2.10 cents per Mcf and $2.12 cents per Mcf for the second sixty days. The Administrator allows Southern to purchase Category II gas (Gas made available by El Paso Electric switching to an alternate fuel by reducing the output of a gas-fired plant in Texas and increasing the electrical output of an oil-fired plant in New Mexico) from El Paso at $2.90 cents per Mcf plus increased generation taxes. This amount is less than El Paso's requested price of $3.25 to $3.50 cents per Mcf. However, the Administrator suggests that "if, after operational experience, El Paso Electric verifies by affidavit costs in excess of the rates permitted herein, an application for a prospective rate increase will be considered at that time."

(4) Emergency Order, Docket No. E77-5 issued February 4, 1977, rejects Southern Natural Gas Company's petition requesting authorization to purchase 100,000 Mcf per day of natural gas at 65 cents per Mcf for thirty days from Pacific Gas and Electric of California. The Administrator rejected this petition since Southern would be required to return one and one-half times the volume it received with the pay back equated to 98 cents per Mcf.

(5) Emergency Order, Docket No. E77-10 issued February 6, 1977, authorizes Columbia Gas Transmission Corporation to purchase 60,000 Mcf per day of natural gas on an interruptible basis from Pacific Lighting Service Company.

In return, Columbia will incur an obligation of 37.5 cents per MMBtu for general storage to Pacific and on an Mcf-per-Mcf basis, Columbia will deliver a thermally equivalent volume of gas to Pacific during the summer months.

(6) Emergency Order, Docket Nos. E77-7 and E77-9 issued February 8, 1977, rejects Pennsylvania Gas and Water Company and McCormick Oil and Gas Corporation's petition seeking approval of sixty day emergency purchases of natural gas at a price in excess of $2.40 per Mcf. Without showing by petitioners that would justify exceeding the $2.25 per Mcf price ceiling set in Order No. 2, the Administrator will only authorize the proposed transaction at $2.25 per Mcf inclusive of all charges.

(7) Emergency Order, Docket No. E77-10 issued February 8, 1977, supplements the Administrator's previous order authorizing Columbia Gas Transmission Corporation to enter into a receipt and return of gas with Pacific Lighting Service Company. During transportation, gas to be delivered to Columbia by LoVaca may be commingled with gas owned by others. All owners of contracts with provisions which prohibit the commingling of gas with gas flowing in interstate commerce may not terminate exising contracts nor will they become subject to the Natural Gas Act. LoVaca's transportation charge will be $.20 per Mcf plus a two percent fuel charge. El Paso Natural Gas Company with install a meter and valve in order to deliver gas to Delhi Gas Pipeline Corporation at Waha Field. Columbia will reimburse El Paso for all reasonable expenses.

(8) Emergency Order, Docket No. E77-4 issued February 9, 1977, supplements the Commission's previous order to Southern Natural Gas Company on February 4, 1977. This Order applies to those contracts of Texas Utilities and LoVaca which prohibit commingling of gas, and under the provisions of P.L. 95-2, the producers of such gas, which is so commingled, may not terminate existing contracts with such other parties, nor shall other parties, thereby, become subject to the Natural Gas Act or to regulation as a common carrier under any provision of state law. These contractual or prohibition conditions are not enforceable, by reason of Section 9 P.L. 95-2 since LoVaca is transporting gas for Southern pursuant to authorization granted under Section 6(a) of that Act.

Notice, issued February 10, 1977, of a public on the record conference between represenatives of Texas Utilities Company and Southern Natural Gas Company and staff designated by the Coordinator to discuss the cost of using alternate fuels other than natural gas in the generation of electricity will be held on Tuesday, February 15, 1977 at 9:00 A.M.

(9) Emergency Order, Docket No. E77-14, issued February 10, 1977, authorized Phillips to sell 15,000 Mcfd of natural gas to Transco and directed Houston Pipe Line and Amoco Gas Co. to transport the gas volumes. Phillips will purchase the ethane at a price of 15 cents per gallon from Exxon Corp. and Transco will pay Phillips 16 cents per gallon for the ethane which is equal to or less than Phillips cost plus 7 percent.

(10) Emergency Order, Docket No. E77-12, issued February 11, 1977, denied Memphis Light, Gas and Water Division the authority to purchase 3,000 Mcf per day from B.V. Long, et al. Trustee at $2.45 per Mcf. The Administrator would authorize the proposed sale if the price per Mcf were not to exceed $2.25.

(11) Emergency Order, Docket No. E77-17, issued February 15, 1977, authorized Transcontinental Gas Pipe Line Corporation, acting as an agent for its customers to purchase up to 60,000 Mcf of natural gas per day from Southern California for an initial period of seven days with an option to extend for an additional period. Request For Supplemental Order, Docket No. E77-17, received February 16, 1977 was made by Delhi Gas Pipeline Corporation to clarify the provisions of the Order relating to Delhi's available transportation capacity.

(12) Emergency Order, Docket No. E77-18, issued February 16, 1977, authorized Texaco Inc. and Transcontinental Gas Pipe Line Corporation to transport the 1,000-2,000 Mcf/d of natural gas purchased from the Chapman Oil Company to Danville.

(13) Emergency Order, Docket Nos. E77-3, E77-6, E77-11, E77-15, E77-16, issued February 17, 1977 set the conditions to be met for mandatory allocations. Specifically, interruption of service to high priority uses must be imminent; all voluntary methods for obtaining natural gas must be exhausted; conservation practices must be considered. The Administrator will issue mandatory orders only when the recipient will be required to pay back in kind all gas received before August 1, 1977. A Stand-By Pool was created designating the pipeline companies who are the potential recipients and providers of natural gas.

(14) Supplemental Emergency Order, Docket No. E77-14 issued February 17, 1977 stated that Order No. 4 imposed a general reporting requirement on the purchaser or recipient of emergency gas supplies, and in certain instances, a specific reporting requirement on the seller. Order No. 4 also superseded specific reporting requirements contained in previous orders issued by the Administrator. Phillips' information satisfied the initial reporting requirements imposed by Order No. 4; all future weekly reports must be submitted by the purchaser, Transcontinental Gas Pipeline Corporation pursuant to paragraph (2) of Order No. 4.

(15) Supplemental Emergency Order, Docket No. E77-17, issued February 17, altered the time by which Delhi and Lone Star must notify the Administrator from commencement of deliveries to available line capacities.

(16) Emergency Order, Docket No. E77-19 issued February 18, 1977 authorized Phillips Petroleum Company to sell its 70% share of 540,000 barrels of liquefied natural gas to Columbia Gas Transmission Corporation at $2.25 MMBtu.

(17) Emergency Order, Docket No. E77-21 issued February 18, 1977 authorized Columbia Gas Transmission Corporation and UGI Corporation to purchase up to 100,000 Mcfd of natural gas from Pacific Gas and Electric Company. The proposed sale is to continue until midnight March 10, 1977 or such later date agreed to by the parties during the period the Act is in effect. The method for transporting the gas and the prices charged for transportation were authorized by the Administrator.

(18) Supplemental Emergency Order, Docket No. E77-4 issued February 18, 1977 authorized (1) LoVaca to redeliver the gas to United Gas Pipeline Company at a point in Jackson County, Texas for delivery to Southern through existing interconnections; (2) LoVaca may install a meter and valve to deliver such gas to United and recover from Southern its unrecovered expenses of such installation; (3) LoVaca may deliver such gas on a best efforts basis for up to 60 days following commencement of deliveries at a charge of 25 cents per Mcf plus 2.7% of the delivered volumes for fuel.

(19) Emergency Order, Docket No. E77-25, issued February 20, 1977 authorized Pelto Oil Company to recover reasonable actual costs incurred for installation of a temporary line not to exceed $10,000 for the delivery of gas to Alabama-Tennessee Natural Gas Company. In addition, Pelto will recover $2.25 per Mcf of gas delivered to Alabama-Tennessee.

(20) Supplemental Emergency Order, Docket No. E77-12, issued February 20, 1977 authorized B.V. Long, et _., Trustee to charge and collect $0.25 per MMBtu transportation charge in addition to $2.25 per MMBtu for the natural gas.

(21) Supplemental Emergency Order, Docket No. E77-5, issued February 20, 1977 authorized the purchase by Southern Natural Gas Company of up to 100,000 Mcfd of natural gas from Pacific Gas and Electric Company. The transaction would continue until March 10, 1977 and is based on a one for one payback plus monetary compensation of reasonable charges for storage or transportation services rendered by the seller.

(22) Supplemental Emergency Order Docket No. E77-10, issued February 20, 1977 authorized a change in the transportation network to that authorized in Docket No. E77-21 in order for Columbia Gas Transmission Corporation to received gas it has purchased from Pacific Lighting Service Company.

(23) Emergency Order, Docket No. E77-22, issued February 20, 1977, authorized Texas Gas Transmission Corporation, as agent for its customers, to purchase 2,000 to 2,500 Mcfd at $2.25 per Mcf from McGoldrick Joint Venture No. 1-73.

(24) Emergency Order, Docket No. E77-20 issued February 21, 1977 authorized Eastern Shore Natural Gas Company to purchase up to 3,500 Mcf of natural gas at the delivered price of $2.25 per Mcf and to pay up to $10,000 for the installation of metering and treating facilities and connections to the well.

(25) Emergency Order, Docket No. E77-24, issued February 22, 1977 authorized Transcontinental Gas Pipeline Corporation to purchased up to 100,000 Mcfd of natural gas from Texas Utilities Fuel Company for a period of up to 150 days but no later than July 31, 1977. The Administrator did not find the "gas system costs" acceptable; Transco shall pay a reasonable cost for transporting the natural gas from the field to the points of interconnection but not for the cost of a transportation system to the extent such system is not used.

(26) Emergency Order, Docket No. E77-26, issued February 23, 1977 authorized Marathon Oil Company to sell its 30% share of 440,000 barrels of LNG to Columbia Gas Transmission Corporation at $2.25 MMBtu.

(27) Supplemental Emergency Order, Docket No. E77-19, issued February 23, 1977 stated that 400,000 barrels of LNG is the correct number from which Phillips Petroleum Company will sell 70% to Columbia Gas Transmission Corporation.

(28) Emergency Notice, Docket No. E77-27, issued February 23, 1977, notified those interested parties of a public conference to be held on Monday, February 28, 1977 at 2:00 P.M. to discuss the possible availability of natural gas from electric utility companies in the Southwest at $2.90 to $3.50 per MMBtu.

(29) Supplemental Emergency Order, Docket No. E77-1, issued February 24, 1977, authorized a change in the transportation network by which Transcontinental Gas Pipeline Corporation will receive the emergency natural gas it purchased from Northwest Pipeline Corporation.

(30) Supplemental Emergency Order, Docket No. E77-21 issued February 24, 1977 authorized the carrying charges of 1.8 cents per Mcf charged by Pacific Gas and Electric Company, and 1.0 cent per Mcf charged by El Paso Natural Gas Company.

(31) Supplemental Emergency Order, Docket No. E77-20, issued February 26, 1977, authorized Transco to deliver gas purchased by Eastern Shore from Clajon pursuant to the Administrative Order of February 21, 1977.

(32) Emergency Order, Docket No. E77-28, issued February 26, 1977 authorized United Gas Pipeline Company to purchase up to 150,000 Mcfd of natural gas at $2.25 MMBtu from United Texas Transmission Company.

(33) Emergency Order, Docket No. E77-30, issued February 26, 1977 authorized Columbia Gas of Kentucky, Maryland, New York, Ohio, Pennsylvania, Virginia, and West Virginia to purchase up to 30,000 Mcfd of natural gas from Pacific Lighting Service Company. Columbia Distribution will pay Pacific Lighting 37.5 cents per MMBtu for general storage charges and will make repayment in thermally equivalent volumes of gas.

(34) Emergency Order, Docket No. E77-32, issued February 26, 1977 authorized Texas Gas Transmission Corporation to purchase and transport up to 2000 Mcfd of natural gas at $2.25 per Mcf from Enserch Exploration Inc.

(35) Emergency Order, Docket No. E77-34, issued February 26, 1977 authorized Transcontinental Gas Pipeline Corporation to purchase up to 50,000 Mcfd of natural gas, at $2.25 per MMBtu from Good Hope Refineries, Inc. The transaction will terminate July 31, 1977.

(36) Emergency Order, Docket No. E77-36, issued February 26, 1977 authorized Columbia Gas Transmission Corporation to purchase up to 30,000 Mcfd of natural gas at $2.25 per MMBtu from Monterey Pipeline Company.

(37) Emergency Order, Docket No. E77-31, issued February 28, 1977 authorized Colorado Interstate Gas Company to purchase approximately 3,000 Mcfd of natural gas from Chandler & Associates, Inc. at $2.25 MMBtu through July 31, 1977. At the end of that period, CIG will purchase the remaining volumes at the applicable national rate for new gas.

(38) Emergency Order, Docket No. E77-29, issued February 28, 1977 authorized Eastern Shore Natural Gas Company to purchase approximately 1700 Mcf per day of natural gas at $2.25 per Mcf from Jack O. McCall and Midland National Bank, Midland, Texas, Trustee. National's charge of 15% of the gas transported may not be fair and equitable; the Administrator therefore directed National to submit further information.

(39) Emergency Order, Docket No. E77-37, issued March 1, 1977 authorized Tennessee Gas Pipeline Company to purchase up to 32,000 Mcfd of natural gas at $2.25 per MMBtu from Channel Industries Gas Company for the effective period of the Act.

(40) Emergency Order, Docket No. E77-38, issued March 1, 1977 authorized Columbia Gas Transmission Corporation to purchase up to 60,000 Mcfd of natural gas from Delhi Gas Pipeline Corporation at $2.25 per MMBtu. The transaction will terminate on July 31, 1977.

(41) Emergency Order, Docket No. E77-39, issued March 1, 1977 authorized Delhi Gas Pipeline Corporation to sell up to 61,000 Mcfd at $2.25 per MMBtu on an "if, as and when available" basis to Transcontinental Gas Pipeline Corporation.

(42) Emergency Order, Docket No. E77-33, issued March 2, 1977 denied United Gas Pipeline Company's request to continue purchasing gas under § 6 of the Act and denied United's request to purchase those supplies for which an agreement to purchase had been reached but no formal contract had been executed by February 22, 1977.

(43) Emergency Order, Docket No. E77-40, issued March 2, 1977 authorized CNG Transmission Company to purchase up to 10,000 Mcfd from Onix Corporation at a price of $2.20 per Mcf until the contract terminates on July 31, 1977.

(44) Emergency Order, Docket No. E77-41, issued March 2, 1977 authorized United Cities Gas Company to purchase up to 10,000 Mcfd from a group of five producers, Petro Funds, Inc., Sunny South Oil and Gas., Inc., O. Biller, Exchange Oil and Gas Corporation, and the South Coast Corporation at a price of $2.25 per MMBtu.

(45) Emergency Order, Docket No. E77-42, issued March 2, 1977 authorized United Cities Gas Company to purchase up to 7,500 Mcf per day of natural gas at $2.25 per MMBtu from Energy Consultants, Inc. United Cities is purchasing 4,500 Mcfd for its own account and 3,000 Mcfd for the account of Pennsylvania and Southern Gas Company.

(46) Emergency Order, Docket No. E77-43, issued March 3, 1977 authorized Northern Natural Gas Company and Columbia Gas Transmission Corporation to purchase up to 35,000 Mcfd of natural gas at $2.25 per MMBtu from Pioneer Corporation through July 31, 1977. Compliance with Order No. 6 must be met by Peoples Natural Gas Division to authorize Northern's purchase of gas for Peoples' use.

(47) Emergency Order, Docket No. E77-45, issued March 3, 1977 authorized Texas Gas Transmission Corporation to transport natural gas purchased by United Cities Gas Company for its own account and for Texas Gas. 15,000 Mcfd of natural gas is purchased from Louisiana Gas Intrastate, Inc. at $2.25 per MMBtu.

(48) Emergency Order, Docket No. E77-44, issued March 3, 1977 authorized Consolidated Edison Company of New York, Inc. to purchase up to 50,000 Mcfd of natural gas from Pacific Gas and Electric Company. Con Ed will repay PG&E with equal volumes of gas; it will also pay a storage charge and transportation charge of $.35 per Mcf.

(49) Emergency Order, Docket No. E77-47, issued March 3, 1977 authorized Columbia Gas Transmission Corporation to purchase up to 61 billion BTU of natural gas at $2.56 per MMBtu from Houston Lighting and Power Company and Exxon Company.

(50) Emergency Order, Docket No. E77-46, issued March 3, 1977 authorized Entex, Inc. to purchase up to a total of 600,000 Mcf of natural gas at a rate of up to 15,000 Mcfd per day on a best efforts basis from Houston Pipeline Company at $2.20 per Mcfd. The transaction period shall end April 30, 1977.

(51) Supplemental Emergency Order, Docket No. E77-24, issued March 4, 1977 determined that the gas system cost charged by TUFCO of $3.28 per Mcf is just and equitable. Also, all deliveries for the account of Transco will be made to Lone Star Gas Company at the existing interconnections at Ennis, Texas.

(52) Emergency Order, Docket No. E77-48, issued March 4, 1977 denied Natural Gas Pipeline Company of America's request to determine that purchases which had not been formalized prior to February 22, 1977 be considered emergency purchases under Order No. 6.

(53) Emergency Order, Docket No. E77-49, issued March 7, 1977 authorized the purchase of emergency natural gas under Order No. 6 executed by the seller prior to February 22, 1977 but executed by Northern subsequent to that date.

(54) Supplemental Order, Docket No. E77-20, issued March 7, 1977 authorized the direct sale of a portion of the emergency gas purchased from the well owned by McCormick Oil and Gas Corporation and Dow Chemical Company to Eastern Shore Natural Gas Company at $1.75 per MMBtu plus severance taxes.

(55) Emergency Order, Docket No. E77-50, issued March 7, 1977 authorized Texas Eastern Transmission Corporation to purchase up to 50,000 Mcfd per day from Houston Pipeline Company at $2.20 per MMBtu inclusive of state and local taxes.

(56) Supplemental Emergency Order, Docket No. E77-5, issued March 8, 1977 authorized Southern Natural Gas Company to pay the transportation charges incurred during the period of February 2 through February 20, 1977.

(57) Supplemental Emergency Order, Docket No. E77-37, issued March 8, 1977 stayed the Order issued March 1, 1977 in Docket No. E77-37 until determination of the propriety of the sale from Channel to Tennessee is made. Section 6(a)(1) of ENGA precludes a "producer of natural gas" from selling under the Act natural gas that is "certificated under the Natural Gas Act."

(58) Erratum Notice, Docket No. E77-49, issued March 9, 1977, inserted the word "not" after the words "Northern had" on the seventh line of the first paragraph in the Order issued March 7, 1977 in Docket No. E77-49.

(59) Supplemental Emergency Order, Docket No. E77-48, issued March 9, 1977 authorized Natural Gas Pipeline Company of America to make purchases from TUCO, Western, Brown, Yates and Clajon since documented expenditures were made prior to February 22, 1977 for the purpose of delivering such gas supplies to Natural, notwithstanding Order No. 6.

(60) Supplemental Emergency Order, Docket No. E77-21, issued March 9, 1977 clarified a previous order by stating that "the carrying charge is 1.8 cents per Mcf per month on the outstanding volumes to be repaid to PG&E on April 1, 1977 and the first of each month thereafter until repayment is complete.

(61) Supplemental Emergency Order, Docket No. E77-33 issued March 9, 1977, denied the request of United Gas Pipeline Company to approve the proposed purchases set forth in the appendix of its filing since the filing lacked the information necessary to determine which of the proposed purchases satisifed the criteria of Colorado Interstate.

(62) Emergency Order, Docket No. E77-51, issued March 10, 1977, authorized Panhandle Eastern Pipeline Company to purchase up to 30,000 Mcfd of natural gas from Good Hope Refineries, Inc. at $2.25 per MMBtu.

(63) Emergency Order, Docket No. E77-54, issued March 10, 1977 authorized Texas Gas Transmission Corporation to purchase up to 150 Mcfd of natural gas from Breathitt Gas Transmission Corporation at $2.25 per MMBtu.

(64) Emergency Order, Docket No. E77-52, issued March 10, 1977 authorized Raton Natural Gas Company to purchase up to 500 Mcfd of natural gas from Independent Gas Service Company for thirty days at $2.25 per MMBtu.

(65) Emergency Order, Docket No. E77-53, issued March 10, 1977 granted El Paso Natural Gas Company's request in part. Those purchases for which there were executed formal written agreements prior to February 22, 1977 and those instances in which deliveries had also commenced on or before February 1977 were granted. However, the proposed purchases from Yates Petroleum Corporation and Monsanto Company did not satisfy the criteria as there were no written contracts for these purchases and no indication that the construction of facilities for El Paso to receive these gas supplies had commenced on or before February 22, 1977.

(66) Supplemental Emergency Order, Docket No. E77-48, issued March 10, 1977 authorized Natural Gas Company to make purchases from Pioneer Natural Gas Company, Good Hope Refineries, Inc., and Coronado Transmission Company since documented expenditures were made prior to February 22, 1977 for the purpose of delivering such gas supplies to Natural, notwithstanding Order No. 6.

(67) Supplemental Emergency Order, Docket No. E77-52, issued March 11, 1977 amended the Order issued March 10, 1977 by changing the seller's name to Industrial Gas Services, Inc.

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(68) Emergency Order, Docket No. E77-55, issued March 14, 1977 authorized Columbia Gas Transmission Corporation's purchase of LNG from Phillips Petroleum Company at $1.55 per Mcf and the transportation and delivery arrangements for the LNG.

(69) Supplemental Emergency Order, Docket No. E77-37, issued March 14, 1977 authorized Tenneco, Inc. to make a late filing of requested information as well as filing all available information by March 14, 1977.

(70) Supplemental Emergency Order, Docket No. E77-1, issued March 15, 1977 authorized Texas Eastern Transmission to receive up to 10,000 MMBtu per day of natural gas for Transcontinental Gas Pipeline Corporation's account. Texas Eastern will transport such volumes for redelivery to Transco at a transportation charge of 19.22 cents per MMBtu.

(71) Supplemental Emergency Order, Docket No. E77-33, issued March 15, 1977 determined that additional information submitted by United Gas Pipeline Company on proposed purchase from Goldking, Systems Fuels, and Delhi met the criteria set in Order 6. However, United had not submitted any information which indicated that Basin commenced installation of facilities prior to February 22, 1977 and therefore United's request to make this purchase is denied without prejudice. United's request to make a purchase with Superior was denied.

(72) Supplemental Emergency Order, Docket No. E77-53, issued March 16, 1977 denied El Paso Natural Gas Company's request to make a purchase from Mahun Oil and Gas Corporation since it did not meet with the criteria set by Order No. 6.

(73) Emergency Order, Docket No. E77-57, issued March 16, 1977 authorized Morris Cannan to be reimbursed $42,812 for expenditures necessary to transport gas from the wellhead to Texas Eastern Transmission Corporation's pipeline facilities. It authorized the sale of gas to Texas Eastern at $2.25 per MMBtu.

(74) Emergency Order, Docket No. E77-58, issued March 16, 1977 authorized Transcontinental Gas Pipeline Corporation to purchase up to 21 Bcf of natural gas, not to exceed 150,000 Mcf per day from Houston Pipeline Company at $2.20 per MMBtu.

(75) Emergency Order, Docket No. E77-59, issued March 17, 1977 authorized Texas Eastern Transmission Corporation to reimburse Petroleum Evaluation Corporation approximately %56,070 for the transportation of gas from the wellhead to the pipeline facilities. The purchase of 1500 Mcfd at $2.25 per Mcf was approved.

(76) Emergency Order, Docket No. E77-56, issued March 17, 1977 authorized Sumpf-Williams and Nahama & Weagant, Inc. and Aminoil USA to make its natural gas supplies available to any interstate pipeline or local distribution company served by an interstate pipeline which has a repayment obligation to any California utility.

(77) Supplemental Emergency Order, Docket No. E77-48, issued March 17, 1977 authorized Natural Gas Pipeline Company of America to purchase gas from Tortuga Oil and Mineral notwithstanding Order No. 6.

(78) Emergency Order, Docket No. E77-60, issued March 17, 1977 authorized Panhandle Eastern Pipeline Company to purchase 3,000 Mcfd of natural gas from Ran Ricks, Jr. at $2.25 per MMBtu.

(79) Emergency Order, Docket No. E77-61, was issued on March 21, 1977 authorizing Panhandle Eastern Pipeline Company to purchase all volumes available from the McClure No. 1 well of H & L Operating Company at $2.25 per MMBtu.

(80) Emergency Order, Docket No. E77-62 was issued March 21, 1977 authorizing Pennsylvania Gas and Water Company to purchase approximately 700 Mcfd of natural gas from Carpenter Oil and Gas Company at $2.25 per MMBtu.

(81) Emergency Order, Docket No. E77-64 was issued March 21, 1977 authorizing Texas Gas Transmission Corporation to purchase up to 1500 Mcfd from Amoco Production Company at $2.25 per MMBtu.

(82) Emergency Order, Docket No. E77-65, was issued March 21, 1977 authorizing Panhandle Eastern Pipeline Company to purchase up to 3,000 Mcfd from B & W Operating Company at $2.25 per MMBtu.

(83) Emergency Order, Docket No. E77-66, was issued March 21, 1977 authorizing Panhandle Eastern Pipeline Company to purchase up to 1000 Mcfd from W. C. Payne at $2.25 per MMBtu.

(84) Supplemental Emergency Order, Docket No. E77-58, issued March 21, 1977 amended the previous order by substituting the phrase "an average rate of 150,000 Mcfd" for the prior phrase "at a rate not to exceed 150,000 Mcfd."

(85) Emergency Order, Docket No. E77-67, issued March 21, 1977 authorized Transcontinental Gas Pipeline Corporation to transport up to 7500 Mcfd of gas for Atlanta Gas Light Company. Southern Natural Gas Company purchase of gas at $2.25 per MMBtu from Great Plains Production Company was authorized.

(86) Emergency Order, Docket No. E77-68, was issued March 23, 1977 authorizing Equitable Gas Company to purchase up to 6,000 Mcfd of natural gas from the Dow Chemical Company at $2.25 per MMBtu.

(87) Emergency Order, Docket No. E77-70, issued on March 23, 1977 authorizing Delhi Gas Pipeline Corporation to sell up to 30,000 Mcfd to United Gas Pipeline Company on an "if, as and when available" basis at $2.25 per MMBtu.

(88) Emergency Order, Docket No. E77-73, was issued March 23, 1977 authorizing Texas Gas Transmission Corporation to purchase and transport up to 1500 Mcfd of natural gas per day from Edwin L. Cox at $2.25 per MMBtu for its customers.

(89) Erratum Notice, Docket No. E77-5, issued March 24, 1977 changed the date "February 20" to "February 22" in lines 8, 14, and 16 of the first paragraph of the Supplemental Order issued March 8, 1977.

(90) Erratum Notice, Docket No. E77-62, issued March 24, 1977 deleted the words "as agent for Citizens" and inserted "after PG&W" on the second line of the first paragraph on page 2 of the order issued March 21, 1977.

(91) Emergency Order, Docket No. E77-71, issued March 24, 1977 denied Columbia Gas Transmission authorization to purchase up to 16,000 Mcfd of natural gas from Wainoco Oil Corporation and from Exchange Oil and Gas Corporation at $2.25 per MMBtu since Columbia did not state that it was presently qualified to purchase the gas as required by Order No. 6. Columbia was instructed to resubmit its application to make this purchase at such time as Columbia can demonstrate that it was not serving directly or indirectly any uses defined in 18 C.F.R. §2.78(a)(1)(iv)-(ix) contemporaneously with the execution of the contract for such purchase under Order No. 6 or any successor order; or Order No. 6 or any successor order is rescinded.

(92) Supplemental Emergency Order, Docket No. E77-70, issued March 24, 1977 deleted the sentence authorizing Delhi to transport and deliver gas to United since Delhi will not perform a transportation service for United.

(93) Emergency Order, Docket No. E77-74, issued March 24, 1977 authorized Panhandle Eastern Pipe Line Company, as agent for its customer, Ohio Gas Company to purchase up to 1,000 Mcfd of natural gas from Seneca Oil Company at $2.25 per MMBtu.

(94) Supplemental Order, Docket No. E77-33, issued March 24, 1977 authorized United Gas Pipeline Company to make emergency purchases from Basin Operating Company, Ltd. not withstanding Order No. 6 since it has submitted information from Basin which purports to demonstrate that these sellers had incurred expenses prior to February 22, 1977 in order to make emergency sales to United.

(95) Emergency Order, Docket No. E77-63, issued March 24, 1977 authorized Transco, as agent for certain of its customers, to purchase up to 1,500 Mcfd through April 9, 1977 and up to 6,000 Mcfd subsequent to April 9, 1977 from Sun Gas Company and up to 4,100 Mcfd from M. H. Marr at $2.25 per MMBtu.

(96) Emergency Order, Docket No. E77-72, issued March 24, 1977 authorized Transco, acting as agent for certain of its customers or for itself, to purchase up to 150,000 Mcfd from LoVaca Gathering Company at a price of $2.25 per MMBtu plus a transportation-delivery charge of 11.0 cents per Mcf.

(97) Emergency Order, Docket No. E77-75, issued March 25, 1977 authorized Panhandle Eastern Pipe Line Company, acting as agent for its customer Citizens Gas and Coke Utility, to purchase from Martin Oil Services, Inc. all the volumes available from the Lorenz No. 1 and Succo No. 3 wells, Weld County, Colorado at a price of $2.25 per MMBtu.

(98) Emergency Order, Docket No. E77-76, issued March 25, 1977 authorized Texas Gas Transmission Corporation, acting as agent for certain of its customers, to purchase up to 750 Mcfd from North American Royalties, Inc. and Energy Development Corporation at a price of $2.25 per MMBtu.

(99) Emergency Order, Docket No. E77-69, issued March 25, 1977 authorized Consolidated Edison Company of New York, Inc. to purchase 101,458 MMBtu from Odessa Natural Gas Corporation at a price of $2.25 per MMBtu. This gas will be used to repay Pacific Gas and Electric Company for some 89,598 Mcf (96,626 MMBtu) of natural gas taken by Con Ed for itself and others on January 30, 1977 and February 4 through 7, 1977.

(100) Emergency Order, Docket No. E77-77, issued March 25, 1977 authorized Panhandle Eastern Pipe Line Company, acting as agent for its customer, Ohio Gas Company, to purchase all natural gas produced by Scarth Petroleum Inc. at the Scarth No. 1 Hill Well, Hansford County, Texas at a price of $2.25 per MMBtu.

(101) Emergency Order, Docket No. E77-78, issued March 25, 1977 authorized Panhandle Eastern Pipe Line Company, acting as agent for its customer, Kokomo Gas and Fuel Company to purchase 2,000 Mcfd from Champlin Exploration Inc. at $2.25 per MMBtu.

(102) Emergency Order, Docket No. E77-79, issued March 28, 1977 authorized Transwestern to continue an emergency purchase under Section 6 from Inexco Oil Company through July 31, 1977 even though Transwestern subsequently learned that the information supplied by its customers

stating it was in compliance with Order 6 was incorrect. The Administrator stated that Order No. 6 prescribed a "rule of reasonableness not an absolute rule. The circumstances at the time of the execution of the contract are to be looked at to determine if a pipeline's execution of that contract is reasonable in light of the information then practicably available to it."

(103) Emergency Order, Docket No. E77-81, issued March 30, 1977 authorized Texas Gas Transmission Corporation, acting as agent for certain of its customers to purchase up to 1,000 Mcfd from the National Exploration Company at $2.25 per MMBtu.

(104) Supplemental Emergency Order, Docket No. E77-38, issued March 30, 1977 authorized Columbia Gas Transmission Corporation to divert gas purchased from Delhi Gas Pipeline Corporation under the March 1, 1977 authorization to Pacific Lighting Service Company and Pacific Gas & Electric Company and have such gas transported by El Paso Natural Gas Company and amend the March 1, 1977 authorization to permit Columbia to purchase up to an average of 60,000 Mcfd from the commencement of deliveries through July 31, 1977.

(105) Emergency Order, Docket No. E77-80, issued March 30, 1977 authorized Tennessee Gas Pipeline Company to purchase up to 1,000 Mcfd from Texaco Inc. at a price of $2.25 per MMBtu but denied the other proposed purchases as not in compliance with Order No. 6.

(106) Emergency Order, Docket No. E77-82, issued March 31, 1977 authorized Panhandle Eastern Pipe Line Company, acting as agent for its customer, Kokomo Gas and Fuel Company, to purchase gas from Grayrock Corporation at the Tolpers No. 1 Well, Adams County, Colorado at a price of $2.25 per MMBtu.

(107) Emergency Order, Docket No. E77-83, issued April 4, 1977 authorized Transco to impose transportation charges for all interruptible transportation services provided under the Act, subject to the condition that Transco agree to collect such amounts subject to refund pending the resolution of Transco's pending rate proceedings in Federal Power Commission Docket Nos. RP76-136, RP77-26, and RP77-48 and any other rate proceeding applicable to the period during which these transportation services are rendered.

(108) Emergency Order, Docket No. E77-84, issued April 4, 1977 authorized Texas Gas Transmission Corporation, acting as agent for certain of its customers, to purchase up to 1,500 Mcfd from Amoco Production Company at $2.16 per MMBtu.

(109) Supplemental Emergency Order, Docket No. E77-79, issued April 4, 1977 clarified the Order issued March 28, 1977 for Cities Service Gas Company by stating that Order No. 6 is directed to "the initial purchaser of the gas not subsequent recipient of the gas. Transwestern's authorization to purchase this gas encompasses the right to sell such gas to its customers. Therefore, Transwestern may sell the appropriate share of this gas to Cities Service."

(110) Emergency Order, Docket No. E77-85, issued April 5, 1977 authorized Texas Gas Transmission Corporation, acting as agent for Indiana Gas, to purchase gas from Good Hope Refineries at a price of $2.25 per MMBtu.

(111) Emergency Order, Docket No. E77-86, issued April 6, 1977 authorized Piedmont Natural Gas Company, Inc. to purchase up to 1,000 Mcf from Sabine Production Company at $2.15 per MMBtu and authorized Texaco Inc. and Transco to transport the subject gas. Texaco will charge Piedmont 10 cents per Mcf for costs incurred in transportation; Transco will charge 45.8 cents per MMBtu plus 3.8 percent of the volumes for compressor fuel. This transportation rate is to be collected subject to refund pursuant to order issued in Docket No. E77-83.

(112) Emergency Order, Docket No. E77-87, issued April 6, 1977 authorized Texas Gas Transmission Corporation, acting as agent for its customers, to purchase approximately 2,000 Mcfd from Par Oil Corporation at a price of $2.25 per MMBtu.

(113) Emergency Order, Docket No. E77-89, issued April 6, 1977 authorized Texas Gas Transmission Corporation, acting as agent for certain of its customers, to purchase approximately 350 Mcfd from Getty Oil Company at a price of $2.25 per MMBtu.

(114) Erratum Notice, Docket No. E77-86, issued April 7, 1977 changed the word "Texas" to "Texaco" in line 2 of page 3 of the order issued April 6, 1977.

(115) Emergency Order, Docket No. E77-91, issued April 7, 1977 authorized Texas Gas Transmission Corporation, acting as agent for its customers, to purchase approximately 1,500 Mcfd from Continental Oil Company at a price of $1.994 per MMBtu.

(116) Notice of Proposed Order, Docket No. E77-92, issued April 7, 1977 prescribing rules to implement Section 7 of the Emergency Natural Gas Act of 1977. Section 7 provides for the allocation of charges paid for deliveries under Section 4 or purchases under Section 6 to the local distribution companies receiving such gas from an interstate pipeline. Comments on the proposal were to be submitted no later than Wednesday, April 13, 1977.

(117) Emergency Order, Docket No. E77-90, issued April 8, 1977 authorized Piedmont Natural Gas Company, Inc. to purchase approximately 2,500 Mcf from Davis Oil Company at $2.25 per MMBtu. In addition, Piedmont will pay Davis 10.0 cents per MMBtu to pay for a portion of the cost of installing approximately four miles of 3-1/2 inch pipeline to connect this well to United's pipeline. United Gas Pipe Line Company and Transcontinental Gas Pipe Line Corporation were authorized to transport this natural gas for Piedmont.

(118) Supplemental Emergency Order, Docket No. E77-38, issued April 8, 1977 found that the amendments in the contract between Columbia and Delhi as approved in the March 30, 1977 order were appropriate; amended the March 30, 1977 order to state that Delhi will make deliveries to El Paso in Reeves County, Texas and reiterated that all protection and authorizations granted in the March 30, 1977 order remain in full force and effect to the extent not inconsistent with the provisions of this order.

(119) Emergency Order, Docket No. E77-93, issued April 8, 1977 authorized Texas Gas Transmission Corporation, acting as agent to purchase approximately 250 Mcfd from Chevron, U.S.A., Inc. at a price of $2.25 per MMBtu.

(120) Emergency Order, Docket No. E77-88, issued April 12, 1977 authorized Transwestern Pipeline Company to purchase gas from the Madden Field, Fremont County, Wyoming of North Central Oil Corporation at $2.25 per MMBtu notwithstanding Order No. 6.

(121) Notice, Docket No. E77-92, issued April 12, 1977, extended the time from April 13, 1977 to April 22, 1977 for comments on the proposed order.

(122) Supplemental Order, Docket No. E77-53, issued April 14, 1977 authorized El Paso Natural Gas Company to purchase gas from Mahun Oil and Gas Corporation at a price of $2.25 per MMBtu notwithstanding Order No. 6 since Mahun has demonstrated substantial detrimental reliance on El Paso's eligibility to make the proposed purchase under Order No. 2.

(123) Emergency Order, Docket No. E77-94, issued April 14, 1977 authorized Columbia Gas of Ohio to purchase gas at a price of $2.25 per MMBtu from the following: 500 Mcfd from Kilgore Brothers, 500 Mcfd from Marie Edwards Gillespie, et al., 3,000 Mcfd from Energy Industrial Development, Inc., 4,000 Mcfd from Pride Refinery, Inc., 4,000 Mcfd from James P. Dunigan, Inc., 5,000 Mcfd from Onix Corporation, and 1,000 Mcfd from Rocanville Corporation.

(124) Supplemental Order, Docket No. E77-71, issued April 15, 1977 denied Columbia Gas Transmission Corporation's petition for reconsideration of the March 24 Order as no new facts or other information which might demonstrate that the sellers relied upon Columbia's offer to purchase to their detriment or that additional monies were spent to make the sale to Columbia were presented.

(125) Supplemental Order, Docket No. E77-79, issued April 15, 1977 clarified the March 28, 1977 order for Cities Service Gas Company by stating that "Order No. 6 is directed to the initial purchaser of the gas not a subsequent recipient of the gas. Transwestern's authorization to purchase this gas encompasses the right to sell such gas to its customers."

(126) Supplemental Emergency Order, Docket No. E77-94, issued April 19, 1977 instructed Lone Star Gas Company, Columbia Gas of Ohio, Inc. and Pride Refinery, Inc. to submit a joint statement determining if Pride has legal authority to make the proposed sale to Columbia-Ohio.

(127) Erratum Notice, Docket No. E77-79, issued April 19, 1977 changed the word "authoriaation" to "authorization" in the first line of the fifth paragraph of the Supplemental Order issued on April 15, 1977.

(128) Emergency Order, Docket No. E77-95, issued April 19, 1977 authorized Columbia Gas Transmission Corporation to purchase up to 5,000 Mcfd from Cadasco, Inc. at $2.25 per MMBtu and 2,000 Mcfd from Kettle Oil Producing Company at $2.25 per MMBtu. Approval of these contracts was based on "firm oral agreements" to make these purchases and the expenditure of funds in reliance on Columbia's offers to purchase.

(129) Emergency Order, Docket No. E77-96, issued April 19, 1977 authorized Honesdale Gas Company to purchase up to 30,000 Mcf from Roy M. Teel Co. at a price of $2.00 per MMBtu. Further it authorized Tennessee Gas Pipeline Company to transport the natural gas which Honesdale has purchased.

(130) Emergency Order, Docket No. E77-97, issued April 19, 1977 authorized Larco Gas Corporation to sell approximately 1,000 Mcfd to Transwestern Pipeline Company at a price of $2.25 per MMBtu. Larco demonstrated detrimental reliance on Order No. 2 and therefore was permitted authorization of the proposed sale even though the purchaser is not otherwise qualified to make the purchase under Order No. 6.

(131) Emergency Order, Docket No. E77-98, issued April 19, 1977 authorized Texas Gas Transmission Corporation, acting as agent for its customers, to purchase and transport approximately 8,000 Mcfd from Bodcaw Company at a price of $2.25 per MMBtu.

(132) Supplemental Emergency Order, Docket No. E77-18, issued April 20, 1977 authorized an amended transportation agreement between Danville and Texaco which provides for extension of the term of the prior agreement from April 29, 1977 until July 31, 1977.

(133) Emergency Order No. 7, Docket No. E77-92, issued April 22, 1977 proscribed rules to implement Section 7 of the Emergency Natural Gas Act of 1977 by stating inter alia that (1) if curtailment is on a daily basis, the pipeline shall allocate its available gas supplies on a daily basis; (2) if curtailment is on a monthly or seasonal basis, the pipeline shall allocate its available gas supplies during each billing period on such basis; (3) Section 6 gas purchased by a pipeline as an agent shall be allocated to those customers which received such gas; (4) Section 6 gas purchased for system supply shall be allocated to all customers in proportion to system volumes purchased by

each customer during the applicable billing period. The proposed order also included a billing procedure which might be utilized by interstate pipeline companies to flow through all authorized costs of ENGA purchases pursuant to Section 6 of the Act.

(134) Emergency Order, Docket No. E77-99, issued April 28, 1977 authorized Pennsylvania Gas and Water Company to purchase approximately 3,000 Mcfd from Mellon Creek Operating Company at a price of $2.25 per MMBtu. It authorized Florida Gas Transmission Company and Transcontinental Gas Pipe Line Corporation to transport gas for PG&W.

(135) Supplemental Emergency Order, Docket No. E77-95, issued April 29, 1977 authorized Columbia Gas Transmission Company to purchase up to 2,000 Mcfd from Ketal's No. 1 King Well and No. 1 Westfall "A" Well at a price of $2.25 per MMBtu. It further authorized Ketal and Cities Service and Panhandle to transport gas for Columbia.

(136) Emergency Order, Docket No. E77-100 issued April 29, 1977 authorized Texas Gas Transmission Corporation as agent to purchase up to 500 Mcfd from Daniel Oil Company at a price of $2.25 per MMBtu.

(137) Supplemental Emergency Order, Docket No. E77-53, issued May 2, 1977 stated that the Order denying the proposed sale by Yates Petroleum Corporation and other Yates entities "remain(ed) in effect unless and until Order No. 6 is modified or rescinded." With the expiration of Order No. 6 by its own terms, there are no restrictions on El Paso's right to make purchases under Section 6 of the Act.

(138) Emergency Order, Docket No. E77-101, issued May 5, 1977 authorized Texas Gas Transmission Corporation, as agent for certain of its customers, to purchase approximately 1,000 Mcfd from Hunt Oil Company at a price of $2.25 per MMBtu.

(139) Supplemental Emergency Order, Docket No. E77-87 issued May 6, 1977 authorized Texas Gas Transmission Corporation, acting as agent for certain of its customers, to purchase up to 5,000 Mcfd from Par Oil Company at a price of $2.25 per MMBtu.

(140) Supplemental Emergency Order, Docket No. E77-99, issued May 9, 1977 authorized Florida Gas Transmission Company to charge $0.1254 per MMBtu plus 1.0 percent of the volumes transported for compression fuel to transport such gas for PG&W.

(141) Emergency Order, Docket No. E77-103, issued May 16, 1977 authorized Mid Louisiana Gas Company to purchase up to 15,000 Mcfd from Houston Pipeline Company at $2.20 per MMBtu.

(142) Emergency Order, Docket No. E77-102, issued May 17, 1977 authorized El Paso Natural Gas Company to purchase gas at $2.25 per MMBtu from the following: Yates Petroleum Corporation, Yates Drilling Company, Alan J. Antweil and Moranco, Husky Oil Company.

(143) Errata Notice, Docket No. E77-103, issued May 17, 1977, changed the word "Houston" to "Transco" in line 13, second paragraph on page 3; it also changed all references to "Midland Louisiana" to "Mid Louisiana".

Mr. DINGELL. Do you have a formula that you can suggest to the committee, which would be clear in terms of its definition and also clear in terms of orderly administration, for defining the difference between new gas and old gas.

Mr. DUNHAM. I would recommend for your consideration the methodology that we used in the 770-A opinion. In that opinion essentially what we said was that the experts involved, the geologists involved in administering the offshore leases of the Department of Interior, would make that determination of whether it was, in fact, a new reservoir, whether it was a recompletion of a new well, et cetera. Then furnish us with the explanation of why that determination was made. Onshore, the State conservation agencies would be the acting agencies to provide for primary analysis.

Mr. DINGELL. I am going to ask something that I think is important, if you please.

Would you submit to us the different criteria that might be used in establishing the difference between new gas and old gas?

Would you also submit to us, please, your comments as to the merit of each of the different criteria so that we can come to the best judgment of what is the fairest and most proper way of arriving at the decision as to what constitutes new gas and old gas?

Mr. DUNHAM. Be happy to do so.

[The following information was received for the record:]

What are the different criteria that might be used for old and new gas definitions?

The different criteria that might be used for old and new gas definitions would include the following:

(1) Date of Commencement of Individual Well Drilling

(2) Date of Contract

(3) Date of Initiation of Sale in Interstate Commerce

(4) Date of Reservoir Penetration

(5) Date of Renewal Contract for Old Expired Sale

(6) Linear Distance from Existing Wells

(7) Deeper Drilling

Present producer rate regulations encompass all of these criteria through the various applicable Commission Opinions establishing just and reasonable rates. For example, old sales are governed by Contract dates where there is no recent well drilling or contract termination. As a producer drills wells or deepens them in subsequent periods (i.e., 1973-1974 and 1974-1975) or completes them in formerly non-productive horizons, he is entitled to higher rates as established by cost data for these particular periods. Other sales receive rates dependent upon the date of initiation of the sale in interstate commerce whereas others qualify for rates dependent upon the expiration date of the basic contract or the date of execution of a replacement

contract therefor. The rationale for the present state of producer rate regulation is embodied in Commission Opinion No. 770-A (Pages 12-15) wherein the Commission not only established rates for wells commenced on or after January 1, 1973, but also refused to apply such rates to sales under expired contracts, from recompletions in previously drilled wells, or for sales initiated on or after January 1, 1973, from previously drilled wells.

The various pending House bills propose definitions for old and new gas in various combinations of the above criteria, usually with a modification based on a certain date. For example, H.R. 687 would define new gas as the gas dedicated for the first time after January 1, 1976, and would exclude offshore gas dedicated for less than a 15 year term. H.R. 2088 on the other hand, defines new gas as that gas sold or delivered in interstate commerce for the first time on or after January 1, 1977, with essentially the same applicability as H.R. 687. These bills do differ in certain areas such as treatment afforded formerly interstate sales, new reservoir discoveries, and when the involved wells were initiated or completed.

H.R. 6831 represents a basic adoption of the Commission's present area rate regulation with price modifications dependent upon the location of post April 20, 1977, wells or leases and the execution of new contracts for old sales or otherwise new sales. To a large degree, it maintains the present vintaging concept which relates to date of contracts and the commencement date of wells.

Several of the bills address the distance and/or depth of new wells in relation to existing wells as a basis for defining new gas. Specifically, H.R. 6831 provides that post-April 20, 1977, wells drilled at a surface distance of 2.5 miles from existing wells or at least 1,000 feet deeper than such existing wells would be entitled to special rate treatment. This problem was presented to the Commission after Opinion No. 770 was issued as it affected new wells in the proximity of existing wells. Upon rehearing, the Commission in Opinion No. 770-A, set up a procedure (Section 2.56 a (p)) whereby wells drilled in existing proration units would have to be justified on an individual well basis. During rehearing, the Commission considered adopting a 1,000 linear foot rule for individual well justification. However, upon further study, it was found that existing state spacing requirements generally required a greater spacing of wells. Accordingly, the Commission ultimately determined that the states' respective spacing requirements would be observed rather than a Commission adopted linear distance standard. Such action was taken to recognize the states' interest in maximizing gas recovery commensurate with sound development practices. Opinion No. 770-A therefore was designed to recognize the states' prior determination of spacing standards. In the case of offshore Federal Domain properties, the spacing of wells is under the supervision of U.S.G.S. and their determination was deemed presumptive of the need for the new well(s). This Commission's determination in Opinion No. 770-A recognizes the states' in achieving maximum gas recovery consistent with sound conservation practices. H.R. 2088 to some extent adopts this standard.

The Commission also found in Opinion No. 770-A that production attributable to deeper formations (through the deepening of existing wells) qualified for the new gas rate. This was premised upon the finding that such deeper drilling was as expensive as drilling new footage. It applies where a well is deepened, and not specifically only where new reservoirs are discovered. The concept of new reservoirs is misleading since virtually all of the reservoirs have already been discovered by prior drilling, hence, the deeper drilling criteria was adopted.

There appears to be no engineering or geologic grounds for establishing a new gas definition in relation to distance and/or depth relationship to exisitng wells. Rather, it would appear more appropriate to adopt the Opinion No. 770-A criteria which gives effect to state spacing determinations, while still investigating those wells drilled in existing proration units.

Although the Commission has consistently atempted to eliminate the various vintages of gas, it has found through its cost-based rate methodology, that it is impossible to establish a single rate for all gas sales, which is sufficient to enable cost recovery, provide adequate incentive for new exploration and development, and provide proper protection to the natural gas consumer. This decision was expressed in Opinion No. 770-A where more vintages were established due to the great potential for excessive and unjustified profits or burdensome consumer costs. While administratively burdensome, the decision was made to set different rates dependent upon the costs associated with finding that particular category of gas. It appears

that the same type of approach is contemplated in the pending energy legislation. Basing the definitions on the first delivery or sale commencement date does not follow any cost-basis and has the potential for encouraging a practice at withholding gas on the possibility of receiving a higher price.

Mr. DINGELL. I have imposed quite a burden on you.

Mr. DUNHAM. No.

Mr. DINGELL. The time of the Chair has expired.

Before we recognize members for additional questions, I would like to have staff ask some questions. So at this time the Chair recognizes Mr. Demarest for the purpose of asking questions.

Mr. DEMAREST. Thank you, Mr. Chairman.

Have you had an opportunity to review the natural gas utility regulatory reform provisions contained in title I of this bill? I believe they are contained in subpart E. There are both electric utility reform and natural gas reform proposals.

Mr. DUNHAM. Title I, you mean on the utility programs?

Mr. DEMAREST. Yes.

Mr. DUNHAM. The answer is no, but I have been asked to appear on Thursday on that matter and I could be prepared at that time.

Mr. DEMAREST. Thank you.

You have indicated that you have some technical problems with the new gas definition; whether it is administerable or not. There are other pieces of legislation before the committee dealing with natural gas issues, including H.R. 2088.

Have you a preference for H.R. 6831 or H.R. 2088, on the merits and apart from problems related to technical implementation of the policies?

Mr. DUNHAM. No, I have not. I would be very happy to look at those in some of the definitional—I think that is your question, Mr. Demarest, with regard to definitions.

Mr. DEMAREST. Not merely the definitions but the substantive approaches.

Mr. DUNHAM. The substantive parts? I have not, Mr. Demarest. I would be glad to do so and be prepared to answer those questions perhaps Thursday.

Mr. DEMAREST. Thank you.

Mr. KRUEGER. [presiding.] I should like to recognize at this time Mr. Schroeder for a couple of questions and then recognize minority counsel.

I might say to the other members that I think that in order to try to keep on schedule we will not have another round of members' questioning.

Mr. Schroeder.

Mr. SCHROEDER. Thank you, Mr. Chairman.

Chairman Dunham, in the appendices to your statement, you provided an analysis of rollover profiles or contract expiration profiles.

Am I correct in understanding that this is based on data which you collected in 1972 and included in Opinion 669?

Mr. DUNHAM. It is 1972 data, yes.

Mr. SCHROEDER. We have asked a number of interstate pipelines to provide us with similar information in the analysis of which I would hope to involve your staff. We have asked the 10 largest interstate pipelines to provide the volumes and expiration dates of their 50 largest contracts.

Could we ask that you direct the following questions to your staff on our behalf: One is what percentage of total interstate contract volumes does such a sample represent?

The second question is: Assuming that this represents a representative sample of all interstate natural gas contracts by year, what volumes of gas currently under contract will expire or rollover?

Mr. DUNHAM. Yes, we will attempt to do that. You have provided that list to us.

Mr. SCHROEDER. We would like that information independent of any assumptions about production decline. In other words, we are interested in the rollover volumes by year, not in the aggregate, rolled over volume inclusive of decline as you have calculated it here.

Mr. JOURNEY. I understand.

Mr. SCHROEDER. Thank you, Mr. Chairman.

Mr. KRUEGER. Thank you.

At this time I would recognize minority counsel, briefly.

Mr. VLCEK. Thank you, Mr. Chairman.

I wonder, Mr. Dunham, if you could provide information for the subcommittee with respect to Btu equivalency. What I am particularly interested in is the Btu comparisons with respect to the transportation costs of gas as opposed to oil.

Mr. DUNHAM. Yes.

Mr. VLCEK. Also, the refining, processing costs of gas as opposed to oil.

Mr. BROWN. Would the staff yield for just a moment?

The point is that this bill we have before us calls for Btu equivalency between the wellhead price of natural gas and the refiner cost of oil. Now those are two different items.

Mr. DUNHAM. Two different things.

Mr. BROWN. What we are trying to figure out is what is the real Btu equivalency. It seems to me that is a decision made at the burner tip by somebody who has to decide whether they are going to burn gas, which is relatively clean and cheap to transport, oil which is somewhat more expensive perhaps to transport and has to be refined, and coal which has a downside burning cost, to clean up the pollution.

So what we are trying to get at here is the relative Btu cost for transportation—the average cost for transportation of natural gas, the average refining cost of natural gas and oil and coal has I guess very little refining cost, the average storge cost, consumption cost, and cleanup cost.

Now, I want to get a real Btu equivalency.

Can you provide us with any of those figures?

[The following information was received for the record:]

What are the average costs for natural gas, oil, and coal for the different functions such as production, transportation, refining, storage, clean-up, and consumption?

A comparison of the prices of gas, oil, and coal is difficult due to the limited amount of information that is available to the Federal Power Commission as a result of its data gathering authority. Nevertheless, we have attempted to compile data from various sources for the month of December 1976 for purposes of making a comparison. The Bureau of Labor Statistics reports that the average price in December 1976, for natural gas consumed for residential heating purposes was $2.12 per MMbtu. The FPC Form No. 11 reports for December 1976 show that the average price charged by interstate pipelines was roughly $1.19 per MMbtu and that the average purchased gas cost was roughly 66 cents per MMbtu. This would result in an average distributor markup of 93 cents per MMbtu and pipeline transportation and storage costs of 53 cents per MMbtu. This can be summarized as follows:

	$*
Average residential price	2.12
Average pipeline charge	1.19
Distributor markup (difference)	.93
Average purchased gas cost (P/L)	.66
Average transportation, gathering, and storage costs ($1.19-.66)	.53

*Prices adjusted to reflect 1,021 Btu/cubic foot.

It must be recognized that these are national averages and will vary between markets both because of the different sources of supply available to individual pipelines and the distances that the gas must be transported. Moreover, the averages will vary depending upon the

extent of storage investment by different pipeline companies.

Regarding the price of oil for residential heating, Federal Energy Administration statistics show an average price of 43.0¢ per gallon or $3.11 per MMbtu for the month of December 1976 (based upon 5.8 MMbtu per barrel). Their historical statistics also show an average wellhead price on domestic crude oil of $8.62 per barrel or $1.49 per MMbtu and a refiner cost of domestic crude of $9.25 per barrel or $1.59 per MMbtu leaving roughly 10 cents for transportation. The total average cost to the refiner, including imported oil, was $11.32 per barrel or $1.95 per MMbtu leaving a difference of 54 cents per MMbtu for refinery costs and any additional transportation. This can be summarized as follows:

	$
Average residential price	3.11
Dealer Margin	.62
Difference	2.49
Average cost to refiner (domestic and imported supplies)	1.95
Refinery and other costs	.54

We are not able to evaluate the 54 cents to determine the composition of costs that may be recouped through amount.

Our data on coal is limited to the FPC 423 reports submitted by electric generating plants. The reports for December 1976, show the average price paid for coal was 86.6¢ per MMbtu. Transportation costs vary considerably depending upon the type of coal, the producing area and the mode of transportation. The differences in coal transportation costs are clearly indicated in a study prepared by the President's Council on Wage and Price Stability published on March 16, 1976. More-

over, there is little coal burned for residential heating purposes so that no meaningful comparison can be made with natural gas and oil used for that purpose. Finally, one of the major difficulties in comparing the prices for gas, oil, and coal is the way that fixed costs are allocated to the different classes of service. Residential consumers have historically borne most of the fixed costs and industrial consumers have borne the variable fuel costs along with those fixed costs which enable the particular form of energy to remain competitive with other forms of energy.

Mr. DUNHAM. I think we can—I have asked for some of those figures myself in the past; I have not been totally successful. But we will make a calculation. I think what you are interested in, Mr. Brown, is essentially what we call the city gate price at the point at which it goes into the plant, which is the point at which a significant economic decision that either an individual or a city has to make.

Mr. BROWN. I think that is a lot closer than what we are talking about here.

Mr. DUNHAM. Wellhead.

Mr. BROWN. Because obviously there is a storage cost with coal and as there is a cleanup cost with coal that the average plant does not have to contend with with natural gas and to some degree in oil. That is what we are trying to get at.

Mr. DUNHAM. I understand what you are trying to get at.

Mr. BROWN. I would like to ask some other question, Mr. Chairman, in which you may have some interest. That is, isn't it true that under this bill the rollover cost of natural gas could go as high as $1.75?

Mr. DUNHAM. No, not on interstate rollover contracts.

Mr. BROWN. Intrastate gas.

Mr. DUNHAM. Intrastate, yes, if my reading is good.

Mr. BROWN. And under the bill which Mr. Krueger and I have coauthored the maximum price to which that could go would be the present Federal Power Commission set price of $1.44.

Mr. DUNHAM. Yes.

Mr. BROWN. And finally one other question, Mr. Chairman, in conclusion, from the staff, and that is with reference to your information on pages 14 and 15 about SNG, LNG and coal gasification costs.

Are those in your testimony because you see those as the average or prospective costs of achieving some other form of gas besides natural gas and therefore prices that might be in some way limiting on the price of natural gas?

Mr. DUNHAM. No, not particularly, they were examples of the two or three and it is very limited examples of what we have.

Mr. BROWN. Could you give us some prices that might be average prices in those areas that might in fact have some limiting factors on the price to which natural gas might go?

Mr. DUNHAM. Certainly the first example, naphtha refining, that is a pretty good standard. On coal gasification, you will see other prices.

[The following information was received for the record:]

The best data available on the cost of SNG is on Algonquin's Systems. This is as follows:

Feedstock at 36.749/gal	$3.853/M²Btu
Other Plant Costs	1.345
Plant Outlet	$5.198
Incremental Customer Cost	0.013
	$5.211/M²Btu

Since there are not any commercial size coal gasification plants in operation, coal gasification data is not available.

Mr. KRUEGER. The time of minority counsel has expired.

At this time we wish to thank you very much, Mr. Dunham. We will be prepared to receive the testimony of the next panel. Thank you very much.

I should like first to ask the witnesses to identify themselves for the record, please.

STATEMENTS OF RICHARD L. O'SHIELDS, CHAIRMAN, INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA, ACCOMPANIED BY W. J. BOWEN, PRESIDENT, TRANSCONTINENTAL GAS PIPE LINE CORPORATION; TRAVIS PETTY, PRESIDENT, EL PASO NATURAL GAS COMPANY, AND JACK HEAD, EXECUTIVE VICE PRESIDENT AND GENERAL COUNSEL, TEXAS EASTERN TRANSMISSION CORPORATION; AND DAVID S. SCHWARTZ, PROFESSOR OF ECONOMICS, MICHIGAN STATE UNIVERSITY PUBLIC UTILITIES PROJECT

Mr. HEAD. My name is Jack Head, with Texas Eastern Transmission Corporation.

Mr. SCHWARTZ. I am David Schwartz, Michigan State University.

Mr. O'SHIELDS. I am Richard L. O'Shields, Panhandle Eastern Pipe Line Company.

Mr. BOWEN. W. J. Bowen, Transcontinental Gas Pipe Line Corporation.

Mr. PETTY. Travis Petty, El Paso Natural Gas Company.

Mr. KRUEGER. I thank you. Now, it is my understanding that Mr. O'Shields is going to make a statement for all four of the pipeline companies. If that is correct, I wish the committee to recognize that we have some time problems today. We understand we are going to be going under suspension voting, which means a vote every five minutes, probably about 12:30 or thereabouts. Therefore, what I shall ask you to do, Mr. O'Shields, please, is to summarize, if you will, the statement that you would make for the other three members of the panel and yourself.

If you can summarize it in 5 to 10 minutes, that would be desirable and then I will recognize briefly for a summary statement Mr. Schwartz and then the committee will be open for questioning.

STATEMENT OF RICHARD L. O'SHIELDS

Mr. O'SHIELDS. I shall endeavor to summarize as quickly as possible.

Our statement is on behalf of the Interstate Natural Gas Association, which is a national nonprofit association representing virtually all of the interstate pipeline companies operating in the country. The legislative proposals before this committee are of deep interest to INGA and its members and we appreciate the opportunity to be here. On many occasions in the past INGA has appeared before this committee urging Congress to enact legislation to correct the disastrous effects of more than 20 years of court-mandated Federal Power Commission regulation of wellhead prices for natural gas.

We have previously recommended and we recommend again today that legislation be enacted which would remove price controls from wellhead sales of new natural gas as the single most effective step that can be taken to restore balance to supply and demand for this premium fuel.

President Carter and his administration are certainly to be commended for their efforts to evolve a national energy policy and lay it before the Congress and the people of the country. In principle we agree with the President's generalized statement of the salient features of the needs of the country as expressed in the national energy plan. Unfortunately, we have considerable difficulty with many of the specific proposals of his plan.

The President has chosen to recommend continued regulation of the price of new natural gas. This we are convinced is a mistake and, as I said earlier, we urge Congress to enact legislation deregulating the price of new natural gas.

I would add if Congress should elect to follow the President and continue price regulation for new natural gas, it should be phased out as rapidly as possible.

With respect to the President's bill, I would like to comment on some of the specific areas which concern us. First of all is the definition for new natural gas. The bill would define new natural gas offshore as coming only from new leases issued on or after April 20, 1977, and onshore from new wells which are more than 2.5 miles from an existing well and deeper than one thousand feet below the producing level of any existing well which might be in the 2.5 mile radius. This definition in our opinion is far too restrictive and arbitrary. The arbitrary 2.5 mile and one thousand foot stricture completely ignores the geological facts surrounding the presence or absence of hydrocarbons in the earth. Experience over the years has demonstrated time and again that completely new reservoirs are discovered within 2.5 miles of old wells and many times at depths shallower than a thousand feet below the existing producing wells.

Attached to our statement are two figures. One is a map and another a cross-section, which illustrate some examples of the difficulties with the President's definition. We have charts here to your right which illustrate that. The left chart is a map view showing an illustration of accumulations of hydrocarbons. In this illustration the center of the circle that is colored dark brown is the

only one with any producing wells in it. The others are completely undiscovered. Yet with the strictures put on by the President's proposal, all three of the undiscovered reservoirs, would have areas that would disqualify at least parts of them from being classified as new gas.

Mr. KRUEGER. I would ask that a copy of that illustration be provided the committee so it may be inserted in the record at this point.

Mr. O'SHIELDS. There are copies of that attached to our statement.

Mr. KRUEGER. Very well. Thank you very much.

Mr. O'SHIELDS. Such an arbitrary definition as in the act would in our opinion discourage rather than encourage exploration in a large part of the prospective areas yet to be explored in this country. History has shown that established productive areas of hydrocarbons are among the best places to look for new hydrocarbons. We therefore offer a substitute definition for new natural gas to apply both onshore and offshore, which would define new gas to be gas produced from a reservoir discovered on or after April 10, 1977, or produced from wells commenced on or after that date and completed in an extension of a previously discovered reservoir, as those discoveries and extensions are determined by the proper Federal or State regulatory agency having jurisdiction over the drilling of wells and the production therefrom. This definition, of course, is substantially similar to the one used in H.R. 9464 and Senate bill S.2310, both of which passed the respective houses in the last Congress.

The meaning of these terms, new reservoir and extension, are not something that is mysterious or elusive, but on the contrary, they have been used by the American Association of Petroleum Geologists and others for many, many years, and we believe it administratively is workable and much superior to that contained in the bill.

Our next area of concern is the price level for new natural gas contained in the bill which says it will be the average of the Btu equivalent of refiner acquisition costs of domestic crude oil. This we are told will equate to a price of $1.75 cents at the beginning of 1978.

On the other hand, the national energy plan would establish a higher equivalent price for newly discovered domestic crude oil. This ceiling, according to the plan, would be initially $11.28 per barrel, which is the equivalent of $1.94 per Mcf, and would be allowed to rise over a three-year period to the current world oil price of $13.50 per barrel, which is the Btu equivalent of approximately $2.33. We submit it is completely illogical if you are going to establish a ceiling price, that that for new natural gas, which is a premium fuel, should be at a level substantially less than that for crude oil which is in many respects a less desirable fuel than natural gas. Certainly the development of new natural gas supplies would entail the same, if not a greater, degree of risk than the development of oil and the importance to this country of developing new natural gas is certainly as important as developing new oil. For these reasons, if price ceilings are enacted, we propose the ceiling price of new natural gas be fixed at the Btu-related price of newly

discovered domestic crude oil rather than the average price of all domestic crude oil as proposed by the President.

Also, we recommend if a price ceiling is enacted that producer sales of new natural gas be specifically exempted from regulation under the Natural Gas Act. It is not in the bill.

In regard to ceiling prices, as I said earlier, we recommend they be deregulated, but if they are continued, it should be realistically on a commodity-value basis; and they should apply to all sales of gas whether they are interstate or intrastate.

Another aspect that concerns us is the extension of the section 4 mandatory allocation provisions of the Emergency Natural Gas Act of 1977, and the extension or expansion of that authority to intrastate pipelines. While it would extend that, it would not extend the emergency purchase provisions of section 6 of that act. We do not feel it either necessary or desirable that this extension be granted. In the first place, the section 4 mandatory allocation provisions were not needed in this past winter, the coldest in over one hundred years. The important thing that happened this last winter was the ability on the part of the Interstate Pipeline Companies to purchase emergency gas supplies from intrastate pipelines and producers on a basis which would not subject either the intrastate pipelines or the producers from Federal regulation by virtue of making those emergency sales.

Now, we offer in lieu of the extension of the mandatory allocation provision an adequate provision under which the President may authorize contracts for purchases from and transportation of natural gas by the intrastate pipelines, which would also provide that those pipelines would not by virtue of such an act become subject to regulation under the Natural Gas Act, or regulations as a common carrier under any provision of Federal or State law.

Now, this provision, coupled with two other special rules which are set out in section 412 of this bill, we believe would provide an adequate means for getting gas supplies which might be available during an emergency period to areas where service to high priority consumers might be threatened.

The next area of our concern in this bill is incremental pricing which would require future increases in average cost of natural gas to be fully allocated to industrial users which would serve to discourage the use of natural gas by industry. We submit it is not in the interests of the residential consumer to indiscriminately discourage all industrial uses of natural gas by the device of incremental pricing. Pipelines and distributors have historically been able to keep residential natural gas bills at relatively low levels by serving industrial loads which relieve the residential consumers of fixed costs during periods of off-peak demand.

Incremental pricing would be a disservice to the residential consumer. Their best interests lie in receiving reliable service from distribution systems which also serve industrial users to the extent gas supplies permit. Loss of the ability to serve industrial users would constitute the loss of important revenues to pipelines and distribution companies, which in turn would inevitably result in an increase in residential natural gas bills. Incremental pricing would make it nearly impossible to implement supplemental gas supply

projects such as LNG, and coal gasification, which are needed for the long term protection of residential and commercial users. Currently the residential market cannot absorb these supplemental supplies on a constant year-round basis, so the ability to make such supplements available to industrial users during periods of off-peak demand makes it possible to attach important new supplies today that will be urgently needed for residential use tomorrow.

The incremental pricing theory might be applicable in cases where the incremental supplies serve an entirely new and additional market, but such is not the case for natural gas. Incremental supplies are needed to offset declining supplies and to augment and protect service to all customers, particularly the residential and small commercial user. Incremental pricing makes absolutely no sense for today's natural gas industry and would only serve to prevent the acquisition of new supplemental supplies sorely needed to protect existing customers.

With respect to the provisions on synthetic gas in the act we have long urged that this statutory modification be made, but we do suggest that there be an additional provision which would make it clear that once the Federal Power Commission has authorized a company to engage in such projects, the company would be entitled to recover its reasonable cost.

Now, as you know, there are no commercial high Btu coal gasification plants in existence in the United States. One of the primary reasons is that the capital costs involved have grown to staggering sums rendering it virtually impossible for any pipeline company to finance a first-generation plant. We are most disappointed that the administration's proposal does not provide any assistance on the financial problem. Loan guarantees or similar financial assistance from the Federal Government are urgently needed and we strongly urge the Congress to seriously consider this subject once again. We do this particularly in the light of the fact that the country has abundant supply of coal and that it is far more efficient and economical to provide high Btu gas from coal than it is to generate electricity from coal.

There is one other area of the bill that gives us considerable problem——

Mr. KRUEGER. Mr. O'Shields, will you be able to conclude in one or two minutes? We will have a quorum. We will go to the quorum and return.

Mr. O'SHIELDS. I have but one other point. In part E, title I of this bill, it would give the Administrator of the Federal Energy Administration unprecedented powers to control State regulatory policies. We do not think that is needed or necessary and we would recommend strongly that that extension of Federal control over State regulatory policies not be granted.

We have attached to our statement a marked-up copy of the bill with all of the changes we recommend for your consideration.

In conclusion, we wish to reiterate our position that the most effective step that can be taken on natural gas is to remove price controls from wellhead sales of natural gas. Additionally, we wish to emphasize most strongly that it is imperative that natural gas legislation be enacted this year. It would indeed be tragic if another

year went by without substantive long-term gas legislation. The Nation just cannot afford further inaction on natural gas.

The other members of our panel and I are glad to have this opportunity to appear and we would be pleased to answer any of your questions. Thank you.

[Mr. O'Shields' prepared statement follows:]

STATEMENT OF
RICHARD L. O'SHIELDS, CHAIRMAN
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA
BEFORE THE SUBCOMMITTEE ON ENERGY AND POWER
OF THE COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
HOUSE OF REPRESENTATIVES
RE: H.R. 6831 -- THE NATIONAL ENERGY ACT
MAY 17, 1977

Mr. Chairman, and members of the Subcommittee on Energy and Power, my name is Richard L. O'Shields. I am President and Chief Executive Officer of Panhandle Eastern Pipe Line Company, Houston, Texas. I am also Chairman of the Board of the Interstate Natural Gas Association of America (INGAA) for whom I am appearing here today. I am accompanied by W. J. Bowen, Chairman of the Board and President, Transcontinental Gas Pipe Line Corporation; Jack D. Head, Executive Vice President and General Counsel, Texas Eastern Transmission Corporation; and Travis Petty, President, El Paso Natural Gas Company; all member companies of INGAA. INGAA, as you know, is a national non-profit association representing virtually all of the interstate pipeline companies operating in this country.

Natural Gas transported and sold in interstate commerce by INGAA member companies serves all of the lower forty-eight states with the exception of Vermont. Approximately 90 percent of all natural gas transported and sold annually in interstate commerce flows through facilities

owned and operated by INGAA's member companies. The legislative proposals before your Committee, Mr. Chairman, pertaining to natural gas are of deep interest to INGAA and its members, and we appreciate the opportunity to present our views.

As you know Mr. Chairman, INGAA has appeared before your Committee on many prior occasions urging that Congress enact legislation to correct the disastrous effects of more than twenty years of court mandated Federal Power Commission regulation of wellhead prices for natural gas. We have recommended and continue to recommend legislation to remove price controls from wellhead sales of new natural gas as the single most effective step that can be taken to restore balance to supply and demand for this premium fuel. We have also on prior occasions expressed the need for a comprehensive national energy policy and we reaffirm our position that the country needs such a policy.

President Carter and his Administration are to be commended for their efforts to enunciate a comprehensive national energy policy and to lay it before the Congress and the American people. In principle we agree with the President's generalized statement of the salient features of the needs of the country as expressed in The National Energy Plan, such as the need for:

- conservation and fuel efficiency;
- rational pricing and production policies;
- reasonable certainty and stability in Government policies;
- substitution of abundant energy resources for those in short supply; and
- development of nonconventional technologies for the future.

Unfortunately, however, we have difficulty with several of the specific proposals of the National Energy Act as they would apply to producing, transporting and supplying natural gas to the consumers of this country.

The President has chosen to recommend continued regulation of the price of new natural gas. This, we are convinced, is a mistake and we once again urge the Congress to enact legislation which deregulates the price of new natural gas. However, if Congress elects to continue price regulation for new natural gas, it should be phased out as rapidly as possible.

I would like to emphasize, Mr. Chairman, that INGAA supports the conservation of energy use and the phasing out of large boiler fuel usage of natural gas for electric generation over a reasonable period of time. As we understand it, phasing out of such usage is now going forward in an aggressive way under existing state and Federal laws. Furthermore, we strongly support the development of new sources of energy, such as production of synthetic gas from coal and other feedstocks, the importation of

LNG as an important supplemental gas supply, expanded development of solar energy, and other such programs.

Turning now to the President's bill insofar as it pertains to natural gas, I would like to comment briefly on some of the more significant aspects of our concerns.

"New" Gas Definition - Sec. 402(5).

The bill would define "new" natural gas offshore as coming only from new leases issued on or after April 20, 1977, and onshore from new wells not more than 2.5 miles from an existing well or not less than 1,000 feet deeper than an existing completion within the 2.5 mile radius provided that the deeper well was not completed in the same producing zone of the old well. This definition, in our opinion, is far too restrictive and arbitrary. With respect to offshore, we all certainly expect that existing leases will be the source of much newly discovered gas. For example, Mr. Chairman, if the outstanding leases in the offshore Atlantic are confirmed after court appeals, none of the gas yet to be discovered on those leases would qualify as new gas under the terms of the bill. This, we feel, would be a tragic discouragement to the exploration for new gas offshore in outstanding leases.

Onshore, the arbitrary 2.5 mile-1,000 feet strictures completely ignore the geologic facts surrounding the presence or absence of producing reservoirs in the earth. Experience over the years has demonstrated time and time again that completely new reservoirs are discovered within 2.5 miles of old wells and many times at depths shallower than 1,000 feet below existing, producing wells. The 2.5 mile limit and other definitions in the bill will disqualify an area of over 2,800 acres around every "old" well which ever produced, or was ever capable of producing, oil or natural gas. As a matter of fact, you could have the anomalous situation of a discovery well in a new reservoir being slightly more than 2.5 miles away from such an "old" well, thereby qualifying as "new" natural gas, but development wells drilled to the same new reservoir thereafter would not qualify because they would be within the 2.5 mile radius of the "old" well. Even if a producer could locate all plugged and abandoned wells within a 2.5 mile radius of his proposed drilling location, he could not possibly determine whether old wells classified as "dry holes" were capable of producing some quantities of crude oil or natural gas.

I have attached to this statement a map view, Figure 1, and a cross section, Figure 2, which illustrate "old" and "new" gas or oil as proposed in H.R. 6831. In this hypothetical example you can quickly see how the arbitrary distance definitions result in a nonsensical mix of "old" and "new" from reservoirs that (except for the one "old" reservoir) are actually all new discoveries.

Such an arbitrary definition would, in fact, in our opinion, discourage, rather than encourage, exploration in a large part of the area yet to be explored in this country. History has shown that established productive areas of hydrocarbons in sedimentary basins are among the best places to look for new hydrocarbons.

We, therefore, offer a substitute definition for "new" natural gas to apply both onshore and offshore, which would define "new" gas to be gas produced from a reservoir discovered on or after April 20, 1977, or produced from wells commenced on or after that date and completed in an extension of a previously discovered reservoir as those discoveries and extensions are determined by the proper Federal or state regulatory agency having jurisdiction over the drilling of wells and production therefrom. As you may recall, Mr. Chairman, we

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have urged a similar definition of "new" gas on prior occasions and this definition corresponds to the definition contained in H.R. 9464 which was passed by the House on February 5, 1976, and in Senate Bill S. 2310, passed by the Senate on October 22, 1975. The meaning of the term "new reservoir" and "extension" of a previously discovered reservoir is not mysterious, mythical or elusive, but on the contrary has been utilized by the American Association of Petroleum Geologists and others for many, many years. As you can see from our attached proposed amendments, substitution of this definition for that used in the bill would make unnecessary the use of many of the defined terms contained in Sec. 402, which, in themselves if allowed to stand, would cause considerable confusion and ambiguity.

Price Level - Sec. 402(19).

The bill establishes a maximum lawful price for "new" natural gas equal to the Btu equivalent of the average refiner acquisition cost of all domestic crude. This, we are told, will equate to a price of $1.75 per Mcf at the beginning of 1978. On the other hand, The National Energy Place would establish a higher equivalent price for newly discovered domestic crude oil (pp. 50-52).

This ceiling price for newly discovered domestic crude oil would be set initially at $11.28 per barrel or a Btu equivalent of $1.94, and the initial price would be allowed to rise over a three-year period to the current world oil price of $13.50 per barrel (p. 50) or a Btu equivalent of approximately $2.33.

We submit that it is illogical to establish a ceiling price for new natural gas, which is a premium fuel, at a level substantially less than that established for crude oil, which is in many respects a less desirable fuel than natural gas. Such approach is completely inconsistent with President Carter's recognition of the fact that new natural gas should be priced to provide a sufficient incentive for the development of future supplies with substantially higher long-range development costs. (The National Energy Plan, p. 53.) Certainly, the development of new natural gas supplies will entail the same if not greater degree of risks and costs as the development of new crude oil supplies. Certainly, it is equally, if not more, in the public interest to develop new supplies of the premium fuel, natural gas, as it is to develop new supplies of crude oil. Certainly, therefore, it is essential that new natural gas be accorded a price no less than newly discovered domestic crude oil.

For these reasons, if price ceilings are enacted, we propose that the ceiling price of new natural gas be fixed at the Btu related price of newly discovered domestic crude oil rather than the average price of all domestic crude oil as proposed by the President.

In this regard, Mr. Chairman, we note that the ceiling price regulation established by the bill applies to all newly discovered gas, both for the intrastate and interstate markets. While we have always chosen to achieve parity with the intrastate market by asking the Congress to deregulate the price of "new" natural gas, we reaffirm our belief that in the event ceiling pricing is to continue in the interstate market, a ceiling price such as the one here proposed should be applied to all gas in order to enable the interstate pipelines to compete with the intrastate buyers in the purchase of onshore natural gas.

Unnecessary Federal Jurisdiction - Sec. 409.

In view of the fact that under the bill ceiling prices are established for the sale of new natural gas by producers, there is no need for those sales to continue to be regulated under the Natural Gas Act by the Federal Power Commission. The interstate pipelines have for years been at a disadvantage in purchasing new gas, even in instances where the intrastate and interstate prices were the same, because a seller of gas did not wish to assume the burdens of regulation by

the Federal Power Commission under certificate and other provisions of the Natural Gas Act. We feel that continued regulation under such circumstances is a detriment and not needed and, therefore, we would recommend that the Congress specifically exempt producers from regulation with respect to such sales. We have included a proviso, however, which would extend this freedom from jurisdiction in the offshore only when a long-term contract was entered into in order to assure the interstate pipelines that the gas will be contracted for a term sufficient to justify the costly installation of the offshore facilities necessary to pick up such gas.

Emergency Natural Gas Act - Sec. 404 and Sec. 416.

The bill would extend the Sec. 4 mandatory allocation provisions of the Emergency Natural Gas Act of 1977 until April 30, 1979, and would expand these provisions to apply to intrastate pipelines but would not extend the emergency purchase provisions of Sec. 6 of that Act. We do not feel this is necessary or desirable. In the first place, the Sec. 4 mandatory allocation provisions were not needed in this past winter, the coldest winter in 100 years. The important thing that happened in the emergency of 1977 was the ability on the part of the interstate pipeline companies to purchase emergency gas from intrastate pipelines

and producers and to utilize intrastate pipeline systems for transportation of gas from one part of the country to another under conditions assuring the sellers and transporters of such gas that they would not be subjected to permanent Federal regulation. We offer, in lieu of the extension provisions set out in the bill, an adequate provision under which the President may authorize contracts for purchases from and transportation of natural gas by intrastate pipelines, and providing that such intrastate pipelines will not, by virtue of such acts, become subject to regulation under the Natural Gas Act or regulation as a common carrier under any provision of Federal or state law. Such a provision coupled with the special rules set forth in Sec. 412(b) and (c) of the bill, we believe, will provide adequate means for getting gas supplies which may be available during emergency periods to the areas where service to high priority consumers may be threatened.

Incremental Pricing - Sec. 414.

The bill requires that increases in the average cost of natural gas delivered after the date of enactment shall be fully allocated to industrial users in order to discourage the use of natural gas by industry and utilities.

As we have previously stated, we favor the phasing out of large boiler fuel uses of natural gas by utilities for the generation of electricity. We also recognize that

there may be other large industrial uses of natural gas which should be phased out. However, the phasing out of these large scale utility and industrial uses can best be accomplished by outright prohibitions, such as those contained in Sec. 601 of the bill..

Certainly, it is not in the interest of the residential consumers to indiscriminately discourage all industrial uses of natural gas by the device of incremental pricing. It is well recognized that pipelines and distributors have been able to keep residential natural gas bills at relatively low levels by serving industrial loads which relieve the residential consumers of fixed costs during periods of off-peak demand. Further, many industrial users are entirely dependent upon natural gas and cannot switch to alternate fuel. If raising the price of their natural gas supplies to artificially high levels does not force them out of business it could well require them to raise the prices of their products, further feeding inflation. This situation would be further aggravated by the imposition of the Natural Gas Consumption Tax as proposed in Title II, Part E, Sec. 1501 of the bill.

For these reasons we are convinced that incremental pricing would constitute a disservice to the residential consumers. Their best interest lies in receiving service

from well balanced pipeline and distribution systems which can serve industrial users when and to the extent that available gas supplies are not required for higher priority purposes. The loss of the ability to serve industrial users, together with the loss of the revenues they contribute to the pipeline and distribution companies, would inevitably result in a like increase in residential natural gas bills. This would not achieve the goal of The National Energy Plan to hold down the price of gas to residential and commercial users.

Moreover, the maintenance of industrial sales should materially assist in the initial implementation of supplemental gas supply projects (such as coal gasification and LNG imports) as they are brought onstream. Currently the residential market cannot absorb these supplemental supplies on a year round basis. Thus the ability to make such supplements available to industrial users during periods of off-peak demand not only reduces the cost per Mcf to residential users but also makes possible the attachment of new supplies today that will be urgently needed for residential use tomorrow.

The incremental pricing theory might be applicable in cases where the incremental supplies serve an entirely new market. Such is not the case for natural gas as new

incremental supplies are needed to offset declining supplies and to augment and protect service to all customers, particularly the residential and small commercial customer. Since these supplies serve all customers, all users should pay their pro rata share of the cost involved. Incremental pricing makes absolutely no sense for today's natural gas industry and would only serve to prevent the acquisition of new supplemental supplies sorely needed to protect existing customers.

Synthetic Gas - Sec. 415.

The bill would amend the Natural Gas Act to extend the jurisdiction of that Act to synthetic gas projects engaged in by natural gas companies, such as the interstate pipelines. As you may recall, Mr. Chairman, we have long urged this statutory modification and welcome the Administration's proposal here. We have, however, found it appropriate to suggest an additional provision which would make it clear that once the Federal Power Commission has authorized a company to engage in such a project, the company will be entitled to recover its reasonable costs.

As you know, there are no commercial high Btu coal gasification plants in existence in the United States. The primary reasons for this are the regulatory gap now present in the Natural Gas Act and the fact that the capital costs involved in such an endeavor have grown to staggering sums,

rendering it virtually impossible for any pipeline company to finance a "first generation" plant. The proposed amendment contained in the bill with the addition we suggest should adequately close the regulatory gap; however, we are most disappointed the Administration's proposal does not contain specific provisions for some assistance from the Federal government on the financing problems. Loan guarantees, or similar financial assistance, from the Federal government are urgently needed. We strongly urge the Congress to seriously consider this subject once again. We do this particularly in light of the fact that the country has abundant supplies of coal and that it is far more efficient and economical to produce high Btu gas from coal than it is to generate electricity with coal.

Public Utility Regulatory Policies - Title I, Part E.

We are greatly disturbed with Part E, Public Utility Regulatory Policies, of Title I of the bill. The provisions of this Part would give the Administrator of the Federal Energy Administration far-reaching and unprecedented powers to dictate to state and local regulatory authorities the policies to be employed in setting local rates and charges for electric and gas service. We believe that these provisions would constitute an unwarranted interference by the Federal government into matters which have traditionally

been and are properly within the province of the states. More importantly, in our view, the individual states and local regulatory authorities are far better equipped to evaluate the impact of rates and charges for electrical and gas service on the consumers and industries served within their jurisdiction. The imposition of Federal regulatory control, while diminishing the ability of local authorities to design rates in a manner which best meets the needs of their citizens, is likely to result in rates being imposed which are purely arbitrary and non-responsive to the needs and problems of individual communities. Certainly, no one has established the need for this additional heavy handed intrusion of Federal regulation into the local affairs of the states and their regulation of local utilities and we perceive no justification for doing so here.

Attached to this statement is a marked-up copy of Part D of Title I of the bill showing the changes which, in our considered opinion, must be made in H.R. 6831 if this legislation is to truly "provide a sufficient incentive for the development of future supplies" and help to "bring natural gas supply and demand back into balance" (The National Energy Plan, p. 53). I will not go into further detail on these

changes here since they are explained in the attachment; however, my associates and I will be glad to discuss any of these items with the Committee if you so desire.

In conclusion, Mr. Chairman, we wish to reiterate our position that the most effective step that can be taken to restore balance to supply and demand for natural gas is to remove price controls from wellhead sales of new natural gas. If, however, the Congress determines to follow the basic approach of the President, we strongly urge that the changes I have discussed here be made in H.R. 6831. I want to emphasize as strongly as I can on behalf of INGAA and its member companies the imperative need for natural gas legislation this year. It would indeed be tragic if another session of Congress went by without substantive, long-term gas legislation. This nation cannot afford further inaction on natural gas. We would be pleased to work with you and your Committee in any way to see that this is accomplished.

The other members of the panel and I will be glad to respond to any questions the Committee may have concerning our testimony and the bill which is the subject of this hearing.

Thank you.

ILLUSTRATION OF "OLD" AND "NEW" GAS AS PROPOSED IN H.R. 6831

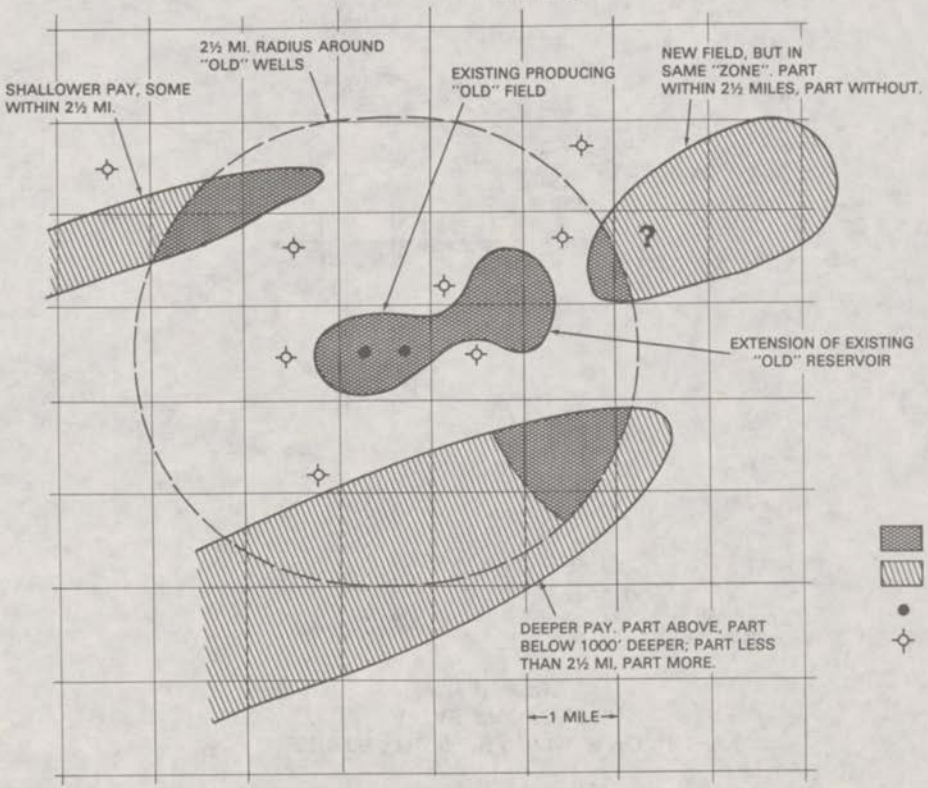

FIG. 1
MAP VIEW

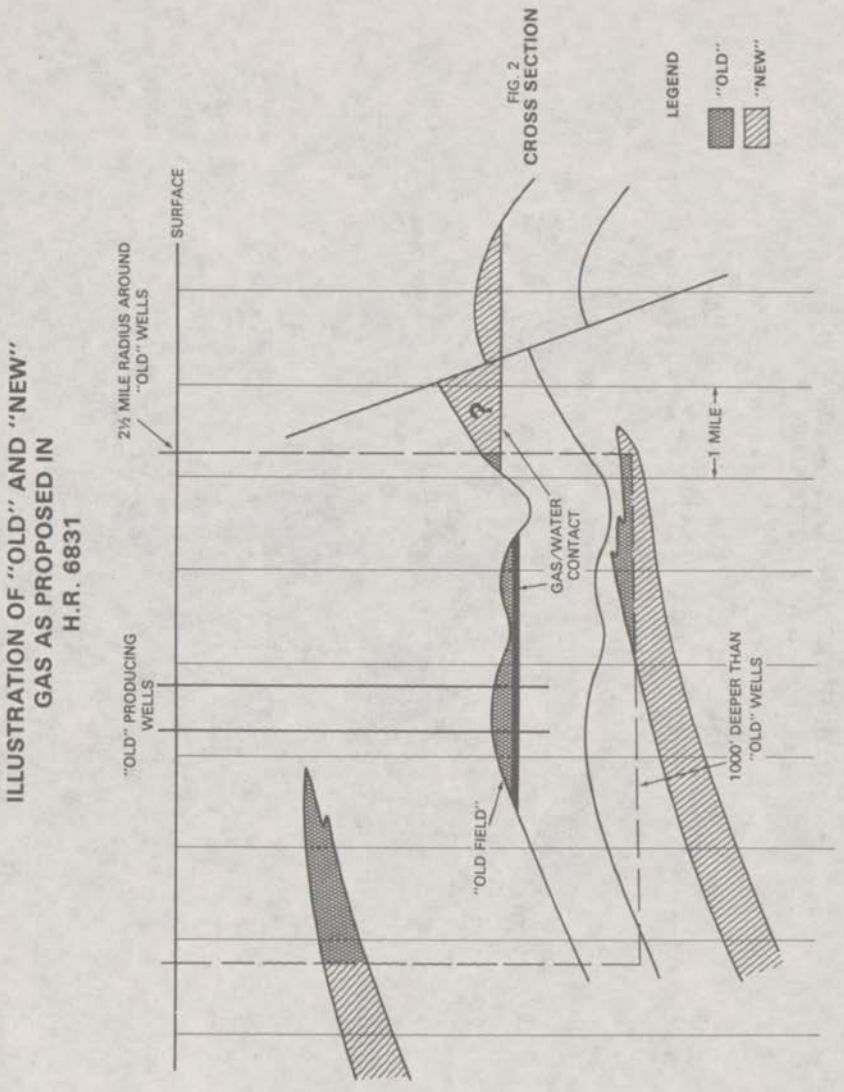
ILLUSTRATION OF "OLD" AND "NEW" GAS AS PROPOSED IN H.R. 6831
FIG. 2
CROSS SECTION
LEGEND
"OLD"
"NEW"
SURFACE
2½ MILE RADIUS AROUND "OLD" WELLS
"OLD" PRODUCING WELLS
"OLD FIELD"
GAS/WATER CONTACT
1 MILE
1000' DEEPER THAN "OLD" WELLS

95TH CONGRESS
1ST SESSION

H. R. 6831

IN THE HOUSE OF REPRESENTATIVES

MAY 2, 1977

Mr. WAGGONNER introduced the following bill; which was divided and initially referred for a period ending not later than July 13, 1977, as follows: sections 101 through 109 and sections 201 through 603 to the Committee on Interstate and Foreign Commerce; sections 110 through 131, and, concurrently with the Committee on Interstate and Foreign Commerce, those portions of subpart 1 of part A of title I relating to financial assistance to residential customers defined in section 101, to the Committee on Banking, Finance and Urban Affairs; section 701 to the Committee on Government Operations; sections 721 through 746 to the Committee on Public Works and Transportation; title II to the Committee on Ways and Means; and sections 2 through 4 concurrently to all of the above committees

A BILL

To establish a comprehensive national energy policy.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

That this Act may be cited as the "National Energy Act".

TABLE OF CONTENTS

Sec. 2. Findings.
Sec. 3. National energy goals.
Sec. 4. References to Federal Power Commission and Federal Energy Administration.

appropriated such sums as may be necessary to carry out the provisions of this part for each fiscal year in the three consecutive fiscal year period ending September 30, 1980.

"NONDISCRIMINATION

"SEC. 309. No person in the United States shall on the grounds of race, color, religion, national origin, or sex, be excluded from participation in, be denied the benefits of, or be subjected to discrimination under any program or activity funded in whole or in part with funds made available under this part.".

PART D—NATURAL GAS

FINDINGS AND PURPOSES

SEC. 401. (a) The Congress finds that—

(1) in the early history of this Nation's petroleum industry natural gas was a byproduct of the production of crude oil, was not easily marketable, and was often flared off and treated as waste or sold at very low prices;

(2) the natural gas market changed dramatically through the course of the last forty years as a national distribution system was built to deliver natural gas to commercial and industrial consumers throughout the Nation;

(3) the Congress enacted the Natural Gas Act in 1938 to provide protection for consumers and to provide

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a regulatory structure through which interstate pipelines could be assured a fair rate of return;

(4) in 1954, the Supreme Court held that the Natural Gas Act applied to the wellhead sale of natural gas in interstate commerce, subjecting producers selling interstate gas, but not intrastate gas, to a reasonable rate of return regulatory standard based on a determination of historic production costs;

(5) the differential between the price of natural gas and oil has widened with the continuation of cost-based regulation of natural gas, the fourfold rise in world oil prices in 1973 and 1974, and the increasing pressure to burn natural gas because of its environmentally superior qualities;

(6) as a result, the incentives to find new natural gas have declined along with the proven reserves of natural gas, while demand for this premium and relatively inexpensive fuel has increased;

(7) at the same time, increasing amounts of higher priced gas and wasteful industrial and boiler fuel uses have moved to the intrastate market, resulting in growing critical shortages in the interstate market of the fuel which provides 30 per centum of the Nation's energy;

(8) a new system of natural gas pricing is needed

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that recognizes the costs and risks associated with finding future supplies of natural gas as well as the commodity value of substitutable fuels.

(b) The purposes of this part ~~are~~ is—

~~(1) to bring the natural gas market back into~~ better balance by reducing the demand for natural gas and increasing the supply through the establishment of an incentive based pricing approach for new natural gas, wherever it is used, that moderates producer revenues and protects consumers by moving toward a commodity value price ceiling;

(2) to deal with short-term supply shortages of natural gas through extension of the allocation provisions of the Emergency Natural Gas Act of 1977; and

(3) to provide for the conservation of natural gas by pricing natural gas to certain industrial and other users at a level which will provide incentives for ~~conversion to other more plentiful fuels and for conservation.~~

SEE INSERT

DEFINITIONS

SEC. 402. (a) As used in this part—

(1) The term "Commission" means the Federal Power Commission.

(2) The term "natural gas" has the same meaning as such term has under section 2(5) of the Natural Gas Act.

Line 4: Change "purposes" to "purpose" and change "are" to "is"

Lines 5-18 Delete.
Insert in lieu thereof the following:

"to provide a more rational policy with respect to the pricing of natural gas to encourage exploration and development of new supplies and to encourage the conservation of gas by permitting it to be priced nearer to its commodity value."

Explanation: The purpose clause is amended so as to restate the national policy on the pricing of natural gas in a more direct fashion to encourage exploration and development of new supplies and to encourage the conservation of gas by permitting it to be priced nearer to its commodity value (see The National Energy Plan, pp. 52-54) and to reflect the revisions proposed herein to this bill.

(3) The term "producer" means any person who produces natural gas.

(4) The term "person" includes (without limitation) the United States and any State, and any political subdivision, agency, or instrumentality of either.

(5) The term "new natural gas" means natural gas—

~~(A) which is produced from a new lease on the Outer Continental Shelf; or~~

(B) which is produced other than on the Outer Continental Shelf from a new well—

(i) the completion location of which is 2.5 statute miles or more (surface measurement) from the completion location of any old well, or

(ii) the completion location of which is at a depth of 1,000 feet or more in excess of the depth of the completion location of any old well with a completion location that is within 2.5 statute miles (surface measurement) provided that the completion location of any such new well is not in the same producing zone as ~~the completion location of any such old well.~~

(6) The term "Outer Continental Shelf" has the

Line 3 — After the word "person", Insert the following:

"has the same meaning as such term has under Section 2(1) of The Natural Gas Act but for the purposes of this Act shall also"

Change the word "includes" to "include"

Explanation: The definition of the term "person" has been amended in order to make it clear as to the type of entity the word "person" includes by cross-referencing to the definition of "person" in The Natural Gas Act.

Line 7 — Delete the dash after the word "gas" and insert the following:

"produced from a reservoir discovered on or after April 20, 1977, or produced from wells initiated and completed in an extension of a previously discovered reservoir on or after April 20, 1977, as determined by State or Federal agencies having jurisdiction over the drilling of wells and production therefrom."

Lines 8-23 — Delete.

Explanation: The term "new natural gas" has been redefined to utilize a geological classification of what, in fact, will be new natural gas and to eliminate the arbitrary geographic limitation of the 2.5 miles, 1,000 feet depth definition utilized in the bill. The arbitrary definition in the bill would discourage rather than encourage the expanded exploratory efforts required to increase our nation's natural gas supplies. The definition proposed, referencing newly discovered and extended reservoirs, is more directly related to the facts actually encountered in the subsurface exploration for gas and is based upon the terms utilized by the American Association of Petroleum Geologists, The American Petroleum Institute, and others.

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same meaning as such term has in section 2 of the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

SEE INSERT

(7) The term "new lease" means a lease, entered into on or after April 20, 1977, of an area which—

(A) was not leased before April 20, 1977; or

(B) which was leased before such date, under a lease which terminated or was abandoned before such date and was not in effect on such date.

SEE INSERT

(8) The term "new well" means a well the drilling of which was not begun on or before April 20, 1977, or with respect to which a drilling permit had not been issued on or before April 20, 1977, in the case of a well for which such permit is necessary.

(9) The term "old well" means a well that produced or was capable of producing crude oil or natural gas on or before April 20, 1977.

(10) The term "completion location" means the location at which crude oil or natural gas is withdrawn from a producing zone.

(1) The term "depth" means the depth determined by reference to the vertical distance between mean sea level and the lowermost point of the completion location of any old well or by reference to the vertical distance between mean sea level and the uppermost point of the completion location of any new well.

Line 3 — Delete the words " ' new lease' means a lease entered"

Lines 4-8 — Delete and insert the following:

" 'interstate pipeline company' means any Natural Gas Company as defined in Section (2) (6) of the Natural Gas Act which is engaged in the transportation by pipeline of natural gas subject to the jurisdiction of the Federal Power Commission."

Line 9 — After the word "term", delete the words " 'new well' means a well the drill --"

Lines 10-13 — Delete and insert the following:

" 'intrastate pipeline company' means any person (other than an interstate pipeline company) engaged in the transportation by pipeline of natural gas produced, transported and sold wholly within a state."

Lines 14-25 — Delete.

Explanation: see page 47

~~(12) The term "surface measurement" means the distance at mean sea level between the points at which vertical lines, drawn through the nearest points of any two completion locations, would intersect the surface of the earth at mean sea level.~~

(13) The term "producing zone" means a geological formation having common characteristics that contains crude oil or natural gas, whether or not there is ~~communication between the portions thereof.~~

9
~~(14)~~ The term "old natural gas" means natural gas other than new natural gas.

10
~~(15)~~ The term "new contract" means a contract entered into after April 20, 1977, SEE INSERT or a renewal after April 20, 1977, of a contract entered into on or before April 20, 1977, if such renewal occurs by agreement of both parties to the contract on or after the expiration of a fixed term specified by the contract.

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~~(16)~~ The term "existing contract" means any contract other than a new contract.

~~(17) The term "current Btu related price" means the most recently published Btu related price.~~

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~~(18)~~ The term "Btu related price" means the SEE INSERT average per barrel crude oil acquisition cost (excluding any amounts attributable to the tax imposed by section 4996 of the Internal Revenue Code of 1954) for re-

Lines 1-9 Delete.

Explanation: The definitions used in Section 402 (9), (10),(11), and (12) are deleted since such terms are not used in the bill as it is proposed to be amended. The definitions of interstate and intrastate pipeline companies have been added for the purposes of Secs. 409 and 415, as amended herein.

Line 10 Subparagraph should be renumbered (9)

Line 12 The subparagraph should be renumbered (10)

Line 13 After "April 20, 1977," insert the following:

"for the sale of new natural gas or the sale of old natural gas to another buyer after the expiration of a fixed terms specified by a contract entered into on or before such date,"

Explanation: The definition of "new contract" has been amended to more clearly express what we believe the intent of the bill is, namely, to cover a contract entered into after April 20 for not only new natural gas but for the sale of old natural gas to another buyer after the expiration of the fixed term in the original contract.

Line 18 The subparagraph should be renumbered (11)

Lines 20-21 Delete.

Explanation: Subparagraph (17) has been deleted as it will not be needed under the amended bill.

Line 22 Redesignate the subparagraph as (12) and insert after the word "the" at the end of the line the following:

"ceiling price per barrel for newly discovered oil produced in the United States as established from time to time by law [i.e., in accordance with the oil pricing principles spelled out in The National Energy Plan, pp. 50-53]"

Lines 23-25 Delete.

Explanation: See page 48

fineries in the United States (with respect to all crude oil produced within the United States) for the most recent calendar quarter for which data are available to the President, divided by a factor of 5.8.

(~~19~~ 13) The term "United States" includes the Outer Continental Shelf.

(~~20~~ 14) The term "inflation adjustment" means the first revision of the quarterly percent change, seasonally adjusted at annual rates, of the most recent implicit price deflator for the gross national product. Such adjustment shall be computed and published for each calendar quarter by the Department of Commerce.

(b) The President shall have the authority to define, by rule, the terms used but not defined in this part in a manner consistent with the purposes of this part.

CALCULATION OF THE ~~CURRENT~~ BTU RELATED PRICE

SEC. 403. As soon as practicable after the date of enactment of this Act, and on a timely basis thereafter as new data become available, the President shall calculate and publish in the Federal Register the ~~current~~ Btu related price, then in effect.

SALES OF NEW NATURAL GAS

SEC. 404. The President shall, by rule, establish a maximum lawful price applicable to ~~any first sale~~ by a producer of new natural gas ~~delivered in any calendar quarter which~~

Lines 1-3 Delete.

Line 4 Delete the word "President"
Explanation: The term "Btu related price" has been deleted and redefined to make it clear that the ceiling for new natural gas is to be equated to the price per barrel of newly discovered domestic crude oil (see The National Energy Plan, pp. 50-52) rather than the lower priced average cost of acquisition for refineries of a mixture of lower priced old and higher priced new domestic oil and newly discovered domestic oil.

Line 5 Redesignate the subparagraph as (13)

Line 7 Redesignate the subparagraph as (14)

Line 14 After the word "used", insert the words "but not defined"
Explanation: Section 402(b) is amended to make it clear that the President does not have the authority to redefine the terms defined in the statute.

Line 16 Strike the word "CURRENT"

Line 20 Strike the word "current"

Line 21 Strike the period after the word "price" and insert "then in effect"
Explanation: Section 403 has been amended to reflect the deletion of the definition of the term "current Btu related price"

Line 24 Strike the words "any first" and change the word "sale" to "sales"

Line 25 After the word "gas", delete the words "delivered in any calendar quarter which"

~~begins on or~~ after the date upon which such rule is promulgated and made effective. Such maximum lawful price shall be a price equal to the ~~current~~ Btu related price as determined by the President from time to time. ~~(determined as of the date of such delivery).~~

SALES OF OLD NATURAL GAS UNDER EXISTING CONTRACTS

SEC. 405. The President shall, by rule, establish a maximum lawful price applicable to ~~any first~~ the sale by a producer of old natural gas under an existing contract. Such maximum lawful price shall be a price equal to the lesser of—

(1) the contract price; or

SEE INSERT

(2) the price heretofore or hereafter received for sales under such contract which was determined to be just and reasonable by the Commission and was in effect on April 20, 1977 (without regard to the outcome of any appeal of such determination pending on April 20, 1977), plus the inflation adjustment as defined in section 408(c).

SALES OF OLD NATURAL GAS UNDER NEW CONTRACTS

SEC. 406. (a) The President shall, by rule, establish the maximum lawful price applicable to ~~any first~~ the sale by a producer of old natural gas under a new contract.

(b) In the case of old natural gas referred to in subsection (a) ~~(1)~~ which is committed or dedicated to interstate commerce on April 20, 1977 (other than by reason of a limited term certificate of five years or less or a

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Line 1 — Delete "begins on or"

Line 3 — Delete the word "current" and "(deter--". After the word "price", insert the following:

"as determined by the President from time to time".

Line 4 — Delete

Explanation: This section has been amended in order to make it clear that the maximum lawful pricing to be established by the President will not cause a quarterly vintaging of contracts entered into in such quarter and to avoid any confusion as to the meaning of the words "first sale".

Line 8 — Delete the words "any first" and insert the word "the" before the word "sale"

Line 12 — Insert after (2), the words "if the old natural gas was sold in interstate commerce," and after the word "price", insert the words "heretofore or hereafter received"

Line 15 — After the word "to", insert the words "the outcome of"

Explanation: The first paragraph of Section 405 was amended to avoid confusion as to the meaning of the term "first sale" and to implement the goal of The National Energy Plan (p. 53) that "currently flowing natural gas would be granted price certainty at levels currently set by the Federal Power Commission". Subparagraph (2) was amended to make it clear that this subparagraph was intended to apply only to old natural gas being sold in interstate commerce on April 20, 1977 and without regard to the outcome of any pending appeals.

Line 20 — Strike the words "any first" and insert the word "the" before the word "sale".

Line 23 — Strike "(1)"

temporary emergency contract under section 7(c) of the or the Emergency Natural Gas Act of 1977
Natural Gas Act), ~~or (2) which is produced from a new well or a new lease~~, the maximum lawful price under this section shall not exceed $1.45 per Mcf; plus the inflation adjustment as defined in section 402(a) (20)[14]. In establishing any maximum lawful price under this subsection, the President shall take into consideration the maximum lawful price of such gas under the prior contract and the price necessary to maintain production of such gas.

(c) In the case of old natural gas referred to in subsection (a) which is not described in subsection (b), the maximum lawful price under this section shall be equal to the ~~current~~ Btu ~~equivalent~~ related price[7] as determined from time to time following the initial delivery of such gas under the new contract. ~~(determined as of the date of delivery of such gas)~~.

EFFECTIVE DATES OF RULES WITH RESPECT TO MAXIMUM LAWFUL PRICES

SEC. 407. The President shall promulgate and make effective rules under sections 404 through 406 within thirty days after the date of enactment of this Act. Such rules[7] and the prices provided therein shall apply to deliveries which take place after the date SEE INSERT of ~~enactment of this Act~~.

SPECIAL PRICING PROVISIONS

SEC. 408. (a) Notwithstanding any maximum lawful price under sections 404 through 406, the President may, by rule, specify a special price under this section in excess

Line 2 — After the word "Act" and within the parenthesis, insert the words "or the Emergency Natural Gas Act of 1977" and strike "or (2) which is produced from a new"

Line 3 — Strike the words "well or a new lease"

Line 5 — Change "(20)" to "(14)"
Explanation: Section 406(b) was amended to delete a reference to the category of gas produced from a new well or a new lease in that it is obvious that the intent of the bill was to provide for the pricing of new natural gas pursuant to the provisions of Sec. 404. It was also amended to make it clear that gas purchased under The Emergency Natural Gas Act of 1977 was not to have been deemed to have been committed to interstate commerce.

Line 13 — Strike the word "current"; strike the word "equivalent" and insert the word "related"; after the word "price", delete "(determined as of the"

Line 14 — Delete. Insert in lieu thereof the following:

"as determined from time to time following the initial delivery of such gas under the new contract."

Explanation: The wording of Sec. 406(c) was amended to make it clear that natural gas entitled to the Btu related price would not be vintaged permanently to a price in a specific quarter.

Line 19 — After the word "rules", insert the words "and the prices provided therein"

Line 21 — Strike the words "enactment of this Act.", and insert:
"the promulgation of the rules; provided, however, that such prospective application of the rules shall not require refunds of any portion of the rates theretofore collected by producers pursuant to the Federal Power Commission's just and reasonable rate determinations in effect on April 20, 1977."

Explanation: The wording of Sec. 407 was revised to make it clear that the rules and prices to be promulgated by the President would apply only after the date of the promulgation of the rules to avoid retroactive pricing. However, the intendt of The National Energy Plan is preserved by the proviso that no refunds will be required for prices theretofore collected at levels currently set by the FPC, i.e., rate determinations in effect on April 20, 1977.

of any such maximum lawful price, which shall be applied for purposes of such sections if the President determines that such special price is necessary to provide incentives for the production of natural gas ~~or the manufacture of synthetic gas~~ in categories which involve high costs, such as (but not limited to) production—

(1) in depths of more than 500 feet of water,

(2) more than 15,000 feet below the surface of the Earth, or

(3) from geopressurized brine.

The President may specify such special prices for categories of production or on a national, geographic area, or case-by-case basis in accordance with section 553 of title 5, United States Code.

(b) In the case of a ~~first~~ sale by a producer of any natural gas with respect to which such producer bears all or part of the cost of transportation or liquefaction of such gas, the President, by rule, may adjust the maximum lawful price determined under sections 404 through 406 or the special price under subsection (a) to reflect such cost.

(c) The Commission may not increase any price for any first sale by a producer of natural gas determined prior to April 20, 1977, by the Commission to be just and reasonable, except that the Commission shall, to the extent permitted by the terms of any contract, cause an inflation adjustment in such prices as defined in section 402(a) ~~(20)~~ (21).

Line 4 Strike the words "or the manufacture of synthetic gas"

Line 5 After the words "such as", insert ",but not limited to,"

Explanation: This section was amended to delete the reference to synthetic gas from the special pricing provisions since synthetic gas is not covered by the ceiling prices established by the bill for natural gas. It was also amended to make it clear that the illustrations of categories of higher costs were included as illustrations and not as limitations.

(d) In addition to his authority respecting first sales by a producer of natural gas, the President may, by rule, establish maximum lawful prices applicable to any sales of natural gas by any other person if he determines that such rules are necessary to prevent circumvention of the pricing policies specified in sections 404 through 408. This subsection shall not apply to sales for resale by such other persons if such sales are subject to the Natural Gas Act.

SEE INSERT

RELATIONSHIP TO THE NATURAL GAS ACT

SEC. ~~409~~ 410. (a) For purposes of sections 4 and 5 of the Natural Gas Act, any price for any natural gas which is not in excess of the maximum lawful price (or special price specified under section 408) applicable to such natural gas under the provisions of this part shall be deemed just and reasonable and the Commission may not disallow any rate which is not in excess of such maximum lawful price. -- SEE INSERT

(b) The Commission may not condition the grant of or deny a certificate of public convenience and necessity under section 7 of the Natural Gas Act solely on the basis of the price for the ~~first~~ sale by a producer or sold of natural gas sought to be transported pursuant to such certificate, if such price is not in excess of the maximum lawful price (or special price) applicable to such natural gas pursuant to this part.

SEE INSERT

ENFORCEMENT AND DELEGATION

SEC. ~~410~~ 411. (a) Any rule promulgated by the President under this part shall be enforceable to the same extent and

Line 10 Renumber this section as Section 410 and insert a new Section 409 after line 8 to read as follows:

"Sec. 409. The maximum lawful price for sales of natural gas prescribed by Sections 404 through 408 of this Act shall not be applicable to sales of natural gas after such natural gas has been transported through pipeline facilities owned or operated by an intrastate or interstate pipeline company."

Explanation: A new Sec. 409 has been added to make it clear that the ceiling prices provided for in the bill are not applicable to sales of natural gas by a pipeline after the gas has been transported through its facilities.

Line 16 Insert at the end of the paragraph a new sentence reading:

"Further, the Commission shall have no power to deny, in whole or in part, or order a decrease in, any rate or charge made, demanded or received by any natural gas company for, or in connection with, the purchase of any natural gas at any price not in excess of said maximum lawful price or special price applicable to such gas."

Explanation: The language added to this section is to make it clear that the intent of the bill is that the Federal Power Commission will have no power to deny a pipeline company the right to recover purchased gas costs at prices not in excess of the maximum lawful prices established pursuant to the bill.

Line 17 After the word "not", insert the words "condition the grant of or"

Line 19 Strike the word "first"

Line 20 After the word "sale", insert the words "by a producer" and after the word "transported", insert the words "or sold".

Explanation: The amendments to this subsection are to more clearly express the intent.

Line 23 See page 52 cont'd. for insert

Line 23 At the end of subparagraph (b), insert a new subparagraph (c) to read as follows:

"(c) From and after the date of enactment of this Act, the sale of either new natural gas or old natural gas referred to in Section 406(c) by a producer to a natural gas company for resale in interstate commerce shall not be subject to regulation by the Commission under The Natural Gas Act provided, however, that such sale by a producer of new natural gas produced and delivered in the Outer Continental Shelf shall be committed for a contract term of not less than fifteen years or for the life of the reservoir if less than fifteen years in order to qualify under the provisions hereof.

Explanation: New subsection (c) has been added to free from jurisdiction of the Federal Power Commission a sale by a producer of new natural gas or old natural gas referred to in Sec. 406(c) in order that producers will not be discouraged in selling their gas in the interstate market. Since ceiling prices are imposed under the bill, there is no need for continued regulation of producer sales of this type gas by the Federal Power Commission. A provision is also included which would require offshore contracts to be for a term of not less than fifteen years or the life of the reservoir in order for the exemption from Commission jurisdiction to be applicable. This is needed because of the large expenditures required to connect offshore reserves.

Line 25 Renumber Sec. 410 as Sec. 411.

in the same manner as a regulation, or rule, promulgated under the Emergency Petroleum Allocation Act of 1973.

(b) The President may delegate all or any part of the authority granted to him under this part to such officers, departments, or agencies of the United States (including the Commission or any member thereof) as he determines appropriate.

(c) In order to obtain information to carry out his authority under this part, the President may—

(1) sign and issue subpenas for the attendance and testimony of witnesses and the production of books, records, papers, and other documents;

(2) require any person, by general or special order, to submit answers in writing to interrogatories, requests for reports or for other information, and such answers shall be made within such reasonable period, and under oath or otherwise, as the President may determine; and

(3) secure, upon request, any information from any Federal department or executive agency.

(d) The appropriate United States district court may, upon petition of the Attorney General at the request of the President, in the case of refusal to obey a subpoena, or order of the President issued under subsection (c) issue an order requiring compliance therewith, and any failure to obey an order of the court may be punished by the court as a contempt thereof.

(c) The President may not exercise authority under subsection (c) (3) with respect to information in possession of a Federal agency the disclosure of which to another Federal agency is expressly prohibited by law.

~~EMERGENCY SALES~~

~~SEC. 411. Nothing in this part shall apply to any price for the sale of natural gas which is allowed under section 4 of the Emergency Natural Gas Act of 1977.~~

SPECIAL RULES

SEC. 412. ~~(a) The Commission may grant abandonment under section 7(b) of the Natural Gas Act at any time prior to the committing or dedication of natural gas for interstate commerce.~~

~~(b)~~ (b) Any contractual provision—

(1) prohibiting the sale or commingling of natural gas subject to such contract with natural gas subject to the provisions of the Natural Gas Act, or

(2) terminating, or granting any party the option to terminate, any obligation under any such contract as a result of such sale or commingling,

is hereby declared against public policy and unenforceable with respect to the sale of any natural gas.

~~(c)~~ (c) The price of any natural gas determined under this part shall not be taken into account for purposes of any contractual provision which determines the price of any

Lines 5-8 Delete.
Explanation: Section 411 is stricken for the reasons set forth regarding Section 416 of the bill.

Line 10 Strike "(a) the Commission may grant abandonment"

Lines 11-13 Delete.

Line 14 Change "(b)" to "(a)"

Line 23 Change "(c)" to "(b)"
Explanation: Section 412(a) is deleted in view of the fact that the Commission already has the power to permit pregranted abandonments. Further, we recommend that most future producer sales be exempted from Commission jurisdiction (see new Section 410(c), supra).

natural gas (or terminates, or permits renegotiation of, a contract) on the basis of sales of other natural gas.

COVERAGE

SEC. 413. Sections 402 through 412 shall apply only to the sale of any natural gas produced within the United States.

~~INCREMENTAL PRICING OF NATURAL GAS~~

~~SEC. 414. (a) Not later than ninety days after the date of enactment of this Act, the President shall, by rule, provide that, to the maximum extent practicable, any portion of the average cost of natural gas delivered after the date of enactment of this Act to any pipeline company which exceeds the average cost of natural gas to such company during the most recent twelve-calendar-month period ending before the date of enactment of this Act (plus an inflation adjustment as defined in section 402(a)(20)), shall be fully allocated in the rates and charges of such company to low priority uses; except that such rules may not require that such portion be fully allocated for such uses if such allocation would result in rates or charges for such uses equal to an amount no greater than the reasonable price (as determined by the President) of substitute fuels.~~

~~(b) For purposes of this section:~~

~~(1) The term "low priority use" means a use other than a high priority use.~~

Lines 7-25 Delete.
Explanation: see page 56

~~(2) The term "high priority use" means:~~

~~(A) use of natural gas in a residence; or~~

~~(B) use of natural gas in a commercial establishment in amounts of less than 50 Mcf on a peak day.~~

~~(3) The term "pipeline company" means any person (including a governmental agency) who is engaged in the business of transporting natural gas by pipeline and who sells natural gas for ultimate consumption.~~

~~(c) If any pipeline company sells natural gas in violation of rules promulgated by the President under subsection (a), such pipepline company shall be fined not more than $10,000 for each sale made in violation of such rules.~~

SYNTHETIC GAS

SEC. ~~415~~ 414. The Natural Gas Act is amended by redesignating section 24 as section 25, and by inserting after section 23 the following new section:

"COMMISSION JURISDICTION OVER SYNTHETIC

"SEC. 24. (a) (1) Subject to the provisions of paragraph (2), the provisions of this Act shall apply to—

SEE INSERT owned in whole or in part

"(A) any facility ~~constructed or operated~~ by such natural-gas company or an affiliate thereof for the manufacture of pipeline-quality gas for the purposes of transportation in interstate commerce or sale in interstate commerce for resale for ultimate public consumption,

Lines 1-13 Delete.

Explanation: The incremental pricing section has been deleted because of the firm conviction that incremental pricing will be contrary to the best interests of residential and commercial consumers in that it would result in loss of desirable industrial load which would raise residential and commercial rates and, in addition, jeopardize the industry's ability to add supplemental supplies required for the long-term benefit of high priority users.

Line 15 Sec. 415 is renumbered Sec. 414.

Line 21 Insert after "(A)", the following:

"the production by a natural gas company or an affiliate thereof of pipeline quality gas in"

Strike the words "constructed or operated", and insert the words "owned in whole or in part"; strike "a" and insert the word "such"

Explanation: The amendments to this subsection are intended to clarify the scope of the synthetic gas jurisdiction to be vested in the Commission under The Natural Gas Act.

"(B) to such transportation or sale by a natural-gas company or affiliate thereof, and

"(C) to natural-gas companies or their affiliates engaged in such manufacture, transportation, or sale.

"(2) The provisions of this Act shall not apply to the mining, production, transportation, sale, delivery, or any other activity related to the furnishing of hydrocarbon-containing material (other than natural gas) to a natural-gas company or its affiliate for the production of such pipeline-quality gas.

"(b) If, prior to the date of enactment of this section, any natural-gas company was engaged in the manufacture of pipeline-quality gas from hydrocarbon-containing material or transportation or sale for resale of such pipeline-quality gas, subject to the jurisdiction of the Commission, or if a certificate of public convenience and necessity has been issued by the Commission authorizing the transportation or sale for resale of such pipeline-quality gas by a natural-gas company, the Commission shall issue a certificate for such manufacture, transportation, or sale for resale of such pipeline-quality gas without requiring further proof that the public convenience and necessity will be served by such operation, and without further proceedings pursuant to the Natural Gas Act or any other provision of law, if application for a certificate is made to the Commission within 90 days after such date of enact-

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ment. Pending the determination of any such application, the continuance of such operation shall be lawful.

"~~(b)~~ (c) SEE INSERT For purposes of this section, the term 'pipeline-quality gas' shall mean gas the principal ingredient of which is methane and ~~which is interchangeable and com-~~ shall be deemed to be natural gas for the purposes of this Act." ~~patible with natural gas as determined by rule by the Commission.~~".

~~AMENDMENTS TO THE EMERGENCY NATURAL GAS ACT OF 1977~~

Sec. 415 -- SEE PAGE 59

~~SEC. 416. The Emergency Natural Gas Act of 1977~~ is amended—

~~(1) in section 2, by striking out paragraphs (2), (3), and (4) and inserting in lieu thereof the following:~~

~~"(2) The term 'pipeline' means any person engaged in the transportation of natural gas.";~~

~~(2) in section 2, by redesignating paragraphs (5), (6), and (7) as (3), (4), and (5), respectively;~~

~~(3) in section 4(a)(1), by striking out subparagraphs (A) and (B) and inserting in lieu thereof the following:~~

~~"(A) any pipeline to make emergency deliveries of, or to transport, natural gas to any other pipeline or to any local distribution com-~~

Insert after line 2 and before subparagraph (c) a new subparagraph (c) to read as follows:

"(c) The Commission shall have no power to deny, in whole or in part, that portion of the rates and charges made, demanded or received by any natural gas company representing reasonable and prudent costs, including a reasonable rate of return, related to facilities, acts or operations for the production, transportation or sale of pipeline quality gas from hydrocarbon-containing materials authorized by a certificate of public convenience and necessity issued by the Commission pursuant to Section 7(c) of this Act. Any natural gas compay receiving Commission authorization to construct and operate such a plant, or to acquire from an affiliate pipeline quality gas produced from such a plant, may include in its cost of service during the construction period of such plant a reasonable return on funds expended in connection therewith."

Explanation: New subparagraph (c) has been added to assure natural gas companies of the recovery of reasonable and prudent costs related to SNG facilities.

Line 3 — Redesignate "(c)" as "(d)"

Line 5 — Delete the words "which is interchangeable and com —"

Lines 6-7 — Delete and insert after the word "and" on line 5 the words "shall be deemed to be natural gas for the purposes of this Act."
Explanation: This is to make clear that synthetic gas would come under the provisions of The Natural Gas Act.

Line 8 -9 — Delete.

Lines 10-24 — Delete.

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~~pany for purposes of meeting such requirements;~~
~~or";~~

(4) in section 4(a)(1), by redesignating subparagraph (C) thereof as subparagraph (B); SEE INSERT

(5) in section 4(a)(1), by striking out "April 30, 1977" and inserting in lieu thereof "April 30, 1979";

(6) in section 4(a)(2), strike out "interstate" wherever it appears;

(7) in section 4(d), strike out "interstate pipeline, intrastate";

(8) in section 4(f)(2)(A), strike out "by August 1, 1977, to the maximum extent practicable" and insert in lieu thereof "as expeditiously as practicable,";

(9) in section 7, strike out "interstate" wherever it appears; and

~~(10) in section 2(b), after "October 1, 1977,", insert "October 1, 1978, and June 1, 1979,".~~

PART E—PUBLIC UTILITY REGULATORY POLICIES

Subpart 1—General Provisions

FINDING AND PURPOSES

SEC. 501. (a) The Congress hereby finds that the generation, transmission, and sale of electric energy and the transportation and sale of natural gas affect interstate commerce, and that adequate and reliable supplies of electric

Lines 1-18 Delete and insert in lieu thereof a new Section 415 [as renumbered] to read as follows:

"The President may authorize any interstate pipeline to contract with any intrastate pipeline for the purchase or transportation of natural gas upon such terms and conditions, including provisions respecting fair and equitable prices, as the President determines to be appropriate. The sale or transportation of natural gas by any intrastate pipeline under such a contract with an interstate pipeline authorized by the President shall not subject such intrastate pipeline to regulation under the Natural Gas Act or to regulation as a common carrier under any provisions of Federal or State law.

Explanation: In lieu of an extension of The Emergency Natural Gas Act of 1977 for a two-year period, permanent legislation is suggested which would make it possible for intrastate pipelines to sell to and transport natural gas for interstate pipelines upon such terms and conditions as may be prescribed by the President.

Mr. KRUEGER. Thank you very much, Mr. O'Shields.

At this time the committee will recess for about 15 minutes to give us time to respond to the quorum call. We will return and receive at that time the testimony of Mr. Schwartz.

We will then proceed with questioning. We will hope that we don't get too early into the business of our suspension votes. We think that is likely to come later in the afternoon. The committee will at this time recess for 15 minutes.

[Brief recess.]

Mr. KRUEGER. The committee will come to order.

At this time the Chair will recognize Mr. Schwartz for a brief statement. Mr. Schwartz, I would ask you to submit your statement and summarize your testimony if you can do it in the neighborhood of five to seven minutes, something like that. Then we will have the panel prepared to offer questions at that time following your summary.

STATEMENT OF DAVID S. SCHWARTZ

Mr. SCHWARTZ. Mr. Chairman, I did intend to read the statement. It will be very difficult to summarize it in five to seven minutes, but I will endeavor to do so.

Let me first thank the members of the committee for the opportunity to appear here today and to address the administration's energy program specifically as it relates to natural gas regulation or deregulation, depending on your point of view.

My statement essentially can be divided into three parts. There is an introductory section, then there is an effort at analyzing the major provisions of the bill. Lastly, I did examine some specific problems as they relate to pipeline regulation or the lack of meaningful regulation of the interstate pipelines. In my introduction the major points I try to cover include the fact that the bill essentially institutionalizes OPEC prices and uses as a point of departure for new natural gas and for that matter new oil prices produced domestically, the OPEC price.

Now, Mr. Chairman, this essentially can provide the same type of disillusionment which we read about today in the Harris poll as to the consumers' views, as to the business community, as to its pricing practices, as well as its standards with regard to the quality of the goods produced.

I would say that the average consumer, if in fact he did analyze this bill, would realize there is a complete negation of consumer protection in this bill; that in fact the bill, if anything, abandons any consumer protection and turns the entire process of natural gas regulation over to the OPEC cartel. This really is ironical. Given all of the criticisms of OPEC, given all of the misgivings we have had about the OPEC arrangements, the new natural gas price is supposedly to be equal to the Btu-related price. In my mind this in effect is deregulation, because the only meaningful regulation is cost-based regulation. When you start tying prices of a product external to their resource costs and their capital costs, at that point what you are doing in effect is using as a guidepost and as a benchmark not the indigenous cost of bringing the product to the consumer, but some arbitrary basis for using some arbitrary method of obtaining an economic rent and that is exactly what is involved in this bill.

Why don't we at this point tie the price of poultry and pork to the price of beef or vice versa? They all have caloric value. But we at this point, because agriculture is such a competitive industry, you find that each product has to be priced based upon its cost and hopefully to provide some return for the investment to the farmer.

But when it comes to natural gas or oil at this point we go to a physical consideration such as Btu and we want to tie our prices to that physical factor and not based upon the actual resource cost involved in producing the product. This, I say, is totally wrong-headed, number one, and, number two, it completely abandons the consumer and the effort to protect the consumer against exorbitant prices.

The energy program that the administration essentially promulgates is to underpin the status quo. That is, to underpin the existing monopoly structure of our major petroleum companies which many times are referred to as our major energy companies because this is in fact what they are. The extensions by our petroleum companies into other fuels such as uranium and coal and geothermal is well known and the concentration problem in these industries is also well known.

I am saying that what this bill does not do is what should be done to protect the consumer and that is to deal with the market structure issue, to address the problems of horizontal and vertical divestiture, to address the problems of the producer market, and to address the problems of anti-competitive arrangements within the producer industry and within the pipeline industry as well.

Now, I would like to turn to the major provisions of the bill in a very brief form. As I have indicated earlier, the so-called new gas price will follow the OPEC price. As I indicated this in no way provides adequate consumer protection against exorbitant prices.

Secondly, the bill uses a rulemaking mechanism and essentially this undermines due process because there are no adjudicative procedures involved here; there is no substantial evidence requirement involved here, and I say the consumer is badly served by this type of rulemaking.

In addition, it obliterates the entire just and reasonable standard in the Natural Gas Act. That standard has become a bulwark for consumer protection because in fact the courts have insisted that as an anchor you must use a cost-based rate in order to get just and reasonable rates.

Now, this is entirely eliminated from this piece of legislation.

In addition, we find that the definition of new gas, with this 2.5 mile limit with respect to the location of an old well and a thousand foot depth in excess of an old well may redefine old gas into new gas, and this I say is a very serious escape mechanism. In fact, what you could be doing is to drill a well and drain the existing reservoir or you could penetrate a new horizon through an existing reservoir and reclassify that gas as new gas, which I think is totally inequitable.

The bill itself also has a provision with regard to rollover contracts in which it sets the price at $1.45 for contracts that terminate and then are again recommitted. Now, I say that the Federal Power Commission's 52-cent price in Opinion 699 in December 1974, itself,

is too high because the average price under those contracts was approximately 10 cents. The consumer and public interest groups are taking this very provision to court. Here we have the price set at $1.45. Not the 20 cent contract price.

In addition, what this bill will permit is significant quantities of shut-in gas to be repriced as new gas, providing windfall profits to producers and also pipeliners who have producing affiliates.

Section 401(b) of the bill specifically will permit the President to rewrite the entire act by rule which I say is much too arbitrary and provides much too much discretion.

Section 404 involving new gas sales uses the term "first sale" for new gas, and this I say can create many problems because you can get brokered sales which will not be the first sale to a pipeline.

Section 408, which has the so-called special pricing provision which will permit prices above the maximum lawful price—that is in waters beyond 500 feet, even though currently there is drilling in waters above one thousand feet, and onshore above 15,000 feet although there has been drilling over 30,000 feet, will in fact provide again an escape whereby you can even go beyond the maximum price. I say there are enough escapes in this bill to in fact impact negatively on the consumer.

Now, the bill has a couple of good points and I think we should recognize them. I think extending regulation to the intrastate market is critical because, granting all of the problems we have had and the exploitation of the intrastate market, the current investigation as to a possible conspiracy by the Justice Department indicates that in fact the intrastate market is not workably competitive.

But it is a very heavy price to pay to extend regulation to the intrastate market, and therefore set a price somewhere above the $1.75 level which I say this bill will do.

Lastly, with regard to the effort to protect residential consumers by the incremental pricing provision of section 414, I think this also is a good idea. Hopefully it won't be anything more than just a shell because if in fact gas is redefined, old gas in existing reservoirs is drained and redefined as new gas, then this becomes nothing more than a facade and not a reality of protecting residential users.

Lastly, I want to turn my attention to some of the specific problems relating to pipeline regulation. If I may I will summarize these quickly.

Mr. KRUEGER. If you will, please. It has been 10 minutes.

Mr. SCHWARTZ. Thank you, Mr. Chairman, but this is a very complex area.

Mr. KRUEGER. I know.

Mr. SCHWARTZ. Let me just say in essence all major pipeliners are also producers of gas. All the major pipelines. Their efforts to maximize are on both levels, not just as pipelines, but also as producers. We have seen a whole proliferation of abuses involving this effort in terms of diverting gas from the interstate market to the intrastate market. We found that in fact you have had problems associated with the pipelines failing to press the producers in their failure to meet their contractual obligations, and the ever downward revision of reserves by producers and the effort of the pipelines to determine independently whether or not these are down-

ward provisions, or to sue the producers and not to mention the Gulf-Texas Eastern warranty and Texas Eastern's effort to press for deliveries of 625 Mcf a day which the warranty requires. Not only that, but we find the Justice Department is currently looking into the potential conspiracy between Gulf and Texas Eastern.

All I am saying in conclusion, Mr. Chairman, is this: That there are many serious problems that are not addressed by this bill, particularly they go to the question of monopoly structure and market structure, that the consumers are poorly served by this bill and that in fact we cannot look to the pipelines or the producers or the distributors to be the arbiters for consumers' needs. Thank you very much.

[Mr. Schwartz' prepared statement follows:]

STATEMENT OF DAVID S. SCHWARTZ*
MICHIGAN STATE UNIVERSITY

Hearings Before The
Subcommittee on Energy and Power of the
House Interstate and Foreign Commerce Committee

May 17, 1977

Introduction

Mr. Chairman, and members of the Subcommittee, I wish to thank you for the opportunity to appear before you to discuss the Administration's energy program. While I am currently Adjunct Professor of Michigan State University working on the second year of an NSF grant, when I previously resigned my position, after ten years of service at the Federal Power Commission in mid-1975, I was Assistant Chief of the Office of Economics. My immediate research concerns, "The Role of Competition and Regulatory Reform in the Energy Utilities."

Before discussing Part D - Natural Gas, of H. R. 6321, the "National Energy Act," it may be helpful to address some fundamental considerations. One factor of major concern is the pricing provisions of the bill that essentially institutalizes OPEC prices as the "lodestar" for new natural gas prices. For that matter, OPEC pricing becomes the basis for new oil prices as well. This, indeed, is ironical considering all of the inequities and criticisms

* The views and opinions expressed in this statement are entirely personal and are submitted in an individual capacity. Any opinions, findings, results or conclusions are exclusively those of the author and do not necessarily reflect the views of the National Science Foundation. (I am currently on RANN Program Grant Number APR 76-80077).

that have been leveled against the OPEC cartel pricing arrangements. The impact of OPEC prices is clearly demonstrated because the price of new natural gas is to be "equal to the current Btu related price." The net effect of tying new natural gas prices to the OPEC equivalent world oil price is to deregulate wellhead gas prices. In addition, the thrust of the bill is to establish high prices for fuels as national policy. The program accepts the status quo and underpins the existing monopoly control by the major petroleum (energy) companies. There is nothing in the Bill that addresses the problem of the anticompetitive arrangements in the fuels sector, and it completely ignores the need for vertical and horizontal restructuring of the industry if the public is to be assured of increased supplies of fuel at reasonable prices.

The testimony that follows will specifically cover the following areas:

A. The major provisions of the Bill dealing with natural gas, and

B. Some specific problems relating to pipeline regulation, or the lack of meaningful regulation.

A. The Major Provisions of the Bill Dealing With Natural Gas

The insenstitivity to regulatory standards and basic consumer protection manifest in the Bill can be seen in Section 401(a) in the discussion of "Findings and Purposes." For example, in Section 401(a)(3) it provides that "The Congress enacted the Natural Gas Act of 1938 to provide a regulatory structure through which interstate pipelines could be assured a fair rate of return." This is entirely

at odds with the purpose of the Act which was essentially to curb the monopoly power of the pipelines in order to protect consumers from excessive rates, and the Act did not provide assurance of a fair rate of return but an opportunity to earn a fair rate of return. In addition, there is the implication that the Natural Gas Act did not apply to the production function prior to the extension of well-head regulation to producers by the Supreme Court in the Phillips Case. In fact, the term "natural gas companies" in the Act does not just relate to interstate pipelines but covers production operations as well.

In Sections 401(a)(5)(6) there is a discussion concerning the development of natural gas prices and oil prices and the ever widening gap attributed to the continuation of cost-based regulation of natural gas. After citing a fourfold increase in world oil prices in the 1973-1974 period, there is an indication that the failure of natural gas to keep pace with the price of oil has resulted in a decline in proved reserves.

Firstly, the implication that gas prices should follow the path of OPEC oil prices is an essential negation of any possible consumer protection. If anything, the concern should be with bringing down OPEC oil prices and establishing a cost-based determination for oil as well as gas. Secondly, there is a complete failure to recognize that the Federal Power Commission has continually escalated well-head prices and there has been a negative supply response associated with very marked increases in interstate pricing of natural gas.

For example, in July of 1971 the FPC set a new gas rate for Southern Louisiana of 26¢ per Mcf, and the new area rate was increased to 35¢ per Mcf in Permian Basin II in August 1973. In December of 1974 the Commission set the modified national rate at 50¢ per Mcf

(these are on base rates and do not reflect annual escalations or adjustments, Btu value or other factors), and this rate was increased eighteen months later in July 1976 to $1.42 per Mcf. These price increases permitted by the Commission in the last five years for new gas rates represents an increase of prices of approximately 550%.

The commitments of new reserves in the interstate market significantly declined over this period while prices markedly increased. The only logical explanation must relate to supply constraint on the part of producers to bring about legislative deregulation or, as a case in point, the type of administrative deregulation embodied in H. R. 6831.

The implication that these prices have not been adequate incentives for gas exploration and development is not supported by the facts. Gas well drilling activity in 1975 exceeded any previous year since statistics were available from the 1955 period forward. In fact, developmental and exploratory gas footage drilled annually since 1972 was approximately equal to or greater than the drilling activity of the late 1950's and early 1960's which is looked upon as the "heyday" of drilling activity. In 1975, there was 34 million feet of developmental drilling and 8 million feet of exploratory drilling, and this exceeded drilling activity in any previous year.

The modus operandi of the bill is to price new natural gas at the commodity value of substitute fuels, specifically world oil. Therefore in reviewing the various sections of the bill this must be the point of departure for assessing the reasonableness or unreasonableness of the provisions. Taken as a whole, the Bill cannot be conceived of as providing adequate protection for consumers

so as to prevent exorbitant prices and producer exploitation.

While Section 402(a) provides the definitions of the terms used and contains, among other things, definitions of "Btu related price," "new natural gas," "old natural gas," "inflation adjustment," and "surface measurements," (using the 2.5 statute miles as a basis for new gas wells), all of this can be negated because of the provisions in Section 402(b). Of special concern is the provision that defines a new well, on shore, as a completion which is 2.5 miles or more from the location of any old well. This opens up the possibility for gas which is currently being produced in an existing reservoir, and therefore considered old gas, to be drained by a new well from the same reservoir. There is no certainty in this definition that old gas will be priced at the regulated rate, but in fact may be redefined as new gas under this provision.

In Section 402(b) the President has the authority to rewrite the entire Act by rule (undoubtedly this responsibility will be delegated to the Secretary of Energy) and set new rate levels and vintages of gas which he chooses. This Section provides that the authority to redefine by rule "the terms used in this part in a manner consistent with the purpose of this part." In effect, this can abrogate the subsequent pricing and other provisions of the Act, and provides the type of political leverage for the Administration that is reflective of a non-regulatory standard.

As previously discussed, Section 404 deals with the sales of new natural gas, sets the price, by rule, equal to the current Btu related price of world oil. In Section 405 the sales of old natural

or more onshore. The essential question is the amount of gas found relative to the costs incurred. Given the more prolific findings offshore it may very well be that the cost per unit, even though it is in significantly deeper water may be less than more shallow depths.

Now to turn to the positive features of the Bill. Certainly the provision extending regulation to the intrastate market has merit. The unfortunate aspects concern the price levels that are part of the "political trade-off" for including the intrastate market in the bill. The need for protection of intrastate consumers is clearly demonstrated by the recent undertaking of the investigation by the Justice Department of 30 intrastate natural gas producers and pipelines of possible unlawful price fixing.

Finally, Section 414 of the Bill concerning incremental pricing of natural gas appears to be designed to require that higher cost new supplies are to be allocated to low priority commercial and industrial users. The lower priced "old gas" is reserved for the residential and small commercial users. While I support the efforts to protect residential users from the impact of billions of dollars of additional costs associated with the price escalations implicit in the Bill, my major concern is whether the definitions in the Bill will provide significant reclassification of "old gas" to "new gas." This may result in nothing more than the "shell," but not the substance of meaningful consumer protection.

Some of the greatest inequities, which will result in billions of dollars of additional costs to consumers, are reflected in the provisions of Section 406 of the bill. This section permits a contract which expires, and is renewed, to obtain a price of $1.45 per Mcf (plus inflation adjustments) for the volumes under the contract. This is almost three times the 52¢ per Mcf permitted by the Commission in Opinion No. 770-A and is totally without cost justification. A recent study indicates that this will cost consumers approximately $2.3 billion. The truth is that the 52¢ permitted by the Commission is currently under attack by a large group of consumer interests as improper, because the level permitted by the Commission was more than double the price (without cost justification) under existing contracts.

In addition, Section 406(c) permits old gas which has not been dedicated to the interstate market to obtain the new gas current Btu equivalent price. In effect this rewards producers that have withheld gas from the market either in a shut-in status or uncommitted to contracts. It is ironical that producers will garner "windfall profits" for creating shortages and providing the type of dislocations that we faced last winter.

In Section 408 dealing with special pricing provisions no where is there the need for cost justification for any special price in excess of "the maximum lawful price." This completely arbitrary basis for "special prices" will permit prices beyond the maximum in water depths beyond 500 feet or 15,000 feet onshore, and provides the opportunity for significant abuse. Currently drilling takes place in water depths of 1000-1200 feet offshore, and at 30,000 feet

or more onshore. The essential question is the amount of gas found relative to the costs incurred. Given the more prolific findings offshore it may very well be that the cost per unit, even though it is in significantly deeper water may be less than more shallow depths.

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B. Some Specific Problems Relating to Pipeline Regulation, or the Lack of Meaningful Regulation

As I indicated earlier the Administration's Bill fails to deal with the problems of industry structure and the anticompetitive arrangements in the natural gas producer market. Before focusing on the pipelines directly, it is essential to realize that producers were placed under regulation because market forces were inadequate to protect consumers from exhorbitant rates. Certainly the producer market with the institutional arrangements such as joint ventures, bidding combinations, individual and banking interlocks, as well as ownership of intrastate pipelines has resulted in anticompetitive arrangements.

In addition, all major interstate pipelines have producing affiliates, and therefore their efforts to maximize will not be centered in keeping rates down as buyers of gas, but to maximize as producers as well as pipeliners. This is particularly true because the purchase gas adjustment clause (PGA) permits an automatic pass-through of higher wellhead prices into rates. Therefore there is very little incentive to keep purchased gas costs down, particularly when the pipeline benefits from higher prices which will accrue to its producing affiliates. In addition, the recent pattern of backward integration by distributors has eroded the countervailing power by distributors as buyers because now they have become sellers as well.

In introducing S. 1448 on May 4, 1977, Senator Howard M. Metzenbaum recognized the problem of restoring and promoting competition in the natural gas industry. The enactment of his Bill will go

a long way towards injecting some degree of competition by separating the producer function, pipeline function, and distributor function. The Bill seeks to restore arms-length relationships and countervailing power by requiring vertical divestiture and separating the three elements. That is, (1) production, (2) transportation, and (3) local marketing of gas. In addition, major restructuring is necessary within the producer sector, as well, if we are to obtain a workably competitive market.

Curtailments and the Impact on the Interstate Pipelines

All of us are aware of this winter's serious shortage of natural gas and the ensuing dislocations associated with curtailments by interstate pipelines of end-use customers. One would assume that in a period of shrinking sales that profit margins of the firm would be significantly decreased if not bordering on losses. Quite to the contrary, it appears that these pressures that exist in an unregulated industry where the declining sales usually mean a decline in earnings or losses, in the regulated interstate pipeline sector, as evidenced by recent announcements of exceptional earnings, shortages can mean good business.

The protective procedures to prevent the erosion of pipeline earnings by the FPC will be discussed shortly. The results of regulatory protection can be seen by contrasting the rate of return on equity capital of the major pipeline companies, as over against the curtailments of firm requirements. The table that follows shows the rate of return for the major interstate pipeline companies in the the recent past reflects and contains data supplied by the FPC staff to Congressman John E. Moss of the House Oversight and Investigations Subcommittee:

	Curtailments	Major Interstate Natural Gas Pipeline Companies (34)
1970	17,534,756 Mcf	12.5%
1971	286,404,893	14.0
1972	649,430,280	14.2
1973	1,131,233,599	15.0
1974	1,678,691,336	16.2

It is obvious from the above data that curtailments grew (approximately/ one hundred times) from 17.5 billion cubic feet in 1970 to 1.7 trillion cubic feet in 1974. As curtailments deepened the rate of return on equity increased over 33 1/3%.

This pattern of increased and protected earnings has resulted from a distortion in the regulatory process as implemented by the FPC over the past 7-8 years. The FPC has permitted a shift of operating and financial risk of the firm to the consumer by the adoption of unconventional regulatory procedures such as the purchase gas adjustment clauses (PGA), the advance payment programs, and the retention of revenues in excess of "just and reasonable" rates for pipeline investment in exploration and development (in one rate case El Paso Natural Gas was permitted to retain $31 million).

The magnitude of the advance payment program can be measured by the fact that at the time it was terminated in 1975 (because it did not lead to any appreciable increase in interstate commitments of new gas) the FPC had permitted $2.7 billion of advances. In the case of Tennessee Gas Pipe Line Company, $96.5 million of interest free loans were made to its affiliate, Tenneco Oil, under these procedures. These payments are included in the pipeline's rate base and the financing of the interest free loan to Tenneco Oil is borne by the ratepayers.

The Short Fall in the Contractual Delivery of Natural Gas

One of the major problems, that has had inadequate exposure, is the failure of the FPC to investigate significant recent downward revision in reserves made by the producers, which they have then used to justify the reduction of gas deliveries to the interstate pipelines. For that matter, the interstate pipelines themselves have not insisted upon an independent determination of gas reserves, and the potential deliverability from these contracted for and committed reserves.

This problem was highlighted when the Transcontinental Gas Pipe Line Corporation (Transco) applied to the FPC for an interim curtailment plan which was rejected by the Commission. Transco took the Commission to court in order to provide a justification for its curtailment program which differed from the curtailment priorities established by the FPC. The D. C. Circuit Court challenged Transco's claim that the curtailments were due to insufficient reserves and ordered the Commission to investigate on its own Transco's claim with respect to reduced reserves and declining deliverability.

The Court ordered the immediate subpoena of the company's books and records pertaining to all gas supplies. The Court further pointed out that the claim of diminished deliverability was not supported by "substantial evidence" necessary to support a finding of gas unavailability. In addition, the Court made clear that deliverability data alone cannot distinguish between curtailments necessitated by a legitimate gas shortage and curtailments resulting from a pipeline's "own negligence, bad faith, or wrongful conduct." It is interesting to note that in the material submitted by Transco to the FPC in response to the Court's requirement to explain the basis for declining deliverability, that of the annual shortfall of 429.3 billion cubic feet (Bcf) of curtailed volumes in 1974, the failure of pro-

ducers to deliver gas under their contractual obligations amounted to 328.5 Bcf.

The basic issue of deliverability relating to the certification of service was raised by seven Congressmen (including the Chairman of the Interstate and Foreign Commerce Committee - Harley O. Staggers, Chairman of the Subcommittee on Energy and Power - John D. Dingell, Chairman of the Subcommittee on Oversight and Investigations - John E. Moss). In a letter to FPC Chairman Richard L. Dunham dated August 12, 1976, the Congressmen indicated that Section 7 of the Natural Gas Act provides that a certificate authorizing service shall be issued when the applicant is "able and willing to properly ... perform the service proposed, and is or will be required by the present or future public convenience and necessity." They further emphasized that the specific quantity of gas to be delivered by a producer is part of certificated "service." They further criticized the FPC for failing to require that natural gas producers deliver a fixed quantity of natural gas which is the producers' obligation under their "certificated minimum daily delivery obligation."

It is this tie between the certificate to construct facilities on the part of the producer based upon the reserves committed to the pipeline, that is determinative of the pipeline's construction of facilities to provide a certain level of service in its end-use markets. The acceptance by the interstate pipeline and the Commission of the producers' downward revision of committed reserves and the related reduction in deliverability (and the resulting curtailments) without an independent determination of the causal factors of suit to establish their legal rights does not provide adequate protection for the consuming public.

An Example of the Anticompetitive Effects of Pipelines as Producer and Transporter

In order to comprehend the question of deliverability, curtailments, and available gas supply an examination of Tennessee Gas Pipeline and the vertical relationships within the Tenneco, Inc., holding company structure is most illuminating. On March 8, 1977, the FPC instituted an investigation of the diversion of gas from interstate pipeline (Tennessee Gas) to the intrastate affiliate (Channel Industries Gas Company). This situation came to the Commission's attention because Tenneco, Inc., in filing a registration statement with the SEC for a new common stock issue revealed that a number of customers had brought suit for damages because they did not receive specified volumes of gas at the agreed upon contract price.

The Tenneco filing with the SEC reveals that since 1965 approximately 350 Bcf had been diverted from Tennessee Gas (from the interstate market) to Channel Industries for sale in the intrastate market. Recently, Channel has been receiving approximately 30,000 Mcf/day. It would appear that Tennessee was diverting gas to its affiliate Channel, which in turn was making sales at significantly higher prices in the intrastate market. In some instances Channel was reselling the gas back to Tennessee on the basis of an emergency sale at significantly higher prices than the nationwide rate.

For example, on March 1, 1977, Richard Dunham, acting as administrator of the Emergency Natural Gas Act, authorized an emergency sale of 32,000 Mcf per day at $2.25/Mcf from Channel to Tennessee Gas Pipeline. On March 8 when the Commission instituted an investigation of these illegal diversions, Dunham suspended the authorization for this sale.

In an earlier instance involving a diversion of gas (Docket No. CI75-466) the FPC investigated the diversion of gas by Tenneco Oil Company (the producing affiliate). The Commission found that since 1965 Tenneco Oil had been diverting 15,000 Mcf/day to the intrastate market for delivery to Creole Gas Pipeline Company. This was accomplished by Tennessee illegally transporting the gas for its affiliate, Tenneco Oil, for delivery to Creole. In Opinion No. 755 (March 1, 1976) the FPC directed Tenneco Oil Company to repay Tennessee Gas Pipeline 18.6 Bcf which resulted from the "imbalance" of deliveries which should have been made to the interstate market. While the Commission resolved this issue by insisting that the deficiency be corrected, it did not adopt the suggestion of the FPC staff that the matter be referred to the Justice Department.

Another facet of the problem, which will be discussed more fully in the conclusion, concerns the fact that Tenneco, Inc., desiring to maximize profits at all operational levels does not define the role of Tennessee Gas Pipeline strictly in the context of a pipeline purchaser, but tries to maximize on the basis of Tenneco Oil being a major producer. In this regard, the relationship between Tennessee Pipeline and Tenneco Oil is not unlike the dual role of all major pipelines because they all have producing affiliates as well.

The failure on the part of producing affiliates of pipelines to accelerate production to alleviate curtailments and the decline in the deliverability was clearly brought out in the recent so-called "Behind the Pipe" investigation at the FPC of nonproducing gas reserves. The evidence adduced in this proceeding revealed that in the Gulf of Mexico Tenneco Oil controlled 235 reservoirs with 909.7 billion cubic feet of nonproducing reserves that were dedicated to Tennessee Gas Pipeline.

In addition, the recent investigation by the Secretary of Interior (February 1977) indicated that on the East Cameron Block 271 Field, in which Tenneco Oil is the operator, production declined from 15 million Mcf in January 1975 to approximately 8 million Mcf in December 1976. This was in large part, due to the closing down of two platforms and the total removal of ten wells from production for an extended period of time. Not only did Tenneco Oil fail to drill additional wells to increase production from producing reservoirs, but failed to develop and produce from nonproducing reservoirs. In the last quarter of 1976, there were 43 nonproducing reservoirs in East Cameron Block 271 Field which operators' estimates of 90.7 Bcf of proved reserves dedicated to interstate pipelines from which there was no production.

The Other Side of the Coin - Texaco, Inc., as a Producer and Intrastate Pipeliner

On March 17, 1977, the Federal Power Commission ordered an investigation into the diversion of gas from Tiger Shoal and Lighthouse Point Fields in the offshore Gulf of Mexico. The major issue concerns the failure of Texaco to file with the Commission for certificate authority under Section 7 of the Natural Gas Act to construct facilities to transport this gas to its refinery in Port Arthur, Texas. Since 1964 Texaco has been transporting this gas through its wholly owned intrastate pipeline, Sabine Pipeline, from Texaco's Henry Plant in Louisiana to the Port Arthur refinery.

The information provided reveals that 176,000 Mcf per day was transported by Sabine for a cumulative total of 580 Bcf over the entire period. Texaco did not obtain authorization for use of their own gathering lines to transport offshore gas from Tiger Shoal and Lighthouse Point to the Sabine Pipeline, and this may be an illegal

diversion of natural gas from the interstate market. In addition, to the extent that Texaco was using gas at the Port Arthur refinery that was purchased intrastate and substituted interstate gas, they could release this gas for intrastate sale. This diversion of interstate gas obviously resulted in a great hardship for interstate users.

Finally, additional evidence of supply constraint by Texaco was developed in the February 19, 1977, hearings before the House Oversight and Investigations Subcommittee. A study by the Subcommittee staff revealed that 429 Bcf of proved reserves in the Tiger Shoal field, and 107 Bcf in the Lighthouse Point Field were nonproducing and shut-in. The Subcommittee staff witness pointed out that it was "technically feasible" to put this gas on stream quickly because the reserves are located in shallow waters and expensive drilling platforms are not required. The witness testified that "production from these reservoirs should have been on line this winter."

Gulf Oil-Texas Eastern Transmission Possible Conspiracy

On August 13, 1976, an Administrative Law Judge in an initial decision involving a warranty contract between Gulf Oil and Texas Eastern Transmission recommended to the Commission that the possible conspiracy between Gulf Oil and Texas Eastern be referred to the Department of Justice for thorough investigation. The Administrative Law Judge placed the problem in the following context:

> "When viewed in its totality, Texas Eastern's inaction here concerning Gulf seems not only inappropriate, but it smacks of a conspiracy between the two of them to withhold gas from the interstate market until the price has been driven up in violation of federal antitrust laws. For these reasons, the Presiding Judge strongly

> "recommends that the Commission transmit relevant evidence in this case to the U. S. Department of Justice pursuant to Section 20(a) of the Natural Gas Act, urging that a thorough investigation be made and that appropriate criminal action be taken."

The Assistant Attorney General of the Antitrust Division, Donald I. Baker, indicated recently that he is reviewing the evidentary materials for prosecution in the Gulf Oil-Texas Eastern case for the possibility of an antitrust conspiracy between the companies to withhold gas from the interstate market.

Conclusion

It is apparent from the analysis above that the consumer interests are not adequately protected by the Administration's energy program. This is true with respect to protection from unreasonable prices, as well as, providing greater certainty as to adequate supplies of natural gas. It is obvious that the industry interests are well served because natural gas prices are geared to OPEC oil prices. In addition, the Bill provides broad latitude in a definitional sense, as well as, unlimited discretion on the part of the Secretary or Administrator so as to create great uncertainty as to the specific terms and conditions in the Bill. For example, there is the possibility of redefining "old" gas as "new" gas and the open-ended possibility of using the special pricing provisions to exceed maximum allowable Btu equivalent prices, and provides too much discretion for the President or his designate.

The need to redress the current inequities are ignored in the Administration's energy program. There is nothing in the Bill addressing the anticompetitive market constraints and the abuses concerning the failure by producers to deliver contractual obligations of natural gas, to deal with illegal diversions of gas, or requiring production from committed or uncommitted shut-in reserves. There is no doubt

that the major interstate pipelines (as well as distributors with producing affiliates) will benefit from the pricing provisions because all of them have producing affiliates or divisions. In addition, the protective regulatory procedures will continue to protect the interstate pipelines from any erosion of earnings levels.

Mr. KRUEGER. At this time the Chair will begin the process of recognizing members for questioning.

I shall begin in the sequence in which the members have been present for the hearings and therefore will begin with the gentleman from Louisiana, Mr. Moore, for five minutes.

Mr. MOORE. Mr. O'Shields, I would like to direct a question toward you. Currently, of course, we know we have an imbalance in new gas; it is going to the intrastate market opposed to the interstate market.

We have heard testimony from producers, from Governors and indeed this morning even from the Chairman of the Federal Power Commission, that this imbalance may well continue under the President's bill wherein all you have done is put a ceiling on both prices but have done nothing to deregulate the interstate market.

Producers will continue to deal with their friends in the intrastate market. Do you see that as a problem in this bill as well?

Mr. O'SHIELDS. I see it as a potential problem and that was one of the reasons we recommended very strongly that if price ceilings are enacted that there be a specific provision which would exempt producer sales of new natural gas from regulation under the Natural Gas Act.

Mr. MOORE. That is your reason for making that recommendation, so they won't have this fear of coming under FPC regulation?

Mr. O'SHIELDS. It is not only fear of regulation, it is just that the red tape and procedures involved under any type of regulation—if you can do your business in the same vein and not have it, you're going to do it. Not fool with it.

Mr. MOORE. Would it be fair to say that you are serving interstate consumers, residential users too?

Mr. O'SHIELDS. Right.

Mr. MOORE. Would it be fair to say that the best way for you to get increasing supplies of natural gas into your pipelines and to those consumers would be a deregulation of both markets?

Mr. O'SHIELDS. That is correct. That is the reason we recommend deregulation of new gas. We are interested in re-establishing a competitive position of securing supplies for our consumers.

Mr. MOORE. I know you probably don't have this information at hand, but we would like for you to get it and submit it to the committee if you could. A percentage of your customers, as to what percentage are residential, what percentage are industrial, what percentage are business, and basically break that down by use, whether boiler fuels, whether strictly comfort heating, whether it is

used for feed stock and what-have-you, so we can have that to study. I would liek to get that from each company represented here if you could forward that to us so we have some idea of who are your users.

As a second part of that, I would like for you to give us an idea of what has been a trend of change if there has been any over the last ten to fifteen years. Are you having residential users drop out and go to coal? Are you having them drop off and go to nuclear energy? We would like to see what kind of trends are developing.

Mr. KRUEGER. Would the gentleman yield?

Mr. MOORE. I would be glad to yield.

Mr. KRUEGER. I wonder whether something like those percentages might already be on hand?

I wonder whether the panel might know, for example—Mr. O'Shields, for Panhandle Eastern might know the percentage of industrial.

Mr. O'SHIELDS. I can't give as extensive a breakdown as you refer to. Our residential use on a year-round basis on our pipeline is about 47 percent of total sales. Our sales in the FPC categories 1 and 2, which is residential, small commercial, the very high priority industrial uses such as feedstocks and that sort of thing, the two highest priorities, account for 75 percent of our sales on a year-round basis, leaving 25 percent in the categories 3 and 4. We serve nobody in lower categories. Perhaps others can respond for their companies.

Mr. BOWEN. With regard to Transcontinental Gas Pipe Line, I would say we are about 99 percent priority one and priority two. Possibly there is some very small percentage, probably less than one percent that would be priority three and higher.

As far as the breakdown between the priority one, which is residential-small commercial, I would say we are about 80 percent, or 79 percent would be involved in priority one and the balance the very high priority, firm industrial markets for process, plant protection and feedstock.

Mr. PETTY. The El Paso Pipeline in 1972 served approximately 60 percent of its load to industrial market. That has declined to the present time to approximately 20 percent. We expect that within two years we will have zero industrial load below priority two.

Mr. HEAD. I would say for Texas Eastern historically before the gas shortage, during the winter we had about a 75 percent residential and 25 percent industrial load. Nowadays I would say that in the wintertime we have at least 90 percent of our load in priorities one and two. In the summertime, of course, our industrial load does increase to some extent, but I have no knowledge, for example, of any boiler fuel load being served on Texas Eastern's system.

Mr. MOORE. The second part of my question may obviate the necessity for any information being furnished. Mr. Petty gave an indication of the change in trend. Over the last 6 years, let's say, have you had any change in these figures you have given me?

Has residential gone up dramatically or industrial up and down? Tell us what the trend is.

Mr. HEAD. Certainly the trend on Texas Eastern's system has been that the industrial load has been going down. There has been

some increase in residential load, but no dramatic increase because of the restrictions some of the States impose upon the distribution companies prohibiting their increasing the residential load.

Mr. O'SHIELDS. That is certainly true for Panhandle Eastern Pipeline Company and its subsidiary trunkline gas company.

In the last five years our total available gas supply for interstate customers has dropped about 23 percent. All of that has had to come off of the industrial load to our system so the industrial load as a percentage has gone down and the residential, small commercial, high priority feedstocks, has gone up.

Mr. BOWEN. I would say for Transco during the last five or six years when we have been unable to compete for any new gas onshore, deliveries to customers have dropped about 40 percent and all of that has come off of the industrial market.

The residential market is still pretty much what it has been for the last two or three years. There has been very little growth because there have been restrictions in the market area but the industrial market is now right down to just a portion of priority two.

Mr. MOORE. Let me ask you this question: The cut has been generally from each of your testimonies in the industrial market. Has that been in the priority three boiler fuel primarily or feedstocks or what—priority four, rather?

Mr. BOWEN. No, it has been in the categories for boiler fuel and of recent date, the last two years, we have had to curtail high priority, priority 2, which is feedstock, and plant protection and that sort of thing, where there is no alternate fuel capability. That is speaking for Transco only.

Mr. MOORE. Could the other three gentlemen tell me where your curtailments have been in the industrial area? What are they cutting out?

Mr. PETTY. The largest part of our industrial load prior to the time of curtailment was boiler fuel primarily for electric generation. That accounted in the early 1970s for almost 50 percent of our load. That has been the first to come off.

The curtailments that have been experienced have reached into and through priority 3. We have not curtailed any priority 2, but generally speaking we serve for the most part now in addition to priorities 1 and 2, and priority 3 for a substantial portion of the year, and on occasions deliver even into priorities 4 and , but as I mentioned earlier, we expect that within 2 years everything through priority 3 will be off in order to protect priorities 1 and 2.

Mr. MOORE. Mr. Chairman, I believe that Mr. Head is the last witness yet to answer this last part of the question, if he may be permitted.

Mr. KRUEGER. All right.

Mr. HEAD. During this past winter, Texas Eastern on one or two occasions for a few days curtailed into priority 1 slightly. We were not out of priority 2 during the winter. I would say that today we are serving at least through priority 3, perhaps into 4.

Mr. KRUEGER. The Chair now recognizes Mr. Stockman for 5 minutes of questions.

Mr. STOCKMAN. Mr. O'Shields, I would like to go back to your chart because I think you correctly pointed out that the arbitrary 2-

1/2 mile perimeter definition is going to have a strong disincentive effect on drilling of new deposits or reservoirs which would be within that perimeter, but I would ask you another question.

Wouldn't there be a corollary to that, and, that is, that it would lead to considerable suboptimum drilling from a geological or recovery point of view, in the case of those totally new reservoirs which are right on the edge of the perimeter, and part of which may be in and part of which may be out?

Let me give you a hypothetical case. Say, you had an old well at 52 cents, and on the edge of the 2.5-mile perimeter you had a totally new gas sediment that contained different geological characteristics and so forth and therefore met the definitions of the bill, one third of which was outside the perimeter, two thirds of which was inside. It seems to me there is going to be a great incentive for the producer, since his differential is going to be 52 cents versus $1.79, to drill at a point and get his completion location at a point which may be terribly suboptimal from a geological or recovery point of view but it will be in the $1.79 pricing zone. In other words, he will drill in the one third that is outside, and that may mean from the point of view of society we are going to recover less gas, and there is not going to be the in-fill and drilling you need to recover that deposit or sediment completely, so isn't this another good reason why the 2.5-mile definition is totally arbitrary, not only the disincentive effect but incentives for suboptimal drilling?

Mr. O'SHIELDS. You could have the result you describe under those conditions. The occurrence of oil and gas just does not follow property lines or horizontal division lines, and there is just no standard of that type that you could establish. While it would be easy to understand and theoretically easy to administer, which would correspond with the geologic facts of life, it can't be done.

Mr. STOCKMAN. One other question that I wanted to go to was one argument we have heard against instant deregulation, in other words, an argument for a kind of ceiling that would phase out controls over a short period of time. Given the current rolled in price structure that you have, and if we don't adopt all the incremental pricing provisions of the bill, there would be a strong incentive for interstate pipelines and for utilities and for other users to go into the new gas market, and at least for a short period of time while your supply was still primarily old or vintage gas, to bid up very rapidly the price of new gas because the costs of that could be rolled into your final price. You wouldn't have the demand response on the user end that you would normally have if they were paying the full new costs that you were paying.

Is that a worry? Is that something that we need to be concerned with? Is it very likely?

Mr. O'SHIELDS. It seems to be mainly a concern of the theoretical policymakers. It is a concern about letting the free market work its will, and as somebody said in the earlier hearing, oil and gas are the only two commodities in the United States subject to price ceilings. As long as price ceilings exist, there are going to continue to be problems in supply and demand.

Mr. STOCKMAN. I don't think you have really answered the question though. I agree with you in some abstract sense we start

from scratch but the point is most of the gas we would have in 1978, 1979, 1980 if we adopt the regulation is going to be vintage gas and your rolled in cost or price of that is going to be very low relative to a new field price under your deregulation proposal. Because you are laboring under the burden of previous regulatory policies and interventions in the market, it seems to me that those increments of new gas you buy in the first few years would permit you to bid or to pay prices for new gas which woud be totally out of line with what you would pay in a pure free market situation where the price would be immediately passed to the user in its full volume.

Do you see what I am saying?

Mr. O'SHIELDS. Yes, I understand what you are saying, and it is very difficult to speculate on what actually would occur. I think the competitive market would settle down right away. There might be some temporary aberrations if you had immediate deregulation, but as a percent of the total amount of gas supply involved, and the total impact on the entire system, I wouldn't expect even temporary aberrations to have much impact.

Mr. STOCKMAN. Thank you.

Mr. KRUEGER. The time of the gentleman has expired.

The Chair recognizes the gentleman from Texas, Mr. Gammage, for 5 minutes.

Mr. GAMMAGE. Mr. O'Shields, I would like to get not just your response but responses from the panel generally on one question that has not been raised this morning but has been raised in previous hearings. In his statement given the first day of this subcommittee's hearings, and in the President's proposed plan, Dr. Schlesinger pointed out that the distinction between the interstate market and the intrastate market would be erased for a number of purposes, for all purposes, not only for pricing whether we have a local market situation or an interstate control situation. It would all come under the umbrella of control as far as pricing is concerned.

Also in one area that distressed me in particular, and to recount a little history, and I am sure you are all familiar with this, during the debate on the emergency natural gas bill that was passed very early in this session of Congress, there was a new definition of interstate natural gas included in that bill, language that had not been debated or adopted in either the House or the Senate was included in the conference committee report in the new definition of interstate natural gas to include intrastate gas which had previously not fallen within that definition in terms of what in the trade we call inshore gas, that gas that is produced and consumed within the borders of a particular State but travel through an interstate pipeline.

I think it is no secret to anyone who is familiar with the industry that the producing States in particular have a much higher dependency on the local produce than industries in the balance of the Nation is concerned. Many of them use alternate fuels, fuel oil, coal, and what-have-you, but that in Texas, for instance, some as high as 94 percent of the natural gas that is consumed is industrial gas to support the local industry either for boiler fuels, feedstocks or what-have-you, and I think that particular State has about 43 to

46 percent of the petrochemical industry in the country, and if you add in Louisiana and Oklahoma, you have over two thirds of the petrochemical industry in the country. This allocation authority over intrastate gas that was included on an emergency basis in the emergency natural gas bill would be much expanded, broadened and extended under the President's plan.

I have received a lot of vibrations from my area to the effect that people in the community are afraid of having their basic necessities as far as their industrial supplies, not just their residential supplies, but as far as the lifeblood of their industry is concerned being pirated away from them at the discretion, not just under emergency situations but at the discretion of someone in the executive department whom no one can put a finger on at this time because no one seems to have any coordinating authority over anything so far in the executive department, the executive branch, as far as energy questions are concerned and related questions, whether they deal with the environment or other factors.

I would like to get a response from the panel members generally on their attitude towards that particular new and expanded authority.

Mr. O'SHIELDS. In our prepared statement we are on record as opposing the provisions of the bill which would extend that mandatory allocation authority, and which would expand it to intrastate use. We are very definitely opposed to that. It is not needed.

What is needed is adequate incentives for developing new gas supplies, and the interstate consumer should have an equal opportunity to secure those supplies with anybody else. We are not asking for anybody to have the right to take gas away from an intrastate user to give it to an interstate user, we in the interstate pipeline business aren't, because spreading misery in the shortage is not a solution.

Mr. GAMMAGE. I think that is probably particularly true when you consider the petrochemical complex that more or less feeds the Nation, that has a greater dependency on that.

Mr. HEAD. I would just like to add one thing to what Mr. O'Shields said. We do, as he said, advocate elimination of the provisions of the bill giving the President or the Federal Power Commission authority to allocate intrastate gas.

We also say, however, that a provision should be added which will give intrastate pipelines the right to sell gas to interstate pipelines, and to transport gas for them free of Commission jurisdiction, under such terms and provisions as the President may prescribe. We appreciate all of the efforts that the intrastate pipelines made during the past winter to help out the interstate consumers. We think they should be free to do that on a voluntary basis in the future.

Mr. GAMMAGE. Thank you, sir.

Mr. BOWEN. I might say that we feel the experiences that we all had last winter would clearly indicate that the industry itself had a capability to reallocate and transfer gas from one end of the common to the other and this tremendous flexibility in the pipeline system, I think, would preclude the need for a mandatory allocation, but we do need the ability to continue to buy from the

intrastate market supplies of emergency gas that may be available for the balance of this year, and certainly next winter.

Mr. KRUEGER. The time of the gentleman from Texas has expired.

The Chair now recognizes the gentleman from Tennessee, Mr. Gore, for 5 minutes.

Mr. GORE. Thank you, Mr. Chairman.

Mr. O'Shields, is this statement of yours merely self-serving, or do you really believe that there is a free market for energy?

Mr. O'SHIELDS. There is certainly a competitive market for energy, and in light of the real world that we live in, we believe our recommendations are the best solution that this country can pursue at this point in time.

Mr. GORE. Do you think there is a free market for oil?

Mr. O'SHIELDS. What is your definition of a "free market"?

Mr. GORE. What is yours? This statement assumes that we have a free market in energy. Yet you propose letting it flow to the price of oil that is set by OPEC. That is not a free market, is it? Is that your definition of a free market?

Mr. O'SHIELDS. Whether it is a free market in the mind of any individual or not, it is the real world that we live in.

Mr. GORE. That is what I am talking about too.

Mr. O'SHIELDS. What we are recommending is a realistic ability to have commodities priced on a commodity value basis.

Mr. GORE. So you don't really believe that we have a free market for energy in the classic definition. You believe that we have what you now describe as the real world. That is what I am talking about too, the real world. We don't have a free market for energy. Do you believe we have a free market?

Mr. O'SHIELDS. If we don't, do you know of some way to secure it?

Mr. GORE. Well, certainly this is no way to secure it. You all just want to be plugged into the OPEC cartel, so when they push through another price increase, you all get the benefits too.

Now let's examine it for a minute, just in terms of natural gas. I am going to put you in the position, if you will, of a consumer of natural gas in my hometown, and I think this hypothetical consumer is probably representative of most of the natural gas consumers in this country. He gets a natural gas bill for the month of May, and he believes it is too high. Okay, he is in a free market for natural gas, according to you.

Now what does he do? Does he go out and try to get natural gas from another supplier? How does he exercise his option in the free market? Can he go out and buy it from another supplier?

Mr. O'SHIELDS. He is subject to acquiring it from the utility that has the franchise.

Mr. GORE. There isn't another supplier, right? You have got a monopoly. It is by nature a monopoly. You might as well propose deregulating the telephone company.

Mr. O'SHIELDS. We have a monopoly as far as the transportation and the distribution of natural gases, but there is no monopoly on the supply.

Mr. GORE. Which is 80 percent of the cost of natural gas, and the producer is insulated by this 80 percent monolith from any effective way of manipulating the market at the other end by his consuming

responses. There is a captive market, and when these new deposits that you talk about here on your charts are explored, you have consortiums of seven, eight, or nine companies.

What is competitive about that? I just think that this is——really as I sat here and listened to it, and I don't mean to sound disrespectful because I appreciate your testimony and you giving us the benefit of your views, but I quite candidly do find it more self-serving than many of the statements that we get here, because it just assumes a fairy tale world. We don't have a free market for energy at all. The price of uranium is set by a cartel that meets behind closed doors and fixes the price of uranium. The price of oil is set by the OPEC cartel. They fix the price of oil, and you want to peg everything to a Btu equivalency so that you all just become in effect part of the cartel. I don't mean that to have any overtones of violating any laws. I don't mean it that way, but you would reap the benefits of the cartel price when the cartel price went up, isn't that right? Isn't that really what you are proposing?

Mr. O'SHIELDS. No. What we are proposing is a system that we believe will generate the maximum amount.

Mr. GORE. Of what?

Mr. O'SHIELDS. Of domestic supplies, and you are not going to do anything about OPEC if we don't have domestic supplies, and by domestic supplies I am talking about oil, gas, coal, uranium, any supply of energy.

Mr. GORE. Didn't the pipelines use to come up here and argue in favor of regulation?

Mr. O'SHIELDS. Not the pipelines. Some of the distributors did, but the interstate pipelines, the majority of them ever since the *Phillips* decision, has been recommending deregulation.

Mr. GORE. I want to touch one other point before my time is up, Mr. Chairman. You explain again about the definition of new gas, and you say that the historical evidence shows that most of it is going to be discovered within this 2.5-mile radius, right?

Mr. O'SHIELDS. No, I didn't say that. I said that was among some of the best places to look for it.

Mr. GORE. All right, I'll quote exactly.

"History has shown that established productive areas of hydrocarbons in sedimentary basis are among the best places to look for new hydrocarbons."

If we know that that is where the new deposits are going to be found, if the historical evidence shows us that that is the most probable place to look, that that is where it is going to be found, and if present prices, and clearly they do, present prices include an enormous incentive to recover that natural resource, why do we need an additional encouragement on top of that, if you know it is there and the present price is high? How much encouragement do we need?

Mr. KRUEGER. The time of the gentleman has expired.

The panel may respond to the question, but his 7 minutes are up.

Mr. O'SHIELDS. Mr. Congressman, we were just pointing out that the definition proposed in the act has no relationship to the geologic facts of life. If you are going to have this type of legislation on new gas, then we think there should be a definition that would permit

any newly discovered reservoir to be treated as new gas whether it is inside or outside 2.5 miles.

Mr. KRUEGER. The time of the gentleman has expired.

The Chair now recognizes the gentleman from Texas, Mr. Collins, for 5 minutes.

Mr. COLLINS. Thank you, Mr. Chairman.

Dr. Schwartz, this morning while we were talking, we talked about the fact that the only commodity, the only raw material, the only fixed product in this country that is subject to price control is oil and gas. You are an economist and served on the Federal Power Commission for 10 years.

Have you known of any price control system that worked in peace times?

Mr. SCHWARTZ. Any price control system that worked in peacetime?

Mr. COLLINS. That is what we have. We have a price control system. Have you known of one that has worked in peacetimes?

Mr. SCHWARTZ. Yes, I do.

Mr. COLLINS. Which one?

Mr. SCHWARTZ. I think regulation of the natural gas wellhead prices up until about 1969-1970 worked very well.

Mr. COLLINS. What happened then?

Mr. SCHWARTZ. At that point the producers started constraining in terms of new additions, and what happened is that exploration dropped off and developmental drilling dropped off. The majors went to the North Sea. The majors went to Alaska, and the majors at that point stopped drilling in terms of new exploration and development, and we had a very marked decline in new additions of reserves, but up until that point, there was gas overhanging the market. There was too much gas, and the pipelines were going out trying to at that point saying we don't want long-term contracts. We would rather pick up spot gas and the producers were trying to talk them into long-term contracts so here we had a peaceful period and very effective regulation and adequate supplies until we got monopoly constraints.

Mr. COLLINS. Dr. Schwartz, taking oil, which was actively traded more than gas on an international basis they paid $5.25 for old oil, and at the same time the world price went on up to $14. It seems that moves of them, as you said, went to the North Sea or where they could be paid the price. They were in the free open market.

Now let's take gas. You mentioned gas. LNG today is coming in this country anywhere from $2 to $3.67.

Now why shouldn't they pay the same price? There isn't any constraint or cartel.

Mr. SCHWARTZ. Because a great deal of that cost is associated with liquefaction of that gas, with transportation of that gas, with regasification at the terminal, and these costs have nothing to do with the production, exploration and development and finding costs associated with gas. It is a totally irrelevant analogy.

Mr. COLLINS. They are paying them as little as they can. They were paying them $1 and now to get it they have to pay $2.10 to $3.67.

Mr. SCHWARTZ. That is what the firm is paying. I say regulation to be effective in terms of protecting the consumer interests and in a workably competitive market you would get costs of bringing that product forward to market, the production costs of bringing that product to market, and I am saying with an OPEC relationship and the same OPEC countries, Algeria is one of the biggest suppliers of LNG, these people are setting prices not based upon costs but they are setting prices based upon the type of market leverage that a monopolist can obtain. Certainly the end purchaser, the pipeline at that point is faced with a $3 cost for LNG.

Does that have anything to do with the cost of finding and developing the product? The answer is no.

Mr. COLLINS. Dr. Schwartz, there are ways of making gas. You can make it synthetically. We were told you can make it for $5 to $6. You can make it.

Now if they want to they can go out and make it, so it looks to me if they sell below what you can do artificially that they are below the natural price in the market.

Mr. SCHWARTZ. As long as you look at prices and make your comparison on that level you can pick any price you want and you will get the analogy you want. I say if you want to protect the consumer the only way you can, and to prevent the monopoly exploitation that comes in this energy market is to go with cost based rates to get a market that is workably competitive, because then in fact the price of the product will reflect its cost, and it is only in a monopoly market that you can talk about prices and not talk about costs as a predicate for what has to be paid.

Mr. COLLINS. This isn't a monopoly market. You have got coal, you have got nuclear, you have got solar, you have got all kinds of energies. Where do you get the word "monopoly"?

Mr. SCHWARTZ. Because your major petroleum companies control all those sources. I would like to refer you to hearings before Senator Abourezk on S. 489, which occurred in the summer of 1975. That was a bill to, in effect, provide horizontal divestiture, and try to get Exxon, Mobil, Arco, and Texaco and all your majors out of coal and out of uranium to get into fuel competition.

Sure, there are fuels, and alternative fuels, and your major petroleum companies control the great bulk of them.

Mr. COLLINS. Let me tell you last year and I am sure you have checked the case—I just want to tell one thing, Mr. Chairman—the 10 major oil companies last year invested 180 percent of their net profits into exploration, drilling and capital expenditures. That doesn't look to me like there is any withholding on the part of these big companies.

Mr. SCHWARTZ. You were talking about capital as opposed to a resource. They are two different considerations.

Mr. KRUEGER. The time of the gentleman has expired.

The Chair now recognizes himself for 5 minutes.

We have had some discussion earlier of free market pricing. I perhaps have not looked well enough through your testimony, Mr. O'Shields, but I am not sure you ever used the word free market and if you didn't use it, I am not sure you need to be held responsible for someone else's definition of it, but I think it is important first of all to get our proper terms in order.

Now you are as a pipeline, a regulated industry, and it is my understanding that you receive your return under Federal regulations by being granted a specific amount for the amortization of your pipeline and overall transportation costs; is that correct?

Mr. O'SHIELDS. That is correct.

Mr. KRUEGER. Now if that is correct, then you have never been, as a pipeline, you have never been as such in what anyone choses to decline free markets in it because you are by definition a regulated public utility; is that correct?

Mr. O'SHIELDS. We are regulated as a public utility. We are not a utility in the pure sense of the word.

Mr. KRUEGER. I would like to turn particularly if I could to the pipeline which I believe has been most curtailed, and that is Transco and ask Mr. Bowen, am I correct that the amount of gas that you have been able to deliver in recent years has dropped so that your pipeline is at about 55 percent of capacity? Is that correct?

Mr. BOWEN. Including gas that we transport for others, we are at about 60 percent of our certificating capacity.

Mr. KRUEGER. You are at about 60 percent of your certificated capacity. We were earlier told by the Chairman of the FPC that on average of that amount paid by a consumer served by interstate pipeline, about 20 percent went to the producer and about 80 percent went to the distribution and transportation systems. If your capacity to deliver has declined to about 60 percent, does that mean that since your amortization costs have remained the same that it is requiring you to charge more for each unit of gas that passes through because your pipeline has not been full? Would that be a correct inference?

Mr. BOWEN. That is right. The load factor has dropped from about 99 percent down to about 60 percent, so the average cost of transporting an Mcf of gas from, say, Texas to New York City has more than doubled, a little more than doubled, and this is due to the fact that we don't have as much gas to spread our fixed cost and our return over it as we did before.

Mr. KRUEGER. So if the cost—let me make sure this is clear—if the cost has just about doubled to a New York consumer for the gas actually delivered, the major portion of that increase in cost to the consumer has come not as a result of any increased price paid to the producer, bur rather because the pipeline itself has not been able to secure sufficient supplies, is that correct?

Mr. BOWEN. When I talked about prices doubling, I was just talking about the transportation charge. When we sell gas in New York City it is made up of two things, really, the cost of gas plus the cost of transporting gas to the city gate in New York City.

The cost of gas has gone up considerably, too. It is averaging about 64 cents per Mcf as of today.

Mr. KRUEGER. Your purchase cost is now about 64 cents an Mcf.

Mr. BOWEN. About 64 cents, that is the average cost of gas I think last month. But on top of that we have about a 62-cent charge for hauling the gas up there. So the total city gate charge might be $1.26 at New York City. Now that was 35 cents seven or eight years ago. So it has gone up both in the cost of the gas and the transporta-

tion of gas. We make no money out of the gas, we get back exactly what we pay for the gas. The only money we make is the return on our original pipeline costs less depreciation.

Mr. KRUEGER. So the reason that the transportation cost has increased so much is in part because there is less gas flowing through?

Mr. Bowen. That has been by far the big reason because we have not been able to buy gas. So our gas supplies have dropped off, the cost of transporting the gas that we do have remaining has gone up.

Mr. KRUEGER. If the city gate cost is then about $1.26 and the consumer is paying about $3, that means that the remaining $1.70 to $1.80 is the cost imposed by the distribution system for the amortization of its distribution system and its attendant costs; is that right?

Mr. Bowen. That is right, and it is a regulated rate by the New York Public Service Commission. That cost has gone up too, because their load factor has dropped down about the same as ours.

Mr. KRUEGER. Thank you.

I see that my five minutes has expired, or it will in five seconds. I shall at this time return to other members of the subcommittee for three minutes of questioning, and it will be strictly enforced, three minutes, and then at the end of that we will have a brief break before the next panel convenes.

I am sorry. Counsel also has some questions. I shall first recognize members in order of their appearance for three minutes total.

The gentleman from Florida, Mr. Moore.

Mr. MOORE. Thank you.

Mr. Schwartz, earlier in your testimony you mentioned that the interstate pipelines had a control on the production of gas; did I understand you right?

Mr. SCHWARTZ. No, I do not believe I said that. I said that all of the major interstate pipelines have producing affiliates.

Mr. MOORE. What percent of the gas do they produce, total gas produced in this country?

Mr. SCHWARTZ. I will give you that percentage, but I would like to elaborate on the question.

Mr. MOORE. I have three minutes. I want the answer.

Mr. SCHWARTZ. I would say somewhere between 8 and 10 percent, but that is not significant. There is a question of whether or not they identify their interests as the way the producers identify their interests, and that is with high wellhead prices.

Mr. MOORE. Well, the point I am trying to make is, you constantly refer to a monopoly going on.

Mr. SCHWARTZ. That is correct.

Mr. MOORE. If there was a monopoly in restraint of trade, would that not be vested and be proven?

Mr. SCHWARTZ. The fact that the interstate pipelines have production? They had that before you had producer regulation.

Mr. MOORE. You say monopoly, what monopoly? Tell us about it.

Mr. SCHWARTZ. I will be glad to.

Looking at the producer market, you have specific institutional arrangements that result in concentration with regard to new sales.

Secondly, with regard to joint ventures among the producers, so that in fact instead of the producers competing with one another, through a joint venture they assign an operator on those leases and that operator may market the gas for all of the producers rather than market them as individual streams.

Mr. MOORE. That is monopoly.

Mr. SCHWARTZ. Hold it, I have not finished: I would like to elaborate.

Mr. MOORE. I have three minutes, I am sorry.

Mr. SCHWARTZ. The problem is that complex. If you want a full answer I have to give you——

Mr. KRUEGER. I would just like to have a certain degree of civility going on. I would observe there are 1 minute 20 seconds left. Now one or another of you may proceed.

Mr. MOORE. Mr. Schwartz——

Mr. SCHWARTZ. I have not finished my answer.

Mr. MOORE. You finish your answer.

You know there are thousands of natural gas producers. You tell us they are all acting in concert with one another?

Mr. SCHWARTZ. No, I am not telling you that. I am telling you that the institutional arrangements are such, relative to the farm-outs to the operators and small producers, that in fact they will buy out these small producers if they hit or give them a very small working interest. I am saying that the nature of the communal ties and the institutional arangements among all these producers through joint ventures, bidding combinations, interlocking directors, and all these specifics in fact coalesce the interests of all these producers in what I call a shared monopoly.

Now that in fact is what you have in this industry.

Mr. MOORE. They agree on a price, they fix a price to the detriment of the consumer?

Mr. SCHWARTZ. The price is regulated by the Federal Power Commission.

Mr. MOORE. Now in the intrastate market it is not.

Mr. SCHWARTZ. Of course the Justice Department is looking at some of the problems of price-fixing right now and we will see what that shows up. But just because there has not been these investigations at that point reveals we do not have enough information.

Mr. MOORE. I agree.

What you are telling me is a little bit out of context.

Mr. KRUEGER. The time of the gentleman has expired. The Chair recognizes the gentleman from Michigan for three minutes.

Mr. STOCKMAN. I hesitate to proceed on a question regarding your testimony, because I think we have a totally different framework. I do not think we will get too far because we are not communicating.

Let me take a totally different angle. We have had testimony along the following lines, that most of the natural gas that we have historically produced in this country has come from two sources, number one, associated gas, in other words, joint gas-oil wells, and because the price of gas has been so much below the equivalent price of oil, even pre-OPEC, basically that was a free product because the economic calculations made by the companies involved in exploration and development largely turned on their prospects for finding oil and not gas.

The other part of it has come from shallow non-associated deposits. We found those easy ones, we produced most of these easy ones and there is not much left. But the testimony we had two days ago was that the third source of natural gas in this country is really the largest in terms of magnitude relative to geologic deposits we have, and that is deep gas sediments that range anywhere from 15,000 to 30,000 feet below the ground.

The estimate we have is that there is likely somewhere between 600 and 800 trillion cubic feet of gas lodged in these deep sediments, and one example that was given to us was the Anadarko field, where the previous surveys, U.S. Geological Survey and so forth, showed there was 15 to 30 trillion cubic feet estimated, but if you go to the deep gas, it could be as high as 60, certainly they said it was a probability, and probably as high as 200 trillion cubic feet, just in this one basin. They indicate there are probably 30 or 40 such basins around the country. They said that the deep gas could be produced at from $2 to $6, depending on what figures you pump into the calculations.

Let me ask you two questions that I would like you to respond to very quickly.

Number one, do you think that is true and, number two, what would be wrong with producing that gas, which is admittedly more expensive? Because it is deeper, it is going to be more costly to drill and so forth.

What would be wrong with producing that gas at a price of from $2 to $6, because it is pretty clear to us by now that any other alternative source to be used, conversion to coal, gasification of coal, LNG, or SNG, is certainly going to be in that range.

Mr. SCHWARTZ. Certainly I cannot answer your first question, because I am not a geologist or petroleum engineer, as to whether or not those estimates are accurate. I have heard the same estimates that in the Anadarko there may be 200 Tcf.

I have also heard estimates from El Paso that in fact in the Rocky Mountain tight formations you have 600 Tcf. Whether these are true or false, we do not seem to get much production out of the Rocky Mountain area.

Now the next question, as to the questions of price, I think has to be handled in the context of what market are you talking about? In the workably competitive market you get one set of price alternatives which in fact will give you the lowest cost price alternative fuel to fulfilL the objective demand requirements.

Now if in a constrained monopolistic market the few suppliers who bring it forward——

Mr. STOCKMAN. Wait a minute. I understand——

Mr. KRUEGER. Three minutes and 40 seconds have expired.

The Chair now recognizes the gentleman from Texas, Mr. Gammage, for three minutes.

Mr. GAMMAGE. I would like to yield back some of my time to Mr. Stockman.

Mr. STOCKMAN. Thank you.

These estimates have nothing to do with the institutional arrangements. They are estimated drilling costs plus hypothesized rates of return. So forget your institutionalization of the market. I

am only saying the estimates show that at from $2 to $6 you can get an enormous new source of natural gas which we have not been able to touch thus far because it is outside the range of the market.

I am wondering whether or not you feel this is a qualitatively different kind of resource we are dealing with? In all of the things you are telling us about pricing the current suppplies of gas—we have associated with gas in categories 1 and 2 I mentioned—are really irrelevant to the third category.

Mr. SCHWARTZ. I do not agree that they are irrelevant. You are looking for an answer in the framework that I think is really unfortunate because in fact, if this were workably competitive, that gas may or may not be marketed. It depends on whether or not alternatives would come forward, if you had new entrants who would come forward with other alternative fuels at lower cost.

In a market where entry is foreclosed, where the major firms dominate, they may or may not bring that forward, depending on whether or not they feel that the market at this point should be further constrained or whether or not they should bring an alternative fuel forward rather than deep Anadarko.

Therefore, I say you cannot assume that because you have explicit physical resource costs of $5 or $6 that in fact that fuel should or should not come forward. In a tight market, where in fact you have constraint, it may or may not, depending upon the decisions of the firms. In a workably competitive market, since you have many buyers and many sellers and no one seller controls any significant amount of the supply, if the basis is lowest cost marginal alternative, it will not come forward.

Mr. STOCKMAN. I thank the gentleman for yielding.

Mr. KRUEGER. The gentleman has 55 seconds remaining.

Mr. GAMMAGE. The reason I yielded is because you were asking some of the questions I was going to ask.

I point out that my information is some 80 to 85 percent of the exploration drilling done in this country today is performed by independents and, if monopolistic, 8 to 10 percent of those that have relationships with the pipelines out there control the entire industry, not for the benefit of the consumers, I fail to see where it is.

I would point out further, my information also indicates that some 90 percent of the wells being drilled today, because of price instability, because of instability in the regulatory area of the market, is being drilled where there is 30 percent of the known reserves and that some 70 percent is going unexplored because it is deeper, more expensive, and there is no incentive to recover it.

Mr. KRUEGER. The time of the gentleman from Texas has expired.

The Chair recognizes the gentleman from Tennessee for three minutes.

Mr. GORE. Thank you.

Mr. O'Shields, Dr. Schlesinger testified here last week that in a completely deregulated market for natural gas, during last winter's crisis, consumers would have been paying up to $6 per Mcf—he said between $5 and possibly as high as $6 per Mcf.

Do you think the government should take that into consideration in devising its natural gas policy or do you think that the govern-

ment should ignore the enormous economic consequences that would flow from such a price?

Mr. O'SHIELDS. Well, I would not disagree with Dr. Schlesinger's statement, but you have to recognize that he is talking about a little bit of peaking gas to get over a very temporary short-term serious problem, which does not have any particular bearing on a longer-term situation.

Mr. GORE. It has plenty of bearing on someone who is cold, who is trying to warm his or her family and has to pay that price. Are they supposed to do without it during that little peaking period, while it is cold?

Mr. O'SHIELDS. I did not suggest that they should or that they would.

Mr. GORE. If they cannot afford it, they would have to.

Mr. O'SHIELDS. If someone concluded to pay that, in order to keep all of the households warm, it would amount to a very small percent of the total supply going to those households and it would be my judgment, if it was the difference between them freezing or not, that the company supplying it should pay that to protect their customers.

Mr. GORE. Let me proceed because my time is very limited.

Are you familiar with the concept of tie-in sales in monopoly law?

Mr. O'SHIELDS. No, I am sorry, I am not

Mr. GORE. Then let me ask a question that I asked earlier.

How is the hypothetical consumer tied into one pipeline distribution network going to affect the economic choices made at the other end, if he or she is not satisfied with the price that he or she is having to pay?

Mr. O'SHIELDS. Directly?

Mr. GORE. Yes.

Mr. O'SHIELDS. They do not directly participate in the process.

Mr. GORE. Okay, that is the answer to my question.

Mr. O'SHIELDS. The public utility commissions, that is the reason that all distributors are regulated, it is for their protection.

Mr. GORE. Mr. Chairman, I would like permission to ask additional questions in writing so that I can conclude in my remaining 17 seconds with a brief statement. I agree with Dr. Schlesinger when he says we have a lot of slogans going under the banner of incentive, but what is really being talked about is a massive transfer of wealth to the natural gas producers.

Mr. KRUEGER. The time of the gentleman has expired. We will ask the panel whether they would be prepared to receive questions in writing from members of the committee and, if so, the record will be held open for their responses.

Mr. Bowen. Yes, sir.

Mr. O'SHIELDS. Certainly.

Mr. SCHWARTZ. Fine.

Mr. HEAD. Yes.

Mr. KRUEGER. The Chair now recognizes the gentleman from Texas, Mr. Collins, for three minutes.

Mr. COLLINS. I would like to ask the gentleman in the gas business: We have had vague generalities from the professor about monopoly. I have been sitting on this committee for many years. I have never

seen a specific charge that was substantiated. You deal with those oil companies, these majors, quite a bit.

Have you ever had a major approach you on an idea of some type of working in collusion or in constraint of trade, any one of you?

Mr. O'SHIELDS. I have not any such experience.

Mr. BOWEN. Not here.

Mr. PETTY. I am not aware of that.

Mr. HEAD. Certainly, I have not.

I might take this opportunity—Mr. Schwartz in his opening statement accused Texas Eastern and Gulf of being in some inclusive conspiracy. I would like to read just very briefly from the supplemental views of yours and the chairman:

"We believe that Texas Eastern has handled itself in every way in the best interests of its consumers and the general public. Texas Eastern made an amazing contract that provided them with gas in large quantities at a low price and in guaranteed amounts. Their business ability in securing this contract was commendable in behalf of their stockholders. They are to be congratulated for not being engaged in a lawsuit as this was to the interest of their customers who preferred to have the gas and not to have cash."

Mr. SCHWARTZ. Could I refer to my section of the statement?

Mr. COLLINS. I want to say, Dr. Schwartz, you talk in generalities.

Mr. SCHWARTZ. This is a specific quote.

Mr. COLLINS. I wrote that particular paragraph. I never knew this gentleman from Texas Eastern before. They have been caught in a terrible contract, from Gulf's viewpoint all to the advantage of Texas Eastern.

You have a case where a gas company is trading on a hard basis against a major oil company, trading to the best of their ability; it was a complete arm's-length transaction. It has been my experience that is what it has been all the way across; all of them were under oath when they said they had never acted in collusion. Every one of them did not hesitate to say they did not act in collusion at any time. We have heard this before the Federal Power Commission, we have heard it before the Interstate Commerce Commission, and we have not heard any grounds to justify saying we had any monopoly in the United States.

Thank you, Mr. Chairman.

Mr. KRUEGER. The time of the gentleman has expired.

The Chair now recognizes majority counsel briefly.

Mr. DEMAREST. Dr. Schwartz, part of the President's legislation recommends natural gas utility rate and regulatory reform. Basically the proposals mirror the recommendations that would be applied to the electric utility sector.

Is such similar treatment of both gas utilities and electric utilities warranted in your judgment?

Mr. SCHWARTZ. Are you specifically talking about the question of rate design so that in fact on the electric side the bill provides that, through load-balancing, they utilize peak versus off-peak pricing?

The utilization or the effort to, in fact, do away with the declining block rate, is it in this area of rate designing that you are referring to?

Mr. DEMAREST. Yes.

Mr. SCHWARTZ. Well, very frankly, I think that the operational characteristics of the electric utilities are unique and distinct and totally different from the gas utilities. I think one of the problems on the electric side certainly was the problem of trying to digest scaled plants, which caused a great deal of outage and questions of interruption.

I think the problems on the electric side that relate to the difficulties in raising capital because of declining earnings are not indigenous to the gas side. I think that the whole problem on the electric side in rate design, because of the erosion of the earnings levels and an effort to use such things as projected test year and the various other components in the cost of service to try to shore up those earnings levels, are unique and distinct, and I do not see how, in fact, you can parallel the operational aspects on the gas side with the electric side.

The industries have unique characteristics that in no way, I think, permit you to say these forms of rate design are generally applicable and uniformly applicable to both industry sectors.

Mr. DEMAREST. Thank you.

Mr. KRUEGER. The time of the majority counsel has expired.

I recognize minority counsel for a question.

Mr. VLCEK. Thank you, Mr. Chairman.

Dr. Schwartz, on page 5 of your statement you make reference to section 402(b) of the President's proposal.

You refer in the final full paragraph of that section to this proposal as being "reflective of a nonregulatory standard." Would it be your recommendation to the committee if it were to adopt this section that we strike that subsection or that we provide some alternative means of giving the President flexibility with respect to definitions.

Mr. SCHWARTZ. Well, 402(b) essentially opens up the door for the President to rewrite the entire act. In other words, you have the definitions on Btu equivalent value, old gas, new gas, in 401(a).

Then in 402(b) it says the President by rule can in fact, according to the purposes of the act, redefine the objectives. Now I am contending that certainly this is much too broad and discretionary.

Secondly, I am contending that the bigger problem is that there is no cost base determination for rates in the act.

Thirdly, I am contending that certainly if you want to look at this whole problem of adequate consumer protection you have to start from the top down.

Mr. VLCEK. One other question. On page 7 of your testimony you refer to a recent study that indicates that section 406 would cost consumers $1.3 billion. What study is that?

Mr. SCHWARTZ. It was a study that was done at the Federal Power Commission that in effect tries to delineate, based upon interstate, I guess it is form 16 data that goes to volumes and revenues that are filed monthly by pipeline; what volumes are involved, what the pricing would be, if in fact the volume were shifted from 52 cents to the $1.45, also using Bureau of Mines data to get some sort of impact relative to intrastate.

Mr. VLCEK. Do you know if that study takes into account the effect of the sentence in section 406 which says:

"In establishing any maximum lawful price under this subsection, the President shall take into consideration the maximum lawful price of such gas under the prior contract and the price necessary to maintain production of such gas." This sentence means in effect that not necessarily all roll-over contracts will go to $1.45, that in fact many of the contracts may remain at prices very close to what they were under the original terms.

Does this study assume that all contracts go to $1.45?

Mr. SCHWARTZ. I think the study assumes that in fact the current volumes on roll-over contracts will in fact be priced at the $1.45.

Mr. VLCEK. Thank you, Mr. Chairman.

Mr. KRUEGER. The Chair recognizes himself for three minutes.

I would begin by returning to some questions about markets, free and otherwise, because we heard Dr. Schwartz give testimony that agriculture was a good example of a free market, that conspiracy was very difficult.

We also heard that the proper market was a cost-based market.

Now, I am in a small way in the cattle business and I have always found that when I send a steer to auction that they never ask me how much it cost me to produce that steer. They simply bid on that steer and I have lost money on some steers and occasionally make some money on steers. But I never find that they ask me, when it goes to auction, what I will get for a steer.

If in a proper market it ought to be cost-based, I assume they ought to ask me every time I send one through, what it cost me to raise that steer and then in turn give me an appropriate response and increase my prices, but in fact I have not found that they have done that.

When I was a professor for 12 years I never found that they asked me what it cost me to become a professor or what it costs me to prepare lectures. I got paid just as much for the lectures that you put less time into as those into which I put more.

I guess my inference from that is that the way in which a marketplace works is that there is a variety of factors and there is not only the cost of the product that goes in, but also the demand.

I occasionally doodle during these hearings and I have never found that anyone bid me any extraordinary prices for my doodles, although I have seen Picasso get paid a great deal for some of his. I judge there might be some difference in quality.

I judge there are factors other than just cost that determine pricing. It seems to me one of those is demand, and I think it will be our task to try to balance out both the cost of production, whether it be of wheat or beef or of gas, as well as the demand, and to see which is likely to be in the overall best interests of the Nation.

Mr. SCHWARTZ. Is that a question?

Mr. KRUEGER. No, it is not a question. That is a statement.

Mr. SCHWARTZ I have an answer to the question——

Mr. KRUEGER. It is a statement.

You have had more time than I and I have just given you a statement. But at this time it is 5 minutes to 2 o'clock and the committee will adjourn, and we thank the panel for their testimony.

At this time we will recess and the committee will resume at 2:30.

[Whereupon, at 1:55 p.m., the subcommittee recessed to reconvene at 2:30 p.m., the same day.]

AFTER RECESS

[The subcommittee reconvened at 2:30 p.m., Hon. Robert Krueger presiding.]

Mr. KRUEGER. The subcommittee will come to order.

At this time we have before us a panel of technical experts who will comment particularly on the technical details of the legislation before us and who will perhaps help us refine legislation.

We are very grateful to have you here, and at this time I would ask each of you to identify yourselves for the record following which we will receive your statements.

STATEMENTS OF GORDON GOOCH, RICHARD SOLOMON, AND LEO FORQUER, ALL FORMER GENERAL COUNSELS OF THE FEDERAL POWER COMMISSION; AND DREXEL D. JOURNEY, GENERAL COUNSEL, FEDERAL POWER COMMISSION

Mr. GOOCH. My name is Gordon Gooch.

Mr. SOLOMON. My name is Richard Solomon.

Mr. JOURNEY. I am Drexel Journey.

Mr. FORQUER. I am Leo Forquer.

Mr. KRUEGER. I neglected to mention that each of the members is a former General Counsel, with the exception of the present General Counsel, of the Federal Power Commission, Mr. Drexel Journey.

Mr. BROWN. Are the others currently unemployed?

Mr. KRUEGER. I do not know whether the others are currently unemployed or not, Mr. Brown.

Mr. Gooch, would you care to begin with any statement that you might wish to make?

Mr. GOOCH. Thank you, Mr. Chairman.

It is an honor to be called upon by the subcommittee.

I have endeavored to file with the committee a short statement outlining some of the problems that I perceive, and have gone farther to indicate what I consider some major changes in the law. I have to start by saying that the bill as drafted is not clear to me in many, many respects, and I am in many respects giving my best guess as to what the bill will do rather than being able to say with certainty that the bill in fact does that.

I also have some problem in correlating the expressed intent for the legislation with the actual legislative language, but if I can pass that, it seems to me that the major points that can be made about this bill is, first, that the new gas wellhead rate is probably below the cost of finding and producing new natural gas for wells drilled in 1975, 1976, or 1977 as determined by FPC cost methodology, even if the new gas price is $1.75.

Second, I am unable to ascertain what the new gas rate is for qualifying wells today. As I try to calculate a rate, it seems to fall somewhere between $1.47 and $1.59 an Mcf. If this is accurate, then the producer is expected to drill for gas today at less than the cost

found by the FPC for wells drilled in 1975 and 1976. This cost finding is under review in the District of Columbia Circuit, as this testimony is being given.

Let me pause and say that I assume that this rate is before Btu adjustments and State severance taxes as the FPC rate is. It doesn't say in here, but if it is not, then the rate is significantly lower even than these numbers.

Mr. KRUEGER. I want to get that clarified. You are assuming that the rate is before adjustment?

Mr. GOOCH. Before an adjustment based on the heating value of an Mcf of gas, and before State taxes, State severance taxes are added. When you talk about the FPC rate of, say, $1.45 that is before State severance taxes are added, and before an adjustment is made for the heating value of the gas.

Mr. BROWN. Will the gentleman yield?

Could you give us some assessment as to what that is on the average? Does it vary from community to community?

Mr. GOOCH. It varies from State to State depending on the State taxing laws, and I am very bad in math, but say, you might take like 7 cents off as a rough average. In other words, if it is $1.45 without the State taxes, you would have to subtract about 7 cents to get back to what the wellhead price is to the producer, and that is not a hard number. As I say, it varies from taxing jurisdictions.

Mr. BROWN. More specifically if you take the 7 cents off the $1.75, would you not?

Mr. GOOCH. I can't find $1.75 in this bill, sir. I can only find somewhere around $1.47 to $1.59, so I can't respond to the $1.75.

Now it appears to me that Federal price controls are apparently extended beyond the scope of the Natural Gas Act to reach at least producer sales of gas in the intrastate market. I realize that this is directly contrary to the intent expressed, but I can only read the bill to preempt the intrastate market, and I also note that the bill would extend mandatory allocation controls to the intrastate market.

Now I realize that my time runs short. I wanted to point out if I could, if I may step to some charts, I wanted to cover very briefly.

Currently these are the federally regulated prices for oil and natural gas today, under either direct or indirect Federal regulation. At the top of the chart you will find cents per million Btu down this column. You will find cents per Mcf, and on the other side of the chart the crude oil equivalency.

At the top of the chart are liquid-based synthetic natural gas, the SNG that this bill addresses, which sells now from the two basically federally regulated projects at the equivalent of about $28 a barrel crude oil. Others sell for just $24 a barrel crude oil equivalent.

Then you get to stripper wells, which are regulated at the present time through a floating system. The latest would be $13.17 a barrel. The next is upper tier crude, which shows here at $11.45 but that is before the last price rollback. This was the 1-1-77 price. Actually I believe it is about $10.90 at the present time.

Then next down is the new natural gas for 1975-1976 wells, which is $1.43 on January 1, 1977, which translates to $8.35 a barrel crude. Then natural gas from 1973-1974 wells, lower tier crude, and then

down into the 53 cents price for pre-1973 wells under post-1972 contracts, and finally down into what is called flowing gas at 29.5 cents. This is the price level of federally regulated rates today, but then if you put the costs on there, according to the Federal Power Commission, in 1975 and 1976 the cost of drilling a well was $1.61 per Mcf. That was based on projected data.

If you look at the actual cost data for those same wells, you will find that it was really about $1.90 an Mcf, and if you look at the cost for 1977-1978 wells, that will be $2.40 per Mcf minimum under Federal regulation for selling gas in the interstate market by my calculations, so when you set a then price of $1.75, you see you are saying that the producer now will sell gas to the interstate market at less than cost picking up Mr. Schwartz's point, talking about the producer should sell at cost. Cost would be $2.40, and under rate design that would start the rate at $2.21.

If I can illustrate briefly the point of the 2.5-mile rule and what the impact is on 2-1/2 mile wells, we had a case last year on the Blanco Mesa Verde Basin, so I had this map on hand, each of the small squares that you see is a square mile. These little stars are wells that were in existence at that time. For comparison purposes, this is the District of Columbia, this red square, and this circle is how much territory would be blocked out if you had a well in the middle of the District of Columbia. The 2.5-mile rule would block out all wells inside that circle.

Translating that to scale to this chart, you see that the 2.5-mile rule eliminates the entire Blanco Mesa Verde field from further drilling for the incentive rate.

Now in doing that, you realize of course that the New Mexico Commission found that reserves would be substantially increased by permitting in-field drilling, wherever there is an open drilling unit, in these fields. The testimony showed that proven reserves would go from 9 to 16 trillion cubic feet, that is new reserves, with drilling inside the field limits. This would push people beyond the field limits of the Blanco Mesa Verde field.

Now let me take a second to illustrate the impact of the 1,000-foot rule. This also is the Blanco Mesa Verde field, but only this much of it is. This is an entirely different field, Pictured Cliffs in the Dakotas. This map is a cross section of the San Juan Basin, and it has been squeezed, so it is to scale up and down, but it is not to scale sideways. Otherise it would be really long.

To show you the impact of what the 1,000-foot would do, notice that these are different reservoirs, and even within these reservoirs they are isolated individual reservoirs that cannot be tapped without a well in each reservoir. The 1,000-foot rule you see——

Mr. BROWN. Is this because there is nonporous material——

Mr. GOOCH. That is correct.

Mr. BROWN. ——between the various segments?

Mr. GOOCH. That is right. You will notice in this particular field you don't have heavy faulting like you have in other fields, but these are a series of beaches that were laid up, covered with mud, some with sand, and there is no communication between them, but this bill expressly leaves out communication as a criteria, so that means that here you can run a 1,000-foot depth in the same formation, and this hole from here to here is the same formation.

You also then would knock out the formation below it, and the formation above it with the 1,000-foot rule, so a combination of the 2.5-mile and the 1,000-foot virtually says do not go to the San Juan Basin any more.

Mr. KRUEGER. We will have copies of this inserted into the record without objection. It is so ordered.

[The charts referred to were not suitable for reproduction in the record and may be found in the subcommittee files:]

Mr. GOOCH. In contrast the Federal Power Commission under its rate design encourages a new well to be drilled wherever the State authorities have determined that a new well will tap new reserves or increase deliverability from other reserves that have been previously discovered but would not be economically recovered through existing wells. That is a major change.

Another major change by this statute is to put State-owned oil and natural gas, or rather natural gas, under Federal regulation. At the present time State gas, be it Alaska, Texas or Louisiana, is not regulated. This would do so.

Moving to the transportation and sales sector, this bill moves away from the basic end use considerations used by the Federal Power Commission in determining priorities. This bill treats only residential and small commercial as a high priority.

This bill, as I indicated, encourages synthetic natural gas plants, even those from light liquid hydrocarbons that yield this $24 to $28 a barrel crude equivalent result. The FPC in the past has not encouraged synthetic natural gas plants because of their high cost, and suggesting that conventional drilling projects would be more in the consumers' interests.

I did not have time to try to quantify the impact on the interstate pipelines and the distributors of the loss of tremendous industrial and utility loads, and I have to say that on the one hand the bill seems to imply that gas is going to be taken away from current consumers and allocated to others, and yet the tables in the national energy plan show increased gas use by the industrials, so I don't know really what that means, but if you do take the industrial, all industrials and all electric utility loads off of the interstate pipelines, it seems to me you will have a tremendous capacity problem, and you will have to ask yourselves whether you need all existing interstate pipelines to deliver such a small amount of gas. I would be pleased to respond to any questions and be of any assistance that I can, Mr. Chairman.

[Mr. Gooch's prepared statement follows:]

STATEMENT OF GORDON GOOCH
BEFORE THE SUBCOMMITTEE ON ENERGY AND POWER,
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE,
UNITED STATES HOUSE OF REPRESENTATIVES
(MAY 17, 1977)

My name is Gordon Gooch. I am an attorney in private practice with Baker & Botts in Washington, D. C. It is my understanding that I, along with the present and other former General Counsels of the Federal Power Commission, have been asked by this Subcommittee to provide an analysis of the Natural Gas sections of the National Energy Act, Title I, Part D, confining comments to this subject.

Summary

Natural Gas

As I read the Bill, 1975-1976 Federal Power Commission (FPC) gas rate levels would be frozen, subject to an inflation adjustment. No new rates would be set for 1977-78. Some new 1977 wells would qualify for a rate tied to an average domestic crude oil price, projected to be $1.75/Mcf. This price is comparable to crude oil at $10.15/barrel. New crude oil, however, defined the same as "new" gas, would be priced at $13.50/barrel over a three-year phase in. If applicable to natural gas, the comparable new gas price would be $2.33/Mcf, without any inflation adjustment.

I also read the Bill to extend federal wellhead price controls to the intrastate market, preempting all

present intrastate contracts, effecting a price rollback for the intrastate consumers.

I further note the extension of the Emergency Natural Gas Act to the intrastate market, giving the federal government the power to seize gas supplies of intrastate consumers.

Current policies limiting synthetic or substitute natural gas, including imported liquified natural gas, would be modified to encourage more projects. Two current large scale SNG plants using liquid petroleum feedstocks produce gas at $4.14 to $4.97 per Mcf.

There is also a broad incremental pricing provision aimed at all large commercial, industrial, and electric utility consumers of gas.

Comparison of Regulation Under NGA with NEA

A. Present situation.

Federal price controls on the wellhead sales of natural gas apply to sales by producers either to interstate gas pipelines or to distributors who resell the gas to consumers. Once a producer contracts and sells in interstate commerce, he may not terminate the sale without FPC approval, even when the contract expires.

The Federal Power Commission sets the producer rate relying primarily on cost calculations. The cost calculations are translated into rates. There is an

eleven-tiered rate structure, but five "vintages" are the most significant:

"flowing" gas	$.295	(on review in CA5) Op. 749 et seq.
"new" 73-74 gas & expired contracts	.53 up	)
"new wells" 73-74	.94 up	) (on review in CADC) Op. 770 et seq.
"new wells" 75-76	1.45 up	)
"new wells" 77-78	pending	(some producers have filed for an interim rate of $2.21 based on Op. 770-A findings and current cost calculations of $2.40 per Mcf)

The principal operative fact for qualification for the highest rate is the date on which drilling is commenced on a specific well, regardless of date of contract. All new wells qualify, so long as they do not replace an existing producing well (replacement well). This means that developmental drilling is encouraged so that all reserves will be drilled for and produced, as well as encouraging wildcatting.

It is important to note the word "up" by some rates. Where indicated, the ceiling price escalates on a fixed schedule. For example, the FPC in Opinion 770-A found the cost of drilling a new well to find an Mcf of gas in 1975-76 was $1.61 per Mcf, but set the rate at $1.42, below cost, then promised a 4¢/year escalation over a 15-year period so that the producer would average $1.61/Mcf from 1975 through 1990.

No rates have been set for 1977-78 wells yet. Some producers have filed with the FPC a cost study showing that, using the FPC's formula adopted in Opinion 770-A, the cost in 1977 is $2.40/Mcf.

Federal price controls do not apply to the sale of natural gas within a single state (unless commingled with gas flowing out of state). In the free market in states such as Texas, new contracts averaged $1.97 in the fourth quarter of 1976.

The FPC does not have jurisdiction over the sale of synthetic natural gas until it is mixed in an interstate pipeline with natural gas. The FPC considers the rate for SNG in determining whether to authorize transportation of SNG in regulated pipelines. The Commission has required incremental pricing of SNG so that the high cost will be reflected in the rate for the wholesale sale or the transportation.

B. Proposed changes.

All present FPC rates would be frozen, subject to an inflation adjustment. No new FPC rate would be calculated and set for wells drilled in 1977 and beyond.

An additional tier of rates would apply to some (instead of all) new wells drilled after April 20, 1977. That rate tier is said to be $1.75 (subject to adjustment relating to the cost to refiners of domestic crude oil). The

new wells (in the lower 48 states) that qualify are those wells 2-1/2 miles from, or 1000 feet deeper than, a well in existence on April 20, 1977 (the depth allowance does not apply if the completion is into the same producing zone as the existing well). Thus developmental drilling would be eliminated from the highest rate of encouragement.

(For perspective, and as an example, consider drilling sites regulated on the basis of 640 acres in the form of a square mile. State authority might permit one well per 640, one well per 320, one well per 160, or two wells per 160, depending upon the number of wells needed to produce the underlying reserves. On the basis of wells permitted per 640 acres, the 2-1/2 mile rule would affect the following potential drill sites.

Wells permitted per 640	Approximate Sites Affected
1	13+
2	26+
4	68+
8	136+)

The highest rate would also apply to wells drilled on leases in the offshore federal domain acquired after April 20, 1977.

As to the presently unregulated natural gas markets, federal price controls would apply to all sales of natural gas and synthetic natural gas. A rollback from current contract levels is apparently intended for wellhead sales.

Apparently the FPC would assume jurisdiction over at least some SNG plants. The consequences of certification are (1) the SNG plants will be placed in rate base on which a rate of return (shorthand for profit and interest coverage) can be charged to the consumer; (2) the cost of oil and gas liquids--whatever they are--can be recovered from the consumer with relative ease; and (3) depreciation of the plant will be recovered from the consumer with relative ease.

Legal Analysis

Because of the press of other commitments, time did not permit me to provide as thorough an analysis as I would like. Please permit me to outline some major changes which would be effected by this Bill:

(1) The new gas wellhead rate is probably below the cost of finding and producing new natural gas for wells drilled in 1975, 1976, or 1977, as determined by FPC cost methodology, even if the new gas price is $1.75 mcf.

(2) I am unable to ascertain what the new gas rate is for qualifying wells drilled today. As I try to calculate a rate, it seems to fall somewhere between $1.47 and $1.59. If this is accurate, then the producer is expected to drill for gas today at less than the cost found by the FPC for wells drilled in 1975-1976. (This cost finding is under review in CADC as this testimony is being written)

(3) Federal price controls are apparently extended beyond the scope of the Natural Gas Act to reach at least producer sales of natural gas in intrastate commerce.

(4) Considering (1), (2) and (3), note that the producer and the consumer are deprived of the present right to present evidence and arguments on costs and other pricing issues in a public proceeding before an independent agency (to which certain congressional power over interstate commerce has been delegated). This agency's decision, hopefully free from political influence, is now subject to judicial review. Apparently the Bill would delegate congressional power to the President, putatively beyond the reach of the judicial branch, to control wellhead rates, with only a limited "special relief" procedure for the producer. Apparently the approximately 100 large producers and the thousands of small producers would have to file individual cases for executive branch decision, but limited to certain projects. I would not be surprised to see some legal questions raised if the Bill is enacted.

(5) A major change is the new gas definition which virtually eliminates developmental drilling. (I will try to illustrate the significance of this change in policy at the hearing, if time permits me to have an exhibit prepared)

(6) All State owned gas comes under federal price controls, a change from the Natural Gas Act

(7) Moving to the transportation and sale sector, the FPC has adopted end use priorities for use in curtailment and certification cases. In general, these end use priorities presently rank the largest boilers at the bottom and move up by boiler size until industrial non-boiler fuel use is recognized, then large commercial and industrial feedstock, process, and plant protection gas is recognized, and then, at the top, residential and small commercial. This Bill ranks only residential and small commercial as high priority for purposes of rate design, treating all boiler fuel, regardless of size, all industrial non-boiler fuel use, all feedstock, process, plant protection gas, all large commercial gas, as if there were no distinction.

(8) Under the Natural Gas Act, the FPC has not encouraged liquid based SNG plants, suggesting that comparable amounts of capital invested in conventional drilling projects are more in the consumer interest than high cost conversion plants. When the FPC has permitted transportation of SNG, it has imposed conditions designed to insure, inter alia, that the consumer would not be subjected to unlimited and unrestrained "fuel" adjustment clauses. This Bill would encourage liquid based SNG plants by placing them within the utility rate structure where "cost of service", a fair return and federal income taxes, and depreciation will be reasonably assured.

(9) Time did not permit me to try to quantify the impact of the apparent policy of terminating all industrial and utility sales on the supply and price for the remaining customers. Obviously, large diameter, looped pipelines, operating well below capacity, result in a higher transportation charge in the ultimate gas rate. Indeed, it would seem to me that it would be necessary to consider whether several interstate pipelines serving the same geographical areas can be justified if each operates under a very low load factor. The analogy of the Penn Central and other railroad consolidations is most apt here.

(10) It further seems to me that some distribution companies will be hard put to operate only on residential and small commercial loads.

I consider it an honor to be called upon by the Subcommittee to testify and a duty to respond. I will be pleased to discuss any matters that I can.

Mr. KRUEGER. Thank you very much, Mr. Gooch.
Mr. Solomon.

STATEMENT OF RICHARD SOLOMON

Mr. SOLOMON. Mr. Chairman, I do not have a prepared statement, nor did I come here really prepared to discuss the basic merits of the relative proposals so much as the technical details. I do want to say at this time two things. One, I think Mr. Gooch is right, that the bill as drafted would appear to fix prices irrespective of Btu adjustments or State taxes, subject only to such authority as the President has generally to make special exceptions.

Secondly, he did say, I think, that the bill had for the first time asserted Federal jurisdiction over intrastate sales. As I read the bill, that is deliberate, but what they do with respect to existing intrastate sales, reading in section 405, is in effect to set the maximum price for existing intrastate sales at the contract price, because the provision there for old gas under existing contracts is that the price, the maximum lawful price, shall be equal to the lesser of either the contract price or the price for sales which were deemed to be just and reasonable by the Commission on April, 20, 1977, and the Commission, of course, had no prices for intrastate gas whatsoever on April 20, 1977.

My guess is that that was what was intended, but if there is any doubt about that, undoubtedly you could speak to Dr. Schlesinger's people and see. I think what is done by this bill, or at least intended to be done by the bill, is to leave existing sales of natural gas in intrastate commerce alone. New sales of natural gas in interstate commerce, as I read the bill, clearly are under the price regulation, and that would include new contracts of natural gas now sold in intrastate commerce, which are sold under new contracts. But the latter, unlike interstate gas sold under new contracts, would get the new gas price pursuant to section 406(c) of the act. So that as I read the act, with respect to intrastate sales, you have the following situation: Existing intrastate sales, the contract price would be the maximum rate that the President can fix by rule, and he is not authorized to fix anything else but a maximum.

If a contract expires for intrastate gas and there is a new contract, then they would be entitled to the new gas price, and of course they would be entitled to the new gas price for new sales of intrastate gas, new sales in intrastate commerce.

Mr. Chairman, I have a number of other problems with specific sections of the pricing mechanism, which I assume we will get to further in our discussions here today, but at this time—and I agree certainly very much with Mr. Forquer's written statement with respect to the problems with respect to Alaskan gas, but at this time I suspect it is best for me to stop talking and let us proceed to getting into what I assume—you really want from us—is technical discussions of language draftsmanship.

Mr. DINGELL. Our next witness is Mr. Journey.

STATEMENT OF DREXEL D. JOURNEY

Mr. JOURNEY. Mr. Chairman, I ask that the prepared statement be incorporated into the record as if read.

Mr. DINGELL. Without objection, it is so ordered, and we recognize you for such summary as you choose to give, Mr. Journey.

Mr. JOURNEY. The statement was prepared in coordination with Chairman Dunham's statement this morning. There are several points I would like to emphasize in terms of my understanding of the bill.

Mr. DINGELL. Before you do so, you will recall that this morning we discussed the need for your counsel with regard to technical perfections and imperfections in the bill, and I assume that you will be participating quite actively in the preparation of that for the committee.

Mr. JOURNEY. I will, Mr. Chairman. With respect to the questions that were put to us this morning I have already assigned staff people to work. I am available as the committee wishes.

Mr. DINGELL. We are satisfied that you will serve us well, as you always do.

Mr. JOURNEY. Thank you, sir.

Mr. DINGELL. You may consider yourself recognized.

Mr. JOURNEY. As I understand the concepts of this bill as it relates to wellhead pricing, the draftsmen sought to codify Opinion 770-A pricing techniques for existing gas. I am not sure they did,

because the language that was used does not track what we did in 770-A.

In terms of newly produced old gas, as I read the bill, I think it can go up to a cap of $1.45 an Mcf. I think it is up to the President, if he chooses to want to continue vintaging, to do so. I think under some sections of the bill, if there is a contractual restraint on pricing, the President would have to respect the contractual restraint.

In terms of intrastate gas, whether it is from newly discovered intrastate reservoirs or intrastate production that is now going on, as that goes into the interstate market, as I read this bill, it comes in at $1.75 per Mcf.

I think the concepts of the draftsmen were to apply price functionally in two respects: To further conservation goals, and to further incentive and supply stimulation.

If you look at the national energy plan which the President promulgated, that accompanies the bill, you will find 10 principles. Of those 10 principles, 4 seem to me to be highly relevant to subchapter D we are talking about. They are the third, fifth, sixth and seventh standards. You will find them at pages 25 to 32 of the national energy plan.

Very simply, they are environmental protection, equitable sharing of increased costs, conservation, and efficiency restraints on demand, and energy prices based upon replacement costs.

Now we have been working under the Natural Gas Act, a bill that was basically drafted to achieve pipeline regulation, and we are adapting it. We have adapted it administratively to wellhead pricing and producer regulation. It has really not worked too well. Through court interpretation we have gotten noncost incentive and supply stimulation built into some parts of the pricing formula, but certainly the Natural Gas Act is not a commodity pricing or replacement value regulatory mechanism. As I read chapter D, it seems to move in that direction, but it also seeks to hold a restraint on how far that can go.

When you look at the volumes that are moving interstate, as Chairman Dunham pointed out this morning, in 1976 approximately 11.4 Tcf flowed interstate; 6.4 Tcf flowed at 29.5 per Mcf or less, 1.7 Tcf at 52 cents, 1.2 Tcf at 93 cents, and 0.7 Tcf at $1.42, and 1.4 Tcf at up to $1.80 for Canadian gas.

I have tried to summarize on page 7 what the bill overall seems to me to try to grapple with. I would like to read you one paragraph, if I may, of the prepared remarks.

There is a supply-demand imbalance for natural gas at historical prices. There is a fuel reference problem in allocating shortfalls of natural gas. There is a supply eliciting incentive problem when dealing with a depleting resource. There is a problem of equitable balancing of price changes for natural gas among consumer groups, some of whom are physically dependent, largely or totally upon natural gas, some partially and some optionally, the choice being one of price and alternate fuel availability.

Also, consumer groups can be affected differently in their ability or lack of ability, to pass through price changes in costs of goods or

services, for example, manufacturing, commercial, utility, transportation, or agricultural as opposed to individuals.

We can critique this bill in terms of definitions, concepts, policy choices, but when you come down to the bottom line, the key questions are: Where are we now? Where are we going, and why are we changing?

Chairman Dunham said this morning that there are some definitional problems of new gas; surface measurement and elevation differentials pose problems. I agree with that. They did pose substantial problems for us when we wrote 770.

Mr. DINGELL. Mr. Journey, I want you to understand one thing very clearly. We asked you as our guest to speak your thoughts. I don't want you to be inhibited in any fashion in doing so.

Mr. JOURNEY. I shall not be inhibited, Mr. Chairman.

We also found in terms of the analytical technique of trying to estimate supply elicitation, that elasticity studies, supply elasticity, are really not all that reliable. We had some material that we used in 770, as the committee asked for this morning. We will provide that material.

We think that in terms of the definitions, this bill does articulate a replacement cost for a commodity value pricing concept, assuming that you wish to move from a cost base concept that is in the Natural Gas Act now. I make that assumption for discussion purposes.

We think that in terms of how you handle rollovers, there are some definitional problems and some drafting problems that should be taken care of.

Mr. DINGELL. Do you regard those as substantive or as drafting matters?

Mr. JOURNEY. I regard those as drafting problems. If I am right in my interpretation that they were seeking to codify 770-A, which I think they were, the language of the bill does not reflect the rollover concepts of 770-A. The FPC there went from 29.5 cents to 52 cents or 53 cents.

Mr. DINGELL. Excuse me, Mr. Journey. I must express apologies to you. This is not the way I like to proceed, but you will observe we have two bells up on the clock. That is the second time that they have rung the bells. There are going to be no less than 12 votes on the floor. For the first we have 10 minutes in which to respond. Thereafter we will vote once every 5 minutes, so we are going to have to recess, with apologies to our panel members. We will be voting for 10 minutes plus 11 times 5 minutes, which would be an hour and 5 minutes as my arithmetic works out. We will return here shortly thereafter.

Gentlemen, I express to you the apologies of the committee. We will return as quickly as we possibly can.

Can you stay, please?

Mr. Forquer, I hope you can too.

We will recess and return as quickly as possible.

[Brief recess.]

Mr. DINGELL. The subcommittee will come to order.

The Chair apologizes to our witnesses. We have voted 13 times.

Mr. Journey, had you completed your statement?

Mr. JOURNEY. I have about another two minutes I would like to speak to.

Mr. DINGELL. Mr. Journey, I expect you to offer your thoughts and help the committee. You are recognized.

Mr. JOURNEY. The bill also extends the Emergency Natural Gas Act for three years. I think the key to that is found on page 54 of the plan, the President's plan, where in effect he says until replacement cost pricing, commodity pricing comes in, there will be need to have this kind of an allocation crutch in place, to work for about a three-year period.

Since the equivalent Btu pricing intrastate interstate is intended to cover across the board, I assume that was the reason why the Emergency Natural Gas Act would be amended to reach intrastate gas as well as interstate gas. Public Law 95-2 would be changed.

One other comment, and then I will pass.

The bill doesn't speak to how you treat the costs of syn gas, incremental versus rolled in. But, if you look at page 54 of the plan, the language there says that it would be treated on an incremental basis and allocated to industrial customers. I think that is another definitional problem that we have with it.

Beyond that, Mr. Chairman, I am at this point willing to respond to any questions you may have.

[Mr. Journey's prepared statement follows:]

STATEMENT OF
DREXEL D. JOURNEY
GENERAL COUNSEL
FEDERAL POWER COMMISSION

BEFORE THE

SUBCOMMITTEE ON ENERGY AND POWER
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
U.S. HOUSE OF REPRESENTATIVES

MAY 17, 1977

Mr. Chairman and members of the Subcommittee, Title I, Part D--Natural Gas--of the Administration sponsored National Energy Act, H.R. 6831, carries forward proposed amendments of the Natural Gas Act, 15 USC 717(a) et seq. to implement the President's National Energy Plan.

Based upon conversations with Subcommittee staff, it is my understanding that you wish to focus upon Part D, through a comparative analysis, giving consideration, inter alia, to H.R. 2088, 3136, 3171 and H.R. 687.

Numerous other portions of H.R. 6831 relate to the natural gas industry. Part D directs itself primarily to wellhead pricing changes to reflect replacement cost concepts for new gas, and incentive rates for contracts which replace expiring interstate contracts, and for intrastate production which might be put into the interstate market; incremental pricing pass-through to lower priority users--primarily larger commercial and industrial users--of increased wellhead prices; federal facilities certificate

jurisdiction over synthetic natural gas facilities; and an extension of the Emergency Natural Gas Act of 1977, P.L. 95-2, 91 Stat. 4.[1/]

Wellhead pricing at the present time is essentially a cost based administrative determination. The procedure was summarized most recently by the Commission in its Opinion Nos. 770 and 770-A.[2/] Being cost-oriented, historical factors constitute the starting point in the ultimate price setting determination under the Natural Gas Act, 15 USC, 717(a) et seq. Through judicial interpretation, non-cost incentives have been recognized as essential to elicit increased supplies.

1/ Other portions of Title I, H.R. 6831 are of direct concern to the natural gas industry. Compare, for example, Parts A, B, C, E, F. Also, in cross referencing H.R. 6831 to The National Energy Plan, see Buildings, Plan, pp. 40-3, Appliances, p. 43, Fuel Efficiency In Industry, pp. 43-5, Utility Reform, pp. 46-7, Savings from Conservation, p. 47, Natural Gas Pricing, pp. 52-5, Liquified Natural Gas, p. 57, Synthetic Natural Gas, pp. 57-8, and New Sources of Natural Gas, p. 58. Title II, dealing with tax provisions, also affects the natural gas industry, but that Title is of immediate concern to another House Committee.

Viewing H.R. 6831 in overall perspective, it is well to keep in mind the President's "ten principles," The National Energy Plan, pp. 25-32. Part D commands particular attention to the 3rd, 5th, 6th and 7th standards: environmental protection, equitable sharing of increased costs, conservation and efficiency restraints upon demand, and energy prices based upon replacement costs.

2/ Now pending appeal, American Public Gas Association, et al. v. F.P.C., CADC Nos. 76-2000, et al.

The Supreme Court's opinion in Mobil Oil Corp. v. FPC, 417 U.S. 283, 316-7 (1974), states:

> * * *Mobil's argument assumes that there is only one just and reasonable rate possible for each vintage of gas, and that this rate must be based entirely on some concept of cost plus a reasonable rate of return. We rejected this argument in Permian Basin and we reject it again here. The Commission explicitly based its additional "non-cost" incentives on the evidence of a need for increased supplies. Obviously, a price sufficient to maintain a producer, while not itself necessarily required by the Act* * *may not be sufficient also to encourage an increase in production.

Chairman Richard L. Dunham's statement before the Subcommittee discusses certain policy considerations. It includes data relative to volumes of natural gas flowing and projected, which could be affected. That testimony also includes data as to the overall economic impacts or price changes, which might be anticipated by reason of the provisions and concepts contained in H.R. 6831. That statement should prove to be of substantial value in the Subcommittee's current deliberations.

For my purposes, I note the Subcommittee's familiarity with the details of the bills and therefore limit my remarks to a brief comparative synoptic statement of my understanding as to how each bill is designed to function in respect to wellhead pricing and the pass-through of price changes. However, before doing so, I note that in addition to wellhead pricing changes, these bills cover various other matters. H.R. 6831, Title I, Part D, covers SNG certification and an extension of the Emergency Natural Gas Act of 1977. H.R. 2088 is directed to exemption of 180-day

emergency sales from the Natural Gas Act, the inclusion of a gas information bill amendment to that Act, a restatement of priorities revising FPC practices in curtailment situations, and a phasing out of boiler fuel use of natural gas. H.R. 687 would revise FPC curtailment priorities and would phase out boiler fuel use of natural gas.

H.R. 6831 employs the concept of a legislatively decreed commodity value price at the wellhead for new gas, to remove the distinctions which have risen historically by reason of the interstate and intrastate markets. It allows currently produced gas to receive higher prices upon expiration of prior contracts, if in the interstate market, as well as allowing higher prices for additional production for the interstate market from existing intrastate reservoirs or from new intrastate production. The added cost impact of increased wellhead charges would be directed initially to large industrial and commercial users. The bill would include, under Federal certificate jurisdiction, synthetic natural gas facilities.

H.R. 2088 eliminates onshore wellhead pricing of new natural gas in the interstate market. After December 31, 1981, offshore Federal domain wellhead sale ceiling prices are removed. The standard for wellhead pricing in the intervening period involves interim rates based upon domestically produced crude oil and Btu equivalents; and final rates are based upon prospective costs, exploration incentives, conservation values and the

avoidance of prices above the foregoing. New gas is defined differently from H.R. 6831.

H.R. 687 eliminates wellhead pricing for small non-affiliated independent producers who produce up to 100,000,000 Mcf annually. It extends wellhead pricing to all new sales, interstate and intrastate. The criteria for wellhead pricing include historical and prospective costs, and an incentive rate of return allowance for exploration and development. The definition of new gas in H.R. 687 differs from H.R. 6831 and 2088.

All the bills make provision for special pricing in high-cost production areas. Also, they contemplate continued usage of the rulemaking process of the Administrative Procedure Act, 5 USC, Subchapter II, 551 et seq., for the conduct of wellhead pricing determinations.

Legislative drafting in the area of economic regulation can be critiqued in numerous ways. Policy concepts can be analyzed. Definitions can be explored. Impacts of changes can be assessed. Consequences of non-action can be recognized. When all analyses are completed, the questions are:

-- where are we now?

-- why are we changing?

-- what direction are we to take?

The National Energy Plan is the President's comprehensive response. Through years of administrative work, the FPC has fashioned a wellhead pricing technique under a statute historically interpreted for the regulation of pipelines. The process has not worked smoothly.

There are two markets -- one regulated, one essentially non-regulated. Present day working standards for wellhead pricing of natural gas in the interstate market are largely casuistically developed through Commission opinions and orders, following extensive litigation and judicial interpretation of the terms and conditions of Sections 4, 5, and 7 of the Natural Gas Act, 15 USC, 717 c, d, f. That Act, copied in 1938 from the 1935 Federal Power Act, 16 USC 824 et seq., finds many of its legislative roots in the 1887 Interstate Commerce Act, as amended, 49 U.S.C. 1 et seq. The FPC is coupled to a steam train.

As pointed out in Chairman Dunham's statement, the interstate market had approximately 11.4 Tcf flowing at the following base rates during 1976:

6.4 tcf at 29.5¢/Mcf or less,

1.7 tcf at 52.0¢/Mcf,

1.2 tcf at 93.0¢/Mcf,

0.7 tcf at 142.0¢/Mcf.

The remaining 1.4 tcf at various rates up to $1.80 for Canadian gas.

The intrastate market had roughly 9.0 Tcf flowing during 1976. Prices vary, and only the following general price range data are available on that market which data were taken from Form 45 reports supplied for the year:

> New contracts averaged $1.62 per Mcf for the calendar year 1976
>
> Renegotiated or amended contracts averaged $1.69 per Mcf for the calendar year 1976
>
> Reports for the month of February 1977 show an average price of $1.66 for new contracts and $1.88 for renegotiated or amended contracts.

Historical data trended since 1968 indicate to FPC technical staff, that over the next 12 months, additions to the interstate market may total approximately 2.0 Tcf.

There is a demand/supply imbalance for natural gas at historical prices. There is a fuel reference problem in allocating shortfalls of natural gas. There is a supply eliciting incentive problem when dealing with a depleting resource. There is a problem of equitable balancing of price changes for natural gas among consumer groups, some of whom are physically dependent, largely or totally upon natural gas, some partially, and some optionally, the choice being one of price and alternate fuel availability. Also, consumer groups can be affected differently in their ability, or lack of ability, to pass-through price changes in costs of goods or services, e.g., manufacturing, commercial, utility, transportation or agricultural as opposed to individuals.

Each of the bills before this Subcommittee proposes a legislative response. The concepts differ.

Thank you. I shall be pleased to respond to your questions.

Mr. DINGELL. You indicated some definitional problems. I assume that in due course you will address yourselves to those.

Mr. JOURNEY. The definitional problems that I have, when I was speaking before, were primarily in the rollover sections. The draftsman of the bill, unless I completely misread this bill, intended section 405 to codify 770-A, 406 to deal with the rollover question, 406(c) to deal with intrastate gas going into the interstate market. This is a question of definition, and it is a drafting job to clarify what I think was the intent of the drafters. There I can only go back to the national energy plan.

Mr. Chairman, I don't have any other information.

Mr. DINGELL. Your comments on these points would be of help to us. If you want to discuss that with the administration to make sure, I think it would be helpful. In any event, our staff will be talking to you.

Mr. Forquer?

STATEMENT OF LEO FORQUER

Mr. FORQUER. Mr. Chairman, I have a short prepared statement which I would like to read.

The following comments relate only to title I, part D, sections 401 through 416 of H.R. 6831.

Essentially, the sections relating to gas producer sales prices provide for a system of price setting by the legislative body rather than by an independent agency under standards established by the legislative body.

This is accomplished through the setting of maximum prices for various categories of gas sales, in lieu of the establishment of maximum prices under the Natural Gas Act. The only exceptions are contained in section 406(b) which provides for lower prices and section 408(a) and (b) which provide for higher prices.

It will be noted that the price of new natural gas is determined by formula (section 404). The price under a first sale by a producer of old natural gas under an existing contract is the lesser of the contract price or the just and reasonable rate previously determined by the Federal Power Commission.

In this connection, the rates established by the Commission under its Opinion Nos. 749 and 770 would be the legal rates on the effective date of the legislation irrespective of judicial decisions concerning those opinions. While it is my understanding that the provisions of section 405 were not intended to apply to intrastate contracts, such intention is not explicitly made.

The provisions of section 406(a) and (b) are not clear but it appears that subsection (b) applies to so-called 'rollover' contracts where a previous interstate contract has expired and a new contract entered into after April 20, 1977 pursuant to the definition of a "new contract" in section 402(a)(15). Section 406(b)(2) apparently applies to a new well or a new lease which is old gas by reason of location.

Since the Prudhoe Bay gas in Alaska is not new gas and is not under an existing contract it apparently is covered by the provisions of section 406. Such gas is not included in section 406(b) and is

apparently governed by section 406(c) and could receive $1.75 per Mcf for that gas.

I assume that the reference in that subsection to the "current Btu equivalent price," an undefined term, was meant to refer to the "current Btu related price" as defined in section 402(a)17. The proposed bill does not define the place of sale, but I also assume that wellhead sales are contemplated and the $1.75 price would apply at that point.

If 70 cents per Mcf gas conditioning costs were added to the sales price, the cost would be $2.45 per Mcf at the point of delivery to a pipeline in Alaska. Under the Alaska Natural Gas Transportation Act of 1976, the President's recommendations with respect to Alaska gas will be submitted to the Congress and can be separately treated at that time if considered desirable.

Section 408(a) is a desirable provision permitting prices in excess of the maximum as an incentive for production. It is not clear whether this provision would permit the granting of special relief in cases where the producer cannot economically continue production at existing rates. This is particularly important since under section 408(c) the Commission is prevented from granting relief.

The meaning and purpose of section 412(a) authorizing abandonment by the Federal Power Commission prior to the committing or dedication of natural gas to interstate commerce is not clear.

The provisions of section 414 with respect to incremental pricing and 415 with respect to synthetic gas are drafted in a satisfactory manner. But, in that connection, conversations I have overheard during the recess make me withdraw that.

Mr. DINGELL. The Chair will recognize members at this time. The Chair recognizes the gentleman from Tennessee, Mr. Gore.

Mr. GORE. Thank you, Mr. Chairman.

Mr. Gooch, I was interested in your statement. I thank you for it. I appreciate you being cooperative with the staff in helping us understand these matters. I did want to point out for the record that—and correct me if I am wrong—your perspective is that of a lawyer representing the oil and gas industry at the present time. Is that correct?

Mr. GOOCH. No, sir, it is not. Our clients run the full gamut from small producer to large producer to natural gas transmission companies, to natural gas distribution companies, to industrial users, and to electric utility clients.

Mr. GORE. Everyone but the small user?

Mr. GOOCH. No, sir. Some of our clients are small users too—small producers and small users.

Mr. GORE. Okay. I won't debate the point with you. Do you deny the bulk of your legal business is with gas producers and pipeline companies?

Mr. GOOCH. I would say that probably half of it is producer and pipeline oriented. Half of it is industrial user and electric utility work.

Mr. GORE. Again, I want to put my question in context because I appreciate your testimony. I think a witness' perspective is sometimes important for the record.

You used a figure of $2.40. Did you arrive at that by using the cost methodology which is now under such intensive attack in the courts?

Mr. GOOCH. I used the same cost methodology which was adopted by the Federal Power Commission in Opinion 770-A, and I am one of the people leading one of the hard attacks on that methodology, yes, I am. I used the methodology they used, even though I have it under attack on appeal, yes.

Mr. GORE. On behalf of whom?

Mr. GOOCH. On behalf of some of our producer clients.

Mr. GORE. It is also under attack from other quarters.

Mr. GOOCH. Yes, it is.

Mr. GORE. I won't attempt to pose as a legal expert, but it is my understanding that it is extremely vulnerable to attack from those other quarters.

Mr. GOOCH. We have every hope we will prevail on that appeal.

Mr. GORE. From the other quarters.

Mr. GOOCH. I am sorry.

Mr. GORE. You raise an interesting point when you talk about excess pipeline capacity. Now, in some of our largest cities we have several large pipelines going to that city. I noticed an analogy in your prepared statement to which you did not refer in your oral presentation, to the Penn Central Railroad—a very provocative reference.

Are you suggesting that if total volume continues to decline, that it might be in the national interest to shut down some pipelines and transfer that capacity to the remaining pipelines?

Mr. GOOCH. I suggest that you look into that, yes, I do. That may well be necessary or desirable.

Mr. GORE. How would you continue to amortize the costs of the pipelines shut down?

Mr. GOOCH. You are asking for my personal views?

Mr. GORE. Yes.

Mr. GOOCH. This is a very interesting situation at the present time because you have a problem of whether there will be a gas supply to amortize the whole period that the pipelines project forward to begin with. When you get into the consolidation situation, you are forced then to an election, either to have a government take over or you are going to have to let the pipeline companies recover their investment.

I am not suggesting that their property be confiscated. I am suggesting that you may have to have some form of reorganization, if you get to the point where your gas supply gives you such a bad load factor that you cannot justify three large diameter pipelines delivering gas to a single city.

Mr. GORE. Why wouldn't the so-called free market take care of that problem?

Mr. GOOCH. The free market for transmission capacity?

Mr. GORE. The free market for natural gas that deregulation is supposed to produce.

Mr. GOOCH. There is no—the pipelines themselves are regulated public utilities. There is no—anymore—competition between the interstate pipelines. Their customers are regulated, their sales are

regulated. They cannot even terminate a sale without Federal permission.

Mr. GORE. Could they be used as oil pipelines?

Mr. GOOCH. There are already two pipelines that I am aware of that are either in the process of or seeking approval to convert. I believe there is a line going to Florida that is being converted into a LP or product pipeline. Then there is a project, one or more, dealing with one of El Paso's loops coming from the West Coast.

So, yes, assuming that you have liquid hydrocarbons that need to be transported in one direction or the other.

Mr. GORE. The same would go for coal slurry?

Mr. GOOCH. I don't really know from a technical standpoint whether gas or oil pipelines can be converted to coal slurry, I don't know.

Mr. GORE. Mr. Solomon, do you have an opinion on that?

Mr. SOLOMON. Not on the last question. But there is another possible way, outside of the ultimate way. The ultimate handling of this problem, if pipeline facilities are no longer useful before they have been depreciated, is to remove them from service and amortize the remaining cost over some period of time, which means the customers are paying—well, not as much as they otherwise would, but paying for these costs while it is being amortized.

Another possible way of handling excess capacity, which the Commission staff at least has suggested in an early stage in the Alaskan case, was the possibility that by displacement, new sources of gas coming into the market at different places can make use of existing pipelines which otherwise would not be useful. That also can make use of unused capacity.

Mr. GORE. If I could conclude with one brief statement, Mr. Chairman. I think that the situation we are facing with regard to excess pipeline capacity is illustrative of the situation the entire Nation is facing with regard to oil and gas. We have a declining supply, and increasing demand. We have an industry which has grown up in an artificial environment, nurtured by government control. The consequences of removing the government from that area poses enormous economic consequences and costs which are unacceptably high to the consumers of energy in this country.

Mr. SOLOMON. You want to be aware, Congressman Gore, that the Commission is attempting now, in its depreciation practices, to, within limits at least, look forward to this. For example, they don't set depreciation rates for an offshore line which is only going to a limited production field on the same basis as a line which is going to be able to get gas from various sources.

The depreciation period for the offshore line may be just about half as long as the other one. So, they are attempting, by more or less conventional means, to look forward to these problems. They are not just fixing depreciation in the standard way upon the physical life of the property.

Mr. GORE. I thank the chairman for his indulgence.

Mr. DINGELL. The time of the gentleman has expired. The Chair recognizes the gentleman from Louisiana, Mr. Moore.

Mr. MOORE. Thank you, Mr. Chairman.

Mr. Journey, does the Federal Power Commission have any figures on costs of drilling used by the FPC in coming out with 770-A?

Mr. JOURNEY. Do we have data since 770-A?

Mr. MOORE. Yes.

Mr. JOURNEY. We have a rulemaking proceeding that we have initiated to take care of the next biennium, which would generate that kind of material. It is not presently complete. Some materials are coming back in that docket, RM 77-13. One of the questions that the Chairman got this morning is to provide the committee with a summary of what is there. We intend to do that. That will tell you essentially what is presently existant.

Mr. MOORE. Thank you.

Mr. Gooch, on page 43 we talk about increasing amounts of higher privileged gas, wasteful industries, more fuel usage have moved in the intrastate market. In your opinion, is there any wasteful use of natural gas in substantial amounts in the interstate market at the present?

Mr. GOOCH. Sir, it seems to me that neither market is without some oportunity for criticism on that point. If you look at the situation, you can see vast quantities of natural gas going up under interruptible contracts, offpeak contracts, in the interstate market, even in calendar year 1978. You can see boiler fuel use of gas in the intrastate market, too.

In the State of Texas there is a Docket 600, for example, the Railroad Commission is ordering a phase-out of boiler fuel use of natural gas in Texas. It seems to me it is a stouter phase-out than what the present law is for boiler fuel use in the interstate market.

So, I would have to say that there appears to me to be at least no basis for singling out the intrastate market for its end use of gas.

Mr. MOORE. Mr. Journey, I would like to ask you a question. When an interstate pipeline is carrying less than its capacity—let's assume it is running at 65 percent of its capacity—who bears the cost ultimately of that pipeline not operating efficiently in carrying as high a capacity a possible, 90, 95 and 100 percent capacity? Who ultimately bears that cost?

Mr. JOURNEY. The way the cost allocation procedures work, those customers who remain on the line pick up the cost unless it could be said in a rate proceeding that it was an imprudent expenditure, and therefore to be disallowed for cost of service purposes.

Mr. MOORE. In other words, if I understand you correctly, an interstate pipeline that has not acted improperly, just can't purchase the gas it needs, and sustains curtailments, or can't get gas to bring new customers on the line, the chances are that the small businesses, the party one or two users that may be serviced by that line would pay the cost of the inefficiency of that line.

Mr. JOURNEY. The resale purchasers would find the pipelines would be filing for demand adjustment charges and other ways of trying to insure that their overall costs are recouped.

Mr. MOORE. It passed those on?

Mr. JOURNEY. Passed those on. For the committee's historical interest, if the staff wishes to make a note of it, this problem came up in the 1930s with the communications industry and the traction systems. You will find that leading up to the holding company write-offs of 1935 there is a whole body of case law, administrative

and judicial, on excess capacity. It is in the annals of the section 11 proceedings of the SEC.

Mr. MOORE. Thank you. I yield the balance of my time to the gentleman from Ohio.

Mr. BROWN. Let me clarify the point you were making about the case law. The case law has established that the costs that are fixed costs would be passed on, then, to the consumers if there is no evidence of improper action by the utility.

Mr. JOURNEY. That is what a lot of that case law generated in the early thirties says, yes, sir.

Mr. BROWN. And so the result of the fact that the prices have been held down, and the gas does not flow through the pipe to the extent that the pipe can carry the gas—in other words, less than capacity—means that the consumer pays more money for less gas, isn't that it? Would you all agree that is the result?

Mr. GOOCH. Yes, sir.

Mr. JOURNEY. That is the arithmetic of it.

Mr. BROWN. So those folks who have been pushing us for all these years to hold down the price of natural gas, and given us the result in Ohio, for instance, where we are on an interstate line, that we don't get the gas we need, have actually pushed the price for each unit of gas consumed by the consumer, whether it is an industrial, residential or who, higher and higher and higher.

Isn't that right?

Mr. GOOCH. Yes, sir.

Mr. BROWN. Thank you.

Mr. DINGELL. The witnesses can answer the question. The Chair advises that the time of the gentleman from Ohio has expired.

Mr. BROWN. I guess it should be answered with other than a nod.

Mr. DINGELL. We have had occasion to observe that the reporter does not have a "nod" key on his machine.

Mr. GOOCH. The answer was yes.

Mr. JOURNEY. I indicated yes.

Mr. SOLOMON. The answer is yes in a general sense. Now, which consumers get it, whether it is the Ohio consumers or the other consumers in different States depends on another problem, which is allocation of these costs among zones and things like that, and as to how you allocated costs between demand and commodity charges.

So, when you say it goes to a particular area, you raise a number of other questions. Generally speaking, obviously costs which are prudent—as far as I know the Commission has never found in recent years that any pipeline costs were imprudent—go to, have to be paid for by the consumers.

Mr. DINGELL. The time of the gentleman has expired.

The Chair recognizes the gentleman from Michigan, Mr. Stockman.

Mr. STOCKMAN. Thank you, Mr. Chairman. I would like to follow up on this same line of reasoning. It seems to me that one effect of forcing low priority users off the systems will be a potential reduction in load in the pipelines. It seems to me another equally important effect is that you are going to get greater load variability on the utilities because you are going to have essentially residential and to some degree commercial users left.

Now, if that is the case, it seems to me that what you are really implying is that the utilities or the pipelines, one of the two, are going to have to procure or build much greater storage capacity than they have today in order to meet this substantially increased load variability that they have over the course of the year, assuming they have the same amount of flowing gas, or a declining level of flowing gas.

I am wondering if any of you have any figure, even ballpark figures, on the costs of storage capacity. As I understand, it is pretty expensive and that is going to flow through to the consumer as well. Would any of you want to comment on that?

Mr. GOOCH. I would. Before we get to the storage, though, let me say that that appears to me to be what the purpose of the synthetic natural gas provisions of this bill is, to provide for that fact. The consequences are you have extremely costly plants.

Mr. STOCKMAN. Peaking capacity?

Mr. GOOCH. No, they cannot operate at a peaking. That is the problem. In order to make their economics any good at all, they have to run longer than just the peak, which means that somebody has got to carry those plants when they are not being used for the residential and commercial market.

If you look in your own State, sir, last year, you will find over a billion cubic feet of natural gas under electric utility boilers at the same time SNG plants were being run.

Mr. STOCKMAN. I am aware of that.

Mr. GOOCH. And so somebody has to carry those plants. The only people that can go on and off the gas from time to time are dual-fired interruptible boilers that can be shifted to gas when someone else doesn't need it, and some other fuel when they do.

So, what you really do is squeeze the high priority industrials off the line and put boiler fuelers on the line.

Mr. STOCKMAN. In order to meet that, to carry the load during the off-peak season is what you are saying. Would you care to comment on the storage question?

Mr. GOOCH. Storage has the same potential. It is obviously more costly. I do not have in mind any particular figures on the storage charges, though.

Mr. STOCKMAN. As I understood it this last winter there were some exchanges or trades between flowing gas and stored gas in the order of two to one or two and a half to one.

Now, that could reflect merely the emergency conditions of the need for gas availability. It might indicate something about the relative costs of the two as well.

Would you comment on that?

Mr. JOURNEY. If you are talking about some of those proposals that were made under the Emergency Natural Gas Act, some of them initially were replacement cost of gas concepts—if they took it out of storage, what would it cost to replace it.

Mr. STOCKMAN. That is what I am getting at, right.

Mr. JOURNEY. As I understood your question, initially you were getting to the capital and the operating costs of operating a storage system, either on a distributing system or a pipeline.

Mr. STOCKMAN. Right.

Mr. JOURNEY. If you would like whatever analyses we have at the FPC on that, I will certainly be glad to supply that for the record.

Mr. STOCKMAN. Right. We would appreciate that.

[The following material was received for the record:]

May 20, 1977

Memorandum to: Drexel D. Journey

From: Kenneth A. Williams

Subject: Data for Congressional Response

Pursuant to your memo of May 18, attached are charts indicating summary data on storage expenses and plant in relation to other costs for the jurisdictional Class A & B natural gas pipeline companies. Also included are tables containing, among others, details of cost data for those pipeline companies serving Michigan.

This material is excerpted from the FPC publication "Statistics of Interstate Natural Gas Pipeline Companies—1975" which is compiled from the individual FPC Form 2 filings of the companies.

We, of course, do not have comparable data on distribution companies.

Figure 2

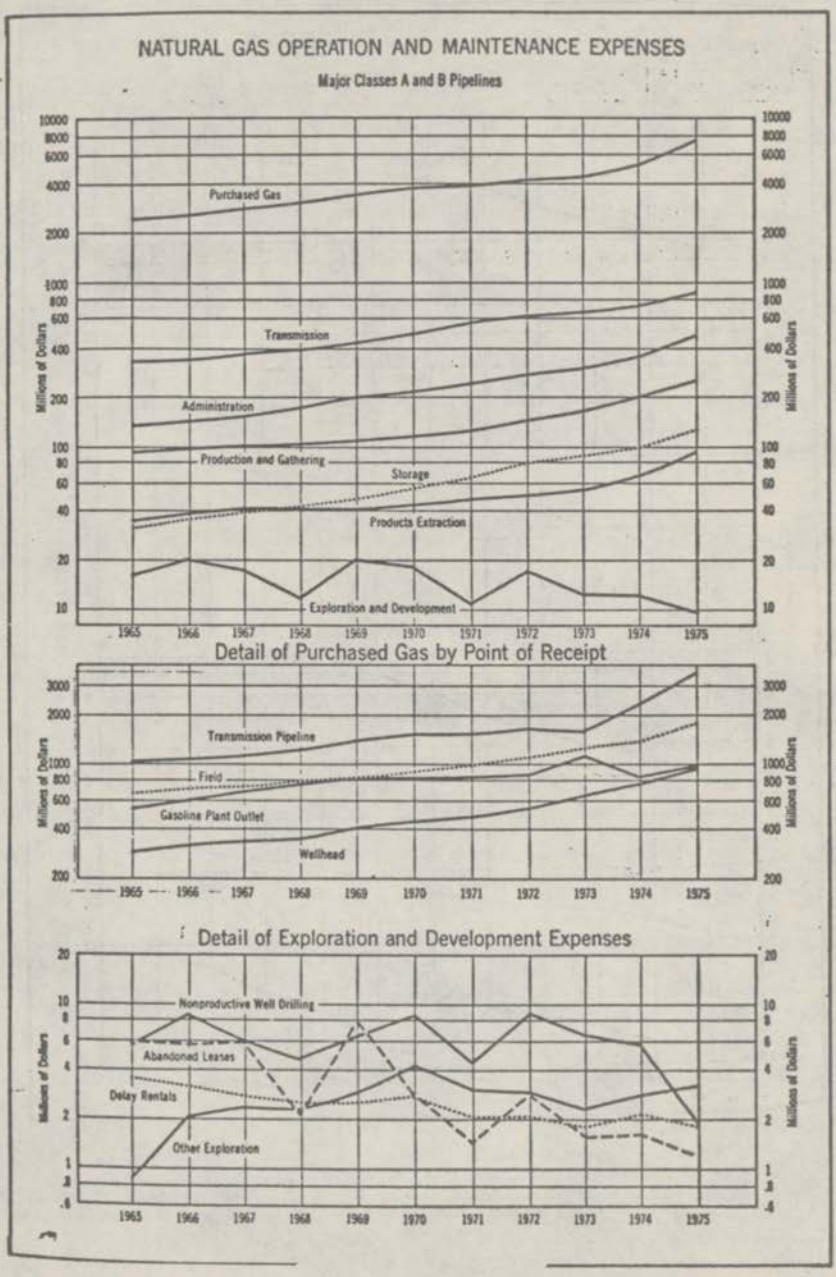
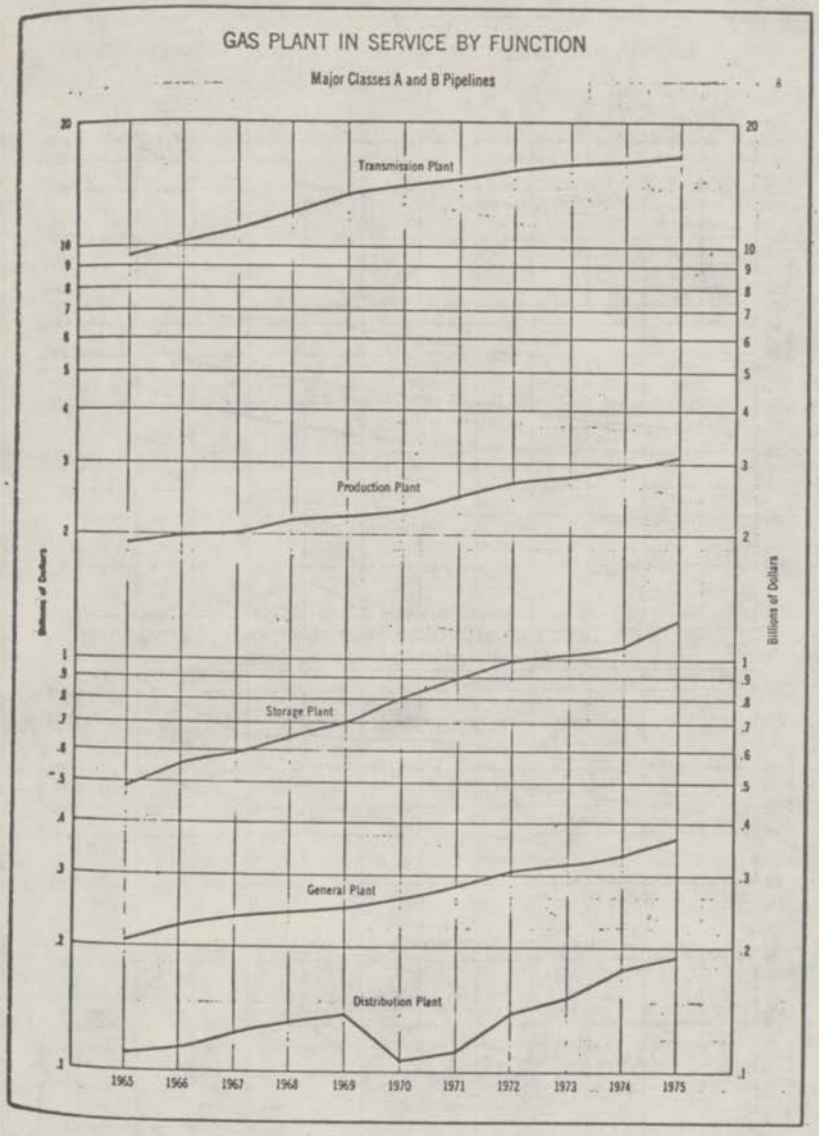

NATURAL GAS OPERATION AND MAINTENANCE EXPENSES
Major Classes A and B Pipelines
Millions of Dollars
Purchased Gas
Transmission
Administration
Production and Gathering
Storage
Products Extraction
Exploration and Development
1965
1966
1967
1968
1969
1970
1971
1972
1973
1974
1975
Detail of Purchased Gas by Point of Receipt
Transmission Pipeline
Field
Gasoline Plant Outlet
Wellhead
Detail of Exploration and Development Expenses
Nonproductive Well Drilling
Abandoned Leases
Delay Rentals
Other Exploration

Figure 3


GAS PLANT IN SERVICE BY FUNCTION
Major Classes A and B Pipelines
Transmission Plant
Production Plant
Storage Plant
General Plant
Distribution Plant
Billions of Dollars
20
10
9
8
7
6
5
4
3
2
1
.9
.8
.7
.6
.5
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1965
1966
1967
1968
1969
1970
1971
1972
1973
1974
1975

STATISTICS OF INTERSTATE NATURAL GAS PIPELINE COMPANIES FOR YEAR ENDED DECEMBER 31, 1978

Gas Operation and Maintenance Expenses

Line No.	Item	Natural Gas Interstate Gas Corporation	American Gas Storage Company	Appalachian Wisconsin Pipe Line Company	Bay Louisiana Gas Company	Big Sandy Gas Transmission Company	Blue Ridge Transmission Corporation	Northern Natural Utilities, a Division of Enron Corp.	Mountain Fuel Supply Company
1									
2	**PRODUCTION EXPENSES**								
3	Operation (and gas purchases)								
4									
5	Natural gas production and gathering								
6	Operation - Supervision and engineering			329 210	21 679			30 109	935 277
7	Production maps and records				2 443			2 550	56 767
8	Gas wells expenses			42 977	46 435		44 226	53 127	94 046
9	Field lines expenses			801 595	36 962			33 570	134 945
10	Field compressor station expenses			600 344	3 210		52 168	2 255	245 161
11	Field compressor station fuel and power			1 253 351			42 125	3 660	35 247
12	Field measuring and regulating station expenses			477 604	41 715			71 453	467 872
13	Purification expenses			25 473	9 644		1 187	34 996	97 443
14	Gas well royalties			94 054	24 222		94 552	120 453	2 194 534
15	Other expenses			10 006	2 334		19	24 940	440 395
16	Rents			69 045				4 431	76 190
17	Total operation			4 007 106	208 112		233 418	435 240	4 747 147
18	Maintenance - Supervision and engineering			95 479				30 253	23 122
19	Structures and improvements			180 989				6 680	39 327
20	Producing gas wells				25 340			74 861	52 166
21	Field lines			572 260	36 702			51 161	24 948
22	Field compressor station equipment			686 696	42			54 869	212 204
23	Field measuring and regulating station equipment			21 931	3 998			18 127	191 716
24	Purification equipment			7 941				14 479	54 963
25	Drilling and clearing equipment								
26	Other equipment			1 437	112				27 671
27	Total maintenance			1 495 832	69 194		52 227	255 816	601 595
28	Total gas prod. and gathering expenses			5 502 938	277 306		285 645	691 056	5 348 742
29	Products extraction								
30	Operation - Supervision and engineering						929		
31	Labor						5 657		
32	Gas shrinkage						6 550		
33	Fuel						6 542		
34	Power						6 447		
35	Materials						3 336		
36	Supplies and expenses						355		
37	Gas processed by others						182 953		
38	Royalties on products extracted								
39	Marketing expenses								
40	Products purchased for resale								
41	Variations in products inventory								
42	Extracted products used by the utility--Cr.								
43	Rents								
44	Total operation						214 955		
45	Maint. - Supervision and engineering								
46	Structures and improvements								
47	Extraction and refining equipment								
48	Pipe lines								
49	Extracted products storage equipment								
50	Compressor equipment						36		
51	Gas measuring and regulating equipment								
52	Other equipment						470		
53	Total maintenance						506		
54	Total products extraction expenses						215 461		
55	Exploration and development								
56	Delay rentals							2 279	1 889 973
57	Unsuccessful well drilling								1 667 774
58	Abandoned leases								225 321
59	Other exploration								1 103 343
60	Total exploration and development expenses							2 279	4 886 411
61	Other gas supply expenses								
62	Natural gas well head purchases			41 584 185	1 193 941		29 343 857	3 116 977	17 343 961
63	Natural gas field line purchases			242 423 742	2 944 858		49 272	40 452	
64	Natural gas gasoline plant outlet purchases	3 150 352		48 413 205			2 142 344	6 337 006	9 434 645
65	Natural gas transmission line purchases		30 933 344	187 850 462	3 82y 890	244 787 818	135 248 428	1 128 727	31 338 453
66	Natural gas city gate purchases							843 490	
67	Other gas purchases								
68	Purchased gas cost adjustment	92 713-		8 341 329-	178 293-	2 141 872	1 119 598		
69	Total purchased gas	3 057 639	30 933 344	527 729 256	4 697 356	248 898 940	132 295 531	11 447 894	58 355 454
70	Exchange gas			842 240-	410 050		1 447 344		
71	Purchased gas expenses								
72	Well expenses-purchased gas							84	19 452
73	Operation of purchased gas measuring stations			148 018	34 120			29 251	203 539
74	Maintenance of purchased gas measuring stations			2 442	2 256			7 865	66 362
75	Purchased gas calculation expenses			23 062			51 488	171	17 394
76	Other purchased gas expenses			220 764	3 014		1 304	84 521	140 034
77	Total purchased gas expenses			392 287	39 390		52 792	121 892	446 781
78	Gas withdrawn from underground storage--Dr.		19 814 748	32 843 275	1 494 447	876 648	21 966 804	3 842 185	110 834
79	Gas delivered to underground storage--Cr.		24 994 484-	34 168 782-	2 251 483-	1 529 048-	35 873 217-	2 298 843-	1 597 230-
80	Gas used in utility operations								
81	Gas used for compressor station fuel--Cr.	182 764-	451 733-	17 228 899-	185 125-	4 520 464-	2 423 274-	333 944-	263 984-
82	Gas used for products extraction--Cr.						19 282-	25 749-	
83	Gas used for other utility operations--Cr.		334 447	725 154-	16 826-	35 113-	81 463-	1 324-	24 893-
84	Total gas used in utility operations--Cr.	182 764-	116 714	17 953 048-	194 043-	4 555 561-	2 529 129-	361 442-	247 993-
85	Other gas supply expenses			749 034				48 377-	
86	Total other gas supply expenses	3 554 033	45 885 383	561 854 344	8 548 456	243 741 448	134 457 246	14 544 841	57 147 956
87	TOTAL PRODUCTION EXPENSES	3 554 033	45 885 383	568 356 282	8 817 851	243 741 448	134 958 123	17 221 981	66 816 253
88	NATURAL GAS STORAGE EXPENSES								
89	Underground storage								
90	Oper. - Supervision and engineering		26 655	486 096	26 878	10 602	33 370	8 476	421
91	Map and records				94			9 207	
92	Wells expenses		122 951	1 488 819	8 852	77 706	15 514	6 680	84 512
93	Lines expenses		82 257		242	39 303	23 717	3 892	1 042
94	Compressor station expenses		243 649	959 682	21 047	98 372	161 503	39 091	31 994
95	Compressor station fuel and power		283 170	1 242 338	64 188	20 103	309 394	7 295	45 451
96	Measuring and regulating station expenses			6 687	9 360	19 112		17 812	4 185
97	Purification expenses			111 933	984	73 889			11 428
98	Exploration and development								
99	Gas lease					89 552			53
100	Other expenses		27 962	402 180	4 885	1 795	18 898	2 248	2 773
101	Storage well royalties		2 561			2 814	13 761	38 216	16 964
102	Rents		5 514	22 804 393	11 243	436		110 325	5 234
103	Total operation		814 553	27 321 371	151 749	366 287	608 467	251 945	213 760

Gas Operation and Maintenance Expenses—Cont.

Item	Mississippi River Transmission Corporation	Natural Gas Pipeline Company of America	Northern Natural Gas Company	Northern Natural Gas Transmission Company	Panhandle Eastern Pipe Line Company	Texas Eastern Transmission Corporation	Texas Gas Transmission Corporation	Texas Gas Utilities Co.	Transcontinental Gas Pipe Line Corporation
(a) Natural Gas Storage Expenses—Cont.									
Underground Storage—Cont.									
Operation—									
Supervision and engineering									
Structures and improvements									
Reservoirs and wells									
Lines									
Compressor station equipment									
Measuring and regulating station equipment									
Purification equipment									
Other equipment									
Total operation									
Maintenance—									
Supervision and engineering									
Structures and improvements									
Reservoirs and wells									
Lines									
Compressor station equipment									
Measuring and regulating station equipment									
Purification equipment									
Other equipment									
Total maintenance									
Total underground storage expenses									
Other storage—									
Operation									
Maintenance									
Total other storage expenses									
TOTAL NATURAL GAS STORAGE EXPENSES									
(b) Transmission Expenses									
Operation—									
Supervision and engineering									
System control and load dispatching									
Communication system expenses									
Compressor station labor and expenses									
Gas for compressor stations fuel									
Other fuel and power for compressor stations									
Mains expenses									
Measuring and regulating station expenses									
Transmission and compression of gas by others									
Other expenses									
Rents									
Total operation									
Maintenance—									
Supervision and engineering									
Structures and improvements									
Mains									
Compressor station equipment									
Measuring and regulating station equipment									
Communication equipment									
Other equipment									
Total maintenance									
TOTAL TRANSMISSION EXPENSES									
(c) Distribution Expenses									
Operation									
Maintenance									
TOTAL DISTRIBUTION EXPENSES									
(d) Customer Accounts Expenses									
Supervision									
Meter reading expenses									
Customer records and collection expenses									
Uncollectible accounts									
Miscellaneous customer accounts expenses									
TOTAL CUSTOMER ACCOUNTS EXPENSES									
(e) Sales Expenses									
Supervision									
Demonstrating and selling expenses									
Advertising expenses									
Miscellaneous sales expenses									
TOTAL SALES EXPENSES									
(f) Administrative and General Expenses									
Administrative and general salaries									
Office supplies and expenses									
Administrative expenses transferred—Cr.									
Outside services employed									
Property insurance									
Injuries and damages									
Employee pensions and benefits									
Franchise requirements									
Regulatory commission expenses									
Duplicate charges—Cr.									
Miscellaneous general expenses									
Rents									
Maintenance of general plant									
TOTAL ADMINISTRATIVE AND GENERAL EXPENSES									
TOTAL GAS OPERATION AND MAINTENANCE EXPENSES									
(g) Gas Operation and Maintenance Distribution of Salaries and Wages Charged									
Production—Manufactured gas									
Production—Natural gas (incl. repl. and dist.)									
Other gas supply									
Storage									
Transmission									
Distribution									
Customer accounts									
Sales									
Administrative and general									
Total salaries and wages									
Number of Gas Department Employees									
Regular full-time employees									
Part-time and temporary employees									
Total gas department employees									

Name of respondent: NATURAL GAS PIPELINE COMPANY

STATISTICS OF INTERSTATE NATURAL GAS PIPELINE COMPANIES FOR YEAR ENDED DECEMBER 31, 1978

Gas Operation and Maintenance Expenses

Line No.	Item	Additional Fuel Gas Supply Corporation	Natural Gas Pipeline Company of America	North Penn Gas Company	Northern Natural Gas Company	Northern Utilities, Inc.	Northwest Pipeline Corporation	Ohio River Pipeline Corporation	Oklahoma Natural Gas Gathering Corporation	Line No.
	PRODUCTION EXPENSES									
1	Manufactured gas production	227 299			81 927					1
2	Natural gas production and gathering									2
3	Oper.--Supervision and engineering	327 774	489 981	751	2 440 188	14 949	519 881		27 649	3
4	Production maps and records	29 245	5 506	11 621	35 744		1 986			4
5	Gas wells expenses	851 778	113 089	13 401	137 344	986	247 734			5
6	Field lines expenses	234 894	309 644	35 353	1 394 505	5 527	1 344 258		105 847	6
7	Field compressor station expenses	13 231	710 445		1 474 178	34 283	852 234		74 691	7
8	Field compressor station fuel and power	2 008	917 714		1 850 770	11 842	2 450 629			8
9	Field measuring and regulating station expenses	40 246	311 751	1 979	12 984	22 257	448 494		11 883	9
10	Purification expenses	1 888	407 788		4 217 584	125 451	1 044 235			10
11	Gas well royalties	102 411	1 290 208	27 782	244 780	124	4 347 362			11
12	Other expenses	254 758		1 828	223 211	7 154	192 751			12
13	Rents	29 774	3 250	254	174 314	1 158	40 939			13
14	Total operation	1 836 947	4 752 448	91 743	13 460 348	224 734	11 911 917		220 135	14
15	Maint.--Supervision and engineering	1 238	36 467		111 484	24	1 733			15
16	Structures and improvements	44 931	84 623	274	94 779	794	78 474			16
17	Producing gas wells	484 825	193 252	2 926	29 489		41 304			17
18	Field lines	75 886	141 738	3 737	350 413	1 248	414 484		33 353	18
19	Field compressor station equipment	6 824	955 246		1 484 243	11 847	306 468		37 374	19
20	Field measuring and regulating station equipment	34 059	120 357	533	9 818		45 927		5 984	20
21	Purification equipment	748	87 356		1 277 879	2 794	324 179			21
22	Drilling and cleaning equipment	48 579								22
23	Other equipment	3 531		54			20 448			23
24	Total maintenance	630 623	1 609 844	7 524	3 358 105	16 712	1 039 239		76 711	24
25	Total natural gas prod. and gathering expenses	2 694 814	6 307 707	99 858	16 914 668	240 921	12 141 751		317 279	25
	Products extraction									
26	Oper.--Supervision and engineering	336			53 907		203 729		1 447	26
27	Labor	9 317			947 018		494 952		7 797	27
28	Gas shrinkage				1 335 357		3 186 933			28
29	Fuel				722 682		1 469 948			29
30	Power				2 129					30
31	Materials				86 175		78 180			31
32	Supplies and expenses	69			335 112		131 716		2 299	32
33	Gas processed by others		52 889		461 892					33
34	Royalties on products extracted									34
35	Marketing expenses	400					77 400			35
36	Products purchased for resale						2 814 215			36
37	Variation in products inventory						73 030			37
38	Extracted products used by the utility--Cr.						12 151			38
39	Rents				400		4 479			39
40	Total operation	10 118	52 889		3 944 332		8 807 453		11 543	40
41	Maint.--Supervision and engineering	202			13 119					41
42	Structures and improvements	582			37 423		47 279		4 529	42
43	Extraction and refining equipment	7 810			267 460		245 319		11	43
44	Pipe lines	4			20 098		22 478			44
45	Extracted products storage equipment	96			27 953		14 829			45
46	Compressor equipment				84 950		36 948			46
47	Gas measuring and regulating equipment	48			5 654					47
48	Other equipment	171			54 886		8 461		839	48
49	Total maintenance	8 913			501 543		375 313		5 379	49
50	Total products extraction expenses	19 031	52 889		4 445 875		9 182 766		16 922	50
	Exploration and development									
51	Delay rentals	127 937	7 141	9 299	1 390		19 419			51
52	Dry holes expense	15 948	29 990							52
53	Abandoned leases	4904	93 289		84 551					53
54	Other exploration	10 430			2 289 332					54
55	Total exploration and development expenses	153 153	129 849	9 299	2 377 274		19 419			55
	Other gas supply expenses									
56	Natural gas well head purchases	145 674	29 620 833	912	218 435 133	206 332	35 424 304		4 706 714	56
57	Natural gas field line purchases	2 404 967	61 814 104	131 183	4 617 194	10 035	1 963 371			57
58	Natural gas gasoline plant outlet purchases		143 772 680		48 148 724	3 134 173	2 868 740			58
59	Natural gas transmission line purchases	156 266 374	146 702 740	21 332 604	14 310 004	3 936	313 440 844	3 164 467		59
60	Natural gas city gate purchases				11 290 917					60
61	Other gas purchases	1 440 183				548 382			24 305	61
62	Purchased gas cost adjustments		899 543	340 079	3 442 288		3 242 047		1 020	62
63	Total purchased gas	154 472 834	343 023 695	21 804 252	298 244 245	3 884 443	345 138 249	3 164 467	4 732 039	63
64	Exchange gas		2 031 286	7754	443 118		348 384			64
	Purchased gas expenses									
65	Well expenses--purchased gas	16 772			381 399					65
66	Operation of purchased gas measuring stations	33 573		16 732	1 127 451					66
67	Maintenance of purchased gas measuring stations	14 350		1 032	273 926				848	67
68	Purchased gas calculation expenses	122 474		4 424	144 361	23 276	319 932			68
69	Other purchased gas expenses	838		39	265 879		134 439		8140	69
70	Total purchased gas expenses	195 823	346 838	22 748	2 231 134	23 276	1 317 535		8140	70
71	Gas withdrawn from underground storage--Cr.	37 132 049	24 294 511	5 042 240	9 540 291		7 217 205			71
72	Gas delivered to underground storage--Cr.	40 203 462	35 484 771	8 130 383	13 279 404	495 726	10 320 702			72
73	Gas used in utility operations									73
74	Gas used for compressor station fuel--Cr.	364 191	17 438 820	134 930	17 444 091	40 726	4 746 424			74
75	Gas used for products extraction--Cr.		32 300		1 923 473		3 822 266			75
76	Gas used for other utility operations--Cr.	134 849	2 841 343	42 318	3 511 214	1 529	1 403 234			76
77	Total gas used in utility operations--Cr.	374 240	20 312 463	177 248	22 878 778	42 256	11 972 124			77
78	Other gas supply expenses	24	1 304 849		2 407 079	817 623	173 243			78
79	Total other gas supply expenses	153 035 458	340 885 868	14 102 840	317 474 304	4 481 340	351 157 187	3 164 467	4 732 039	79
80	TOTAL PRODUCTION EXPENSES	154 134 340	347 450 537	14 211 997	332 212 324	4 722 509	371 853 184	3 164 467	4 766 534	80
	NATURAL GAS STORAGE EXPENSES									
	Underground storage									
81	Oper. -- Supervision and engineering	91 849	992 487	3 951	434 862					81
82	Maps and records	34 809		1 872						82
83	Wells expenses	349 558	780 603	13 687	241 475	1 398				83
84	Lines expenses	248 757	180 444	44 480	14 285	44				84
85	Compressor station expenses	424 747	755 484	75 461	78 458	4 965				85
86	Compressor station fuel and power	294 558	652 960	134 455	84 302	319	89 271			86
87	Measuring and regulating station expenses	124 304	72 463	11 674	32 239	1 327				87
88	Purification expenses		304 314	9 378	39 251					88
89	Exploration and development	1 473	20 2830		1 240 481		68 279			89
90	Gas losses	111 936		20 140						90
91	Other expenses	2 155 943	13 872 773	12 998	3 243 199	4 488	224 478			91
92	Storage well royalties	155 040	17 344		40 339	3 941				92
93	Rents	6 541	238 449	480	200					93
94	Total operation	4 348 155	18 414 843	326 183	5 484 110	17 282	582 128			94

STATISTICS OF INTERSTATE NATURAL GAS PIPELINE COMPANIES FOR YEAR ENDED DECEMBER 31, 1975

Gas Operation and Maintenance Expenses—Cont.

Item	National Fuel Gas Supply Corporation	Natural Gas Pipeline Company of America	North Penn Gas Company	Northern Natural Gas Company	Northern Utilities, Inc.	Northwest Pipeline Corporation	Ozark Gas Pipeline Corporation	Columbia Natural Gas Gathering Corporation
NATURAL GAS STORAGE EXPENSES – CONT.								
Underground storage exp.								
Maint. Supervision and engineering	31 863	18 112		27 424				
Structures and improvements	48 734	129 569	10 381	48 743				
Reservoirs and wells	122 097	277 761	16 876	895 736				
Lines	117 176	58 240	1 440	1 238	39			
Compressor station equipment	216 348	640 110	40 900	116 830	1 178			
Measuring and regulating station equipment	16 484	34 921	3 336	754				
Purification equipment	734	244 042	4 023	36 377				
Other equipment	2 434	24 328	1 704	28 218				
Total maintenance	575 536	1 562 413	102 582	1 215 522	1 217			
Total underground storage expenses	6 617 695	18 078 778	429 188	6 709 744	18 253	249 121		
Other storage expenses								
Operation	91 412			218 148		6 860		
Maintenance	81 811			77 053		402		
Total other storage expenses	173 223			295 201		7 262		
TOTAL NATURAL GAS STORAGE EXPENSES	3 858 348	18 078 778	429 188	7 004 944	18 253	249 383		
TRANSMISSION EXPENSES								
Operation								
Supervision and engineering	298 477	3 791 248	3 597	4 956 204	13 956	1 295 413	2 566	1 500
System control and load dispatching	677 600	241 563	94 756	1 000 701	70 749	248 447	243	
Communication system expenses		427 453	1 290	113 869	4 241	305 348		304
Compressor station labor and expenses	979 344	6 554 844		9 815 182	19 793	1 751 462		
Gas for compressor station fuel	368 211	16 005 828		14 686 478	9 324	3 149 824		
Other fuel and power for compressor stations	220 402			318 972				
Mains expenses	458 274	2 043 406	173 750	2 145 518	84 482	2 048 929	13 814	1 000
Measuring and regulating station expenses	224 940	1 439 227	76 348	1 425 298	98 438	621 721	9 449	1 300
Transmission and compression of gas by others	20 489	15 279 776	4 452	14 083 347	231	1 379 410		
Other expenses	158 422	2 316 731	32 239	1 175 432	1 804	168 050		2 004
Rents	5 000	857 940	2 746	118 044	4 347	98 866	10	
Total operation	4 059 924	50 013 048	394 283	51 401 488	232 847	11 528 527	26 309	8 308
Maintenance	40 346	108 619		220 337		516		
Supervision and engineering	112 144	990 544	3 047	603 992	1 250	111 048	23	
Structures and improvements	245 763	1 542 725	36 800	1 404 448	34 883	1 479 591	8 436	452
Mains	253 493	8 571 403		8 991 009	792	920 003		
Compressor station equipment	184 952	430 864	11 434	853 484	4 050	282 298	870	
Measuring and regulating station equipment		1 154 274	4 187	13 123		49 233	224	
Communication equipment		1 154 274	4 187	13 123				
Other equipment	3 844	498 963	4 104	42 287				
Total maintenance	870 542	13 289 474	63 572	6 728 648	43 581	2 764 170	10 073	452
TOTAL TRANSMISSION EXPENSES	4 930 466	63 302 522	457 855	61 130 136	276 428	14 292 697	36 382	8 760
DISTRIBUTION EXPENSES								
Operation			1 007 197	4 310 490				
Maintenance			244 822	1 751 548				
TOTAL DISTRIBUTION EXPENSES			1 251 524	6 062 038				
CUSTOMER ACCOUNTS EXPENSES								
Supervision								
Meter reading expenses			177 830	454 758				2 004
Customer records and collection expenses			830 261	2 262 971				
Uncollectible accounts			12 487	11 693				
Miscellaneous customer accounts expenses			9 215					
TOTAL CUSTOMER ACCOUNTS EXPENSES			949 313	2 733 584				2 004
SALES EXPENSES								
Supervision			1 200	203 966				
Demonstrating and selling expenses				701 994				
Advertising expenses		7 989	527	376 889				
Miscellaneous sales expenses			18					
TOTAL SALES EXPENSES		7 989	1 745	1 283 745				
ADMINISTRATIVE AND GENERAL EXPENSES								
Administrative and general salaries	1 078 485	11 200 497	401 332	12 389 015	173 235	4 948 237		
Office supplies and expenses	517 379	2 242 457	96 837	5 417 111	73 294	2 797 043		
Administrative expenses transferred—Cr.		103 760—		931 463—	341 820—	827 457—		
Outside services employed	283 271	4 930 860	42 480	740 139	68 404	2 167 027	300	152 367
Property insurance	23 366	271 483	7 280	1 050 091	393	313 337	2 445	
Injuries and damages	190 527	324 775	126 276	999 082	10 823	248 014	2 223	
Employee pensions and benefits	2 594 162	9 868 284	487 997	10 288 152	334 706	3 107 337		21 872
Franchise requirements								
Regulatory commission expenses	140 981	499 876	61 871	926 298	3 987	82 465		3 559
Duplicate charges—Cr.			8 577—					
Miscellaneous general expenses	235 831	4 129 252	49 216	2 360 299	880	1 058 442	524	330
Rents	9 459	1 100 754	4 017	25 128	6 976	491 209		
Maintenance of general plant	127 312	145 597	28 470	843 248	7 403	14 916		
TOTAL ADMINISTRATIVE AND GENERAL EXPENSES	5 201 353	34 404 347	1 287 434	33 345 999	324 467	14 438 913	5 492	178 584
TOTAL O&M OPERATION AND MAINTENANCE EXPENSES	773 181 674	963 443 048	23 249 492	618 745 552	7 103 443	401 845 810	3 187 907	5 274 414
DEFERRED PORTION OF SALARIES AND WAGES CHARGED TO O&M OPERATION AND MAINTENANCE								
Production—Manufactured gas	82 322			28 303				
Production—Natural gas (excl. expl. and dev.)	1 615 201	2 904 491	60 628	7 921 738	120 809	3 699 187		
Other gas supply	123 978	521 452	17 474	2 248 608	22 760	345 693		
Storage	1 240 999	1 807 271	140 937	1 023 804		3 293		
Transmission	2 958 120	16 825 681	290 819	18 903 615	229 720	5 095 060		
Distribution			1 025 401	6 007 611				
Customer accounts			388 283	2 272 779				
Sales			1 219	660 230				
Administrative and general	1 647 878	11 520 420	454 756	12 348 540	62 865	4 949 237		
Deferred both charged, credited, or both to salaries and wages	189 476	112 025	104 812	253 436	57 883	328 433		
TOTAL DEFERRED PORTION OF SALARIES AND WAGES	8 167 972	33 791 344	2 484 329	51 765 617	493 249	14 419 913		
NUMBER OF EMPLOYEES								
Regular full-time employees	162	2 242	244	3 964	170	1 021		
Part-time and temporary employees	6	34	10	142	5	18		
TOTAL NUMBER OF EMPLOYEES	172	2 276	254	4 106	175	1 039		

Name of respondent: INTERSTATE NATURAL GAS PIPELINE COMPANY.

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STATISTICS OF INTERSTATE NATURAL GAS PIPELINE COMPANIES FOR YEAR ENDED DECEMBER 31, 1976

Gas Operation and Maintenance Expenses

Line No.	Item	Arkansas Louisiana Gas Company	Pacific Gas Transmission Company	Panhandle Eastern Pipe Line Company	Pennsylvania & Southern Gas Company	Stanline Pipe Line Company	Texas Eastern Transmission Company	Texas Gas Transmission Corporation	Texas Gulf Coast Natural Gas Company	Line No.
	PRODUCTION EXPENSES									
1	Natural gas production	72 429			11 972					1
	Natural gas production and gathering									
2	Oper. — Supervision and engineering			623 032			2 622			2
3	Production maps and records									3
4	Gas well expenses			1 201 303						4
5	Field lines expenses			2 805 110						5
6	Field compressor station expenses			1 998 526						6
7	Field compressor station fuel and power									7
8	Field measuring and regulating station expenses			375 600						8
9	Purification expenses									9
10	Gas well royalties			823 762						10
11	Other expenses			10 830						11
12	Rents			7 019 763			18 856			12
13	Total operation			787 879			15 456			13
14	Maint. — Supervision and engineering			69 018			126			14
15	Structures and improvements									15
16	Producing gas wells			902 731						16
17	Field lines			1 742 790						17
18	Field compressor station equipment									18
19	Field measuring and regulating station equipment			40 606						19
20	Purification equipment									20
21	Drilling and cleaning equipment									21
22	Other equipment			2 429 032			124			22
23	Total maintenance			5 834 772			19 126			23
24	Total net gas prod. and gathering expenses			6 027						24
25	Products extraction									25
26	Oper. — Supervision and engineering									26
27	Labor									27
28	Gas shrinkage									28
29	Fuel									29
30	Power									30
31	Materials									31
32	Supplies and expenses			22 933						32
33	Gas processed by others									33
34	Royalties on products extracted									34
35	Marketing expenses									35
36	Products purchased for resale									36
37	Variation in products inventory									37
38	Extracted products used by the utility—Cr.									38
39	Rents			10 940						39
40	Total operation									40
41	Maint. — Supervision and engineering									41
42	Structures and improvements									42
43	Extraction and refining equipment									43
44	Pipe lines									44
45	Extracted products storage equipment									45
46	Compressor equipment									46
47	Gas measuring and regulating equipment									47
48	Other equipment									48
49	Total maintenance			10 940						49
50	Total products extraction expenses									50
51	Exploration and development									51
52	Delay rentals									52
53	Nonproductive well drilling									53
54	Abandoned leases									54
55	Other exploration									55
56	Total exploration and development expenses									56
57	Other gas supply expenses			42 343 411						57
58	Natural gas well head purchases			30 994 815			123 219 431			58
59	Natural gas field line purchases			32 409 718						59
60	Natural gas gasoline plant outlet purchases		946 332 946	116 721 046						60
61	Natural gas transmission line purchases	25 254 443			3 455 606			2 780 454	13 846 300	61
62	Natural gas city gate purchases	4 004 260								62
63	Other gas purchases	74 257		5 775 176			24 474 335	677 471		63
64	Purchased gas cost adjustments	29 337 960	946 332 946	245 433 402	3 455 606		147 717 166	3 744 475	13 846 300	64
65	Total purchased gas			1 118 470			5 168			65
66	Exchange gas									66
67	Purchased gas expenses			970 298			284 790		3 781	67
68	Well expenses—purchased gas	4 305		142 987			41 523		1 521	68
69	Operation of purchased gas measuring stations	4 794		127 534			17 330			69
70	Maintenance of purchased gas measuring stations	14 262		2 894 907			159 374	2 460		70
71	Purchased gas calculation expenses	41 253		4 143 717			417 817	2 460	7 312	71
72	Other purchased gas expenses	34 726		8 579 343						72
73	Total purchased gas expenses			4 027 332						73
74	Gas withdrawn from underground storage—Dr.									74
75	Gas delivered to underground storage—Cr.									75
76	Gas used in utility operations		16 373 988	11 742 080			1 425 580		47 194	76
77	Gas used for compressor station fuel—Cr.									77
78	Gas used for products extraction—Cr.	3 754 954		1 303 191	8 826		58		18 022	78
79	Gas used for other utility operations—Cr.	3 754 954	16 373 988	13 044 190	8 826		1 425 654		65 216	79
80	Total gas used in utility operations—Cr.	1 746	56 161	319 467			1 347 521			80
81	Other gas supply expenses	23 467 224	459 032 031	253 781 574	3 446 212		145 179 417	3 749 549	13 836 794	81
82	Total other gas supply expenses	53 718 853	505 917 031	263 251 631	3 476 189		304 347 238	3 749 549	13 836 794	82
83	TOTAL PRODUCTION EXPENSE									83
84	NATURAL GAS STORAGE EXPENSES									84
85	Underground storage			189 998						85
86	Oper. — Supervision and engineering			39 793						86
87	Wells expenses			76 252						87
88	Lines expenses			87 253						88
89	Compressor station expenses			198 237						89
90	Compressor station fuel and power			165 463						90
91	Measuring and regulating station expenses			42 006						91
92	Purification expenses			15 932						92
93	Exploration and development			39 886						93
94	Gas losses									94
95	Other expenses			168 986						95
96	Storage well royalties			70 836						96
97	Rents									97
98	Total operation			1 129 756						98

STATISTICS OF INTERSTATE NATURAL GAS PIPELINE COMPANIES FOR YEAR ENDED DECEMBER 31, 1978

Gas Operation and Maintenance Expenses--Cont.

Line No.	Item	Orange and Rockland Utilities, Inc.	Pacific Gas Transmission Company	Panhandle Eastern Pipe Line Company	Pennsylvania & Southern Gas Company	Pipeline Pipe Line Company	Rio Bravo Pipeline Company	Southern Natural Gas Company	Texas Gas Transmission Corporation	Line No.
	NATURAL GAS STORAGE EXPENSES - CONT.	$	$	$	$	$	$	$	$	
	Underground storage exp.									
92	Maint. - Supervision and engineering			84 878						92
93	Structures and improvements			518 234						93
94	Reservoirs and wells			45 481						94
95	Lines			24 490						95
96	Compressor station equipment			161 811						96
97	Measuring and regulating station equipment			81 231						97
98	Purification equipment			16 489						98
99	Other equipment			1 388						99
100	Total maintenance			931 502						100
101	Total underground storage expenses			1 460 331						101
102	Other storage									102
103	Operation									103
104	Maintenance									104
105	Total other storage expenses									105
106	TOTAL NATURAL GAS STORAGE EXPENSES			1 460 331						106
107	TRANSMISSION EXPENSES									107
108	Oper. - Supervision and engineering		288 831	3 417 471	9 243	44 134	45 233	285	32 791	108
109	System control and load dispatching		121 577	222 237	4 744	53	35 537		48 404	109
110	Communication system expenses		49 271	42 349			72 612		15 381	110
111	Compressor station labor and expenses		847 261	5 855 771			624 826		34 441	111
112	Gas for compressor station fuel		18 879 300	9 819 397			1 416 586		47 463	112
113	Other fuel and power for compressor stations			8 947			12 048			113
114	Mains expenses		198 794	2 340 540	11 561	. 3 128	276 781	13 135	154 110	114
115	Measuring and regulating station expenses		46 712	722 990		1 582	44 389	4 338	77 622	115
116	Transmission and compression of gas by others			18 721						116
117	Other expenses		304 635	2 203 883		408				117
118	Rents		1 154	47 650		512	8 436	95	16 905	118
119	Total operation		20 453 537	25 851 452	25 548	46 896	2 870 610	19 877	431 734	119
120	Maint. - Supervision and engineering		119 282	1 714 209			22 116	39		120
121	Structures and improvements		34 182	1 070 224			1 351	46	4 487	121
122	Mains		52 179	1 377 644		9 624	239 424	9 323	25 557	122
123	Compressor station equipment		1 413 282	4 561 980			408 405		28 692	123
124	Measuring and regulating station equipment		18 434	369 343		168	4 012	2 564	47 151	124
125	Communication equipment		101 174	413 204			22 059		32 124	125
126	Other equipment		3 807	115 533		338				126
127	Total maintenance		1 741 857	12 457 317	6 116	10 130	697 370	12 972	142 131	127
128	TOTAL TRANSMISSION EXPENSES		22 195 394	38 308 769	31 664	57 026	3 568 980	32 849	573 865	128
129	DISTRIBUTION EXPENSES									129
130	Operation	1 349 999			314 854			140 748		130
131	Maintenance	1 245 218			205 429			136 279		131
132	TOTAL DISTRIBUTION EXPENSES	2 595 217			520 283			276 186		132
133	CUSTOMER ACCOUNTS EXPENSES									133
134	Supervision	9 759		61 943	732				1 477	134
135	Meter reading expenses	104 002		43 630	41 797		9 135	29 252	23	135
136	Customer records and collection expenses	419 908		364 278	150 908			89 524	12 836	136
137	Uncollectible accounts	98 487			28 668					137
138	Miscellaneous customer accounts expenses	19 880			28 113					138
139	TOTAL CUSTOMER ACCOUNTS EXPENSES	652 136		369 851	251 218		9 135	88 836	14 336	139
140	SALES EXPENSES									140
141	Supervision	334			152					141
142	Demonstrating and selling expenses	21 713		186 386	6 144			3 389		142
143	Advertising expenses	21 240			210			2 461	962	143
144	Miscellaneous sales expenses	479		30 052	1 321			335		144
145	TOTAL SALES EXPENSES	73 766		138 368	3 216			6 721	962	145
146	ADMINISTRATIVE AND GENERAL EXPENSES									146
147	Administrative and general salaries	408 864	1 212 422	7 176 787	133 537			198 768	187 184	147
148	Office supplies and expenses	101 623	323 427	2 845 084	13 472		19 908	48 552	87 556	148
149	Administrative expenses transferred--Cr.	94 823-	122 442-	1 128 168-	950-				1 962-	149
150	Outside services employed	171 323	199 300	1 021 031	36 523	27 686	1 324 284	12 944	82 602	150
151	Property insurance	29 871	41 941	526 124	69 466		1 246 349	7 857	1 909	151
152	Injuries and damages	58 994	76 878	304 893	730		5 827	20 961	14 931	152
153	Employee pensions and benefits	482 823	397 351	6 340 846	48 743			121 714	172 816	153
154	Franchise requirements									154
155	Regulatory commission expenses	121 765	89 850	115 482	22 446		98 898	2 987	8 848	155
156	Duplicate charges--Cr.	27 979-								156
157	Miscellaneous general expenses	136 964	95 904	4 496 893	9 821		3 298	11 151	9 894	157
158	Rents	54 536	187 [illegible]	1 167 533	27 848		65			158
159	Maintenance of general plant	13 868	4 853	65 145				10 828	48 428	159
160	TOTAL ADMINISTRATIVE AND GENERAL EXPENSES	1 693 [illegible]	2 624 [illegible]	23 [illegible] 152	374 [illegible]	27 686	2 [illegible] 856	424 [illegible]	[illegible] 372	160
161	TOTAL GAS OPERATION AND MAINTENANCE EXPENSES	29 [illegible] 926	474 [illegible] 377	326 [illegible] 474	4 [illegible] 948	57 [illegible] 814	[illegible] 485 [illegible]	6 [illegible] 418	17 [illegible] 878	161
	DISTRIBUTION OF SALARIES AND WAGES CHARGED TO GAS OPERATION AND MAINTENANCE									
162	Production--Manufactured gas	34 264			3 426					162
163	Production--Natural gas (incl. expl. and dev.)			2 496 799						163
164	Other gas supply	34 380		1 339 640				1 868	3 282	164
165	Storage			404 428						165
166	Transmission		1 660 962	13 234 919		34 899		14 455	343 194	166
167	Distribution	2 819 471			290 297			210 921		167
168	Customer accounts	994 888		178 084	138 148			69 823	13 334	168
169	Sales	41 080		103 947	4 166			1 868		169
170	Administrative and general	434 453	1 104 862	6 710 049	121 745			214 484	213 569	170
171	Allocated from affiliated companies	218 338	193 [illegible]	7 [illegible] 384				20 [illegible]	1 [illegible]	171
172	TOTAL SALARIES AND WAGES	3 [illegible] 194	2 [illegible] 144	31 [illegible] 312	[illegible] 402	34 899		[illegible] 412	[illegible] 559	172
	NUMBER OF GAS DEPARTMENT EMPLOYEES									
173	Regular full-time employees	309	175	2 422	195			45	32	173
174	Part-time and temporary employees		[illegible]	[illegible]	[illegible]			[illegible]	[illegible]	174
175	TOTAL GAS DEPARTMENT EMPLOYEES	327	175	2 [illegible]	199			[illegible]	[illegible]	175

*Reader Interstate Natural Gas Pipeline Company.

Gas Utility Plant, Gas Account, Physical Quantities

Line No.	Item	Acadian Gas Corporation	Arkansas Gas Storage Company	Arkansas Western Pipe Line Company	Big Louisiana Gas Company	Mississippi Gas Transmission Company	Mississippi River Fuel Transmission Corporation	Monsanto Chemical Utilities Co.	Natural Gas Pipeline Company
	SUMMARY GAS UTILITY PLANT ACCOUNTS								
1	Gas plant in service	$ 9 878 120	$ 31 874 114	$ 316 727 648	$ 37 044 744	$ 134 103 831	$ 223 749 463	$ 141 806 575	$ 100 134 [illegible]
2	Gas plant leased to others				4 880				
3	Gas plant held for future use			20 857 344	328 741		448	282 043	14 494 [illegible]
4	Construction work in progress	250 830	34 340 740		454 518	4 894	948 825	1 856 445	5 [illegible]
5	Gas plant acquisition adjustments								
6	Total	9 878 120	31 874 114	337 585 192	38 454 525	134 108 725	224 718 435	144 130 181	338 [illegible]
7	Accumulated provisions for depreciation, amortization, and depletion	2 864 217	18 847 143	249 234 446	24 776 825	42 472 853	107 670 946	54 431 747	111 234 [illegible]
8	Net gas utility plant	7 013 903	13 027 [illegible]	88 350 746	13 677 700	91 635 872	117 047 489	89 698 434	226 [illegible]
	GAS UTILITY PLANT IN SERVICE								
9	INTANGIBLE PLANT	105 857	33 467	2 270 231		1 334 043	29 512		76 [illegible]
10	MANUFACTURED GAS PRODUCTION PLANT								
	NATURAL GAS PRODUCTION PLANT								
	Production and gathering plant								
11	Producing lands			2 840	174 381			31 459	
12	Producing leaseholds			263 513	3 218 477		2 870 229	1 227 488	4 [illegible]
13	Gas rights				42 952			34 115	
14	Rights-of-way			2 813 870			406 886	39 127	98 [illegible]
15	Other land and land rights			98 719				2 084	174 [illegible]
16	Gas well structures								216 [illegible]
17	Field compressor station structures			11 845 540	80 673		18 106	21 050	423 [illegible]
18	Field measuring and regulating station structures			194 541	750		11 057	75 448	448 [illegible]
19	Other structures			976 748	5 886 270		44 047	162 354	7 245 [illegible]
20	Producing gas wells--well construction			11 049 448	2 828 344		961 856	1 454 908	12 304 [illegible]
21	Producing gas wells--well equipment			2 252 247	3 745 121		319 713	718 420	8 488 [illegible]
22	Field lines			144 594 507	4 714		10 302 745	3 230 644	15 944 [illegible]
23	Field compressor station equipment			28 795 230	521 988		1 238 421	207 548	6 532 [illegible]
24	Field measuring and regulating station equipment			6 369 234			484 438	317 026	3 438 [illegible]
25	Drilling and cleaning equipment							29 480	334 [illegible]
26	Purification equipment			1 991 893				737 515	1 002 [illegible]
27	Other equipment			12 395				51 257	834 [illegible]
28	Unsuccessful exploration and development costs			14 451 253				2 344 478	
29	Total production and gathering plant			233 338 291	15 687 886		15 891 243	12 742 041	70 665 [illegible]
	Products extraction plant								
30	Land and land rights						8 899		
31	Structures and improvements						161 000	10 816	
32	Extraction and refining equipment						25 370		
33	Pipe lines						29 347		
34	Extracted products storage equipment						21 027		
35	Compressor equipment						4 364		
36	Gas measuring and regulating equipment						27 433		
37	Other equipment						261 956	10 816	
38	Total products extraction plant			233 338 291	15 687 886		16 153 199	12 752 857	70 665 [illegible]
39	TOTAL NATURAL GAS PRODUCTION PLANT								
	NATURAL GAS STORAGE PLANT								
	Underground storage plant								
40	Land	27 991		283 241	193 304	81 404	23 999	2 383	536 [illegible]
41	Rights-of-way	46 213		208 448	67 016	31 086	179 983		4 344 [illegible]
42	Structures and improvements	944 627		3 224 302	2 231 932	779 550	315 841	93 483	155 683 [illegible]
43	Wells	5 995 839		4 205 308		2 541 042	14 440 762	681 216	4 734 [illegible]
44	Storage leaseholds and rights	762 057		175 570	514 113	1 625 617	1 424 409	623 317	48 653 [illegible]
45	Reservoirs			2 213 373					414 243 [illegible]
46	Non-recoverable natural gas					3 226 865	743 272		422 [illegible]
47	Lines	1 821 944		6 292 270	782 744	1 649 210	2 345 329	112 499	523 [illegible]
48	Compressor station equipment	6 981 344		12 811 950	841 729	1 252 130	15 491 445	246 170	1 418 [illegible]
49	Measuring and regulating equipment	90 873		1 778 568	177 817	37 521	946 041	44 267	184 [illegible]
50	Purification equipment			1 786 329	347 104	752 472	135 004	91 208	95 [illegible]
51	Other equipment		166 146		1 033	6 154		11 643	
52	Total underground storage plant	16 875 834	26 993 258	8 183 444	11 242 833	96 849 435	1 834 046	8 333 [illegible]
53	Total other storage plant								
54	TOTAL NATURAL GAS STORAGE PLANT	16 875 834	26 993 258	8 183 444	11 242 833	96 849 435	1 834 046	8 333 [illegible]
	TRANSMISSION PLANT								
55	Land and land rights	214 898	1 976 492	12 846	248 720	146 167	101 754	76 [illegible]
56	Rights-of-way	111 667	1 195 803	12 954 497	275 654	1 343 312	3 170 704	724 837	264 [illegible]
57	Structures and improvements	48 034	1 350 000	34 153 344	455 157	10 214 024	2 291 040	2 442 234	1 433 [illegible]
58	Mains	3 479 829	25 989 928	341 745 897	12 451 129	78 852 044	128 247 294	54 821 470	87 563 [illegible]
59	Compressor station equipment	5 826 406	3 449 034	201 246 582	1 378 757	31 462 587	84 164 [illegible]	15 642 728	6 789 [illegible]
60	Measuring and regulating station equipment	52 567	2 004 857	8 814 220	295 924	1 042 404	2 870 248	1 515 837	1 123 [illegible]
61	Communication equipment	10 322	6 344 820	217 915	172 120	1 474 337			748 [illegible]
62	Other equipment	240 446	514 772	152 770	8 671	719 [illegible]	304 862		691
63	TOTAL TRANSMISSION PLANT	9 984 003	34 823 [illegible]	3 209 447 842	16 149 467	125 345 833	148 103 [illegible]	75 754 [illegible]	94 [illegible]
64	DISTRIBUTION PLANT						132 [illegible]	58 [illegible]	332 [illegible]
	GENERAL PLANT								
65	Land and land rights						142 862	387 784	312 [illegible]
66	Structures and improvements			152 970			3 [illegible]	2 174 [illegible]	6 814 [illegible]
67	Office furniture and equipment	16 868		2 334 124	165 829	234 444	450 [illegible]	484 [illegible]	3 [illegible]
68	Transportation equipment	14 662	290 [illegible]	6 [illegible]	287 [illegible]	426 [illegible]	1 [illegible]		3 [illegible]
69	Stores equipment			5 479				112 736	68 [illegible]
70	Tools, shop and garage equipment			3 934 [illegible]	40 [illegible]	362 [illegible]	384 [illegible]	1 [illegible]	868 [illegible]
71	Laboratory equipment			2 117			20 [illegible]	128 [illegible]	128 [illegible]
72	Power operated equipment			2 [illegible]	194 [illegible]	377 [illegible]		[illegible]	1 [illegible]
73	Communication equipment					138 [illegible]		754 [illegible]	512 [illegible]
74	Miscellaneous equipment				11 [illegible]		21 [illegible]	[illegible]	71 [illegible]
75	TOTAL GENERAL PLANT	31 [illegible]	290 [illegible]	14 [illegible]	[illegible] [illegible]	1 [illegible]	1 [illegible]	[illegible]	14 [illegible]
76	Other tangible property								
77	TOTAL GENERAL PLANT	31 [illegible]	290 [illegible]	14 [illegible]	[illegible] [illegible]	1 [illegible]	1 [illegible]	[illegible]	14 [illegible]
78	Gas plant purchased								
79	Gas plant sold								
80	Experimental plant unclassified								
81	TOTAL GAS UTILITY PLANT IN SERVICE	9 878 120	31 874 114	316 727 648	37 044 743	134 103 831	223 749 463	141 806 575	100 134 [illegible]

STATISTICS OF INTERSTATE NATURAL GAS PIPELINE COMPANIES FOR YEAR ENDED DECEMBER 31, 1978

Gas Utility Plant, Gas Account, and Physical Quantities—Cont.

| Line No. | Item | (a) Acadian-Ozark Corporation | (b) Algonquin Gas Transmission Company | (c) Algonquin Gas Storage Company | (d) Algonquin Hubline, Inc. | (e) Algonquin Interstate Gas Transmission Company | (f) Algonquin Offshore Pipeline Company | (g) Algonquin Tankships, Inc. | (h) Algonquin Tankships Corporation | (i) Algonquin Tankships Limited | (j) Algonquin Tankships Ltd. | (k) Algonquin Tankships Ltd. | (l) Algonquin Tankships Ltd. | (m) Algonquin Tankships Ltd. | (n) Algonquin Tankships Ltd. | (o) Algonquin Tankships Ltd. | (p) Algonquin Tankships Ltd. | (q) Algonquin Tankships Ltd. | (r) Algonquin Tankships Ltd. | (s) Algonquin Tankships Ltd. | (t) Algonquin Tankships Ltd. | (u) Algonquin Tankships Ltd. | (v) Algonquin Tankships Ltd. | (w) Algonquin Tankships Ltd. | (x) Algonquin Tankships Ltd. | (y) Algonquin Tankships Ltd. | (z) Algonquin Tankships Ltd. | (aa) Algonquin Tankships Ltd. | (ab) Algonquin Tankships Ltd. | (ac) Algonquin Tankships Ltd. | (ad) Algonquin 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STATISTICS OF INTERSTATE NATURAL GAS PIPELINE COMPANIES FOR YEAR ENDED DECEMBER 31, 1978

Gas Utility Plant, Gas Account, Physical Quantities

Line No.	Item	National Fuel Gas Supply Corporation	Natural Gas Pipeline Company of America	North Penn Gas Company	Northwest Natural Gas Company	Northern Utilities, Inc.	Northwest Pipeline Corporation	Ohio River Pipeline Corporation	Oklahoma Natural Gas Gathering Corporation	Line No.
	SUMMARY GAS UTILITY PLANT ACCOUNTS									
1	Gas plant in service	139 528 788	1 448 167 548	24 994 848	1 421 447 418	13 542 268	599 469 457	1 147 487	4 441 834	1
2	Gas plant leased to others		58 484	4 348 284	22 484 243	27 300	89 251			2
3	Gas plant held for future use	4 196 569	30 291 597	434 331	15 793 374		4 429 874	21 483	48 498	3
4	Construction work in progress				2 843 304		145 893			4
5	Gas plant acquisition adjustments	144 862 449	513 263 049	27 934 543	472 548 874	13 344 340	504 320 413	1 214 983	4 791 533	5
6	Total									6
7	Accumulated provision for depreciation, amortization, and depletion	54 421 242	454 700 241	8 444 248	444 303 982	5 303 892	147 424 903	718 002	4 534 404	7
8	Net gas utility plant	85 472 351	455 542 824	18 320 334	473 349 777	8 243 848	304 424 413	504 786	2 141 424	8
	GAS UTILITY PLANT IN SERVICE									
9	INTANGIBLE PLANT	103 736	17 304	27 167	440 842	72 432	2 227 106	733	5 946	9
10	MANUFACTURED GAS PRODUCTION PLANT	772 799			4 933 436					10
	NATURAL GAS PRODUCTION PLANT									
	Production and gathering plant	197 703		28 174						
11	Producing leads	498 344	4 272 992	240 481	1 845 854	1	4 259 982			11
12	Producing leaseholds	5 182 279		916 339	5 353 224					12
13	Gas rights	84 942	982 543	28 990	4 534 041	2 447	989 862		149 223	13
14	Rights-of-way	205 389	155 671	1 784	147 448		75 187			14
15	Other land and land rights	48 419		2 918						15
16	Gas well structures	33 538	1 325 457		7 484 023	75 470	1 842 317		18 443	16
17	Field compressor station structures	47 710	612 846	4 859	881 718	12 854	4 484			17
18	Field measuring and regulating station structures	1 622 448	261 711	47 393	5 354 923	178 427	3 459 273			18
19	Other structures	4 540 890	4 093 772	330 408	7 548 544		83 269 122			19
20	Producing gas wells--well construction	4 504 558	1 981 481	171 345	3 142 052		12 429 267			20
21	Producing gas wells--well equipment	6 444 167	24 920 979	1 034 147	117 421 343	447 334	32 935 754		3 201 914	21
22	Field lines	115 233	12 791 802		47 213 375	814 171	15 479 731		1 920 948	22
23	Field compressor station equipment	573 442	3 829 566	45 733	14 894 976	93 844	2 489 852		298 758	23
24	Field measuring and regulating station equipment	537 041		110 405						24
25	Drilling and clearing equipment	67 571	3 480 044		39 585 287	812 388	12 845 789			25
26	P urification equipment	158 013		14 333	1 390 070	19 824	448 450			26
27	Other equipment		2 128 444		9 984 310					27
28	Unsuccessful exploration and development costs	24 914 719	84 795 749	2 927 413	267 845 350	2 452 702	122 143 149		5 412 302	28
29	Total production and gathering plant									29
	Products extraction plant				14 743		104 184		13 402	
30	Land and land rights	22 664			1 956 775		1 924 747		203 900	30
31	Structures and improvements	48 423			4 472 844		28 492 182		433	31
32	Extraction and refining equipment	15 954			3 449 042		973 226			32
33	Pipe lines	9 129			2 844 799		487 316			33
34	Extracted products storage equipment				2 344 840		1 043 422			34
35	Compressor equipment	1 741			191 358					35
36	Gas measuring and regulating equipment	294			178 448		149 485		48 148	36
37	Other equipment	118 278			13 588 424		15 463 344		247 124	37
38	Total products extraction plant	25 492 991	84 795 749	2 927 413	267 844 214	2 452 702	137 748 149		5 434 433	38
39	TOTAL NATURAL GAS PRODUCTION PLANT									39
	NATURAL GAS STORAGE PLANT									
	Underground storage plant	141 879	278 344	47 826	100 841		29 936			
40	Land	125 187	2 513 180	1 550	143 111	2 347	19 826			40
41	Rights-of-way	1 532 695	7 774 434	135 884	3 455 524	10 907	122 291			41
42	Structures and improvements	15 418 719	52 434 140	862 412	21 481 574	144 719	2 853 350			42
43	Wells	5 588 347	6 274 844	142 893	347 424	16 978	123 241			43
44	Storage leaseholds and rights		12 987 894		3 720 948		1 974 946			44
45	Reservoirs		12 986 779		10 384 642		287 275			45
46	Non-recoverable natural gas	9 293 882	32 707 193	306 145	12 246 437	84 995	164 751			46
47	Lines	6 288 543	34 040 244	883 580	4 436 459	42 418	1 061 180			47
48	Compressor station equipment	444 743	5 084 872	78 919	1 147 112	19 090	73 576			48
49	Measuring and regulating equipment	58 843	10 429 640	75 404	4 533 535		231 815			49
50	Purification equipment	159 511	1 444 733	14 800	500 744	442	59 437			50
51	Other equipment	32 117 409	193 011 755	2 547 443	62 345 412	341 976	4 101 046			51
52	Total underground storage plant	496 127			15 207 979		15 141 417			52
53	Total other storage plant	24 113 336	192 912 719	2 547 443	81 773 348	341 976	22 248 858			53
54	TOTAL NATURAL GAS STORAGE PLANT									54
	TRANSMISSION PLANT	1 475 843	1 670 370	24 230	1 444 539	356	1 702 204		350	
55	Land and land rights	1 242 099	20 927 187	234 425	4 942 927	84 518	9 313 372	117 572	21 424	55
56	Rights-of-way	3 447 749	34 296 147	199 981	40 821 352	75 978	11 419 348	13 295	2 434	56
57	Structures and improvements	61 215 224	866 379 384	7 491 234	613 422 321	9 317 285	251 849 019	440 424	663 333	57
58	Mains	4 459 450	204 527 020		234 241 779	147 569	52 241 210			58
59	Compressor station equipment	4 621 783	19 914 665	454 824	22 344 361	230 854	5 472 448	117 451	18 457	59
60	Measuring and regulating station equipment		20 302 990	44 210	1 334 725	26 126	288 748	7 330		60
61	Communication equipment	44 971	14 133 829	34 167	4 704 924	4 442	1 528 846			61
62	Other equipment	74 018 149	134 973 593	8 413 573	929 459 854	4 904 350	334 023 418	1 144 874	724 743	62
63	TOTAL TRANSMISSION PLANT	153 493		11 886 293	87 576 936					63
64	DISTRIBUTION PLANT									64
	GENERAL PLANT	29 593		62 413	1 978 872	7 838				
65	Land and land rights	1 279 908	1 847 308	344 889	12 254 481	68 748	947 584			65
66	Structures and improvements	288 481	2 412 256	278 532	9 417 813	33 674	948 533			66
67	Office furniture and equipment	243 835	7 475 568	34 883	10 448 473	267 834	817 189		28 738	67
68	Transportation equipment	11 761		6 511						68
69	Stores equipment	388 762	3 281 796	18 736	1 476 127	41 481	871 847			69
70	Tools, shop and garage equipment	24 939	76 459		496 459	3 438	123 378			70
71	Laboratory equipment	746 463	2 879 982		4 884 881	230 237	548 948			71
72	Power operated equipment	174 934					174 873		1 858	72
73	Communication equipment	293 153		4 861	194 447	436	372 752			73
74	Miscellaneous equipment	3 470 886	17 344 173	892 725	34 743 727	778 338	3 818 447		24 726	74
75	SUBTOTAL GENERAL PLANT				111 495					75
76	Other tangible property	8 430 866	37 344 155	892 725	34 743 727	778 338	3 818 447		24 726	76
77	TOTAL GAS PLANT									77
78	Gas plant purchased									78
79	Gas plant sold									79
80	Experimental plant unclassified									80
81	TOTAL GAS UTILITY PLANT IN SERVICE	139 528 788	448 167 776	24 994 848	421 447 418	13 542 268	599 469 457	1 147 487	4 441 834	81

STATISTICS OF INTERSTATE NATURAL GAS PIPELINE COMPANIES FOR YEAR ENDED DECEMBER 31, 1975

Gas Utility Plant, Gas Account, and Physical Quantities—Cont.

Line No.	Item	National Fuel Gas Supply Corporation	Natural Gas Pipeline Company of America	North Penn Gas Company	Northern Natural Gas Company	Northern Utilities, Inc.	Northwest Pipeline Corporation	Ohio River Pipeline Corporation	Oklahoma Natural Gas Gathering Corporation	Line No.
	ADDITIONS AND RETIREMENTS OF GAS PLANT									
1	ADDITIONS	$	$	$	$	$	$	$	$	1
2	Intangible plant	9 530	-453-		3 293		2 063 660-			2
3	Manufactured gas production plant				3 465 478					3
4	Natural gas production plant:									4
5	Production and gathering plant	934 141	3 622 267	6 213	28 494 263	41 263	7 213 262		110 504	5
6	Products extraction plant	573			252 251		124 751			6
7	Total natural gas production plant	934 714	3 622 267	6 213	28 804 514	41 263	7 440 453		110 504	7
8	Storage plant—Underground	484 348	27 462 433	98 819	8 432 291	83 904	743 379			8
9	—Other				19 167 644		14 143 812			9
10	Transmission plant	4 473 118	31 096 468	358 048	23 301 730	1 234 833	1 335 266	24 479		10
11	Distribution plant			878 885	1 134 343					11
12	General plant	943 461	2 344 997	6 063	3 224 651	447 324	448 418		13 674	12
13	Gas plant purchased				153 199		943 929			13
14	Gas plant sold or leased									14
15	TOTAL GAS PLANT ADDITIONS	6 444 291	64 278 113	1 348 943	90 548 726	1 841 324	29 821 047	24 479	124 178	15
	RETIREMENTS									
16	Intangible plant				9 362					16
17	Manufactured gas production plant				2 970					17
18	Natural gas production plant:									18
19	Production and gathering plant	274 290	112 834	48 295	1 283 344	27 345	1 413 940		1 563	19
20	Products extraction plant				2 805		443 120			20
21	Total natural gas production plant	274 290	112 834	48 295	1 286 149	27 345	1 857 060		1 563	21
22	Storage plant—Underground	89 831	687 422	84 834	203 879	434				22
23	—Other	2 917								23
24	Transmission plant	582 033	2 334 877	84 163	2 404 321	290 709	1 152 424	162		24
25	Distribution plant	11 793		149 409	473 188					25
26	General plant	194 120	1 424 121	11 455	1 305 221	3 480	46 979			26
27	Gas plant sold				1 121 734					27
28	Experimental plant unclassified									28
29	TOTAL GAS PLANT RETIREMENTS	1 155 984	4 704 454	731 357	7 804 454	284 529	3 435 359	162	1 563	29
	GAS ACCOUNT (Thousands of cubic feet)									
	Adjusted to a standard uniform measurement base of 14, 73 P. S. I.A. and 60° F.									
	GAS RECEIVED									
30	Natural gas produced	3 290 845	40 190 304	76 824	2 984 454	4 341	34 851 735			30
31	Liquefied petroleum gas produced and mixed with natural gas				12 717					31
32	Manufactured gas produced and mixed with natural gas									32
33	Natural gas purchased	190 502 784	962 439 230	24 219 483	945 745 202	30 876 756	373 214 243	6 253 126	14 121 989	33
34	Other gas purchased	5 343 787	487 440							34
35	Gas of others received for transportation or exchange	200 543	155 760 128		72 344 780	13 315 370	14 236 577		343 624	35
36	Receipts of respondent's gas transported or exchanged by others	25 982	145 252 401	222 583	212 467 147	24 395	58 463 579			36
37	Discharge gas received	157 521	291 905 365	215 904	153 874 293	4 551 484	52 367 146			37
38	Gas received from underground storage	46 284 043	102 424 548	4 894 290	34 405 404	2 434 420	12 187 482			38
39	Other sources		241 940 477			34 511				39
40	TOTAL RECEIPTS	245 454 425	960 819 993	28 810 084	373 754 726	42 447 772	544 140 962	6 253 126	14 465 613	40
	GAS DELIVERED									
41	Natural gas sales:			12 177 367	88 422 229					41
42	Local distribution by respondent		7 484 195		137 396 347	9 729 498	5 319 394			42
43	Gas for industrial sales	149 684 481	903 286 149	13 634 790	428 461 125	10 732 861	361 765 578	6 315 446	14 134 611	43
44	Sales for resale				120 349					44
45	Interdepartmental sales									45
46	Other sales									46
47	Total sales	149 684 481	910 666 295	25 812 157	654 400 050	20 462 359	367 084 972	6 315 446	14 134 611	47
48	Deliveries of gas transported or exchanged for others	200 543	155 751 340		72 344 780	13 344 882	14 236 577		343 624	48
49	Deliveries of respondent's gas for transp. or exchg. by others	25 982	145 252 401	222 583	212 467 147	24 395	58 463 579			49
50	Discharge gas delivered	57 925	277 994 251	217 992	181 482 828	4 551 484	52 367 146			50
51	Discharge gas used by respondent	275 148	51 254 427	237 520	77 903 134	155 934	12 533 766			51
52	Natural gas delivered to storage	30 610 396	106 423 455	10 907 729	44 362 505	1 904 130	12 001 984			52
53	Natural gas for Purchase requirements									53
54	Other deliveries	41 044	142 020 513							54
55	TOTAL DELIVERIES	249 439 115	873 652 283	37 398 211	363 443 198	42 774 874	344 368 898	6 315 446	14 478 235	55
	Unaccounted for:					71 590-				
	Production system losses									
	Storage losses					343 294	868 326-	60 357-	34 422-	
	Transmission system losses		3 622 527							
	Distribution system losses									
	Other losses	4 476 373	3 445 411	1 211 877	10 515 134					
56	Total unaccounted for	4 476 373	87 167	1 211 877	10 515 134	171 704	867 326	60 357-	34 422-	56
57	TOTAL DELIVERIES AND UNACCOUNTED FOR	253 915 488	877 652 233	38 610 088	373 958 332	42 603 170	344 140 962	6 255 089	14 443 813	57
	PHYSICAL QUANTITIES									
	GAS RECEIVED (Thousands of cubic feet)									
58	In producing gas lands	190	281 452	4 219	81 273		1 296			58
59	In nonproducing gas lands									59
60	Available from purchase agreements:									60
61	Well head purchases	2 649	662 726	10	7 788 750	34 755	8 647 957		73 678	61
62	Field line purchases	12 854	2 823 867	2 049	119 276	1 144	23 240			62
63	Casinghead purchases		3 959 601		1 339 343	139 062	102 209			63
64	Transmission system purchases	2 212 187	1 788 347	258 244	272 477	48 475	1 014 174	40 345	14 434	64
65	Total to be stored	2 230 540	9 572 413	264 522	9 521 019	223 437	9 788 876	40 345	14 434	65
	Gas withdrawn from storage (Reductions of cubic feet)									
66	Current	47 340	42 300	8 199	27 627	2 878	(1) 7 917			66
67	Recovered	47 620	47 034	7 300	12 522	2 799	2 847			67
	PRODUCING WELLS—Number:									
68	Gas	2 799	(1) 271	(2) 134	(2) 111	2	1 295			68
69	Oil			46	(2) 29					69
70	DRYHOLE WELLS—Number	1 596	866	(2) 26	136		27			70
	PIPE LINES—Miles									
71	Field	1 961	1 202	423	2 201	48	1 279		232	71
72	Transmission:									72
73	- 4.0- 5.9 inches	29	256	249	4 213	43	282			73
74	6.0—10.9 inches	580	1095	177	4 929	233	267	9		74
75	11.0—17.9 inches	484	280	74	572	129	412	14	2a	75
76	18.0—24.9 inches	213	788	1	2 643	118	413			76
77	25.0—29.9 inches				1 458		863			77
78	30.0—31.9 inches	127	1 781		2 951		1 116			78
79	32.0—36.9 inches		4 032				31			79
80	Over 37 inches		2 253		16 814	333	1 115	13	2a	80
81	TOTAL TRANSMISSION	1 433	9 385	501	35 580	856	4 899	36	2a	81
82	Storage	117	253	12	141		12			82
	COMPRESSOR STATIONS									
83	Field	190 1	45 740 43		147 882 48	2 847 2	14 316 3		12 300 1	83
84	Transmission	84 536 14	936 105 86		510 308 61	620 2	348 487 46			84
85	Storage	16 173 2	41 868 8	4 995 1	9 235 2	434 2	3 872 1			85

*MAIN INTERSTATE NATURAL GAS SYSTEM COMPANY.

1. INCLUDES 14 WELLS IN WELL REPAYMENT HOLES LESS THAN FULL DEPOSITS.
2. INCLUDES 2 WELLS IN BRINE REPAYMENT HOLES LESS THAN FULL DEPOSITS.
3. REPAYMENT HOLES LESS THAN FULL DEPOSITS.
4. INCLUDES 1,234 WELLS JOINTLY OWNED.
5. LESS THAN 1 MILE.

Gas Utility Plant, Gas Account, Physical Quantities

Line No.	Item	Orange and Rockland Utilities, Inc.	Pacific Gas Transmission Company	Panhandle Eastern Pipe Line Company	Pennsylvania & Southern Gas Company	Sabine Pipe Line Company	Sea Robin Pipeline Company	Shenandoah Gas Company	South Georgia Natural Gas Company	Line No.
	SUMMARY GAS UTILITY PLANT ACCOUNTS									
1	Gas plant in service	$ 48 811 234	$ 81 145 448	$ 880 434 578	$ 11 325 868	$ 19 184 842	$ 148 249 689	$ 3 994 720	$ 14 921 284	1
2	Gas plant held for future use	33 010	176 819	1 711 703						2
3	Construction work in progress	466 760	2 354 364	15 962 407			2 052 444	1 349	4 816	3
4	Gas plant acquisition adjustments				29 085					4
5	Total	49 311 044	113 681 843	898 108 688	11 354 773	19 184 842	162 304 133	3 996 069	14 926 100	5
6	Accumulated provisions for depreciation, amortization, and depletion	8 323 374	70 789 323	377 748 127	3 216 016	8 445 457	42 738 125	2 800 340	7 240 844	6
7	Net gas utility plant	41 181 467	113 092 520	472 446 761	8 040 757	10 815 405	119 565 919	1 195 721	7 679 256	7
	GAS UTILITY PLANT IN SERVICE									
8	FRANCHISE PLANT	20 825	693 983	144 286	27 301	231		42 072	242 965	8
10	MANUFACTURED GAS PRODUCTION PLANT	2 267 483			1 339 383					10
	NATURAL GAS PRODUCTION PLANT									
11	Production and gathering plant									11
12	Producing leases									12
13	Producing leaseholds									13
14	Gas rights									14
15	Rights-of-way			3 429 848						15
16	Other land and land rights			236 382						16
17	Gas well structures									17
18	Field compressor station structures			3 961 489						18
19	Field measuring and regulating station structures			2 847 815			258 367			19
20	Other structures			999 233						20
21	Producing gas wells-well construction									21
22	Producing gas wells-well equipment									22
23	Field lines			97 251 344						23
24	Field compressor station equipment			48 835 494						24
25	Field measuring and regulating station equipment			7 400 721			1 477 040			25
26	Drilling and cleaning equipment									26
27	Purification equipment			385 951						27
28	Other equipment			3 373 239						28
29	Unsuccessful exploration and development costs									29
30	Total production and gathering plant			169 323 286			1 930 447			30
31	Products extraction plant									31
32	Land and land rights									32
33	Structures and improvements									33
34	Extraction and refining equipment									34
35	Pipe lines									35
36	Extracted products storage equipment									36
37	Compressor equipment									37
38	Gas measuring and regulating equipment									38
39	Other equipment									39
40	Total products extraction plant									40
41	TOTAL NATURAL GAS PRODUCTION PLANT			169 323 286			1 930 447			41
	NATURAL GAS STORAGE PLANT									
42	Underground storage plant									42
43	Land			219 923						43
44	Rights-of-way			148 847						44
45	Structures and improvements			2 491 911						45
46	Wells			12 245 397						46
47	Storage leaseholds and rights			2 250 034						47
48	Reservoirs			2 142 503						48
49	Non-recoverable natural gas			5 207 197						49
50	Lines			4 315 119						50
51	Compressor station equipment			4 905 179						51
52	Measuring and regulating equipment			3 007 583						52
53	Purification equipment			542 050						53
54	Other equipment			179 219						54
55	Total underground storage plant			39 659 793	31 849					55
56	Total other storage plant									56
57	TOTAL NATURAL GAS STORAGE PLANT			39 659 793	31 849					57
	TRANSMISSION PLANT									
58	Land and land rights		229 979	1 034 494	1 896	81 112	93 435	5 197	47 490	58
59	Rights-of-way		2 327 745	9 522 620	41 672	171 041	98 642	229 218	878 851	59
60	Structures and improvements		9 516 115	32 944 521	2 983		4 442 471	14 898	145 734	60
61	Mains		115 802 534	389 142 720	1 334 374	16 441 261	127 354 513	2 434 897	12 774 450	61
62	Compressor station equipment		92 360 226	159 257 809			24 163 959		1 875 775	62
63	Measuring and regulating station equipment		30 153	15 046 999	34 339	411 849	921 495	278 851	687 649	63
64	Communication equipment		2 674 146	5 870 844	4 123		451 274		284 849	64
65	Other equipment		207 113	12 230 478		2 707				65
66	TOTAL TRANSMISSION PLANT		178 475 388	811 471 030	1 418 387	18 108 811	257 481 783	2 963 111	16 877 798	66
67	DISTRIBUTION PLANT	37 625 261			9 951 927			4 974 279		67
	GENERAL PLANT									
68	Land and land rights	13 271						19 420	19 848	68
69	Structures and improvements	9 785		924 812	48 824		248 194	297 219	284 457	69
70	Office furniture and equipment	1 603	905 240	2 810 301	74 771		1 420	76 091	89 858	70
71	Transportation equipment	7 902	629 406	7 852 893	254 406		536 184	233 940	147 519	71
72	Stores equipment	491	31 797	282 301	7 765			21 323		72
73	Tools, shop and garage equipment	427 244	1 894 772	1 550 471	93 177		24 876	94 421	58 444	73
74	Laboratory equipment	90 782		370 930	1 144			1 242		74
75	Power operated equipment	72 957	239 885	2 582 481	184 772		19 495	134 981	132 534	75
76	Communication equipment	69 482			22 898			45 540		76
77	Miscellaneous equipment	2 149	34 483	104 899	3 333			1 836	2 274	77
78	SUBTOTAL (Enter Sum)	715 439	1 472 113	19 211 121	716 731		837 457	899 171	735 934	78
79	Other tangible property									79
80	TOTAL GENERAL PLANT	715 439	1 472 113	19 211 121	716 731		837 457	899 171	735 934	80
81	Gas plant purchased									81
82	Gas plant sold									82
83	Experimental plant gas heating									83
84	TOTAL GAS UTILITY PLANT IN SERVICE	40 811 234	181 145 480	833 434 578	11 325 868	18 184 842	148 249 689	3 994 720	14 921 284	84

STATISTICS OF INTERSTATE NATURAL GAS PIPELINE COMPANIES FOR YEAR ENDED DECEMBER 31, 1939

Gas Utility Plant, Gas Account, and Physical Quantities—Cont.

Line No.	Item	Grande and Rockland Utilities, Inc.	Pacific Gas Transmission Company	Panhandle Eastern Pipe Line Company	Pennsylvania & Southern Gas Company	Sabine Pipe Line Company	Red River Pipeline Company	Tennessee Gas Company	South Georgia Natural Gas Company	Line No.
	ADDITIONS AND RETIREMENTS OF GAS PLANT									
1	ADDITIONS	$	$	$	$	$	$	$	$	1
2	Intangible plant									2
3	Manufactured gas production plant	39 284			944 752					3
4	Natural gas production plant									4
5	Production and gathering plant			42 730 234			41 979-			5
6	Products extraction plant									6
7	Total natural gas production plant			42 730 234			41 979-			7
8	Storage plant—Underground			910 854						8
9	—Other									9
10	Transmission plant		1 291 047	20 072 462	10 179		149 744	4 471	174 547	10
11	Distribution plant	2 194 918			173 294			21 893		11
12	General plant	18 035	104 895	2 137 009	44 404		237 323	79 463	43 190	12
13	Gas plant purchased									13
14	Experimental plant unclassified									14
15	TOTAL GAS PLANT ADDITIONS	2 291 837	1 455 956	68 727 859	824 433		361 088	110 827	217 737	15
16	RETIREMENTS									16
17	Intangible plant									17
18	Manufactured gas production plant	6 790								18
19	Natural gas production plant									19
20	Production and gathering plant			618 131			4 278			20
21	Products extraction plant									21
22	Total natural gas production plant			618 131			4 278			22
23	Storage plant—Underground			352 460						23
24	—Other									24
25	Transmission plant		664 987	1 222 595	1 849		786	11 551	23 667	25
26	Distribution plant	364 184			35 202			13 234		26
27	General plant	99 961	24 462	1 209 196	31 037			21 750	33 043	27
28	Gas plant sold									28
29	Experimental plant unclassified									29
30	TOTAL GAS PLANT RETIREMENTS	470 879	691 304	3 411 744	68 088		5 064	46 535	56 710	30
	GAS ACCOUNT (Thousands of cubic feet) **Adjusted to a standard uniform measurement base of 14.73 P. S. I. A. and 60° F.**									
31	GAS RECEIVED									31
32	Natural gas produced				1 246					32
33	Liquefied petroleum gas produced and mixed with natural gas	9 186								33
34	Manufactured gas produced and mixed with natural gas	24 514 490	390 293 468	441 803 973	4 349 334		248 979 879	3 161 467	24 416 334	34
35	Natural gas produced									35
36	Other gas produced		50 279 976	79 446 244		52 383 633	30 137 943			36
37	Gas of others received for transportation or transmission			799 212						37
38	Receipts of respondent's gas transported or transported by others			55 940 570						38
39	Exchange gas received			28 413 814	134 214					39
40	Gas received from underground storage									40
41	Other receipts						11 272 959			41
42	TOTAL RECEIPTS	24 523 676	438 564 444	606 430 813	4 350 795	52 383 633	290 391 780	3 161 467	24 416 334	42
43	GAS DELIVERED									43
44	Natural gas sold:									44
45	Local distribution by respondent	22 516 650		4 349 329	4 146 280		206	1 816 888		45
46	Main line industrial sales			23 087 846				1 209 037	6 900 964	46
47	Sales for resale	934 720	345 683 290	548 325 292			283 608 352		17 350 491	47
48	Interdepartmental sales	15 196								48
49	Other sales									49
50	Total sales	23 195 576	345 683 290	625 762 467	4 146 280		283 608 352	3 025 925	24 251 455	50
51	Deliveries of gas transported or compressed for others		59 864 442	73 414 244		52 811 248	36 448 837			51
52	Deliveries of respondent's gas for transp. or comp. for others			765 212						52
53	Exchange gas delivered			28 917 751						53
54	Natural gas used by respondent	24 707 452		6 702			3 229 243	3 606	165 902	54
55	Natural gas delivered to storage	27 445 449		293 914						55
56	Natural gas for limited requirements									56
57	Other deliveries	34 774		10 048 039			12 974 481		1 371-	57
58	TOTAL DELIVERIES	75 110 652	438 564 444	834 937 774	4 422 697	52 811 248	336 529 248	3 029 529	24 416 334	58
59	Unaccounted for									59
60	Production system losses									60
61	Storage losses									61
62	Transmission system losses						4 181 932		57 446	62
63	Distribution System losses	723 624			181 797			165 942		63
64	Other losses		224 874	7 454 287		572 385				64
65	Total unaccounted for	723 624	224 874	7 454 287	181 797	572 385	4 181 932	165 942	57 446	65
66	TOTAL DELIVERIES AND UNACCOUNTED FOR	75 834 276	438 789 318	842 392 061	4 604 494	53 383 633	340 711 180	3 195 471	24 473 780	66
	PHYSICAL QUANTITIES									
67	GAS RESERVES (Millions of cubic feet)									67
68	In gathering gas lands									68
69	In transporting gas lands									69
70	Available from purchase agreements									70
71	Net land purchases			2 934 252						71
72	Field line purchases			204 429			751 208			72
73	Gasoline plant outlet purchases			728 518						73
74	Transmission system purchases	480 876	4 494 372	832 372	11 812			843	143 404	74
75	TOTAL RESERVES	480 876	4 494 372	5 830 371	11 812		751 208	843	143 404	75
76	GAS STORAGE LINE ACQUIRED (Millions of cubic feet)									76
77	Current			18 462				366		77
78	Noncurrent			26 606						78
79	PRODUCING WELLS—Number									79
80	Gas									80
81	Oil									81
82	STORAGE WELLS—Number			136						82
83	PIPE LINES—Miles									83
84	Field			3 675						84
85	Transmission									85
86	4.6— 5.9 inches			332	16			12	208	86
87	6.0— 8.9 inches			407	58		11	41	245	87
88	10.0—11.9 inches			421			24	24	204	88
89	12.0—14.9 inches			927		27	50			89
90	15.0—19.9 inches			2 340		27	79			90
91	20.0—24.9 inches			2 417			185			91
92	25.0—29.9 inches						66			92
93	Over 30 inches		632	32						93
94	TOTAL TRANSMISSION		632	6 875	81	134	333	77	765	94
95	Total			14						95
96	COMPRESSOR STATIONS									96
97	Field			121 121	3					97
98	Transmission		139 488	22 412	21		10 348	1	2 200	98
99	Storage			14 180	3					99
100	Other									100

*GRANDE INTERSTATE NATURAL GAS PIPELINE COMPANY.

A. INCLUDED WITH RESERVES OF PANHANDLE GAS LINE COMPANY.

Mr. SOLOMON. Some of the pipelines found that from their standpoint it was cheaper and better for their firm customers to install storage rather than to make the boiler fuel valley type of industrial sales.

Now, unfortunately there are problems in the new allocations that I was mentioning to Congressman Brown. There have been certain tendencies on the part of the Federal Power Commission in their allocation of costs to discourage and penalize people who put in storage in the past, and to assign costs to them which would certainly discourage future storage activities as well as to penalize people that did that in the past.

There are pipelines who found, depending on where they were located and what storage facilities are available, whether they are relatively cheap or not—but there are pipelines in the past which did not go in for the interruptible boiler fuel sale or interruptible industrial sale, but prohibited that type of sale on their pipelines. They instead installed storage and got their load factor up that way.

From my standpoint, storage is still, to the extent is is available, a very useful device for the pipeline under present conditions. It should be encouraged, not discouraged.

Mr. STOCKMAN. Let's put it in a more general context. If we assume that field production is going to continue to decline, as the administration does, and if we assume that conversion is going to work fairly effectively, it seems to me that you are going to get into a tremendous administrative nightmare because this is going to affect each system differently, depending on their current contracts and the vintage of gases they have and when they are going to expire.

It is going to depend on whether or not you have large volumes of conservation gas available and so forth. If you have the allocation authority on top of that, you have got under-utilized pipelines, you have got under-supplied systems, various degrees of storage. Who is going to decide where all those costs and actual tangible supplies of gas are going to flow? Would you all agree yes or no that is going to cause a tremendous problem for the regulatory authority?

Mr. GOOCH. Yes.

Mr. DINGELL. The time of the gentleman has expired. The Chair will permit the witnesses to reply.

Mr. SOLOMON. Mr. Gooch said yes, there would be serious regulatory problems. My answer is yes, there certainly will be serious regulatory problems. Quite frankly, from my point of view, whether the problems in not allocating gas at some future stage, if the decline in gas is really as great as the administration predicts, maybe worse than the administrative problems—you may have to get to the problem of allocating gas in some form or another. Maybe you can simply allocate by giving priorities to pipelines to purchase gas who need it more over pipelines who don't need it more.

There are various ways. Maybe you could try and avoid the comprehensive government determination as to where the gas is going to flow. But as you get into—if we get into a situation where some pipelines have very little gas compared with other pipelines that have a great deal, the pressures for some sort of allocation system, something this act doesn't even discuss, are going to become more and more determined.

Mr. JOURNEY. Mr. Stockman, the problems will be large, but they are foreseeable. I can see them now. We are just seeing the tips of this coming in in rate design, operating problems. They are not going to go away. Unless this is turned around in some way that I don't foresee in terms of one huge increase in supply, these economic and operating problems will become the regulatory or administrative challenge of the late seventies and eighties, whoever is doing the work.

Mr. DINGELL. The Chair recognizes the gentleman from Texas, Mr. Krueger, for five minutes.

Mr. KRUEGER. Thank you, Mr. Chairman.

We appreciate seeing you again. I should first like to ask a question regarding synthetic natural gas.

One of the proposals as I understand it is that SNG facilities should themselves become a part of the rate base. That is the capital construction costs of new SNG facilities should themselves become part of what would then be the rate base for the interstate pipelines. I see from your nodding that you agree on that interpretation.

It seems to me that there are some real risks to consumers in that policy, in that as I understand the way in which regulation of pipelines and utility regulation generally works, the regulated industry is allowed a certain percentage of return on investment it makes.

Now, if for example a pipeline had access to natural gas at $2, which it can purchase, and suppose there were an adequate supply, and they already had their pipelines in place, they would get no profit on that $2 gas as such. They would only get whatever income they have as part of the amortization of their pipeline.

On the other hand, if they turn around and invest $1 billion to build a SNG facility that then provides perhaps 50 percent of the gas for that pipeline, they not only have the amortization costs on the pipeline itself, but they get an allowable rate—I don't know what it would be, 13, 14, 15 percent—on the billion dollars invested in the SNG facilities.

Now, if I understand that correctly, that means that it is not—to rephrase—because of the existence of the regulation, it allows them a guaranteed return on investment. It is not really to the pipeline's financial interest to buy necessarily the cheapest product for their consumers. It is rather to the pipeline's interest to make as large an investment as they can in capital construction for new SNG facilities, for example, because they would then get a return on that, and they would enlarge the pipeline's return by investing in these new SNG facilities at, for example, $1 billion.

Now, I foresee that as a problem. I don't offhand have a solution. I wonder whether I might begin at this end of the table with Mr. Gooch commenting on that, and then perhaps get comments from the other people as well.

Mr. GOOCH. I think your analysis, sir, is accurate.

The situation is that once the SNG plant, the liquid based SNG plant is put in the rate base, then there is a real incentive for the owner of that SNG plant to keep it in operation.

In fact, you will find instances where the Federal Power Commission has denied natural gas supplies to a company that has a SNG plant because otherwise it would go for boiler fuel use. You will see companies with SNG plants that will defer their takes of natural gas.

You will find companies that will actually cut back on their takes of natural gas in order to protect their markets for their synthetic natural gas.

Mr. KRUEGER. Mr. Solomon, would you care to comment on that?

Mr. SOLOMON. I think this is a risk. As I understand the act, with the exception of the plants which would be grandfathered, I assume it is envisioned the Commission would not authorize the construction or the operation of these plants until they have made a sufficient study of the need therefor, and how it would fit into the pipeline's other operations. Presumably they could condition such grants to protect against the gross abuses of the type that Mr. Gooch mentioned. Such SNG facilities would not become part of the rate base, as I understand it, unless these facilities have been certificated by the Commission, and in certificating these facilities the Commission presumably would look just as deeply if not deeper to find out whether they are needed and how they will be operated than it would do before it allows any other major construction operation by a pipeline which is not going into the rate base. While some of these problems you mention certainly exist, again, as I understand the thrust of the act, one of the reasons for the jurisdiction granted over SNG plants is to give the government control to prevent the construction of these plants and then have a bail-out situation, because the alternative is that, absent regulation, you build these plants anyway, and if they get into trouble, they come around to the government and say, "Well, help us out, because it is essential that we, a pipeline, or we, a distributor, stay in business."

The problems, as you say, exist: The question of determining whether this is useful or not, or as to whether government regulation can be helpful or harmful.

Mr. DINGELL. The Chair recognizes the gentleman from Ohio, Mr. Brown, for 5 minutes.

Mr. BROWN. Gentlemen, we have had a pretty good elaboration on why the drilling limitations put in the bill are inadequate or improper to get additional gas. We have talked about the fact that if we don't have adequate gas, such gas as goes through the pipeline is going to cost more for the consumer. In other words, he pays more for less.

I would like to talk a little bit about the Btu equivalency price issue. It seems to me that the decision we are trying to get is a decision by the user of the gas—never mind whether it is a homeowner, an industry, a hospital, a school, or whatever—the decision we are trying to get is the choice between the various kinds of energy that are available to him.

Another thrust of this bill is to encourage conversion to coal from fossil fuels such as oil and natural gas to another fossil fuel we have more of.

Is the Btu equivalency approach in this legislation sound toward encouraging that decision? We have wellhead prices of gas com-

pared to refiner costs of oil, which, of course, embrace not only the wellhead price but also some transportation, whereas the wellhead price of gas does not embrace transportation. Could you comment on that, please, and relate it also to coal and the decision of the burner-type controller, the guy who has to make that decision?

Mr. GOOCH. I would be pleased to take a shot at that, sir. To begin with, you will notice a strange anomaly in the bill, and that is that new crude and new gas are putatively treated the same—that is not in the bill because something happened, and there wasn't an oil section in the bill, but I mean the speeches and the plan—new crude and new gas were defined exactly the same, but new crude was to rise to the 1977 world equivalency of $13.50, whereas new gas could only rise to the average delivered price to the refinery of all of the domestic which will always lag behind the highest cost increment. The charts I offered this morning demonstrate that graphically. You are really not relating the Btu equivalency of new gas to new crude to start with, but having not done that, the bill goes further and further compounds, through the incremental pricing. Theoretically, the incremental pricing provision proposed in this bill would take all of the high-cost supplements, the SNG, the LNG and the higher cost of the new natural gas, whatever that amount turns out to be, and throw that against the entire industrial-commercial-utility sector. But only to a point, because, as soon as the gas price gets up equal with the alternate fuel cost under this bill, the gas is no longer incrementally priced. The higher cost has shifted back to the residential and commercial market so you never feel at the burner tip either the marginal cost-replacement cost at the wellhead, nor do you feel it in the incremental pricing. As far as conversion to coal is concerned, obviously that is not going to do it for two reasons. One, you don't distinguish the nonsubstitutable use of natural gas from the boiler fuel.

Mr. BROWN. You refer to process users such as chemical and glass and the other consumer items for which nothing can be substituted and for which the consumer will have to pay no matter what the price?

Mr. GOOCH. Yes, sir, and the second point is on this chart now, coal sells on a nationwide basis for electric utilities for roughly—I believe the figure is 80 cents a million Btu. So you can put that on a chart lower—well, it is certainly lower than new natural gas, certainly lower than—I can't read my chart from here.

Mr. BROWN. Before my time is altogether gone, do any of the rest of you have any comment on this subject?

Mr. JOURNEY. If you take the conversion factor of 5.8 and 75 cent gas, you come to a little over $10.50 a barrel oil. You asked whether the concept of Btu equivalency would be the technique which would allow people to make the rational, optimum choices for resource utilization. The answer is yes. It wouldn't amount to a constrained price for one fuel or another. What you are talking about, however, is the question of whether the $1.75 is the right price or the wrong price.

Mr. BROWN. Ten-dollar oil is certainly cheaper than the oil we can anticipate paying for under the pricing provisions which have been described to me by Mr. Schlesinger as the price of oil with the tax added on. Is that not correct?

Mr. JOURNEY. The answer to that question is yes. I am not taking one side or the other of this, Mr. Brown. I am taking your question apart and telling you how I would answer it.

Mr. KRUEGER. The time of the gentleman has expired.

Mr. SOLOMON. Congressman Brown, I may be wrong, but I was looking on this current Btu-related price as strictly a compromise figure based upon a determination by the draftsmen of this bill that some price higher than the $1.45 should be fixed, and that the draftsmen believing it would be unwise, at this time at least, to deregulate completely.

Mr. BROWN. A political decision.

Mr. SOLOMON. A political determination as to what the proper rate was. By political I don't mean it in the partisan sense, but a determination by the draftsmen of the bill that from a policy standpoint somewhat higher prices than presently exist for new gas should be put into effect, but that deregulation would have more harmful than beneficial benefits.

Mr. BROWN. You would also describe it as arbitrary rather than logical.

Mr. SOLOMON. If you have a fixed rate, any particular level is arbitrary in some sense. Obviously the Btu price instead of being related to the type oil they pick could have been related to new oil which would have been a higher price.

Mr. KRUEGER. The time of the Congressman has expired.

At this time, the Chair will recognize majority counsel for some technical questions.

Mr. DEMAREST. Thank you, Mr. Chairman.

Gentlemen, I think we have been down this path before. With your cooperation, I would like to go through the bill briefly and try to focus some of the questions on implementation of policy. If you could indicate whether you can discern from the legislative language whether or not the policy set forth in the energy plan is being executed, that would be helpful to the committee. If you believe that the language is ambiguous, that would also be helpful. The point will be to attempt to ascertain areas in which we have to work on making sure that the policy is executed or must find out what should be the policy.

The first major point I would like to address is the new gas definition. One of the terms used in that is the term "completion location." That term is defined. Would it be your understanding that the completion location is a subsurface location and not the surface point at which the well is drilled?

Mr. GOOCH. That would be my interpretation, yes.

Mr. DEMAREST. No disagreement?

Mr. JOURNEY. That is the way I read it, Mr. Demarest.

Mr. DEMAREST. In terms of enforcement, is that an administerable term to utilize? Can we ascertain with any degree of precision the situs of the completion location below the surface, some 15,000 feet, in order to implement this definition?

Mr. GOOCH. The answer is yes, you can. That kind of data is on file if it is not offshore Federal domain, if it is in USGS, and in the State domain you file that data regularly. This chart I brought does that, too.

Mr. DEMAREST. We had testimony from producers who indicated that what is filed is the depth of the completion location. As you know, a well can be drilled directionally, and the producers indicated that the precise position in longitude and latitude would not be on file. Is that information on file?

Mr. GOOCH. I believe what they say is correct. Perhaps I don't understand your question after all.

Mr. DEMAREST. What we have here is not really capable of being reduced to these charts. Those charts represent everything in 2 dimensions, which is nice if you have a straight pipe. We don't have straight pipe. We have pipe that bends. What I am trying to find out is whether this definition is administerable when you have the completion location at a position not directly below the derrick, not directly below the surface opening of the well.

Mr. GOOCH. I am led to believe by my good friend, Mr. Gene Pollock, who is an expert in this area, that you can, in fact, if you choose to do so, locate the subsurface location, you know, of where you have perforated.

Mr. DEMAREST. Is that on file anywhere that you know of?

Mr. GOOCH. He says that the United States USGS has it for the offshore Federal domain.

Mr. DEMAREST. And onshore?

Mr. GOOCH. There are so many State jurisdictions, to be candid with you, I didn't really—the circles I drew on this map are from the surface locations. Now, if you wanted to assume that people were directionally drilling and go to the trouble and expense of surveying each hole and physically locating the longitude and latitude of that hole and then go the 2-1/2-mile circle, if that is the point you are making, it is quite accurate. That would be a very difficult thing to do.

Mr. DEMAREST. Isn't that precisely what is required?

Mr. GOOCH. It seems to me that way. For example, in the State of Texas, in December, 1976, there were 28,026 gas wells producing and 160,193 oil wells producing that had some gas production, so it really would be somewhat inconvenient to have to survey almost 183,000 wells to locate in the various formations where their completion location was, and then draw a 2-1/2-mile circle.

Mr. DEMAREST. Maybe I am wrong, but I think that number substantially understates the total. Would you not agree that the completion location has to be more than 2-1/2 miles from the completion location of an old well. And an old well is defined as any well which was capable of producing crude oil or natural gas on or before April 20, whether it has been shut in or not.

Mr. GOOCH. The number I read for you is from the annual summary of Texas natural gas for the year 1976, and the Railroad Commission of Texas, and obviously it would not include wells drilled subsequent to 1976.

Mr. DEMAREST. I am suggesting wells drilled in 1947 that were capable of producing gas in 1947 and 1948 and plugged in 1950, are old wells under this definition, as I read it. They were capable of producing before April 20, 1977, and anything within the 2-1/2-mile——

Mr. GOOCH. You are correct.

Mr. DEMAREST. It seems that is not administerable, that you could not physically locate those completion locations.

Mr. GOOCH. I think you would find you could do it if you wished to do so because the plugged and abandoned wells obviously have to be filed by the States. Let me say I am giving this on information and belief because my practice really is not in this area, but it is my understanding when you plug an abandoned well, you have to file with the State authorities, so I suppose if you took the trouble to do so, you could go back and locate those things.

Mr. SOLOMON. Counsel, when you prefaced your remarks by asking about an enforcement problem here, you can assume that the only enforcement is going to be on the sworn statement of the applicant; as a practical matter, if you are going to use any definition anywhere near as complicated as this, you will have to simply accept on faith the sworn statement of the applicant subject to the occasional situation where you will find out he wasn't telling the truth. There will be no other feasible method of auditing the truth of the applicant's statement.

As in other areas, they assume people are going to tell them the truth.

Mr. DEMAREST. But in other areas law inforcement agencies have a way of finding out whether people are lying or not.

Mr. SOLOMON. They may have spot checks, but it is the only feasible way for anything of this magnitude.

Mr. DEMAREST. Would you agree with that?

Mr. JOURNEY. It is my understanding Mr. Gooch stated the facts of where these might be on file. Whether that material has ever been located or anybody could access it in any reasonable way, I have no knowledge, but I understand there are records kept. I agree with Mr. Solomon that to administer a test like this, you would be taking a lot on faith.

Mr. DEMAREST. I think we have worked that one to death.

Mr. GOOCH. Do you want to talk for a second about the same producing zone? I think that is also something that doesn't have a lot of meaning, and I really would ask you to try to focus on what that means for the people who are going to have to try to administer this bill, if it passes.

Mr. SOLOMON. May I make a suggestion on this point?

Mr. DEMAREST. Certainly.

Mr. SOLOMON. I gather it has been suggested earlier today that the entire effort here is much too complex and a definition of new gas similar to what FPC has put in in Opinion 770 would be much more useful from an administrative standpoint. I think there is a lot to be said for that, but assuming somebody can demonstrate that a definition should be more detailed than the one the Commission has in Opinion 770, I suggest to you this is exactly the type of definition that cannot feasibly be put in to a statute, there has to be sufficient flexibility so it can be modified by rule from time to time as experience shows is necessary.

Mr. JOURNEY. When we drafted 770, at one point we tried a surface measurement. At one time, we tried to define a producing zone. We had x number of geologists in the room and y lawyers and z-plus-20 definitions came from all of them. We abandoned the

concept and went to USGS and the State proration concepts in 770, which we found workable.

Mr. DEMAREST. In that connection, would subsection (b) of section 402 be a satisfactory resolution, or does this very broad grant of authority——

Mr. SOLOMON. Subsection (b) of what?

Mr. DEMAREST. Section 402: "The President shall have the authority to define by rule the terms used in this part"——

Mr. SOLOMON. Mr. Demarest, you have hit upon a section of this act which I gather has raised a lot of questions both before this panel, during this panel and after this panel, and that is what this section means.

Mr. DEMAREST. What does the section mean?

Mr. SOLOMON. I can't answer that. I can suggest certain things that might have been intended.

If you are asking me by your previous question, should the President be given the power to define certain terms which are not defined, then my answer to you is yes. And if this section means that the President shall have authority to define by rule terms used in this part but not otherwise defined, then I would say that was a useful provision and maybe you would then un-define some of these complex definitions of what is new gas. In other words, I was suggesting that this type of definition of new gas is something that probably should be done by rule rather than by legislation.

The provision that you put your finger on here, as drafted, is extremely ambiguous and could be read—as I gather Mr. Schwartz was reading it this morning—as suggesting that the President could redefine provisions of the act which are very specifically defined in the act. I think if he did that, there would be a lawsuit, and I wouldn't even predict the outcome of the lawsuit. From my standpoint, whatever you decide as a substantive matter, section (b) here clearly should not stand in the way it is presently written. It is much too ambiguous.

Mr. KRUEGER. Would you say that is not boilerplate language?

Mr. SOLOMON. It is not language I have seen in other bills; that is right. I know of no other bill that has a bunch of definitions and then says the administrative body can change them as it sees fit.

Mr. JOURNEY. Mr. Chairman, if you look at section 309 of the Power Act and section 16 of the Natural Gas Act, you will find, as close to the analogues as I know of in the existing statutes, but those sections are worded differently.

Mr. SOLOMON. Those sections, Mr. Chairman, give the power to the Commission to adopt rules, including definitions consistent with the act; i.e., not to overrule the definition that Congress has written into the act. Now, either you write in a definition or you don't. Sometimes you shouldn't write definitions in; you should leave it up to the administrator to define the terms. But you can't do both.

Mr. KRUEGER. We will simply send that message down to the place from which the bill came.

Mr. DEMAREST. If we could, I would like to go to the new contract definition. The term "new contract" includes a renewal under certain circumstances, but a renewal is not a defined term. Would you read this as broad enough to include the abandonment, physical

tearing up of an existing contract and its replacement with an entirely new contract, or is that meant to be left out of the term "new contract"?

Mr. JOURNEY. Let me take a whack at it consistent with the way I read this, as a legislative confirmation of 770-A. I believe they consider that as tje FPC did in 770-A, a contract with a discrete term as opposed to an unlimited contract. I thought that is what the draftsmen tried to restate.

Mr. DEMAREST. Did they achieve that objective?

Mr. JOURNEY. In my mind they did.

Perhaps I read it thinking it was a codification of that concept, but that is the way I read it.

Mr. SOLOMON. I must confess I read it and wondered what it meant, and I didn't quite know from my further reading of the bill why they just didn't stop when they said that a new contract means a contract entered into April 20, 1977. I have not been able to find out—it may be simply my inexperience with the matter—what the remainder of that definition adds which is relevant to anything further in the bill, and why anything would be changed if you simply left that definition with "new contract" means a contract entered into after April 20, 1977.

Mr. DEMAREST. Maybe we should leave that definition and go on to the substantive sections, since time is a limiting factor.

Section 404 deals with sales of new natural gas, and throughout sections 404, 405 and 406, the term "first sale" is utilized. Am I correct that is a term foreign to traditional Natural Gas Act regulations?

Mr. SOLOMON. Not in the Natural Gas Act at the present moment.

Mr. GOOCH. I am unaware of what the term means.

Mr. SOLOMON. To try to understand what the term means—I don't think you will succeed—but I think to find out what it means, you have to look at 408(d) because if it means anything, its analogue is in 408(d) at the top of page 52.

Mr. KRUEGER. I would ask the panel to continue discussion with counsel while the members of the committee go and cast their votes. If you would be kind enough to continue with counsel, we would appreciate that. We will return.

Mr. FORQUER. Mr. Chairman, I may have to leave shortly. I hope I may be excused.

Mr. KRUEGER. You are excused at your will.

Mr. DEMAREST. We will continue for the record and make this information available to the committee. I appreciate your cooperation.

Mr. JOURNEY. May I comment on that first-sale terminology?

Mr. DEMAREST. Of course.

Mr. JOURNEY. You won't find that in the case law, and you won't find it, as far as I know, in the Natural Gas Act. You will find it as a phrase cropping up in the jargon of people who are dealing with wellhead sales, and who are dealing with questions of regulation and deregulation. I have heard individuals use it, just as I have heard the concept of bulk power supply used under the Federal

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Power Act. That had no legislative antecedent, but because we have used it consistently, it has come to have a meaning.

I read this as meaning wellhead sales.

Mr. DEMAREST. Would it be useful at least to define this term and give it some precision with reference to existing case law and the Natural Gas Act?

Mr. SOLOMON. How can you define a term unless you know what you want to define it to mean? There is no reason to define a term for the purpose of defining a term. Tell us what you want it to mean and then we can talk about a proper definition.

Why wouldn't this paragraph be equally sensible if you left out the word "first"? What is the difference between leaving out the word "first" and including it? If it means the same thing when you leave it out, then you don't have to worry about a definition. If you can tell me what is intended, what difference is involved by leaving out this word than by putting it in, then we can discuss definitions.

Mr. JOURNEY. When you leave it in, Mr. Demarest, what happens, is that you raise a question in the reader's mind: Well, maybe there is another set of regulations that apply to subsequent sales because there are a number of sales, one producer to another?

Mr. DEMAREST. That point leads us to the daisy-chain question presented by reason of the first sale by a producer being regulated while subsequent sales are not regulated under section 404. In that connection 408(d) provides that the President may, by rule, establish maximum lawful prices applicable to sales of natural gas "by any other person," that is any person other than a producer.

Would I be correct in reading that narrowly to not authorize the President to control the second sale by a producer, although he could control such sales by other persons?

Mr. GOOCH. Let me say first the sections you referred to that "in addition to his authority," I read that as giving him jurisdiction to set State rates like in Alaska and Texas. I felt that is what it was intended to do. As to whether there would be successive sales, I have to say that I am unable to state an opinion now as to whether a second or successive sale would or would not come under regulation.

Mr. DEMAREST. Would it be fair to say it certainly is questionable whether section 408(d) covers such a second sale?

Mr. GOOCH. Yes.

Mr. JOURNEY. I read 408(d) as being directed to the sale of "reserves in place" problem.

Mr. DEMAREST. All of you are getting back to the definition of the term producer, meaning a person who produces natural gas. The question of whether that definition covers a royalty owner who takes his gas in kind is open, is it not?

Mr. SOLOMON. That has been decided. An owner who takes gas in kind? And does what with it?

Mr. DEMAREST. Sells it. Is he a producer?

Mr. GOOCH. If he takes it and sells it.

Mr. SOLOMON. That, of course, is an issue which happens to be involved in a lawsuit at the present moment in the Fifth District Court of Appeals. I don't think this bill changes that problem.

Mr. DEMAREST. Section 405 deals with sales of old gas under existing contracts. If I could summarize this section the way I read it, it says that a producer of flowing gas under an existing contract is guaranteed the lesser of one of two things: either the contract price, if this gas is sold in interstate or intrastate commerce: or, alternatively, the just and reasonable rate in effect on April 20, 1977. Presumably that latter paragraph applies only to interstate gas.

Would you read the latter paragraph as being limited to interstate gas, or do you apply it to interstate and intrastate gas?

Mr. GOOCH. Mr. Demarest, I have tried very hard to read that as applying only to interstate gas, and I am unable to do so. I have heard the arguments about such contracts, and which was determined, and that the FPC hasn't set the rate, but I have to tell you, while not totally free from doubt and not that I wouldn't be willing to argue the other side in court, that, on balance, that has the effect of rolling back all current intrastate prices.

Mr. DEMAREST. As drafted.

Mr. GOOCH. As drafted.

Mr. SOLOMON. I made the suggestion earlier, Mr. Demarest, that I thought this could be read so that (2) did not apply to existing intrastate sales. I still state that. If you are asking us whether this matter is absolutely clear in its present language, obviously it is not absolutely clear in its present language, and it is another area in which clarification would appear to be useful.

Mr. JOURNEY. Mr. Demarest, if you look at page 53 of the President's Plan, he says "existing intrastate contracts would not be affected," you get the other side of the point that Mr. Gooch made. I read it as being limited to interstate.

Mr. FORQUER. The language, I feel, applies across-the-board. Under the national energy plan, it was intended to, but certainly the language should be clarified.

Mr. DEMAREST. There are a couple of other points in this section which should be addressed. First, it would appear this section would overrule, reverse, FPC Opinion 749 so far as that deals with a minimum 18- cent rate for flowing gas, would it not?

Mr. SOLOMON. It would appear to.

Mr. GOOCH. Yes, it would.

Mr. DEMAREST. Mr. Journey?

Mr. FORQUER. I don't know why they say that is true. Weren't those rates considered to be just and reasonable?

Mr. SOLOMON. It is the lower of the just and reasonable.

Mr. JOURNEY. The way it is worded, it would appear it probably does.

Mr. GOOCH. Again, I don't think it is intended, but I think that is what it does.

Mr. DEMAREST. The section references the contract price. Would you read that as including escalating clauses in the contract price: would you read that as a fixed price as in effect April 20, 1977, or is that a case where we have no means of making a judgment?

Mr. SOLOMON. I would read it as the contract price on any given date, i.e., with escalations in the contract. It is the lower of the two, so if those escalations are higher than the fixed price, at least with respect to interstate sales, this would be not too serious a problem.

Yes, contract price means whatever the price is, including escalations at the particular moment.

Mr. GOOCH. It seems to me there is one problem that has come out in our discussions that I frankly missed, and that is one of the types of escalation clauses are called area rate clauses and under the area rate clause the producer and the pipeline agree they will have whatever price they agree on, but if the Federal Power Commission sets a higher just and reasonable rate, then the price end of the contract can escalate to the just and reasonable rate that applies.

I am now of the view that without some clarification, the rate set under 405—the (2) section, may not apply to the area rate clause and therefore would only be the contract price because it is the lesser.

Mr. DEMAREST. So that would be another form of price rollback?

Mr. GOOCH. Yes, it would be a rollback.

Mr. DEMAREST. Paragraph 2 of section 405 deals with the just and reasonable rates. Now I recognize the words used are "the price for sales determined to be just and reasonable," but the Federal Power Commission rates which are determined to be just and reasonable include adjustments over time.

Mr. SOLOMON. I think again there is an ambiguity in this language here, but since they have added an inflation adjustment——

Mr. DEMAREST. Is this a compound inflation adjustment?

Mr. SOLOMON. Let me finish. Since they have added inflation adjustments and since they are talking in terms of the price which was in effect on April 20, I would read this as in effect—well, it provides, for example, for 1975-1976 vintage gas in effect on April 20, was $1.45. Leaving out the problem on Btu adjustments and state taxes mentioned by Mr. Gooch this morning, I would interpret this language as saying you have $1.45, and when the next escalation came along, you didn't get that, but you did get the inflation adjustment.

Mr. JOURNEY. As I pointed out earlier, Mr. Demarest, I feel that the draftsman was trying to restate 770(a) concepts as to price and structure and did not do it accurately. I think it is a word problem.

As I read this, I read it to mean the pricing structure promulgated in 770(a). That is what popped into my mind.

Mr. SOLOMON. With all due respect, I suggest to Mr. Journey that he must be wrong, or he probably is wrong because that means that the draftsman took the pricing structure, which did include escalations, and added on to those escalations an inflation adjustment. I am not the draftsman, I can only guess at what he was trying to do, but I do not think so. I think he was substituting an inflation adjustment for the Commission escalation.

Mr. JOURNEY. I note that the Commission's escalation factor was not an inflation adjustment per se.

Mr. DEMAREST. Certainly the language is far from clear on this point and we should——

Mr. JOURNEY. It needs attention.

Mr. DEMAREST. With respect to section 408——

Mr. SOLOMON. Mr. Demarest, on that point, maybe this will help your thinking. You will note that there is an inflation adjustment

in section 405, but there is no inflation adjustment in section 404, at least not in terms. Well, that does not mean that the rate for old natural gas under existing contracts is going to go up, but the rates for new natural gas are going to stay stationary.

The way the scheme works out, as I understand it, it is expected over a period of time, and I have seen certain figures and I am sure you have, that the current Btu-related price will go up, in fact there have been some indications that it might go up faster than the inflation adjustment. But the fact they have eliminated it in one place rather than the other place indicates to me again that this is not intended as an addition but as a substitution for the Commission escalations.

Again, Mr. Journey is quite right, what he thinks or what I think is not a substitute for good legislative draftsmanship by you people to avoid Mr. Journey and myself or similar people litigating this in the courts for the next five years.

Mr. GOOCH. If Mr. Solomon is correct on his last point, that would mean under section 404 that the new gas price would never escalate, which means that it would be frozen in concrete by whatever happened in a particular quarter.

For example, the price in the third quarter of 1977 is going to be lower than the price in the second quarter because of the price rollback.

Mr. DEMAREST. However, the provisions of section 404, the second sentence, provide that the maximum lawful price, which again is for new gas, is equal to the current Btu related price, determined as of the date of delivery.

Mr. GOOCH. Does that mean you think that it escalates with the Btu related price?

Mr. DEMAREST. The point I believe is what constitutes delivery. Is that an ongoing event or is that the first delivery under the contract? Does the price periodically go up as new deliveries are made under an earlier contract?

Mr. GOOCH. I do not know.

Mr. SOLOMON. I read it as meaning the ongoing deliveries, plural. If it meant initial delivery, then of course there would be no escalations. But everything I have seen in the writing back and forth on this bill indicates that they do expect that the new gas price will escalate. The reason they did not put in an inflation escalation for the new gas price was they expected that it would escalate at least as fast. Again you have a language problem.

If there is any doubt about this——

Mr. DEMAREST. If we could turn to section 408, the special pricing provisions, recognizing——

Mr. SOLOMON. If you are going to section 408, maybe I will answer your question on 406 when you get to 408, Mr. Demarest.

Mr. DEMAREST. Could section 408 be read as permitting the President, under undefined standards, to permit a higher price for traditional supplies of natural gas, in categories which involve high costs, in order to make economic the manufacture of synthetic gas? The argument would be that synthetic gas is not economic so long as traditional sources of natural gas may be purchased for a price substantially less than the cost of SNG.

Mr. SOLOMON. Could it be read that way? Unless you people clarify the matter, it certainly will be read that way by some people.

As to whether it should be interpreted that way, that will have to be determined in court. Frankly, I do not know why the words "or synthetic gas" are in line 4 on page 51. I do not know what the intent of that is. Therefore, I find it very difficult to discuss with you further the implications of the use of those words there.

Mr. DEMAREST. Could I ask you what other construction could be put on the language which includes the phrase "the manufacture of synthetic gas"?

What other construction could be put on this subsection other than the one I have given?

Mr. GOOCH. The only thing I could come up with myself was, since the Federal Power Commission would pick up jurisdiction over synthetic natural gas and theoretically set the rates, and theoretically would set the rates on a cost-of-service basis, I read this as giving the President the power to go in and raise the rate above the cost-of-service level set by the Federal Power Commission in order to give an extra incentive for people to make liquid-based SNG plants, to convert oil and gas liquids into high-cost substitute gas.

Mr. DEMAREST. Certainly no other explicit pricing authority is contained for SNG.

Mr. GOOCH. Other than that implied by the fact that it has been put under FPC jurisdiction, which would then have rates set by the FPC.

Mr. JOURNEY. Mr. Demarest, there is a procedural explanation that may not be too plausible, but when I read lines 2 through 4 on page 51 of the introduced bill, I thought it was a way of saying that the President could give special relief for high-cost SNG cases for whatever the purpose might be, since he apparently would also have pricing authority through generic rulemaking authority to price classes of resources. He could do ratemaking by rulemaking the way the FPC does it.

I read this as saying maybe he can also have special relief authority on SNG and these other areas.

Mr. DEMAREST. Is there a deficiency in such an interpretation of section 408 as a special relief provision in that the section would not appear to authorize special relief for flowing gas, which does not qualify under one of these categories?

Mr. Gooch is nodding.

Mr. JOURNEY. The answer is yes.

Mr. GOOCH. The answer is yes.

It seems to me it is a very limited definition of special relief that would not reach the current spectrum of special relief potential of the Federal Power Commission.

Mr. SOLOMON. Mr. Demarest, I would like to answer that question in slightly greater depth.

I think the bill as drafted has confused, and seriously confused, two separate problems. You have many cases where you have flowing gas—and it has nothing to do with when the contracts expire— where there are good reasons to spend money which the producer has no obligation to spend, in order to get additional gas,

either by putting in compression or recompletion or various activities like that.

Now, the Commission has always provided in those cases that if the producer is not going to be able to produce the gas or as much gas as he otherwise could unless he gets more money, he can come to the Commission and say, my present rate for this gas is say 29.5 cents, if you will give me $1 I will be able to put in this amount of compression and drill this number of additional wells and produce additional gas.

The Commission looks at the petition under their special relief procedure, usually without any contest, I know very few cases, if any, where this has ever been contested, and either gives them the $1, or if it decides that they are not entitled to $1 it gives them 75 cents, or whatever they are entitled to.

That type of special relief conceivably is legal under the language of section 408(a), but it certainly is not what the provision seems to be talking about. On the other hand, the standards that the Commission applies in granting that type of special relief seemed to me to be put into section 406(b) of the act, where I do not think they belong at all.

You skipped over section 406(b), but I put it to you, that it is absolutely impossible for the President or any delegate of his to establish the rules prescribed by section 406(b) within 30 days or 60 days or 120 days, probably, of the effective date of this rule; if you look at the standards here.

Because those standards are not talking generally of roll-over contracts. Those standards, the maximum lawful price of such gas under the prior contract and the price necessary to maintain production of such gas, are special relief standards. They do not have anything to do with general roll-overs at all.

Mr. DEMAREST. Thank you very much.

Mr. Chairman, could I submit further questions to this panel in writing?

Mr. DINGELL. I think that would be most useful. The Chair observes that counsel for the minority has advised that the minority would also like to submit some questions for written response.

Gentlemen, I am sure that we would have your assistance in appropriate responses. Without objection the record will remain open for that purpose.

Gentlemen, we thank you all.

By the way, gentlemen, you have been here a long time. We thank you for your patience. We have had this running back and forth, which has caused you inconvenience.

Mr. GOOCH. No, sir.

Mr. DINGELL. For which we apologize. We thank you for your patience.

The Chair observes that our last panel, which was scheduled for 3:30, is the natural gas users panel.

Mr. Leonard H. Farmer, Jr., Vice President, Corporate Staff, Owens-Illinois, Inc.; James Flug, Executive Director, Energy Action Committee; Thomas Devine, Consultant, Celanese Corporation; Ernest Hueter, Vice Chairman, Interstate Brands Corporation; Gordon E. Follette, Manager, Energy, Conservation and Utility Services, General Foods Corporation.

We apologize to you all.

Gentlemen, would you each, for the assistance of the committee and also for the assistance of our reporter, identify yourselves, starting on your left and go right across, and after you have each identified yourselves we will recognize you in the same order for your statement.

If you please, sir.

STATEMENTS OF GORDON E. FOLLETTE, ON BEHALF OF THE AMERICAN FROZEN FOOD INSTITUTE AND THE NATIONAL ASSOCIATION OF MANUFACTURERS; LEONARD H. FARMER, JR., VICE PRESIDENT CORPORATE STAFF AND DIRECTOR OF PURCHASING AND TRANSPORTATION, OWENS-ILLINOIS, INC., AND ON BEHALF OF THE GLASS PACKAGING INSTITUTE; THOMAS J. DEVINE, ON BEHALF OF THE PETROCHEMICAL ENERGY GROUP AND THE NATIONAL COUNCIL OF FARMER COOPERATIVES; JAMES F. FLUG, DIRECTOR AND COUNSEL, ENERGY ACTION COMMITTEE; AND ERNEST HUETER, VICE CHAIRMAN, INTERSTATE BRANDS CORPORATION, ON BEHALF OF THE AMERICAN BAKERS ASSOCIATION

Mr. FOLLETTE. I am Gordon E. Follette, General Foods Corporation.

Mr. FARMER. I am Leonard H. Farmer, Owens-Illinois.

Mr. DEVINE. Thomas J. Devine, Celanese Corporation.

Mr. FLUG. James Flug, Energy Action Committee.

Mr. HUETER. Ernest Hueter, Interstate Brands Corporation.

Mr. DINGELL. Mr. Follette, we will recognize you first for your statement.

I suggest that in view of the time that we will insert your full statement in the record and we will recognize you for such summary as you choose to give.

STATEMENT OF GORDON E. FOLLETTE

Mr. FOLLETTE. Mr. Chairman, did you ask me to read the five-page summary.

Mr. DINGELL. You can read the summary. Your full statement is inserted in the record.

You may read the summary or you may summarize from it if you wish.

Mr. FOLLETTE. Thank you.

My remarks will be directed to the incremental pricing of natural gas and the availability of natural gas for industrial use.

Regarding incremental pricing, the cost of new gas should be rolled in with the cost of old gas. The rates for this gas should be the same at the wellhead for industrial, commercial, residential, and utility users. Incremental pricing of new gas does not promote more efficient use of new gas. It would increase the cost of goods and services produced by industry.

It is the duty of State and local regulatory bodies to determine how the cost of new gas should be allocated. Incremental pricing to

industrial users provides very little stimulus for residential users to conserve. Rolled-in pricing is simple to administer.

New criteria for adding on residential customers should be developed, in light of reasonable industrial gas needs. Those reasonable needs are being jeopardized by increasing numbers of new residential users who are converting to gas from an alternate fuel.

We appreciate the opportunity to appear and will attempt to answer any questions that you may have at this time.

Thank you, Mr. Chairman.

[Mr. Follette's prepared statement follows:]

NATIONAL ASSOCIATION OF MANUFACTURERS

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Statement Of

Gordon E. Follette

Before The

House Interstate and Foreign Commerce

Subcommittee on Energy & Power

May 17, 1977

Mr. Chairman and Members of the Committee, my name is Gordon E. Follette and I am Manager of Energy Conservation and Utilities Services for General Foods Corporation. I am also a member of the Energy Committee of the American Frozen Food Institute and I am testifying today on behalf of the Institute and the National Association of Manufacturers. General Foods Corporation has had an active energy conservation program since 1972. In 1976 our energy efficiency measured in BTU's per unit of production, reflected a reduction of 13% from the base year of 1972, representing a savings of 1.5 trillion BTU's. Natural gas is the only fuel that can be used for many food processes. Very simply it is cleaner than any other fuel and in an industry that depends upon a clean, uncontaminated product this is an overriding consideration for the use of natural gas.

My remarks will be directed to the incremental pricing of natural gas and the availability of natural gas for industrial use.

I wish to address incremental pricing of gas first. Title I Part D, Section 414 of the Bill, provides for the President to order new, higher priced natural gas to be allocated to low priority uses. Low priority is defined as any uses other than residential or small commercial. Thus, the President has proposed, by incremental pricing that the most expensive natural gas be sold for uses other

than residential or small commercial. Thus, the President has proposed by incremental pricing that the most expensive natural gas be sold for uses other than residential or small commercial.

The fallaciousness and inequity of the incremental pricing philosophy has been clearly put forth on numerous occasions. I begin with the position that the cost of new gas should be rolled-in with the cost of old gas. The rates for this gas should be the same at the wellhead for industrial, commercial, residential, and utility users. The only possible exception should be the allowance of incremental pricing to boiler fuel users.

Some people argue in favor of incremental pricing that it will promote efficient use of new natural gas because industrial, utility, and large commercial customers will be forced to pay the full cost of producing and transporting new, more expensive gas. This assumes that there is some elasticity in the purchasing capability of the consumer. In other words it assumes that he can switch to an alternate fuel when the price of natural gas reaches a certain level. In the past, when large volumes of gas were used for relatively low priority needs, such as for boiler fuel, this argument may have had some appeal. However, you remember that I began by saying that the price of gas for fuel <u>other than boiler fuel</u> should be rolled in. Much of the fat has already been trimmed from the diet of gas users. Increasing the distinctions between Category 1,2,3, and 4 users are becoming blurred, especially by the realization that curtailment of high-priority commercial and industrial users may create unacceptable levels of unemployment.

Having dealt with the major argument in favor of incremental pricing, I now wish to raise three more points in opposition to it.

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First, incremental pricing of new gas to industry will boost the costs of goods and services produced by industry. The impact on consumers will be immediate and adverse. This is especially true in the food industry since use of natural gas is absolutely necessary to maintain certain food products as we know them today. Any increase in the cost of natural gas will be reflected in the price of the food product. The increased costs are borne by all consumers, including those who are not residential users of gas. Thus, incremental pricing has an unnecessary and prejudicial effect.

Second, state and local regulatory bodies have been charged with the responsibility of protecting the public interest. Incremental pricing deprives them of the opportunity to determine who should bear the cost of new gas. State regulatory bodies may conclude simply in order to encourage industrial development that all users should share the costs of new gas equally. Federal usurpatfon of state regulatory authority may be unconstitutional.

Third, incremental pricing to industrial users would provide no stimulus for residential users to invest in energy conserving technology or other conservation measures.

It is anticipated that H.R. 6831 will create a number of administrative headaches, in addition to the foregoing arguments in favor of rolled-in pricing it is far more simple to administer.

The second major aspect of President Carter's National Energy Plan that I will address is reflected in the proposition that it is perfectly permissible to drive industrial users of natural gas off the line as long as that gas goes to residential or small commercial users.

This proposition is reflected in H.R. 6831 and is specifically is set forth in Chapter IX of The National Energy Plan. There it states in part that, "The Plan is projected to reallocate natural gas to high-priority uses..." High priority uses are defined in the Bill as uses for residential and small commercial customers. As opposed to the Plan, the Bill does not appear to directly address the issue of steadily increasing high priority hookups. This is a gross omission.

Our nation is so often reminded that natural gas is a finite resource. Our proven reserves of gas are steadily declining. It is therefore inescapable that we must set strict new standards for add-ons of residential customers. It is folly for local distribution companies to act in disregard of essential industrial gas needs. These essential industrial needs should be assessed immediately and distribution companies should be sure that reasonable industrial gas needs can be satisfied before one more home is attached to a gas line.

This past winter our nation narrowly averted interruption of service to residential customers of natural gas. Yet between 1970 and 1976, approximately 3 1/3 million new residential gas customers were added on. From 1975 to 1976 over 417,500 new residential gas customers were added on. In 1976 there were approximately 41,368,000 residential customers. These statistics are dramatic, astounding and sobering. Even more sobering are the numbers of residential customers who converted to gas from an alternate fuel. Between 1970 and 1975 approximately 1,372,000

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residential customers stopped using their existing fuel and started to use gas. For the calendar year 1975, approximately 145,000 residential users converted from an alternate fuel to gas. Anticipated residential additions by conversion from alternate fuels were projected for 1976 at 100,600. The figure for 1977 is projected to be 86,300 and for 1978, 85,000. Thus we must not only be extremely concerned about new standards for residential users who are using natural gas from the beginning, we must consider the approximately 272,000 residential users who are projected to convert to gas use from an alternate fuel.

This Congress must critically address the Carter policy which decries even the maintenance of industrial gas supplies while leading residential users to believe that they will never be curtailed. We appreciate the opportunity to appear before your committee and will attempt to answer any questions you may have at this time.

Mr. Dingell. Thank you, sir.
Mr. Farmer.

STATEMENT OF LEONARD H. FARMER, JR.

Mr. FARMER. Mr. Chairman, members of the committee, thank you for the opportunity to appear before you and summarize the written statement which has been filed with your committee.

I am Leonard H. Farmer, Vice President, Purchasing and Transportation, for Owens-Illinois, Inc., a large packaging, technical, and consumer products company.

Our production is primarily in the fields of glass, paper, and plastics. I am appearing today in behalf of the Glass Packaging Institute, a trade association representing manufacturers of glass containers and in behalf of Owens-Illinois, a member of that institute.

My written statement and these remarks are directed to section 414 of House bill 6831, which provides that higher than average cost gas wil be charged to what are defined as lower priority users. There could be several purposes for this provision.

The effect of the clause is to charge residential consumers less than the average cost of gas. If that in effect is the primary purpose of this provision, then it is misleading to the residential consumer, because it hides from him the full impact of increased gas costs.

All of these costs have to be reflected in prices. In the long run it is the consumer who has to pay. If he pays lower gas rates at his home, he will pay higher prices for the products he buys and with normal pricing poicy, there could well be more than a straight pass-

through of those costs, which would add further fuel to the inflationary aspects of cost increases.

Please also note that the consumer using oil or electricity in his home will underwrite the low cost of his neighbor's gas in the prices he pays for industrial products.

Another purpose of this section could be to encourage conservation through higher prices. If this is an objective it is unnecessary and in fact counterproductive.

Industry is working constantly and diligently to reduce energy usage and improve efficiencies. The glass container industry, for example, has reduced energy consumption per ton of glass produced by 50 percent over the last several decades, and purchased energy costs are still a very substantial cost factor.

We do not need any other incentive in this effort. If conservation, indeed, is one of the motivating factors for this section, then the section works against that result. Artificially low prices are extended to residential users, an extremely large segment of energy use.

With lower rates there would not be the same incentive for conservation as if the true cost of that gas were being paid by those customers.

A third possible purpose of this provision is to remove cost incentives as a reason for industry to use gas rather than alternate fuels. It is true that much of the present demand for natural gas was created as a result of artificially low prices. Demand reflected economics rather than the need to use gas because of the manner of its use.

Many boilers were converted to gas from other fuels and the low cost of gas was an important factor in those conversions.

Gestures have been made toward eliminating the use of natural gas under boilers, but a real program to accomplish that result is years overdue. It should be initiated promptly and this bill could be a good vehicle to accomplish that result, but it should be recognized that this will take time and large capital investments.

The Bureau of Mines has estimated that about 16 percent, 15.8 precisely, of total natural gas production is used for electrical generation. If this were converted to coal, it would free up about 3 trillion cubic feet of natural gas per year for higher priority users. To furnish this much additional coal would require a 21.5 percent increase over last year's coal production, 129 million additional tons.

That is an ambitious undertaking which will take several years to put in place.

Forced conversions to oil would only increase our dependence on foreign energy sources, and are inconsistent with the bill's stated purpose, to reduce oil imports.

We thus suggest that the thrust of this bill should be to encourage conversions to coal rather than alternate fuels.

This bill classifies all industrial uses as low priority, although in fact there are many types of industrial applications with varying degrees of priorities according to existing FPC regulations. These range from a low of large volume boiler fuel to a high of process and feedstock applications.

This section completely ignores the fact that there is no substitute fuel for process and feed stock uses of natural gas, and yet the bill purports to establish a price ceiling based on alternate fuels. Coal cannot be used in glass making and much of our use does not permit substitution of an alternate fuel.

Regardless of what may be provided in this bill, there will not be enough natural gas to supply present and projected demand for a good many years. This means that supply will have to be allocated so that the gas is made available where it is most needed and most efficiently used.

This section of the bill could be modified to correspond with those priorities.

It is respectfully urged that if the intention of this bill is to encourage conversion, attention should be directed to effecting conversions to coal from the most wasteful use of natural gas, for example, large volume boiler use for electrical generation. Cost incentives to use gas under boilers should be removed, unles conversions are in process, and tax or other financial credits should be established to support capital investment to make the conversion.

Higher priority industrial uses should not be included. For many of those uses there is no acceptable substitute, and use of the gas is not price-sensitive.

If conversion is the intent of this section, we urge that higher priority industrial uses be excluded from the provisions of this section, that it be directed to encourage conversions to coal, and that the principal target should be coal for electrical generation.

I thank you.

[Mr. Farmer's prepared statement follows:]

STATEMENT OF LEONARD H. FARMER, JR., VICE-PRESIDENT-CORPORATE STAFF AND DIRECTOR OF PURCHASING AND TRANSPORTATION FOR OWENS-ILLINOIS, INC.

Mr. Chairman and Members of the Committee: I am Leonard H. Farmer, Jr., Vice-President Corporate Staff and Director of Purchasing and Transportation for Owens-Illinois, Inc. I am appearing in behalf of the Glass Packaging Institute which is a trade association representing manufacturers of glass containers and in behalf of Owens-Illinois, a member of the Institute.

The Glass Packaging Institute and Owens-Illinois strongly support the purpose of the National Energy Act and the President's energy proposals to conserve vitally important energy resources. United States industry is dependent on a continued supply of energy, and incentive to conserve is already in place. Energy to most industries, for example energy in the glass industry, has always been a cost controlled item. Control and conservation methods have been based on fuel efficiencies. As a result, Owens-Illinois, for example, has reduced the amount of fuel consumed per ton of container glass produced by 50% over the past 40 years. This progress continues and further reductions are anticipated. The glass container industry (SIC32) is currently working with FEA on a voluntary basis to set goals and to report progress in achieving these goals.

Further incentive through the price punitive measure of taxing natural gas and the incremental pricing as proposed in House Bill 6831, Section 414, would increase costs to the ultimate consumer without necessarily reducing natural gas consumption.

Incremental pricing of natural gas to industries who use the fuel for high priority end uses would result in increased costs which would ultimately be passed on to the consumer.

Punitive pricing should not be imposed on uses where natural gas is required. For example in glass container manufacturing the product of combustion is in contact with the product being manufactured, the specific flame properties of gas are difficult to duplicate and it is not technically feasible to convert to coal.

The residential and commercial consumer who, under this bill, would be protected from paying higher prices for gas if all costs were rolled into each unit of gas delivered would have to pay the higher prices for goods purchased and the artificially lower price of gas would be a negative incentive to conservation. The result of this incremental pricing to the high priority user would thus be deceptive to the consumer who would pay for the cost indirectly rather than the cost of gas he used. While it may be politically attractive for residential consumers to pay less than rolled in cost, such action is misleading. Even if in time some industrial consumers who were paying more for gas than its rolled in value could develop technology to eliminate or reduce his use of gas there would be adverse effects. The residential user would then receive the higher priced gas directly and the impact to move from the artificially supported price to the new incremental price would be a severe shock. Since the small user's consumption is temperature sensitive, gas is primarily used in cold weather only. The industrial user has carried the cost of the pipeline and delivery system throughout the year. If the industrial user is eliminated all of these fixed costs would have to be absorbed by the remaining customers, these same small users.

It must be noted that to price the gas lower than the rolled in price to the residential and small commercial user does not differentiate between the needy and the affluent consumer and removes the incentive for these customers to conserve gas.

Since the pricing mechanism which was designed to force the high priority industrial user to alternate fuels is not feasible, the result would be that no less gas would be consumed by the industrial and the lower price would cause waste by the small user.

We would suggest that end use concept, as defined in FPC Order 467-B, which would cause conversion of the lower priority users, would be a better solution to conserving natural gas. First to convert from gas to coal would be large volume generators of electricity. Acquisition of conversion equipment to make this first change and development of transportation equipment to serve this need is estimated to take three to five years. When this conversion is completed, approximately 15% of the total gas supply would be released for high priority end users all of whom should pay the average price of gas plus the costs to deliver this gas to the consumer. Any other incremental pricing method to high priority consumers would not achieve the President's purpose or the purpose of this bill to reduce natural gas consumption, but rather would result only in higher cost.

Mr. DINGELL. Thank you very much, Mr. Farmer.

Mr. Devine.

STATEMENT OF THOMAS J. DEVINE

Mr. DEVINE. Mr. Chairman, members of the committee, my name is Tom Devine. I am a consultant to Celanese Corporation, an independent petrochemical company, and appear before you to express what I believe to be the impact of this bill on high priority industrial and agricultural users of natural gas, including the Petrochemical Energy Group of independent petrochemical producers, and the National Council of Farmer Cooperatives, who were invited to testify today.

As you are aware, PEG member companies and farm cooperatives produce the major share of U.S. petrochemical intermediates, in competition with the major oil companies. These intermediates are the building blocks for many industrial and consumer products, including synthetic fibers, fertilizers, pesticides, synthetic rubber, paints, adhesives and pharmaceuticals—essential to our everyday lives and the Nation's economy.

Virtually all of our products are derived from crude oil, natural gas, or natural gas liquids. These are our raw materials, which we call feedstocks. In addition, some of our manufacturing requires these hydrocarbons in process applications.

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All of us applaud the President's call for a national energy policy. His objectives are commendable. However, we fear that, in part, the proposed National Energy Act will frustrate their achievement. We understand that today's hearing is limited to certain aspects of the natural gas sections 401-415. We will focus on three points, leaving others to future hearings.

Mr. DINGELL. That is a fact, but we will hear testimony on all parts of the bill before we are done. If you have some suggestions on other parts of the bil, we would be more than pleased to receive them.

Mr. DEVINE. Thank you, sir.

First, the President's objectives cannot be met without stimulating increased domestic exploration for natural gas. We believe that freezing some gas prices, rolling back others, extending Federal price controls to intrastate markets, defining new gas too narrowly and holding its price below equivalence with new oil will discourage exploration and development. Instead, we urge that Congress concentrate on the best way to remove Federal price controls from new gas.

Second, synthetic natural gas plants which consume oil and gas liquids should not be encouraged. The act proposes to facilitate construction of more liquid-based SNG plants to offset temporarily the decline in natural gas production until conservation and conversion strategies can take effect.

We believe that construction of more SNG plants would frustrate the President's strategy because: SNG plants are extremely costly. Two such plants which now file transportation tariffs with the FPC charge the equivalent of $24 and $29 for a barrel of crude, compared to an import price of $13.50.

Because SNG plants are wasteful. They convert one clean fuel into another, with appreciable conversion losses.

Because SNG plants must obtain their oil and gas liquid feedstocks by importing them, thereby increasing our dependence on foreign sources, or by taking them from current consumers—residential, commercial, agricultural and petrochemical.

Because SNG plants must operate significant portions of the year and for many years to mitigate their already bad economics. This means that boiler fuel loads will have to be kept on line to absorb SNG production when residential demand is low, thereby frustrating conversion of boilers to coal.

But no boiler fuel user will pay the equivalent of $24 to $29 a barrel for boiler fuel, so SNG is charged to residential, commercial, and high priority industrial customers too. This act provides that residential and small commercial customers will only partially be exempt from paying for SNG and then only to the extent practicable, as part of a comprehensive plan to drive first the industrials, then the utilities, from natural gas to coal.

Third, there is no waste of natural gas in feedstock and essential process uses. In my formal statement filed with the committee, I refer at page 8 to Dr. Schlesinger's testimony before this committee last Thursday. In his written remarks he indicated that only boiler fuel would be incrementally priced or subjected to the use tax. We are disappointed to find that in oral comments Dr. Schlesinger changed his position on feedstock and process uses.

To include these nonsubstitutable end uses is inconsistent with the administration's stated rationale for its conversion incentives.

Apparently the National Energy Act would require incremental pricing to industrial users of any gas which costs more than supplies delivered to a pipeline before the act's passage. The purpose stated in the act is to reduce natural gas demand by pricing it to certain industrial and other users at levels which will induce conversion to other, more plentiful fuels, and conservation 401(b)(3).

The President stated in his April 20 address:

"We must be sure that oil and natural gas are not wasted by industries and utilities that could use coal instead. Our...strategy wil be conversion from scarce fuels to coal wherever possible."

For incremental pricing to achieve the intended result, there must be conversion potential. Yet there is no conversion potential for the feedstock (raw materials) use of natural gas or natural gas liquids because there are no feasible feedstock substitutes. While the President and his advisors have recognized this significant principle in the consumption tax section, if only in part, it is not recognized in the incremental pricing section.

In addition to using oil and natural gas as raw materials, many industries use them as process fuels—among them petrochemicals, steel, glass, textiles, and automobiles—again, because there are no feasible substitutes.

I am not talking about process steam or, indeed, any boiler fuel use. I am referring to the use, for example, of natural gas for direct flame application on textiles, paints, and specialty steels and for indirect flame applications where precise temperatures, uniformly distributed along a surface, are essential.

If either feedstock or process use is subject to incremental pricing, and if petrochemical feedstocks are diverted to SNG plants, then U.S. petrochemical production will decline and become too costly to compete in world markets.

These results would lead to importing oil and gas in the form of textiles and clothing, plastics, medicines, fertilizers, pesticides, tires. Instead of importing crude oil at $13.50 a barrel, we would pay the equivalent of $50 a barrel and more for imported petrochemical derivatives.

Export markets would be lost which in 1974 and 1975 provided a positive trade balance of over $3 billion.

There would be major downstream impact on the economy, including substantial unemployment, due to the wide use of petrochemical intermediates in industrial and consumer products.

Therefore, we urge:

One, that domestic natural gas exploration be stimulated by leaving intrastate natural gas markets free of Federal regulation and ending Federal price controls on new gas sales to interstate markets;

Two, that synthetic natural gas be made from coal, not oil and gas liquids; and

Three, that incremental pricing, if imposed on natural gas sales, be limited to boiler fuel, not feedstock, process and plant protection uses.

Thank you very much.

[Mr. Devine's prepared statement follows:]

May 17, 1977

NATURAL GAS PROVISIONS OF THE
NATIONAL ENERGY ACT (H.R. 6831):
IMPACT ON THE HIGH PRIORITY INDUSTRIAL AND AGRICULTURAL USERS

Mr. Chairman, members of the Committee, my name is Thomas J. Devine. I am a Consultant to Celanese Corporation, an independent petrochemical company, and appear before you to express what I believe to be the impact of this Bill on high priority industrial and agricultural users of natural gas, including the Petrochemical Energy Group of independent petrochemicals and the National Council of Farmer Cooperatives, who were invited to testify today.

As you are aware, independent petrochemical companies produce the major share of U.S. petrochemical intermediates in competition with the major oil companies' petrochemical arms. These intermediates are the building blocks for an almost endless list of industrial and consumer products, including manmade fibers, fertilizers, pesticides, synthetic rubber, textiles, paints, resins and adhesives, and pharmaceuticals--products essential to our everyday lives, and to the nation's economy.

Virtually all of these products are derived from the hydrocarbon molecules of crude oil, natural gas, or natural gas liquids. These are our raw materials which we call feedstocks. In addition, some of our manufacturing processes utilize these same hydrocarbons in process applications.

All of us should applaud the President's emphasis on the need for a national energy policy. His objectives are commendable. But we fear that some of the features of the proposed National Energy Act are more likely to frustrate than to achieve the President's objectives.

We understand that today's hearing is limited to certain aspects of the Natural Gas Sections 401-415. We will focus on three points, leaving other aspects to other hearings.

First--natural gas supply. We are doubtful that the President's objectives can be met without stimulating increased exploration and development of natural gas reserves, whether now proven or not. We believe that the Bill will not achieve such an increase.

Freezing some gas prices, rolling back others, extending federal price controls, and having a severely limited new gas definition (which cannot even reach the comparable price for new oil) cannot stimulate exploration and development; to the contrary, exploration and development would be depressed. Instead of extending price controls, we believe that this Congress should focus on the question of how federal price controls on new gas should be removed. This nation should not pass up the chance to develop our domestic natural gas supply, particularly when the alternative

suggested is to import more liquified natural gas and to build more oil and gas liquid-based synthetic natural gas plants which directly or indirectly increase oil imports.

Consider the Administration's projections for supply in the 1980's:

From "New" Gas	1.1 trillion cf[1/]
From Liquid-Based SNG	1 trillion cf[2/]
From Imported LNG	2+ trillion[3/]

How can the President's goal of limiting oil imports to 6 million barrels a day be attained if this is the projected result of the Bill?

How can this nation adopt a natural gas policy based on bypassing almost all developmental drilling and based on extension of federal price controls, a policy designed to yield 1.1 trillion cubic feet of "new" gas? And at the same time adopt a policy which encourages an almost equal amount of synthetic gas from wasteful SNG plants, the second point we wish to address.

1/ Testimony of James R. Schlesinger, Assistant to the President, Before the Committee on Interstate and Foreign Commerce, Subcommittee on Energy and Power, United States House of Representatives, May 12, 1977.

2/ National Energy Plan, p. 57.

3/ Id.

Second--synthetic natural gas plants using oil and gas liquids, such as propane and butane should not be encouraged. The Act proposes to facilitate the construction of more liquid-based SNG plants to "temporarily" offset the decline in natural gas production until conservation and conversion strategies can take effect. We believe the construction of more SNG plants will frustrate the President's strategy because

- SNG plants are extremely costly. Two such plants who now file for transportation at the FPC charge the equivalent of $24 and $29 a barrel of crude, as compared to an import price of $13.50 a barrel.

- SNG plants simply convert one clean fuel capable of being used as a liquid or gaseous fuel into a gaseous fuel resembling natural gas, with appreciable conversion losses aggravating the waste.

- SNG plants must obtain their oil and gas liquid feedstocks either by importing them, thereby increasing our dependence on foreign sources, or by taking them away from current consumers--residential, commercial, agricultural or petrochemical consumers, thereby indirectly increasing imports.

- SNG plants must operate significant portions of the year and for many years even to keep the already bad economics from getting worse. This means that boiler fuel

loads with dual firing capability will have to be kept on line in order to take this production when residential customers do not need it, thereby frustrating the objective of converting boiler fuel use.

- or, if boiler fuel loads are not kept on the line in order to dump SNG, then the SNG will have to go into storage. It would follow from this that cheaper natural gas will be shut in at the wellhead in order to protect a market for the high-priced SNG. This may seem so absurd as to be a straw man argument, but it already has happened. A pipeline has backed off of natural gas takes while increasing its own production and sale of SNG by over thirteen billion cubic feet in one year.

- if boiler fuel loads are to be kept on the line "to build load factor" as a favor to residential customers, it is difficult to sell boiler fuel gas to a dual-fired boiler at the equivalent of $18 to $29 a barrel, when even home heating oil is much cheaper. If the SNG comes from storage to which the costs of transporting, injecting, withdrawing, and the carrying charges for the investment and cushion gas have been added, the SNG is even more expensive. Thus, the gas utility will want to "roll in" the cost of the SNG, which means that the residential, the commercial, the high priority industrial customers are expected to pay for SNG even when it is going for boiler fuel use. This

Act provides that the residential and small commercial customer will be only partially exempt from paying for SNG--that is, partially exempt until first, the industrials, then the utilities, are driven off natural gas (and oil) and on to coal. This is our third point.

Third--There is no waste of natural gas in the feedstock and essential process uses.

The National Energy Act would require incremental pricing to industrial users[4/] of any gas which costs more than supplies delivered to a pipeline before the Act's passage. The purpose stated in the Act is to provide for the conservation of natural gas by pricing it to certain industrial and other users at a level which will provide incentives for conversion to other more plentiful fuels and for conservation. §401(b)(3)

The President stated in his April 20 address: "We must be sure that oil and natural gas are not wasted by industries and utilities that could use coal instead. Our...strategy will be conversion from scarce fuels to coal wherever possible."[5/] (Emphasis added.)

4/ Part D, Section 414.

5/ Text of an Address by the President to a Joint Session of Congress On Energy, April 20, 1977, p. 6.

There is no conversion potential for the feedstock (raw materials) use of natural gas or natural gas liquids.

While the President and his advisors have recognized this significant principle in the consumption tax section, at least in part,6/ it is not recognized in the incremental pricing section.

In addition to the petrochemical industry's use of oil and natural gas as raw materials, many industries use oil and gas as non-convertible process fuels--steel, glass, textiles, automobiles and petrochemicals--just to name a few. Let me be clear--I am not talking about process steam, or, indeed, any boiler fuel use at all. I am referring to the use, for example, of natural gas for direct flame application on textiles, on paints, on specialty steels, for indirect flame applications where precise temperatures,

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6/ Section 4993(h)(4) and (5) exempts certain end uses including:

> "(4) use for production of anhydrous ammonia or ammonia liquor (except use of natural gas as fuel),
>
> (5) use of petroleum or natural gas (other than as a fuel) by a refinery or natural gas processing plant to produce refined petroleum products,..."

It would be preferable to make the applicability of the sections to all feedstock use clearly, lest some claim that only oil companies who use oil and natural gas as feedstock are exempt.

uniformly distributed along a tube in a manufacturing process, is essential, and for such uses where the by-product of the manufacture of the desired product yields a fuel which is recycled into the process heaters, mixing with smaller quantities of gas. I am also referring to plant protection gas which prevents damage to equipment and processing.

Since Dr. Schlesinger testified before you on May 12, we have been encouraged to believe that the omission of the recognition of feedstock, process and plant protection gas was an oversight which will be corrected. Dr. Schlesinger stated the Administration's intent as follows: "...the legislation's incremental pricing provision requires the higher cost of new gas to be paid by boiler fuel customers of natural gas...." (p. 10, emphasis supplied; accord, p. 11 on taxes). We urge you to make a correction in the Bill consistent with Dr. Schlesinger's statement, because if either or both nonsubstitutable feedstock or process uses are subject to incremental pricing designed to force conversion to coal, or if our feedstocks are diverted to SNG production, nothing is achieved beyond a loss in production.

If we limit our production, not only our industry, but the entire economy will suffer. As an illustration, consider please the impact on petrochemicals.

- Loss of U.S. petrochemical production or uncompetitive U.S. production could result in importing oil and gas in the form of textiles and clothing, plastics, medicines, fertilizers, pesticides, tires. Instead of crude oil imports at $13.70/barrel,[7] the cost goes to $50/barrel and more for imported petrochemical products derived from oil and gas.[8]

- Export markets could be lost which in 1974 and 1975 provided a positive trade balance of over $3 billion.[9]

- As we lose either our markets or our nonsubstitutable feedstocks and process fuels, an adverse impact on U.S. employment will occur. That impact is caused, not by conversion, but by lost production.

Lost production would have significant downstream impact on the economy due to the wide use of petrochemical intermediates in industrial and consumer products.

Key petrochemicals include ethylene, propylene, benzene, naphthalene, ammonia and methanol. From these

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7/ (Average price for 1976) Federal Energy Administration, "Monthly Energy Review," March, 1977.

8/ We estimate that first derivative petrochemicals and monomers are worth 18¢-40¢ per pound. Assuming roughly 250 lbs. of such petrochemicals can be produced from one barrel of feedstock, using 20¢ per pound as the average value, we get $50 per barrel value.

9/ Arthur D. Little, Inc., "Trade Trends in Petrochemicals," p. 1.

intermediate chemicals, the industry and its customers manufacture a host of products. The list includes:

- Synthetic rubber, which is 78 percent of the nation's total rubber supply.[10/]
- Plastics.[11/] The U.S. requires more than 29 billion pounds of plastics each year to meet needs in food processing, communication, transportation, housing and many other industries.
- Fibers. Almost 60 percent of the textile fibers in the U.S. are dependent upon petrochemicals.[12/]
- Agricultural chemicals. All ammonia-based fertilizer, pesticides and herbicides are petrochemical products.

Thus, we would urge that

(1) natural gas supply be stimulated by terminating federal price controls on new gas sales to the interstate market without any extension of federal price controls to the intrastate market

(2) synthetic natural gas should be made from coal, not from oil and gas liquids. Oil and gas liquid-based

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10/ Rubber Statistical Bulletin, March 1975.

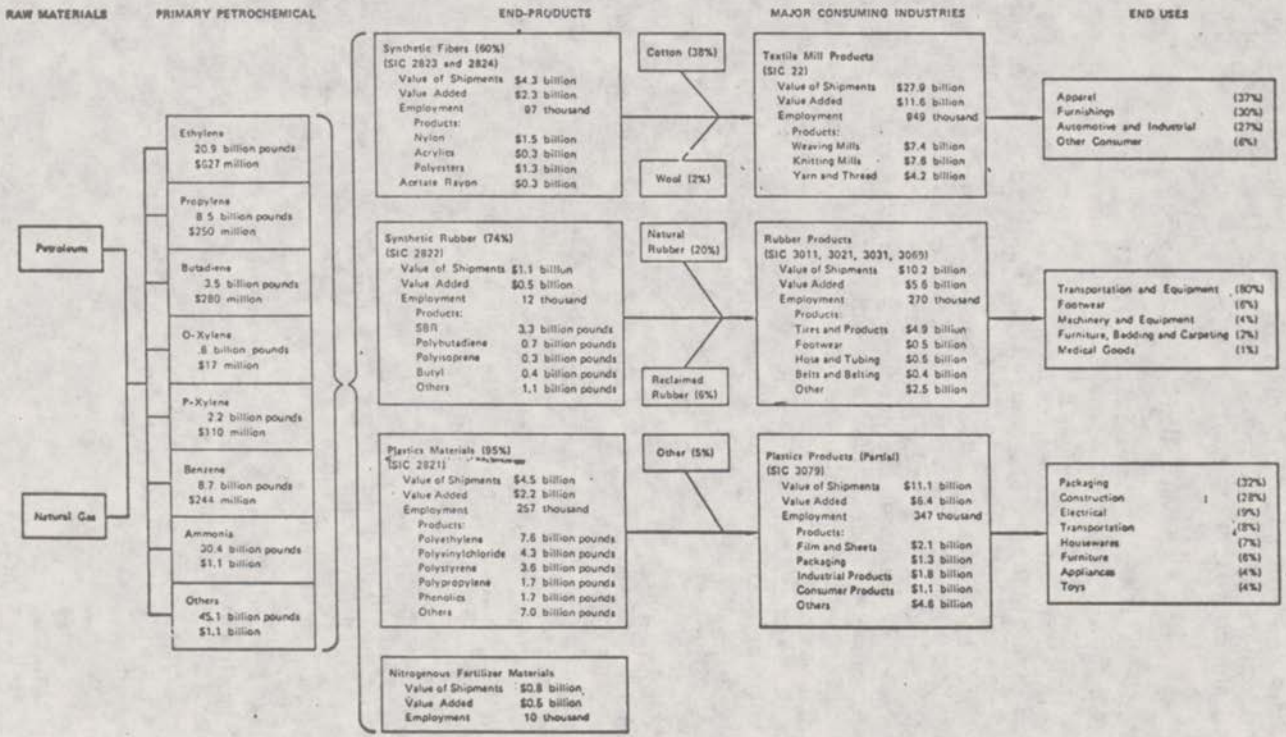
11/ U.S. Department of Commerce, see "Major Petrochemical Product Usage--1972" (attached).

12/ Id.

SNG plants wastefully convert one clean fuel into a different form, increase our dependence on oil imports, and adversely affect present consumers of oil and gas liquids for which there are no substitutes

(3) if there is to be an incremental price imposed on natural gas sales, it should be limited to all boiler fuel, not feedstock, process and plant protection uses.

Major Petrochemical Product Usage – 1972



Mr. KRUEGER. Thank you very much, Mr. Devine.

Mr. Flug, we would be happy to, as was indicated, include your full statement in the record, and perhaps you would wish to summarize your statement.

STATEMENT OF JAMES F. FLUG

Mr. FLUG. Mr. Chairman, I welcome the opportunity to appear at the committee's invitation to discuss the natural gas pricing provisions of the National Energy Act.

Mr. Chairman, deregulation by any other name smells just as bad, and I submit that the natural gas pricing provisions of the National Energy Act are the moral equivalent of deregulation.

From his January 1976 statement in support of legal restrictions to allow a reasonable profit on oil and natural gas to his January 1977 assurance of a prohibition against excessive or windfall profits from energy costs at the expense of the consumer, to his April 18 promise that no one will gain an unfair advantage or profiteer from his energy plan, and right up to his April 20 admission that fuel price decontrol would be disastrous for our economy and for working Americans and would not solve long-range problems of dwindling supplies, President Carter gave the American people hope that whatever he did on natural gas prices, the result would be fair and equitable, spreading the burdens and sacrifices evenly throughout society.

Unfortunately, the reality has not matched that rhetoric. The proposal to set the price of natural gas at the equivalent energy value of U.S. crude oil, beginning at $1.75 per Mcf, is a betrayal of the public interest and a multibillion dollar boon to the oil and gas industry.

It is precisely what President Carter's own energy plan said he wanted to avoid, and I quote again: "an inequitable transfer of income from the American people to the producers, whose profits would be excessive and would bear little relation to actual economic conditions."

I think we have been discussing high gas prices so long that perhaps $1.75 does not sound like much, but it is a huge amount; it is ten times what the producers were getting a decade ago; six and a half times the 26-cent price that was the incentive price agreed upon by industry with the FPC in 1970; three and a half times the last court-approved just and reasonable rate of 52 cents, that court decision coming just over a year ago; almost three times the 60-cent range which the Federal Power Commission's staff has said would produce ample returns and incentives for producers; well above the levels in recent years of the uncontrolled intrastate gas prices. President Carter in his plan correctly called them exorbitant prices; of course, about 25 percent over the $1.42 price through which the Nixon-Ford Federal Power Commission attempted to deregulate administratively.

That price, of course, is in the courts now and many observers think it is going to be overturned as unsupported by the evidence under the just and reasonable standard.

I want to focus on the $1.42 price for a minute because the plan, and most of the analysis in the media, treats that price as some sort of credibly based case against which future developments, and especially the revenue impact on the industry, should be measured. But in fact, that price is just the personal opinion of three particular men, and I think we all know that they were appointed by Presidents who were committed to giving the industry unlimited profits; who themselves were opposed to the very process of price controls they were supposed to enforce, and whose own backgrounds and political sponsorship are reflective of the oil and gas producer viewpoint.

I think that for policy purposes, and looking ahead, all of us are just as entitled to accept as the base case either the opinion of the experts in the Office of Economics that came to a 56-cent price, or the 61-cent price from the Bureau of Natural Gas, or the view of the dissenting commissioner, Commissioner Smith, who disagreed with the majority.

We can take into account the 40 cents worth of hypothetical income tax that the Commission included in the $1.42 rate. We are certainly entitled to have our own thoughts about whether we accept the production cost and reserve figures that the productivity formula was based on, and we are entitled to look at other cost figures from other sources like the recent Oklahoma study that mentioned actual costs of producing gas in 1976 in a range of 35 cents, 44.5 cents, and 60 cents, and that one looks kind of high because it rose from 17 cents in 1973.

The system we have had until now had two fatal flaws:

First, the uncontrolled intrastate market operating right next to a controlled national market, as markets for the same product and thus leading unavoidably to minimal production in the controlled market and maximum production for the uncontrolled market. This factor alone is responsible for a major portion of the supply problems like some of the ones we experienced this winter in the nonproducing States, as the committee of course is well aware and has heard testimony about time and time again.

The second fatal flaw has been the expectation and the fact of continued sharp rises in the regulated price and the continuing expectation and the hope of eventual deregulation which makes withholding gas more profitable than selling gas.

Now to remedy the first flaw, we have to bring the two prices together and we can do it either by bringing the interstate price up to the intrastate level, the uncontrolled levels and give all the production in the country the benefit of those windfall prices that the intrastate producers have been able to get for the past few years, or we can bring what President Carter called the exorbitant intrastate price level down to a just and reasonable national level.

Now the proposal that was sent up here clearly reflects the industry's approach, raising the regulated interstate price to the unregulated intrastate levels, something this committee and this House have protected the American people from in the past. Anyone who has any doubt that this proposal is taking the deregulation route or what amounts to the deregulation route need only look at the FPC's own statistics on intrastate prices for just the last 2 years and of course the prior years would reflect even more of a gap.

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The weighted average of the new intrastate contract sales of the producers, jurisdictional producers, reporting their nonjurisdictional sales to the FPC, never reached the $1.75 level until this crisis of the past winter and then many of the sales and the contract renegotiations in many places were at much lower prices, including prices under $1 per Mcf.

The fact that the highest price for intrastate gas sales in Oklahoma as of January was $1.68, the fact that New Mexico recently set $1.44 as the State imposed cap on its local intrastate sales of New Mexico gas is additional evidence that when we jump to $1.75 price we are basically deregulating.

Of course as this committee well knows and has received much testimony about, the reported intrastate prices are themselves artificially inflated, not only by their spot market nature but also by what the FPC in its report euphemistically calls sales between affiliated companies and I think what most of us would call phony pricing or price fixing. You have had evidence of this as I say in the past.

Now there is publicly available the brand new, startling set of disclosures in the Oklahoma legislature investigation of gas pricing in that State. I hope that each of you will read that so you can judge for yourself whether that was produced by objective and dispassionate people. But I will say after reading parts of it that if the $1.68 price can only be reached by the kind of self-dealing and connivance and flim-flam that that report reflects, then the Nation has no business whatsoever one-upping that price fixing by imposing a national price level of $1.75.

It is hard to think of anything worse than the $1.75 price itself, but the means that the plan calculates that price by and determines its future course is worse because it ties the price to the price of U.S. crude oil and that, of course, immediately builds into the gas price a heavy dose of the OPEC oil windfall already reflected in the price of U.S. crude; but beyond that, as the oil price moves up, and especially in the early years it moves up faster than inflation, so will the price of natural gas. That is, during the next 3 years new oil will move quickly to the world price levels at the same time as the proportion of new oil and the U.S. crude mix will also be rising, so that the overall U.S. crude price and, with it, the natural gas price, under this equivalency formula, will keep rising sharply and much more sharply than the general inflation rate.

Thus, instead of removing this second major flaw in the current system, that is, the incentives to withhold in anticipation of rapidly rising future prices, this proposal would build in that expectation and thus assure future withholding and assure continuing supply problems.

In other words, while the absolute price level in any one year would be, definitely, wildly beyond the most generous notions of incentive prices, the predictability of even higher prices in the coming years would provide a disincentive to current production and a strong economic justification for placing available reserves into inventory.

Of course the whole notion that the oil and gas industry needs additional incentives to produce is really a joke. We know that we

don't know the whole stories about what goes on inside those companies, about their costs and their profits, because they have been unwilling to share that kind of data, really, with the government or the public, despite the fact that they continue to plead for every kind of help based on assertions about that data.

But we do know enough about how well the industry has done and I set out in my statement some of the more recent evidence. Perhaps the most startling evidence is the *Mobil Oil* case. Mobil Oil had $161 million profits on their domestic energy operations, 117 in 1975, and $430 million in 1976, an increase of $261 million. Strangely enough, they are now in a daily bidding race to spend a third of a billion dollars to buy a ranch out in Orange County, California, with our oil and gas money that has no oil and gas on it.

I also submit some evidence of how well the industry thinks it is doing. This cover of this year's Tenneco annual report, I have never see anything like it. It contains the chart of Opinion 770 of the Federal Power Commission. That is, they are so pleased with that price increase, I think probably they would have preferred to put a picture of Chairman Dunham on that, but they wouldn't do that, so they put a chart showing the tremendous rate that the FPC has given them and, of course, their profits will show that jump in the years ahead. The windfall is so great already that there is some reason to believe that the cutbacks in production reflect a fear that level or rising production rates at the rapidly increasing prices would have shown such a gross excess and a sudden excess of profits even by oil industry standards as to bring not only horizontal and vertical divestiture but also a tremendous increase in the already strong public pressure in favor of still more severe government action in this area.

I think Dr. Schlesinger has made the same point recently in various committees that actual deregulation would have brought the same phenomenon, the profits would have been so fantastic that they would have had to be like GM and restrain themselves.

Because we don't know all the facts, we can't accept on faith the industry claims about hardships, insufficient capital, inadequate incentives, especially when the facts we do know are to the contrary. We are going to have a petroleum industry reporting system; once we see the facts then we can decide whether something other than a just and reasonable rate system is called for, whether that system is inadequate or perhaps overadequate to produce the legitimate requirements for continued investment in gas production. But in the meanwhile we have to look at the revenue and profit impact of the plan that we are presented with. I have tried to come up with some projections. They are a first try, necessarily speculative. They are very conservative in some respects. For example, the rollovers compare the rollover price not with the previous actual level of the rollovers, which would be much lower than the weighted average—than the average, but with the average price of the categories of gas that it deals with.

There are some other conservative factors in it as well, and I will be glad to go through some of them in detail. The new gas volumes are based on two alternatives, one the 5 percent figure that President Carter used frequently during the campaign, and secondly,

projections based on the AGA estimate made to Dr. Schlesinger, 5.5 trillion cubic feet by 1980. Obviously they were working with a different definition but they also had some incentive to be very conservative in that estimate, and since the proposed system tries to expand the new gas production as much as possible, I think these figures are likely to be conservative.

Based on these preliminary calculations we come up with a first try on windfall, that is excess profits generated by this new pricing system, and to some extent by Opinion 770, because this pricing system locks Opinion 770 in without any basis in increased cost to risk that amounts to, and for the 10-year periods it is a low of $133.5 billion, and a high of $163.7 billion, based on those two assumptions of the rate of application of the new gas price.

Looking at it in the first few years, it runs between $4.5- and $5 billion the first year, $7.5 to $8.5 billion the second year, a little over $10 to a little over $11 billion the third year. We are talking about very rough estimates, but very large amounts, no matter how you do these estimates.

I welcome the committee, I encourage the industry. I demand that the administration try to come up with some different figures on this, and get different totals, but I am positive that as long as the base case is some realistic notion of actual current and prospective cost plus a reasonable return, the windfalls under the proposed pricing system will be in the tens of billions of dollars over the period of the plan, and if the American people are going to be asked to sacrifice, then we are not going to be able to have a plan that builds in tht kind of unearned bonus to the industry.

Mr. Chairman, we will have a lot of detailed comments on technical aspects of the bill. I hope that we can contribute constructively to those things that are going to remain in the bill, to make some recommendations for major changes in the pricing provision, and we will be glad to submit those on our own initiative in writing or to respond to any questions on particular sections.

[Mr. Flug's prepared statement follows:]

ENERGY ACTION

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May 17, 1977

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FOR IMMEDIATE RELEASE

TESTIMONY OF JAMES F. FLUG, DIRECTOR AND COUNSEL, ENERGY ACTION COMMITTEE, ON THE NATURAL GAS PRICING PROVISIONS OF THE "NATIONAL ENERGY ACT", BEFORE THE HOUSE SUBCOMMITTEE ON ENERGY AND POWER, May 17, 1977.

Mr. Chairman:

Deregulation by any other name smells just as bad, and I submit that the natural gas pricing provisions of the "National Energy Act" are the moral equivalent of deregulation.

From his January, 1976 statement in support of "legal restrictions to allow a 'reasonable profit' on oil and natural gas", to his January, 1977 assurance of a "prohibition against excessive or windfall profits from energy costs at the expense of the consumer", to his April 18 promise that "no one will gain an unfair advantage" or "profiteer" from his Energy Plan, and right up to his April 20 admission that fuel price decontrol" would be disastrous for our economy and for working Americans, and would not solve long range problems of dwindling supplies", Jimmy Carter gave the American people hope that whatever he did on natural gas prices, the result would be fair and equitable, spreading burdens and sacrifices evenly throughout society.

Unfortunately the reality has not matched the rhetoric. The proposal to set the price of natural gas at the "equivalent energy value" of U.S. crude oil, beginning at $1.75 per thousand cubic feet, is a betrayal of the public interest and a multi-billion dollar boon to the oil and gas industry. It is precisely what President Carter's "Energy Plan" said he wanted to avoid: "an inequitable transfer of income from the American people to the producers, whose profits would be excessive and would bear little relation to actual economic conditions".

Perhaps we have become so numb that $1.75 for a thousand of anything doesn't sound like much. But $1.75 for a thousand cubic feet of gas is a huge amount. It is:

-- 10 times what producers were getting for gas a decade ago.

-- 6 1/2 times the 26¢ price agreed to by producers in 1970 as an "incentive" price to bring forth "additional supplies" and "meet the demands" of consumers.

-- Almost 3 1/2 times the last court-approved "just and reasonable" rate of 52¢.

-- Almost 3 times the 60¢ range which the FPC staff has said would produce ample returns and incentives.

-- Well above the levels in recent years of the uncontrolled (President Carter properly called them "exorbitant") intrastate gas prices.

-- And about 25% over the $1.42 price through which the Nixon-Ford FPC attempted to deregulate administratively, a price which the courts are likely to overturn as unsupported under the "just and reasonable" standard.

Let me focus for a minute on the $1.42 price, because the "Energy Plan", and most of the media, treats it as some sort of credible base case against which future developments can be measured. In fact, however, that price merely represents the personal opinion of three men:

-- appointed by Presidents committed to giving the industry unlimited profits,
-- themselves opposed to the process of price controls they were responsible for enforcing,
-- with backgrounds and political sponsorship reflective of the oil and gas producers' viewpoint.

For policy purposes, you and we are just as entitled to accept as a base case, the opinion of the experts in the FPC Office of Economics which recommended a 56¢ price, or the 61¢ price found adequate by the FPC Bureau of Natural Gas, or the view of the dissenting Commissioner who found the $1.42 price "excessive" and unsupportable:

-- We are certainly entitled to exclude from our own calculations the 40¢ of income tax, calculated at the highest rates which the FPC assumed -- without evidence and despite history to the contrary-- that the producers would pay.

-- We are certainly entitled not to accept calculations based on industry production cost, and reserves figures that have repeatedly proved unreliable and that appear on their face to reflect political and legal circumstances rather than physical facts.

-- And we are certainly entitled to look at cost figures developed by other impartial observers, like the recent Oklahoma study which spoke of actual costs of producing gas in 1976 in the range of 35¢, 44 1/2¢, and 60¢(the latter allegedly up from 17¢ in 1973).

The fact is that the nation has been operating under an irrational regulatory scheme for natural gas, with two fatal flaws:

1. The combination of an uncontrolled intrastate market and a controlled national market for the same product has unavoidably led to minimal production for the controlled market and maximum production for the uncontrolled market. This factor alone is responsible for a major portion of the supply problems in non-producing states, as this committee is well aware;

2. The expectation--and fact--of continued sharp rises in regulated price, and the expectation--and hope-- of eventual deregulation, has made withholding gas more profitable than selling gas.

To remedy the first flaw we have to bring the interstate and intrastate prices together. We can do so either by bringing the national prices up to the uncontrolled levels of the intrastate market, giving all production the benefit of the fantastic windfalls which intrastate producers have been receiving for the past few years, or we can bring the "exorbitant" intrastate price down to a "just and reasonable" national level.

The proposal before you clearly reflects the industry's approach of raising the regulated interstate price to the unregulated intrastate levels, something this Committee and this House have protected the American people from in the past. Anyone who has any doubt that this proposal takes the deregulation route need only look at the FPC's own statistics on intrastate prices(Chart I attached). The weighted average of new intrastate contract sales of producers reporting to the FPC has never reached the $1.75 level until the crisis winter of 76-77, and even then many sales and contract renegotiations, in many places, were at much lower prices, including prices under $1.

The fact that the highest price for intrastate gas sales in Oklahoma as of January was $1.68, and the fact that New Mexico recently set $1.44 as the state-imposed cap on its local sales of local gas gives additional evidence that the $1.75 price is truly a deregulated price.

Moreover, as this Committee well knows, the reported intrastate prices are themselves artificially inflated not only by the aberrational spot-type emergency sales, but also by what the FPC euphemistically calls "sales between affiliated companies" or what most of us would call phony pricing or price fixing. You have had evidence of this phenomenon in the past, and now there is a brand new, startling set of disclosures in the Oklahoma legislative investigation of gas pricing in that state. I hope each of you will read it so that you can judge for yourself its objectivity and dispassionate approach. But I will say that if a $1.68 price can only be reached by that kind of self-dealing, connivance, and flim-flam, then the nation has no business whatsoever one-upping the price fixers by imposing a national price level of $1.75.

It's hard to think of anything worse than the $1.75 price itself, but the means of calculating that price, and determining its future course is worse. Tying the gas price to the price of U.S. crude oil immediately, of course, builds into the gas price a heavy dose of the OPEC oil windfall which is already well reflected in the price of U.S. crude. But if the oil pricing system suggested by President Carter is adopted, then the oil price on which the gas is based must move upward much faster than inflation, and thus so will the price of natural gas. That is, while each of the three tiers of oil will ultimately be limited to price rises equal to the annual inflation rate, in the next three years "new" oil will move up faster than that as it rises to world price levels, and the proportion of "new" oil in the U.S. mix will also rise each year, so that the overall U.S. crude price, and with it the gas price, will keep rising sharply, and much faster than the general inflation rate.

Thus instead of removing the second major flaw in the current system, the incentive to withhold in anticipation of rapidly rising future prices, the current proposal would build in that expectation and thus assure future withholding and continuing supply problems. In other words, while the price level in any one year would be wildly beyond the most generous notions of "incentive" prices, the predictability of even higher prices in coming years would provide a disincentive to current production and a strong economic justification for placing available reserves in inventory.

Of course the whole notion that the oil and gas industry needs additional "incentives" to produce is a joke. We know that we don't know the whole story about oil and gas costs and profits, because the industry has been notoriously unwilling to share its data with either the government or the public, despite its continuous pleas for every kind of help based on assertions about that data. But we know enough to know that the industry has done very well under the recent pricing arrangements:

-- The top oil and gas companies increased their profits by over 100% from 1972, the last pre-embargo year to 1975.

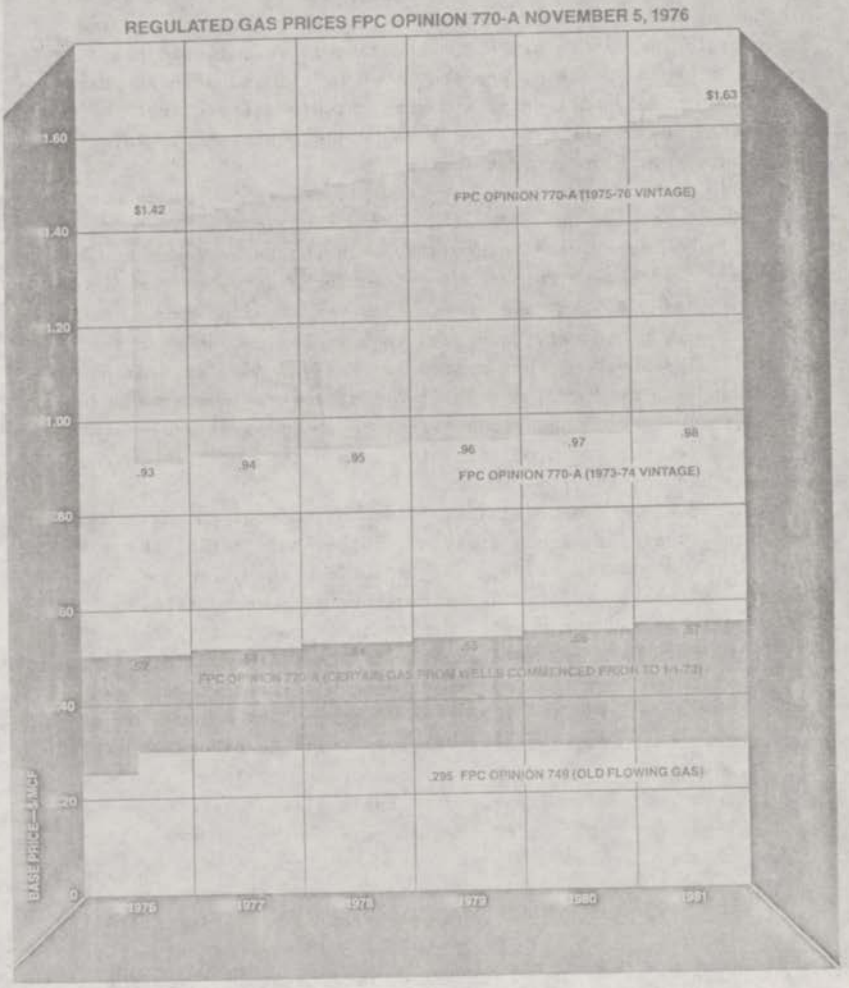
-- Mobil alone increased its profits on U.S. energy operations from $171 million in 1975, to $430 million in 1976, and after spending about a billion dollars on Montgomery Ward and Container Corp., is now offering a third of a billion for the Irvine Ranch.

-- Standard Oil of California increased U. S. earnings from $240 million in 1975 to $461 million in 1976.

-- Exxon admits to a 25% return on capital in 1975 and a 20% return in 1976 for U.S. exploration and production operations, and showed an increase in U.S. oil and gas earnings of $38 million, despite a decrease in production of both gas and oil.

-- Similarly, Phillips Petroleum showed a $350 million increase in revenues, and a $60 million rise in earnings on U.S. oil and gas operations despite a reduction in U.S. oil and

Tenneco Offshore Company, Inc. 1976 Annual Report



gas production.

-- And I submit for your enjoyment and the record the cover of this year's Tenneco Offshore Company Inc. Annual Report which can only be described as an open celebration of the FPC's recent gift to the industry.

In fact what Mobil's Annual Report describes modestly as "some improvement in natural gas prices", has already produced such a windfall to the companies that it is entirely likely that their cutbacks in production reflect a fear that level or rising production rates at the rapidly increasing prices of the last 10 years would have shown such a gross excess of profits, even by oil industry standards, as to bring not only horizontal and vertical divestiture, but also a sharp rise in the already strong public sentiment in favor of still more severe government action.

Because we know that we do not know all the facts, we cannot accept industry claims about "hardships", "insufficient capital", and "inadequate incentives", especially when the known facts are to the contrary. President Carter has called for a detailed Petroleum Industry Reporting System, and once we see the detailed facts which that system will presumably generate, then we can decide whether the "just and reasonable" rate system is really inadequate--or perhaps over-adequate--to produce the cash flow legitimately required for continued investment in gas production. In the meanwhile we should consider the revenue and profit implications of the plan which the White House has put forth.

Any projections are necessarily speculative, but the attached computations (Chart II) are a first attempt at calculating the windfall inherent in the $1.75 "new gas" price, the allowances of interstate rollovers at $1.42 and intrastate rollovers at $1.75, and the locking in of the FPC Opinion 770 rates on the last two biennia. The projection is extremely conservative in that it calculates the rollover windfalls from the respective average prices rather than the actual prices of the rolled-over production, which would be a significantly lower base. It also assumes that the windfall factor would be constant over time, when in fact the windfall will accelerate as the gas price moves upward ahead of the inflation rate because of the oil equivalency factor discussed above. The two assumptions for "new gas" volumes are based (I) on President Carter's past assertions of a 5% rate, and (II) on projections to and from the AGA estimate to Mr. Schlesinger of 5.5 trillion cubic feet of new gas by 1980. Obviously the assumptions of these figures differ substantially from those of the proposed system, but since there is no limit on the amount of "new gas," and since the aim of the program is to stimulate as much "new gas" production as possible, these figures, too, are likely to be conservative. The detailed bases of the calculations as well as further revisions as we refine the projections will be submitted to the committee.

Based on these preliminary calculations, however, it appears that the windfall factor, that is excess profits generated by the pricing system, without any basis in increased cost or risk, will amount to (in billions of dollars):

Preliminary Estimate of Total Producer Windfalls under Natural Gas Provisions of Energy Plan

	Low	High
1978	4.5	4.9
1979	7.5	8.3
1980	10.2	11.4
1981	12.6	14.1
1982	14.7	16.5
1983	16.5	18.6
1984	18.0	20.4
1985	19.2	21.9
1986	20.2	23.2
1987	21.1	24.4
TOTAL	144.5	163.7

I want to emphasize that these are very rough estimates. I welcome and encourage the Committee, the industry, and especially the Administration to set forth different assumptions and derive different totals. But I assure you of one fact: As long as the base case is some realistic notion of actual current and prospective cost plus a reasonable return, the windfalls under the proposed pricing system will be in the tens of billions of dollars over the period of the plan.

The American people cannot be asked to sacrifice when the oil and gas industry is going to be given that kind of unearned bonus.

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Mr. Chairman, we will have some detailed comments on problems with the technical provisions of the bill and some proposed amendments which, with your permission, we will submit in writing.

CHART I

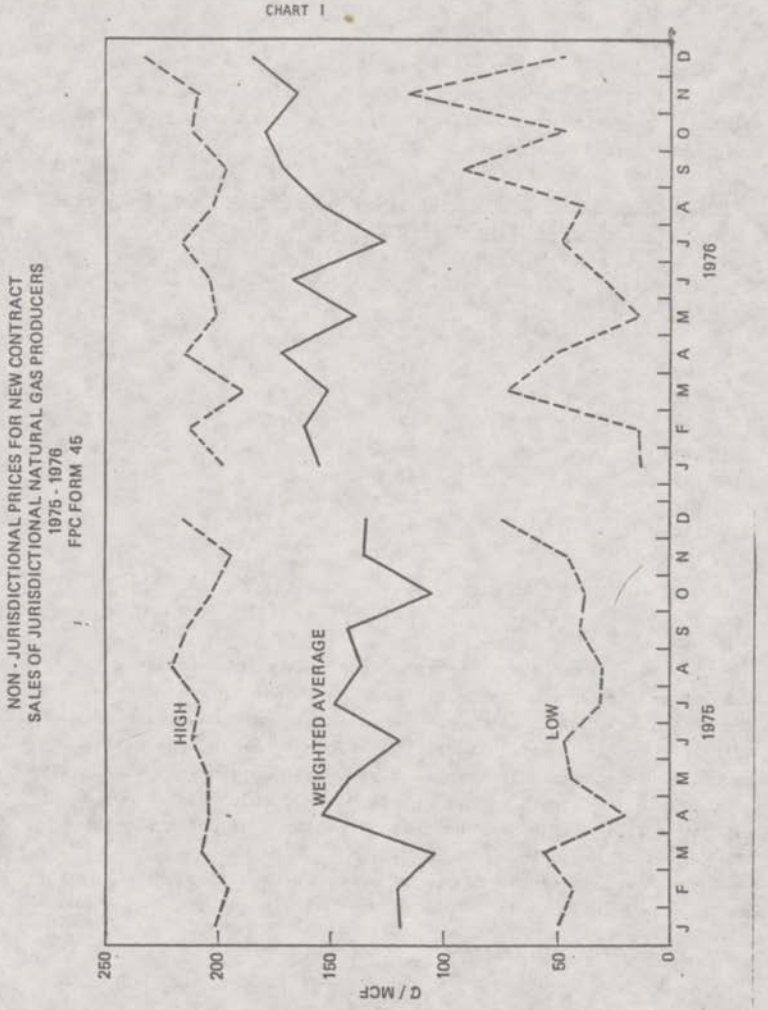

CHART 2 - Preliminary Estimate of Producer Windfalls under Natural Gas Provisions of Energy Plan

	'78	'79	'80	'81	'82	'83	'84	'85	'86	'87	Total
Interstate Rollover	1.3	2.4	3.3	4.0	4.5	4.8	4.9	4.8	4.6	4.4	
Intrastate Rollover	1.0	1.9	2.7	3.4	4.0	4.5	4.9	5.2	5.4	5.5	
New Gas I	1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0	10.0	
New Gas II	1.4	2.8	4.2	5.5	6.8	8.1	9.4	10.7	12.0	13.3	
770 Levels	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	
Total I	4.5	7.5	10.2	12.6	14.7	16.5	18.0	19.2	20.2	21.1	144.5
Total II	4.9	8.3	11.4	14.1	16.5	18.6	20.4	21.9	23.2	24.4	163.7

Mr. DINGELL. There will be questions I am sure by members of the subcommittee, but the Chair observes that your comments and those of others with regard to either technical or substantive points in the legislation would be very much appreciated.

The Chair advises that unfortunately we are proceeding under constrained processes which would indicate that we would look to you for those submissions within 7 days in order that the printing of the record may go forward.

Our next witness is Mr. Hueter.

STATEMENT OF ERNEST HUETER

Mr. HUETER. Mr. Chairman, members of the committee:

It appears as though I am only the second of your panelists representing the food industry, and our testimony might be in some instances diverse to that which you have received during the day.

My name is Ernest Hueter and I am vice chairman of the board of Interstate Brands Corporation in Kansas City, Missouri, which is the third largest bread and cakebaker in the United States, and a member of the American Bakers Asociation Energy Task Force. I have with me today Mr. Donald Gerrish, Secretary of the American Bakers Association. I am speaking on behalf of the wholesale baking industry and the American Bakers Association. The American Bakers Association includes in its membership bakers who produce about 80 percent of the commercially baked bread and other bakery products distributed to grocery stores, restaurants, and institutions.

We, as bakers, applaud the President's energy proposals, and support the program in principle. However, we are here today with some suggestions that we think will improve and strengthen it.

We believe that a comprehensive national energy program should include three basic elements.

First, there should be a long-range national energy policy to facilitate business planning for long-range energy needs. The President's program responds to that need by giving stability and predictability to Federal policy to permit long-range business planning to occur.

Second, there should be adequate incentive to energy producers to provide maximum possible supplies of natural gas. We do not have the expertise to evaluate the adequacy of price incentives contained in the program. However, we are willing to accept any program that appears necessary to optimize investment in domestic resources up to and including deregulation of new gas. However we do not accept any aspects of the program that would price natural gas and petroleum products above world prices.

Third, we must promote conservation in the use of our depleting fossil fuels. We endorse the use of the pricing mechanism, when supplemented by tax proposals, as the most efficient measure to promote conservation investment.

We want to direct our testimony today to the proposed amendents to part D of the National Energy Act—the provisions covering natural gas.

As bakers of bread, an essential basic but perishable food product that is baked in direct fired gas ovens, we believe that the committee should give high priority to assuring adequate supplies of natural gas at all times, as we stated above. If the committee feels that higher prices than those provided in sections 404-408 are necessary to produce more gas, we will not object. However, this must be balanced with an assurance that there be no price gouging or exploitation of the American people by gas producers, distributors, and sellers.

In this connection, we support the basic proposal on incremental pricing included in section 414. However, it should be made clear that the ceiling price should be at parity with substitute fuels. We believe that it is fair and just that industry pay the equivalent of world market price. However, we believe that the incremental burden should be applied to those industries that have a conversion potential or the means of using substitute fuels, and that process users and residential users should be required to share the additional cost only after the price to other users is brought up to distillate parity.

We assume that the word "no" on line 21, section 414(a), page 55, was a mistake and will be deleted from the text.

In this regard, there is no feasible substitute for the use of natural gas in our bakery ovens, and the committee should recognize that our use is every bit as essential as residential or small commercial use. Bakers use this gas very efficiently. In fact, we use 75 percent less natural gas, measured in Btus, to produce bread in our bakeries than a housewife would use to bake bread at home.

In view of the fact that we are concerned about the total supply of gas, we support the provisions of section 415 that would include SNG, synthetic natural gas, under the provisions of the Natural Gas Act, and we support the lifting of restrictions on the importation of liquefied natural gas.

We strongly support the provisions of section 416. We endorse the extension of the Emergency Gas Act to June 1979, and the provision that broadens its reach to permit allocation for priority needs from any pipeline engaging in the transportation of natural gas, thereby eliminating the distinction between interstate and intrastate natural gas. This is in line with the principles of fairness underlying the President's program.

We believe that there should be a single national market for gas, and in times of extreme shortage, that all gas should be subject to allocation to priority users, which was the procedure used under the Emergency Petroleum Allocation Act. This act allocated fuel to meet essential needs in a time of shortage without any distinction between intra- or interstate uses.

We also believe that this should be complemented by the adoption of an agricultural and food processors and packagers priority, which would provide a priority for essential agricultural, food processing and packaging uses, right behind any residential, hospital or public safety use. This was included in section 26(a) of H.R. 9464 passed on February 5, 1976, in the 94th Congress. A copy of this provision is attached to this testimony for the record.

We believe that an agricultural and food processors and packagers priority is necessary in this legislation, because, although me-

chanical energy is important to our economy, the Nation cannot operate without energy for its people, and that is what bread and other essential food products supply. We urge this committee to include in this section a specific priority for an agricultural, food processors, and packagers essential use of natural gas.

As an alternative, if such a specific priority is not acceptable to the committee, we suggest that this section be amended to provide authority to the President or the Secretary of the Department of Energy to allocate natural gas for uses which he determines to be related to the preservation and promotion of the public health, safety and welfare. We are reasonably confident that food processor and packaging uses will qualify under this flexible standard, but again would prefer to have the security of a specific statutory recognition of this industry's needs and the needs of the public health requirements of our citizens.

Mr. Chairman and members of the committee, we are in basic accord with the President's program. But we strongly believe that our constructive suggestions will improve it by safeguarding the American food production system. We hope you will favorably consider them.

[The attachment to Mr. Hueter's statement follows:]

From H.R. 9464 passed 2/5/76 in the 94th Congress

NATURAL GAS FOR ESSENTIAL AGRICULTURAL PURPOSES

Sec. 26.(a) Except to the extent that the Commission determines that natural gas supplies are required to maintain natural gas service to residential users, small commercial users, hospitals, and other similar services vital to public health and safety, the Commission shall, in exercising its authority under this Act to require curtailment plans, shall not cause any interruption or curtailment of natural gas which it determines necessary to assure the ready availability of sufficient supplies of natural gas for use in any essential agricultural, food processing, or food packaging purpose, for which natural gas is essential, including irrigation pumping, crop drying, use as a raw material feed stock, or process fuel in the production of fertilizer and essential agricultural chemicals.

(b) The Commission shall, in carrying out the provisions of subsection (a), review and make any modifications as it determines necessary in criteria under which curtailments of natural gas are approved.

(c) The Secretary of Agriculture shall determine, by rule, the essential agricultural, food processing, or food packaging purposes for which natural gas is essential and shall certify such determination to the Commission. Such determination shall include the judgment of the Secretary of Agriculture with respect to the amount of natural gas which is necessary for such essential uses in order to meet the requirements for full food and fiber production.

Mr. DINGELL. Thank you, gentlemen.

The Chair would like to advise you that your assistance to the committee in presenting us your statement as to technical amendments or substantive amendments, where you deem them to be appropriate, would be very much appreciated.

The Chair now recognizes my colleagues for the purpose of asking questions.

The Chair recognizes first the gentleman from Texas, Mr. Krueger.

Mr. KRUEGER. Thank you, Mr. Chairman.

Members of the committee, I would like first to verify one thing, Mr. Devine, as you are here as a representative of the petrochemical industry users group.

I read your testimony correctly that you are in favor of deregulation of the price of new gas; is that correct?

Mr. DEVINE. Yes, sir.

Mr. KRUEGER. Thank you very much.

The second question that I would like to pose particularly to the four people who represent industrial users on this panel is the President and others have talked about so-called incremental pricing, that is the policy of passing on the full weighted increase of any enlarged price for energy to industrial users rather than across the board to residential and other users, and basically most of you have indicated your opposition to that position.

Now, Mr. Devine, I believe that in particular you pointed to the importance of natural gas as a feedstock for the petrochemical energy industry, and gave examples in your testimony of the large number of uses for that energy. I am wondering whether you would agree with a judgment that I heard from one person a few weeks back, that in 10 years or so, natural gas might be perhaps too precious to be burned even at the burner tip in our own homes, and that we might wish to use a great portion of it for petrochemical feedstocks and things of that sort.

In your judgment is that perhaps—and I think this is perhaps a position that is not of the independent chemical industry—would you see that as being a matter of great importance, because of the fact that natural gas is virtually the only fuel that can be used as that feedstock in many cases?

Mr. DEVINE. Ultimately, it certainly is a possibility. We don't deny the possibility in the very long run that we can go to coal for petrochemical feedstocks. We do know that we can't do it in any reasonable length of time, and that for the moment we have to give highest priority to the chemical uses. The Shah of Iran I believe was the man who first gave the most publicity to that thesis, and certainly it is a commanding one.

I might say that we do advocate incremental pricing as to uses where it can act as an incentive to conversion. We support incremental pricing to discourage people from using natural gas liquids, natural gas as boiler fuel.

Mr. KRUEGER. One of the things that I observed is I believe it is your testimony that suggested that some 16 percent or about 3 trillion cubic feet of natural gas were used for generation of electricity, and the proposal was made that this use should probably be changed and conversion should be made to coal.

One of the problems that some parts of the country have in that conversion to coal is that first of all they can't get the coal that can be burned without violating the Clean Air Act standards.

Secondly, they may not have railway transportation that can bring the coal in.

Third, they may not have the facilities for the use of coal at this time.

Fourth, it may be massively more expensive, and if that is the case, who should bear the full weight of those costs? Wouldn't you agree at any rate that those are legitimate considerations?

Mr. DEVINE. Of course, they are.

Mr. KRUEGER. And would you have any suggestions on how they might be addressed if we were to require an immediate conversion from gas to coal for production of electricity.

Mr. DEVINE. The basic limiting factor is the capacity of the economy to produce the equipment it takes to make the transition. The best work that has been done on this has been done by Battelle in Columbus, and the constraint there is how fast we can actually shift to coal for steam generation?

One clear message that comes through to us is that you must begin with the largest boilers first, and you must take electric power off the top, even when your objective is processed heat.

Mr. FARMER. Mr. Krueger, over the years there have been such forecasts that this was going to have to be done that it really shouldn't come as a surprise to those people in the position of using gas for electrical generation. It should have been in their plans.

Mr. KRUEGER. The gas shortage should have been in a lot of people's plans, but it wasn't. I am interested in the question—I want to turn away for one second to Mr. Flug.

I notice, Mr. Flug, on page 2 of your testimony, the fourth paragraph, you indicated that President Carter referred or used the phrase "exorbitant" with regard to intrastate gas prices. I wonder where that statement was made?

Mr. FLUG. I believe that was in the April 29th document.

Mr. KRUEGER. In the April 29th document.

Do you have a more precise citation?

Mr. FLUG. I will get it for you in just a second.

Mr. KRUEGER. I will simply leave that open for the record for later and go on since the gavel is about to fall.

I will pose one more question, Mr. Chairman, and that is what the panel of industrial users might suppose that we might do with the very large investment already made in gas distribution systems for residential users and other users, if there is a shortage of natural gas, does this not pose a real problem for the heavy investment already made in such a distribution system, and if that is a problem, then some people would argue that incremental pricing is necessary in order to allow such gas as there is to flow largely into that area rather than into industry. I am wondering whether you would have any comments on that.

Mr. FARMER. I am not sure that I understand the question fully, Mr. Krueger. If the industrial load is removed completely, you are going to have a lot of costs in the residential section, because the pipelines are going to be empty during the summer.

Mr. KRUEGER. The amortization costs?

Mr. FARMER. Yes. The suggestion that the disappearance of all industrial gas from the pipeline is going to happen in the immediate future is inconsistent with every study we have done, and we have had a lot of them. We have them from outstanding independent companies, as well as government sources, and we do not see that happening over the 10-year study period.

Mr. KRUEGER. The problem is among other things seasonable.

Mr. FARMER. Yes.

Mr. KRUEGER. With that sort of residential versus industrial.

Thank you, Mr. Chairman.

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Mr. FLUG. Excuse me, Mr. Krueger, I was wrong. That comes from the President's speech to the joint session on April 20, and he was talking about the unreasonable distinction between interstate and intrastate sales, which had "caused people in the producing States to pay exorbitant prices" for their gas.

Mr. KRUEGER. Thank you.

Thank you, Mr. Chairman.

Mr. DINGELL. The Chair thanks the gentleman. His time has expired.

The Chair recognizes now the gentleman from Louisiana, Mr. Moore, for 5 minutes.

Mr. MOORE. Thank you, Mr. Chairman.

I would assume that all five of you here today are essentially representing natural gas consumers. Would that be correct, either individual companies or in the case of Mr. Flug, residential users or something? Would that be right?

Let the record show that all five answered in the affirmative.

My second question is that I would think it is likewise that you are all here concerned that we have an adequate supply of natural gas available for consumption, either by your companies or by consumers. Would that be correct?

Mr. DEVINE. Yes, sir.

Mr. FARMER. Yes, sir, and that it be distributed properly and priced fairly.

Mr. MOORE. Now with the exception of Mr. Flug, I think I know where he stands on this question. I think two of the others of you have answered this, but I would like for all four of you to answer the question. If the evidence before this committee and before you, were you on this committee, showed that the only way to significantly increase the supply of natural gas—I am not talking about allocating existing supplies or conservation, I am talking about increasing the supply of natural gas—would be some form of a stairstep or delayed action decontrol plan, would you support that type plan? I ask each one of you.

Mr. HUETER. Yes.

Mr. FOLLETTE. Yes, we would.

Mr. FARMER. Yes.

Mr. FLUG. So would I, Mr. Moore.

Mr. MOORE. Really.

Mr. FLUG. Yes, if I believed the evidence.

Mr. MOORE. I think all of you identify yourselves and how you are and I really have no further questions. I think the information you have given us is very clear. We understand the problems you have brought to us and we appreciate it very much.

Mr. Flug, I have some questions for you that are based just upon my lack of knowledge of your organization, so I would simply like to ask you could you describe for me what your organization is? I am really not familiar with it.

Mr. FLUG. I think this is the first time I have appeared before you. I have been before this committee. I think this is the fourth time on this subject. The Energy Action Committee was founded by a group of Californians who felt that most of the information that was being fed into energy policymaking in this country was coming

from the same source, that is from the energy industry. They felt that there should be an independent source of information that would have as its basic interest the public interest, would be able to provide some full-time effort in this field, and provide information advocacy from what we perceive to be the public interest.

Mr. MOORE. Let me say I certainly agree with you. There has been a shortcoming of our system. That is why we are in the predicament we are in. I intend to support, I think, at this point those aspects of the President's program that tries to get out what the information is so we will know. I think once any reasonable man gets the figures that we can rely upon, we should come up with a very similar conclusion.

You say that you are a group of people from California.

How big is that group?

Mr. FLUG. It was founded by five Californians, two of whom have testified before this committeee, an actor, the chairman of the board of a New York Stock Exchange listed company, the chairman of the board of an American Stock Exchange listed company, the chairman of the board of another unlisted company and an economist. They have done most of the fund raising for it and there has been public fund raising, and there are I would say something on the order of 1,500 individual contributors to the organization, although those people have raised the bulk of the money.

Mr. MOORE. Would it be fair to say that your membership consists of possibly the 1,500 who contribute to it?

Mr. FLUG. We are not a membership organization in the style of Public Citizen or Common Cause. We are more like but we are not, but we are more like a public interest, a foundation funded, public interest law firm, except that we are not foundation funded.

Mr. MOORE. Thank you, Mr. Chairman.

I yield back the balance of my time.

Mr. DINGELL. The Chair observes the time of the gentleman has expired.

The Chair recognizes the gentleman from Michigan, Mr. Stockman.

Mr. STOCKMAN. Mr. Flug, I would like to ask you a number of questions but since your framework is so totally different from mine, I am hoping we can do this on the basis of very quick answers from you. Otherwise you will waste my 5 minutes with your viewpoint which we have already heard.

Would you agree with me, yes or no, that current production of natural gas primarily reflects the depletion of inventories that are available or reserves in the ground?

Mr. FLUG. No. It is going to be hard to answer those "yes or no" but if that is the only choice I have got——

Mr. STOCKMAN. You have got certain reserves in the ground and certain inventories. Your argument is well, you can produce at a faster or slower rate depending on what you think the regulatories are going to do and so forth; is that right?

Mr. FLUG. I don't think the supply problems are based on physical problems at this point.

Mr. STOCKMAN. Would you agree regardless of the rate at which these inventories or reserves are produced and you and I can differ

on that because you think they are trying to force the political authorities to change the price structure but would you agree that the rate at which these inventories or reserves are developed, regardless of when they are produced or at what rate, is a function of exploratory drilling? In other words, to get more reserves you have got to have more exploratory drilling, within some reasonable parameters?

Mr. FLUG. Yes, and other things. It is not just a function.

Mr. STOCKMAN. But that is a very important part of it, wouldn't you agree?

Mr. FLUG. Yes, but developmental expenditures are also important.

Mr. STOCKMAN. Well, developmental expenditures are not really important for reserve building except to the extent of fully producing those inventories.

Mr. FLUG. No. Let's not get hung up on that but I think there would be a technical distinction.

Mr. STOCKMAN. You seem to suggest through your entire testimony that we would have adequate current production and inventory building at the price levels which prevailed pre-OPEC, late 1960s, early 1970s.

Mr. FLUG. With legitimate increases for legitimate costs, actual cost and risk factors, yes.

Mr. STOCKMAN. So what we are really getting down to here is the rate of exploratory drilling, because that is what in the long run is really going to determine our inventory base for production, and the amount of reserves we have. I want to read to you a couple of figures or a series of figures, and see if you can explain them to me within your framework. I begin with 1955. I am talking only about exploratory drilling, because I think development drilling is primarily a production oriented thing and not a reserve or inventory building oriented process, but in 1959 we had about 15,000 exploratory oil-gas wells drilled, and in 1961 or in 1971 at this golden age of pricing you are talking about we had 6,900, less than 45 percent as many.

In 1955 we had 8.1 thousand new field wildcats drilled, and in 1971 we only had 4.4, about 50 percent less.

In 1955 we had nearly 3,000 new pool wildcats as distinguished from new fields, and in 1971 we only had a little over 1,000, and in 1955 we had about 3,200 extension, reservoir extension drillings as opposed to only 900 in 1971, so you have had a rather substantial decline in all categories of exploratory drilling.

Some of those categories are higher risk than others. Obviously a new field is a higher risk than new pool.

How do you explain that precipitous drop if you don't explain it in terms of price, because when we go to the 1975 series for exploratory drilling, we find that they have risen considerably from that very depressed level that they were at in 1971.

Mr. FLUG. I base it in part on the expectations of the industry during the early 1970s, that is, that there was both the expectation of and hope for deregulation beginning at around the end of 1968, that that led both to an economic and a political reason to slow down the rate of development as well as the 1968 court decision

upholding the ratemaking formula of the FPC which also represented some disincentives to disclosure or counting of new reserves.

I also expect that some of that may reflect a temporary decline, but I am not sure I have the year right, due to the suspension of leasing, and I think that may enter a little bit into that particular year.

Mr. STOCKMAN. Yes, but this is a trend. It is not really a matter of a year.

We have the levels for 1971 and 1973 and the new prices in 1975 and 1976 and you get a dramatic increase in exploratory drilling. It is not an increase in production, but exploratory drilling. That is something you cannot explain except to conjecture, as you have done.

Mr. FLUG. I would complete my answer with two additional factors I think enter into it. One, that there were price increases and incentive price increases granted in 1969, in 1970, in 1971, and I think to some extent that reflects something also consistent with the drilling record on oil as well. The drilling record has been—contrary to the theory that you express—in other words, as the prices have gone up there has been a decline in the finding of new reserves.

Mr. STOCKMAN. I would dispute that statement. I don't think the figures show that.

Mr. FLUG. The figures I have seen show that and I would be glad to sit down with you to discuss it.

Mr. DINGELL. The time of the gentleman has expired. The Chair recognizes the gentleman from Texas, Mr. Gammage, for five minutes.

Mr. GAMMAGE. Mr. Devine, I was reading in the President's national energy plan at page 57 some remarks regarding SNG plants that were operating this winter and reportedly provided the additional margin of natural gas supplied that kept several areas of the country from shutting off residential fuel users during the coldest months.

In your printed remarks at page four you recommend that further development of synthetic natural gas plants be discouraged for a variety of reasons. Would you care to elaborate on that?

Mr. DEVINE. Mr. Gammage, we looked at the record of the principal SNG plants during the crisis last winter. We find the record does not support the statement you have just read. Let me cite three examples if I may and then I would like to present for the record an analysis of what did happen last winter, taken from the public records.

Mr. GAMMAGE. Please do.

Mr. DEVINE. Consumers Power Company, an owner and operator of a plant designed to use natural gas liquids, from February 1976 to February 1977, used in their own electric utility boilers or sold to other electric utilities for boiler fuels, 2.85 billion cubic feet of natural gas at the same time it was producing SNG.

Example Number two. Northern Illinois Gas Company, in the midst of one of the worst winters on record, consented to reschedule 12 billion feet of natural gas for redelivery during the summer. The net result of this arrangement would appear to be that high cost

SNG was being produced and sold to high priority customers, while natural gas costing much less was being rescheduled to serve low priority customers during the summer.

Example Number three. In January 1977, Columbia LNG Corporation's, SNG plant suffered an explosion and the loss of SNG production from one of its production trains. In addition, a recent submission by Columbia Gas Transmission Corporation to the Federal Power Commission demonstrates that cheaper natural gas supplies were cut back and in some instances permanently lost to Columbia while SNG plant operation was continued to increase SNG production at $4.14 per Mcf.

In summary, the economics of those plants and the way you have to operate them leads the owners of those plants to operate them in ways that are counterproductive in terms of the objective which the President set in advocating more SNG plants being built.

Mr. GAMMAGE. Thank you very much. I will appreciate your submitting those additional figures for the record.

[The following letter and attachments were received for the record:]

CELANESE

May 19, 1977

Honorable John D. Dingell
Chairman, Subcommittee on Energy
and Power
Committee on Interstate and
Foreign Commerce
U.S. House of Representatives
Room 2221 Rayburn House Office
Building
Washington, D. C. 20515

RECEIVED
MAY 20 1977
Energy & Power Subcommittee

Dear Congressman Dingell:

This is in response to your request for additional information for your Subcommittee on synthetic natural gas (SNG). First, however, let me say that I appreciated the opportunity to present the views of the Petrochemical Energy Group (PEG) and the National Council of Farmer Cooperatives regarding proposed natural gas legislation before your Subcommittee on May 17. I also appreciate the courtesy and consideration which you extend to all witnesses before you.

As you know, the National Energy Act would extend Federal Power Commission (FPC) jurisdiction to synthetic gas produced by coal- and liquid-based SNG plants and sold for resale or transported in interstate commerce. (§415) This would encourage the construction and operation of SNG plants, since utilities would be able to place the capital costs of the SNG plants in their rate base, thereby resulting in the consumer underwriting the cost, including interest costs and stockholder profits; and could claim "cost of service" treatment for the manufacturing costs, including whatever the cost of the feedstocks. In addition, under the proposed Act, the President may set special "incentive prices" by rule for SNG. (§408(a))

We also note that the National Energy Plan which accompanied the President's legislative proposals, proposes to change existing Federal Energy Administration (FEA) regulations administratively to provide a priority for feedstock allocations to approved SNG plants (pp. 57-58).

As you requested, I am enclosing additional information on SNG facilities relevant to the Administration's belief that these plants helped avoid curtailment of residential users last winter. (National Energy Plan, p. 57). Apparently this is the justification for encouraging liquid-based SNG construction since the National Energy Plan acknowledges that this method of gas production is extremely expensive. (p. 16) It is wasteful, in addition.

I urge the Committee to look carefully at whatever evidence the Administration may have for this assertion. Although PEG has no access to that data, we are attempting to look at the public information available on several of the largest existing facilities and the analysis prepared to date is enclosed as Attachment A. It shows that Consumers Power Company, far from facing any risk of curtailing high priority loads, actually served 2.85 Bcf of natural gas through the height of last winter's gas shortage to boiler fuel customers. Northern Illinois Gas Company had such ample supplies that it rescheduled 12 Bcf of natural gas from its pipeline suppliers due for winter delivery, for subsequent delivery during the summer when it will presumably be sold to low priority customers. PEG has informed the FEA of these facts, which are relevant to ongoing SNG feedstock allocation proceedings, in filings attached for your information at Attachments B and C.

At Attachment D are documents filed with the Federal Power Commission in the Senator Howard Metzenbaum v. Columbia Gas Transmission Corporation proceeding (Docket No. RP77-35) and the 1976 Annual Report for Columbia Gas System. They show that Columbia Gas Transmission Corporation cut back deliveries of cheaper natural gas at the beginning of last winter but increased the output of its SNG plant by 13 Bcf last year.

Finally, I have attached suggested language on the issue of SNG plant jurisdiction, found originally in the Natural Gas Act Amendments of 1976 reported by the Senate Committee on Commerce on May 19, 1976. We would recommend this language as an alternative to Section 415 of the National Energy Act. (See Attachment E).

I hope you or your staff will contact me if there is any way in which I might be helpful as you work toward developing an energy program for our country.

For your convenience I have provided copies to the Subcommittee Counsel.

Sincerely,

Thomas J. Devine
Consultant

Enclosures

cc: William S. Demarest, Jr., Esquire
Jan Vlcek, Esquire

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May 17, 1977

MEMORANDUM

Mr. John L. Present
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You have asked that we provide a status report on synthetic natural gas (SNG) production from liquid hydrocarbons, including an assessment of the contribution existing SNG plants made to natural gas supply during the most recent heating season (October, 1976 - March, 1977).

I. Background

As of October, 1973, forty-nine liquid-based SNG plants were planned, designed to use almost 3,000,000 barrels per day of liquid hydrocarbon feedstocks, including crude oil, naphtha and natural gas liquids. (See Attachment A.) As of January, 1977, 13 SNG plants were operational. (See Attachment B.) Twelve of these SNG plants are located in the continental United States and are currently available to supplement natural gas supplies as follows:

	Design SNG Output (MMcf/D)	Design Feedstock[1] Volume (MB/D)	Design Operation (Days)	Current Maximum Output (Bcf/Y)
NEW ENGLAND				
Algonquin SNG, Inc.	120	26 N[2]	151	18.1
Boston Gas Co.	40	10 P[3]	180	7.2
MIDDLE ATLANTIC				
Ashland Oil, Inc.	60	11 N	350	21.0
Brooklyn Union Gas Co.	60	13.7 N	180	10.8
PSE&G (Linden)	125	25 N	350	43.8
PSE&G (Harrison)	20	4 N	350	7.0
SOUTH ATLANTIC				
Baltimore Gas & Electric Co.	60	12 N	180	10.8
Commonwealth Natural Gas Corp.	29.5	6.45 NGL[4]	154	4.5
EAST NORTH CENTRAL				
Columbia LNG, Inc.	250	70 NGL	350	87.5
Consumers Power Co.	200	50 NGL	350	70.0
NI-Gas	166	32 NGL 16 N	350	58.1
Peoples Gas Light & Coke Co.	160	33 N	350	56.0
TOTAL	-	-	-	394.8

1/ In addition to feedstock volumes, at least five SNG plants are seeking a total of 2,599,620 barrels per year of propane for "BTU enrichment." (41 F.R. 54217, December 13, 1976).

2/ Naphtha.

3/ Propane.

4/ Natural Gas Liquids.

SOURCE: FEA, AGA.

If each of these existing plants were authorized or otherwise able to operate at full capacity for a full year (350 days per year), the maximum SNG output would be 451.7 billion cubic feet (Bcf) per year and the total feedstock demand for liquid hydrocarbons would be 309 thousand barrels per day (MB/D) (141 MB/D of naphtha and 168 MB/D of NGL).

To contribute 1 trillion cubic feet (Tcf) of gas annually by 1980, current SNG output would have to be almost tripled and current usage of liquid hydrocarbons would have to increase from 309 MB/D to from 600-850 MB/D of liquid hydrocarbons, depending upon the feedstock to be utilized.

II. Need For Liquid-Based SNG To Meet Residential Requirements

In the President's National Energy Plan (p. 57), it is asserted that "the 13 SNG plants that were operating this winter provided the additional margin of natural gas supply that kept several areas of the country from shutting off residential users during the coldest months." However, as shown in publicly available information, the three largest SNG plants were on systems where either boiler fuel loads were served during the winter or natural gas purchases were cut back while maintaining SNG production. In addition, one large plant had an accident, reducing SNG service in the winter. For example:

1. Consumers Power Company, an owner and operator of an SNG plant designed to use natural gas liquids, during the period December, 1976 through February, 1977, used in its own electric utility boilers or sold to other electric utilities for boiler fuel use at least 2.85 Bcf of natural gas, at the same time it was producing SNG.5/

2. Northern Illinois Gas Company, in the midst of one of the worst winters on record, consented to reschedule delivery of 12 Bcf of natural gas for redelivery during the summer.6/ The net result of this arrangement would appear to be that high cost SNG was being produced and sold to high priority customers while natural gas costing much less was being rescheduled to serve low priority customers during the summer.

5/ FPC Form 423.

6/ FPC, Findings And Order After Statutory Hearing Issuing Certificates Of Public Convenience and Necessity, Granting Petitions To Intervene, And Continuing Exemption (March 1, 1977).

3. In January, 1977, Columbia LNG Corporation's SNG plant suffered an explosion and the loss of SNG production from one of its production trains.7/ In addition, a recent submission by Columbia Gas Transmission Corporation (Columbia) to the Federal Power Commission8/ demonstrates that cheaper natural gas supplies were cut back and, in some instances, permanently lost to Columbia while SNG plant operation was continued to increase SNG production at $4.14 per Mcf.9/

Very truly yours,

BAKER & BOTTS

By Tucker W. Peterson

Tucker W. Peterson

7/ FEA, Decision and Order, dated March 22, 1977.

8/ Affidavit of W. H. Howard on behalf of Columbia Gas Transmission Corporation, dated February 25, 1977, in Docket No. RP77-35.

9/ 1976 Annual Report, Columbia Gas System.

Attachment A

NATIONAL GAS SURVEY

TASK FORCE REPORTS

VOLUME IV

VOLUME V

UNITED STATES

FEDERAL POWER COMMISSION

TABLE 10-31

Announced Plans for Liquid-Hydrocarbon-Gasification Plants as of October 1973

Company Name	Plant Location	Plant Size MMCF/D	Feedstock		Year Of Completion	Year of Process[1]	Cost of Plant	Source of Feedstock	Source of Data[2]
			Type	Amt. (MMB/D)					
1. Algonquin SNG Inc.	Freetown, Mass.	120	Naphtha	26	Late 1975	CRG	39.5	Domestic	1,2,4,7,8,12
2. Amerada Hess	Port Reading, N.J.	125	Naphtha	–	Proposed '75	MRG	–	–	2,12
3. APCO Oil Corp. ...	Phila., Penn.	125	Naphtha	28	1974-75	LURGI	50.0	Foreign	1,2,4,7,8,12
4. Ashland Oil Co. ...	Tonawanda, N.Y.	50	Naphtha	10	Late 1975	CRG	15.0 (Plt. only)	Canadian	1,2,7,8, 11,12
5. Balt. Gas & Elec. Co.	Near Balt., Md.	60	Naphtha	–	Decision due this year	LURGI	–	–	1,2,3,8, 11,12
6. Boston Gas Co.	Everett, Mass.	40	Propane	10	12/75	MRG	7.0	Venezuela	1,2,3,4,7,8, 11,12
7. The Brooklyn Union Gas Co.	Brooklyn, N.Y.	60 (180 day oper.)	Naphtha	15.7	1/74	CRG	26.0	Domestic	1,2,3,7,8,12
8. Central Ill. Light Co.	Peoria, Ill.	60	Naphtha	12	Feasibility Study Complete	CRG	20.0	–	1,2,3,7,8,12
9. Cities Service Gas Co.	Diamond, Mo.	125	Naphtha	25	1975-76	LURGI	42.7	–	1,2,3,8,12
10. Coastal States Energy Co.	Corpus Christi, Tex.	200	Naphtha	30	1974	CRG	25	Domestic	1,2,3,7,8, 11,12
11. Columbia LNG Corp.	Green Springs, Ohio	250	Nat. gas liq.[3]	87	1/74	CRG	57.8	Canadian	1,2,3,4,7, 8,12
12. Commonwealth Nat. Gas Corp.	Chesapeake, Va.	30	Propane/ butane	7.86	1975	CRG	6.7	Venezuela	1,2,3,4,7, 8,12
13. Consumers Power Co.	Marysville, Mich.	200 (100 MMCF/D prod. by 6/75)	Nat. gas liq.[3]	50	1975	CRG	70	Canadian	1,2,3,4,7, 8,12
14. Continental Oil Co.	Northern Ill.	125	Naphtha/LPG[4]	35	1975	–	–	–	1,2,3,4,7,8, 11,12
15. Continental Oil Co.	East Coast	250 (2 trains)	Nat. gas liq.[3]	66	Planning	–	–	–	2,6,7,10
16. Crown Central Petroleum Corp. ..	Baltimore, Md.	100[5]	Crude oil	100	Early '75	CRG	200	Foreign	1,2,3,4,7, 8,12
17. El Paso Natural Gas Co.	Corpus Christi, Tex.	1,260[6]	Crude oil/ condensate	300 65	12-18 Mo. after FPC Approval	–	750	Foreign	1,2,8,12

TABLE 10-31—Continued

Announced Plans for Liquid-Hydrocarbon-Gasification Plants as of October 1973

Company Name	Plant Location	Plant Size MMCF/D	Feedstock		Year of Completion	Type of Process[1]	Cost of Plant	Source of Feedstock	Source of Data[2]
			Type	Amt. (MMB/D)					
18. Felmont Oil Co. . . .	Olean, N.Y.	125	Naphtha	25	Late 1974	–	30-40	Foreign	1,2,3,4,6,7, 8,10,12
19. Gasco Inc.	Hawaii	16	Naphtha	–	Late 1974	LURGI	10-15	Domestic	1,2,3,8, 10,12
20. Howard Oil Refining Co.	Phila., Penn.	177[7]	Crude oil	150	Awaiting import quotas	MRG	180	Foreign	1,2,3,4,6,7, 8,9,10,12
21. Indiana Gas Co. . . .	Central Indiana	100	Naphtha	–	Negotiating for Feedstock	–	–	–	1,2,3,4, 8,12
22. JOC Oil USA	Burlington, N.J.	125[8]	Crude oil	50-56	Preliminary Planning Oper.–Late '75	CRG	30	–	2
23. Mid Atlantic Clean Energy Center . . .	Nanseman Co., Va.	250-750[9]	Crude oil	180	Preliminary design Complete	CRG	189-326	–	1,2,3,8, 12,13
24. Moore & McCormack Energy Co.	South Carolina	30	–	–	Negotiating for Feedstock (1975)	–	10	–	2,8,12
25. New England Petroleum Corp. . .	Oswego, N.Y.	100[10]	Crude oil	100	10/74	–	70	Foreign	1,2,3,6,7,8, 10,12,13
26. NIGAS Supply Inc. .	Maine or N. Hamp. Refinery (SNG Plt-III)	400[11]	Crude oil	250	Feasibility Oper. 1978	–	–	Foreign	2
27. No. Ill. Gas Co.	Morris, Ill.	166	Nat. gas liq.(t)/ Naphtha	52	6/74	CRG	70	Foreign	1,2,3,4,6,7, 8,10,12,14
28. No. Indiana Pub. Serv. Co.	–	–	–	–	Preliminary Planning Oper. 1975–76	–	–	–	2
29. Northwest Nat. Gas Co.	Portland Oregon	100	Nat. gas liq.(t)	24	11/74	LURGI	25	Foreign	1,2,3,4,6,7,8, 10,12
30. Panhandle Eastern & Amerada Hess . . .	Decatur, Ill.	150	Naphtha	30	1975	–	42	Foreign	3,6,7,10
31. Peoples Gas Co. (Chicago)	Jackson, Ill.	160	Naphtha	33	1975	CRG	50	10 MB-Union Oil-Cal.	1,2,3,4,6,7, 8,10,11,12

TABLE 10-31—Continued

Announced Plans for Liquid-Hydrocarbon-Gasification Plants as of October 1973

Company Name	Plant Location	Plant Size MMCF/D	Feedstock		Year of Completion	Type of Process[1]	Cost of Plant	Source of Feedstock	Source of Data[2]
			Type	Amt. (MMB/D)					
32. Phila. Elec. Co.	Chester, Pa.	125 4 trains by 1986	Naphtha	27.5	1974	–	57.5	–	3,4,6,7,10
33. Phila. Pub. Gas Works	Phila., Penn.	60	Naphtha	-	Await City Council App.	CRG	Plt. 20	Domestic	1,2,3,4,6,7,8, 10,12
34. Phillips Petroleum Co.	Borger, Tex.	67	–	–	1976	–	–	–	2
35. Pub. Ser. E&G Co., N.J.	Harrison, N.J.	20	Naphtha	4	Spring 1973	CRG	7	Domestic	1,2,3,4,6,8
36. Pub. Ser. E&G N.J.	Linden, N.J.	125	Naphtha	25	Fall 1973	CRG	30	–	1,2,3,4,7,8, 10,12
37. Southern Calif. Gas Co.	Los Angeles, Cal.	250	Naphtha	–	Planning & Engineering	CRG	–	–	2,12
38. South Jersey Industries, Inc. . . .	Glouster Co., N.J.	125 (second train planned)	Naphtha	26-52	10/74 & '75-'76	CRG	30 Plt.	–	1,2,3,7, 8,11,12
39. Tecon Gasification Co.	New Hope, La.	500	Naphtha	110	20 mo. after FPC approval	MRG	187.5 (141 for Plt.)	–	1,2,3,4,7, 8,11,12
40. Tidal Transmission Co.	Gulf Coast	125	Naphtha	27	Proposed	–	–	–	2
41. Transco Energy	Marcus Hook, Pa.	250	Naphtha	53.5	10/74	LURGI	85	Foreign/Domestic	1,2,3,4,6,7, 8,10
42. Transco Energy	Eastern U.S.	460	Crude oil	100	1/76	LURGI	300	–	1,2,3,8, 12,13
43. Trunkline Gas Co. . .	Blue Mound, Ill.	130	Naphtha	30	Proposed	–	50	–	1,2,3,6,7, 8,12
44. Tucson Gas & Elec. Co.	Tucson, Ariz.	100	Naphtha	20	Engineering Complete '75	LURGI	30	–	2,3,12
45. United Gas P/L Co.	Pascagoula, Miss.	340[12]	Crude oil	150	Seeking Feedstock 1975	–	250	Foreign	1,2,3,4,6, 7,8,11,12
46. United Gas P/L Co.	Gulf Coast	270	Crude oil	190	Poss. '75, total-4 plants	–	–	Foreign	4,6,7,10

TABLE 10-31—Continued

Announced Plans for Liquid-Hydrocarbon-Gasification Plants as of October 1973

	Plant Location	Plant Size MMCF/D	Feedstock		Year of Completion	Type of Process[1]	Cost of Plant	Source of Feedstock	Source of Data[2]
			Type	Amt. (MMB/D)					
47. Washington Gas Light Co.	Cockpit Pt., Va.	60	Naphtha	10	1975	–	20	Domestic	1,2,3,8,12
48. Zapata/Norness	Gulf Coast	800 (2 plants)	Crude oil/ Naphtha	175	Under consideration	–	190	–	1,2,3,8,13
49. Zapata/Norness	East Coast/La.	400 (2 plants)	Crude oil	85	1975	–	215	Imported	4,6,7,10

[1] Type of Process: CRG—Catalytic Rich Gas
MRG—Methane Rich Gas
LURGI—Lurgi Gasynthan

[2] Sources of Data:
1. A.G.A. Gas Supply Review 5/15/73
2. A.G.A. Gas Supply Review 9/6/73
3. Pipeline & Gas Journal 12/72
4. Oil & Gas Journal 7/31/72
5. Blank
6. Oil & Gas Journal 9/18/72
7. Oil & Gas Journal 3/23/73
8. Oil & Gas Journal 6/25/73
9. Chemical Engineering 8/26/72
10. Chemical Engineering 10/16/72
11. Chemical Engineering 4/2/73
12. The Oil Daily 7/23/73
13. Chemical Engineering 9/18/72
14. CI 73-102 - Testimony of G. T. Jones 10/9/73

[3] Nat. Gas liq.—Natural Gas Liquids
[4] LPG—Liquefied Petroleum Gas
[5] 70 MB/D resid.—low sul.
[6] 100 MB/D resid.—low sul.
[7] 54271 B/D resid. & 51660 B/D distil.—low sul.
[8] 30 MB/D Naphtha, 12.8-20 MB/D Kerosene, 5-11.7 MB/D heavy fuel oil—low sul.
[9] 35-140 MB/D distil.—low sul.
[10] 70 MB resid.—low sul.
[11] 159 MB/D gasoline and No. 2 fuel oil—low sul.
[12] 80 MB/D fuel oil - low sul.

SUMMARY OF SNG-FROM-PETROLEUM PLANTS
(as of January, 1977)

Company	Feedstock: Design Volume 1000 bbl/day	Feedstock: Type	Feedstock: Source	SNG Design Capacity, million CF/day	Invest-ment, $ million	Process for SNG	Contractor	Location of Plant	Remarks
OPERATIONAL PLANTS									
Algonquin SNG, Inc.	26	Naphtha	Domestic	120	60	CRG	The Lummus Co.	Freetown, Mass.	Operational at design capacity from November 1 through March 31.
Ashland Oil, Inc.	11	Naphtha	Imported, crude	60	21.3	CRG	Foster Wheeler Corp.	Tonawanda, N.Y.	Iroquois Gas Corp. to buy 17.5 billion cf-yr. for 10 years at 60 MMcf/day, winter, and 36 MMcf/day, summer. Prices subject to average monthly crude cost to the refinery.
Boston Gas Co.	10	Propane	Imported, Exxon	40	8	MRG	The Badger Co., Inc.	Everett, Mass.	Start-up was in March 1974 with design for 180 day/yr. operation. 1976-77 winter start-up was in November 1976. SNG prices dependent on feedstock costs.
The Brooklyn Union Gas Co.	13.7	Naphtha	Exxon	60	46	CRG	The Lummus Co.	Brooklyn, N.Y.	Start-up was in May 1974 at 180 day yr. design. Operations at full capacity.
Columbia LNG Corp.	70	Propane, butane, and natural gas liquids	Domestic butane and propane and Canadian natural gas liquids	250 (2 trains)	48.2	CRG	Davy-Powergas	Greens Spring, Ohio	First train start-up was in March 1974 and second train in mid-1974. Plant designed for year-round operations.
Commonwealth Natural Gas Corp.	6.45	Propane and/or butane	Mostly imported; some domestic	29.5	7	CRG	J. F. Pritchard and Co.	Chesapeake, Va.	Operations expected to be at full design capacity for remainder of heating season. Recent average prices about $3.50 Mcf with feedstock prices from $110-$134 ton. Plant fuel supplied by plant output, but modifications to use propane are underway.
Consumers Power Co.	50	Natural gas liquids	Imported, Canada; some domestic	200 (2 trains)	155	CRG	The Lummus Co.	Marysville, Mich.	First train start-up was in Aug. 1973, with second train in April 1974. Plant capable of exceeding design capacity, up to 250 million cf day at times. Recent price was at $3.38 Mcf.
Gasco, Honolulu, Hawaii	28,500 lb/hr (3000 bbl/day)	Naptha	Imported	16.6	7.6	Lurgi Gasynthan	Ralph M. Parsons Co.	Barbers Point, Oahu	Start-up was in Sept. 1974. Operating at about 10 MMcf/d.

SUMMARY OF SNG-FROM-PETROLEUM (Continued)
(as of January, 1977)

Company	Feedstock: Design Volume 1000 bbl/day	Feedstock: Type	Feedstock: Source	SNG Design Capacity, million CF/day	Investment, $ million	Process for SNG	Contractor	Location of Plant	Remarks
Northern Illinois Gas Co.	32 16	Natural gas liquids Naphtha	Domestic	166	80	CRG	Bechtel Corp.	Aux Sable, Ill.	Start-up was in fall 1974. Base-load operations are at design capacity.
Public Service Electric and Gas Co.	4	Naphtha	Domestic	20	12	CRG	Foster Wheeler Corp.	Harrison, N.J.	Start-up was in March 1973. 1976-1977 winter season start-up was in January 1977.
Public Service Electric and Gas Co.	25	Naptha	Imported	125	50	CRG	Foster Wheeler Corp.	Linden, N.J.	Start-up was in December 1974 with minimal 1975-76 heating season operation. 1976-77 winter start-up was in November 1976.
Baltimore Gas and Electric Co.	12	Naphtha	Domestic	60	40	Lurgi Gasynthan	Stone & Webster	Sollers Point, Md.	Design for 180 day/yr. Plant testing began in December 1976.
Peoples Gas Light & Coke Co.	33	Naphtha	Domestic	160	100	CRG	Pullman-Kellogg, Division of Pullman, Inc.	Elwood, Ill.	Full-scale, base-load operations began in 1976.
PROJECTS IN PLANNING									
Transco Energy Co.	56	Naphtha	Imported	245	170+	Lurgi Gasynthan	Fluor Corp., Ltd. (Design)	Twin Oaks, Pa.	Construction of base-load plant will begin by mid-1977. $20 million worth of equipment and materials are already on site.
Philadelphia Gas Works	13	Naphtha	Domestic	60	73.4	CRG	Foster Wheeler Corp.	Philadelphia, Pa.	Project scheduled for first use in the winter 1978-79. Plant to include built desulfurization and sulfur recovery FEA feedstock allocation was obtained in Nov. 1975.
Macario Independent Refinery Co., Subsidiary of Pacific Resources, Inc.	100	Crude		100*	150+	Lurgi Gasynthan	Ralph M. Parsons Co.	Carlsbad, Calif.	San Diego Gas & Electric Company has withdrawn from the joint venture. Macario is seeking a new site for the plant.

SUMMARY OF SNG-FROM-PETROLEUM (Continued)
(as of January, 1977)

Company	Feedstock: Design Volume 1000 bbl/day	Feedstock: Type	Feedstock: Source	SNG Design Capacity, million CF/day	Investment, $ million	Process for SNG	Contractor	Location of Plant	Remarks
PROJECTS SUSPENDED									
Crown Central Petroleum Co.	200	Crude	Planned imports	280-300[a]	450-550	CRG	Arthur G. McKee & Co.	Baltimore City, Md.	A 500-acre site is available; but project suspended pending acquisition of acceptably priced feedstock.
New England Petroleum Corp.	200	Crude	Imported	200[c]	125+	—	—	Oswego, N.Y.	Project is suspended indefinitely.
Tecon Gasification	110	Naphtha	—	500	175	MRG	Procon, Inc.	Donaldsonville, La.	Project is suspended indefinitely.
Washington Gas Light Co.	5.7	Naphtha	ARCO	60	25	—	—	Prince William County, Va.	Project is suspended indefinitely.

[a] Plus 40,000 bbl/day low-sulfur power plant fuel and 30,000 bbl/day low-sulfur distillate fuel.
[b] Plus 30,000 bbl/day gasoline, 40,000 to 65,000 bbl/day diesel and 45,000 to 75,000 bbl/day low-sulfur fuel oil.
[c] Plus 100,000 bbl/day of heavy fuel oil.

Attachment B

UNITED STATES OF AMERICA
FEDERAL ENERGY ADMINISTRATION

In Re: Consumers Power Company §
Allocation of SNG Feedstocks § Case No.

APPLICATION FOR RESCISSION

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April 22, 1977

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UNITED STATES OF AMERICA
FEDERAL ENERGY ADMINISTRATION

In Re: Consumers Power Company §
Allocation of SNG Feedstocks § Case No.

APPLICATION FOR RESCISSION

The FEA's order of December 31, 1976, granting an interim allocation of SNG feedstocks to Consumers Power Company was predicated on the assumption that Consumers needed the SNG to supply high priority gas users. That assumption is demonstrably inaccurate. Therefore, the order should be rescinded.

I. STATEMENT OF POSITION

On December 31, 1976, the Federal Energy Administration (FEA) issued an order (the December 31st Order, attached as Appendix A) in the captioned proceeding which assigned suppliers and established a base period volume of up to 4,605,357 barrels of propane, butane and/or natural gasoline for synthetic natural gas (SNG) feedstock in each calendar quarter during the period January 1, 1977 through September 30, 1977, to Consumers Power Company (Consumers) for use in its Marysville, Michigan SNG plant. The December 31st Order is essentially an interim order which extends a previous grant of feedstocks for the 9 months FEA found it would need to conclude its evaluation of Consumers' application and complete an environmental review of the action requested by Consumers. Since the issuance of the December 31st Order, however, findings of another federal agency have called into question the basic assumption made by FEA in issuing the order. Moreover, the alternate sources of feedstock and gas supply available to Consumers have changed dramatically since December 31, 1976.

For these reasons, as detailed infra, the Petrochemical Energy Group (PEG) 1/ submits that the FEA could further its SNG feedstock policy, the national energy policy

1/ PEG is an ad hoc group of independent petrochemical companies which use propane, butane and natural gasoline as feedstocks. PEG companies, in addition, are customers of Consumers and are adversely affected by the operation

(continued on p. 2)

and the interests of Consumers' non-boiler fuel customers by rescinding the December 31st Order until such time as Consumers demonstrates the precise amount of SNG feedstock needed to maintain service to non-boiler fuel customers which do not have alternate fuel capability. 2/

II. THE DECEMBER 31 ORDER

The December 31st Order is only four pages of text and contains no discussion or analysis of Consumers' application or the evidence offered by PEG and others at the hearing held on October 29, 1976. As noted above, it is an interim order adopted so that FEA would have sufficient time to consider the complete record in the case including consideration of the environmental impact as requested by Consumers. Indeed, FEA acknowledges that the order "is based upon the presumed validity of statements, allegations, and documentary material submitted by the applicant." December 31st Order at p. 4. Presumably due to the lack of complete analysis prior to issuing the interim order, FEA provided that the December 31st Order could:

> ...be revoked or modified at any time upon a determination by FEA that the factual basis underlying the application is incorrect... December 31st Order at p.4.

PEG submits that the factual assumption upon which the order is based has been found to be incorrect. The finding in the December 31st Order which justifies the extension of feedstock allocation is the following:

1/ (continued from p. 1)

of Consumers' SNG plant. A complete description of PEG's interest is contained in the record developed in the proceeding below. The PEG companies participating in this proceeding are: Borg-Warner Chemicals; Celanese Corporation; Chemplex Company; Dart Industries, Inc.; E. I. du Pont de Nemours & Company, Inc.; Ethyl Corporation; The Firestone Tire & Rubber Company; Foster Grant Company, Inc.; The BF Goodrich Company; Goodyear Tire & Rubber Company; Hercules Incorporated; Monsanto Company; National Distillers and Chemical Corporation; Olin Corporation; PPG Industries, Inc.; Rohm and Haas Company; Texas Eastman Company, a Division of Eastman Kodak Company; Union Carbide Corporation.

2/ The FPC defines "alternate fuel capability" "as a situation when an alternate fuel could have been utilized whether or not the facilities for such use have actually been installed." 18 C.F.R. §2.78(c)(10).

> 2. This modification of the December 12 Order is necessary to allow Consumers to meet its natural gas obligations to high priority customers until a final evaluation can be made by FEA of the June 1 petition based on all the criteria...
> December 31st Order at p. 2 (emphasis supplied).

Thus, the previous feedstock allocation was continued because FEA assumed from the applicant's submissions that the feedstock allocation was necessary to provide gas service to high priority customers. While this assumption may have been reasonable in December 1976, subsequent events have shown it to be false.

III. THE FPC DECISION IN MICHIGAN GAS STORAGE COMPANY ET AL., DOCKET NO. CP74-322 ET AL.

On January 11, 1977, the Federal Power Commission (FPC or Commission) issued a decision in Docket No. CP74-322 et al. which denied certificates of public convenience and necessity to Northern Michigan Exploration Company (NOMECO), Michigan Gas Storage Company (MGS) and Trunkline Gas Company (Trunkline). NOMECO, an affiliate of Consumers, owns an interest in 12-15 offshore Louisiana federal leases and had sought in this proceeding to have its gas from three leases (approximately 40,000 Mcf/day) transported to its parent--Consumers. The gas would have been delivered by Trunkline to MGS at the Indiana-Michigan border. MGS, another Consumers' subsidiary, would deliver the gas to Consumers. The FPC found that the gas would have been delivered to Consumers at a cost of $1.00 per Mcf.

Although the Commission acknowledges that "it encourages the development of alternative forms of energy by customers who would otherwise be dependent upon interstate natural gas," it nevertheless denies NOMECO's application to supply Consumers with its offshore gas. Michigan Gas Storage Company, et al. Docket No. CP74-322, et al. (Order of January 11, 1977 at p. 9). This action by the FPC was predicated on the FPC Staff's finding that:

> ...the effect of adding the NOMECO volumes will primarily be to augment Consumer's ability to serve the large volume boiler fuel loads in priority 5...
> Michigan Gas Storage Company, supra at p. 8 (emphasis added).

The Commission rejected Consumers' argument stating in footnote 12 on page 10:

> It should be noted here that Consumers originally alleged that the NOMECO volumes would be devoted largely to high priority

> loads, whose attachment depended on issuance of the certificates here requested. It remains, however, that Consumers' addition of these loads can be accomplished regardless of the Commission's disposition of this case; it is just a question of how far Consumers wants to go in curtailing its priority 5 customers. 3/

The FPC concluded that it was not in the public interest to permit the sale and transportation of natural gas for boiler fuel use when other customers served by Trunkline were curtailing into FPC priorities 2 and 3.

The FPC decision and findings discussed above evidence the fact that (a) Consumers is presently serving large volume boiler fuel loads and (b) can continue service to its existing and new high priority customers merely by curtailing some of its FPC priority 5 customers. Thus, there is no longer any basis for assuming, as FEA did in the December 31st Order, that the SNG from the Marysville plant is "necessary to allow Consumers to meet its natural gas obligations to high priority customers." The December 31st Order at p. 2. Consumers SNG is going to boiler fuel customers in FPC priorities 4 and 5 and, of course, to customers in higher priorities with alternate fuel capability. At a minimum, this volume of SNG could be eliminated without threatening service to high priority customers.

It can also be shown that Consumers may be serving boiler fuel loads lower than those in priority 4 or 5. For example, the FPC Form 423's filed by Consumers for December 1976 and January 1977 indicate that at 4 of its plants, it used natural gas for the generation of electricity and that at two of those plants the gas was provided by Consumers. 4/ Consumers also had enough gas to supply boiler fuel to the Detroit Edison Company in December and January of the past winter. See Appendix B hereto. The volume of its own gas used or sold by Consumers for electrical generation in only two months was 2.412 Bcf or approximately 24% of the SNG plant's out put in December and January. 5/ These large volume sales may be in FPC priorities 8 and 9, the lowest possible, if the contracts are interruptible. Despite

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3/ FPC priority 5 is defined as: "Firm industrial requirements for large volume (3,000 Mcf or more per day) boiler fuel use where alternate fuel capabilities can meet such requirements." 18 C.F.R. §2.78(a)(1)(v).

4/ The January Form 423 is the most recent available in the FPC public files.

5/ Plant output was assumed to be 160 MMcf per day for 62 days in December and January.

the fact that it costs at least $3.25-3.50 to produce an Mcf of SNG, the Form 423's indicate that Consumers paid, on a weighted average basis, only $1.95 per Mcf for its SNG boiler fuel in December and January.

Another factor to be considered in the reconsideration of the December 31st Order is the extent to which Consumers' customers have alternate fuel capability. FEA did not have this information before it because Consumers refused and otherwise failed to provide such information. Consumers did, however, provide such data to the FPC in 1975 after it was threatened with dismissal of its application. See Michigan Gas Storage Co., supra at p. 2. Attached as Appendix C are two pages of the exhibits provided to the FPC.

Although the data is now out of date, it indicates that in 1974 Consumers delivered substantial volumes to customers in FPC priorities 3-9 who had installed fuel oil or coal alternate fuel capability. Comparing the volumes delivered to all customers in FPC priorities 3-5 in 1974 with the deliveries to customers in such priorities who had installed alternate fuel capability, it appears that 14% of the FPC priority 3 load, 45% of the priority 4 load and 57% of the priority 5 load had installed alternate fuel capability in 1974. Since it is technically feasible for 100% of these customers to convert to other fuels, the number of customers with installed alternate fuel capability should have increased since 1974. While an update of these figures by Consumers would be helpful in analyzing the impact of curtailing feedstocks to the Marysville plant, it is apparent from this data that many customers do not require SNG for even non-boiler fuel uses.

The unrebutted fact is that Consumers is serving large volumes of boiler fuel and electrical generation load that is not "high priority." Since the December 31st Order assumed that this was not the case, the Order should be rescinded. At the very least, the volume of feedstocks allocated should be reduced so that only enough SNG is produced to serve truly high priority customers which do not have alternate fuel capability.

IV. THE EMERGENCY NATURAL GAS ACT OF 1977

The December 31st Order was issued at a time when a distribution company, such as Consumers, was largely dependent upon its interstate pipeline supplier for volumes of natural gas. Thus, the December 31st Order did not contemplate that Consumers would have access to large volumes of intrastate natural gas from the major producing states.

This situation, however, has changed dramatically since December 31, 1976. The Emergency Natural Gas Act of 1977, Pub. L. 95-2 (91 Stat. 4 (1977))(ENGA), has provided a

means for distribution companies in Michigan and other states to contract directly with producers and intrastate pipelines in the major producing states for supplies of natural gas. This authority, which runs through the end of July 1977, provides Consumers with many alternative sources of natural gas at prices below its cost of producing SNG. If the December 31st Order were rescinded, Consumers would be encouraged to exhaust emergency purchases under this act to protect service to high priority customers.

There appear to be large volumes of gas available in the major producing states. Mr. Dunham, Chairman of the FPC and Administrator of ENGA, has testified that sales under ENGA have reached a total of 42 Bcf and a non-coincident peak of nearly two (2) Bcf per day. 6/ Mr. Dunham has also reported that storage volumes are approaching normal levels for this time of year and, thus, not all of the ENGA gas will be required for storage this summer. At a conference of the Emergency Gas Requirements Group held on March 30, 1977, Mr. Richard Smith of the FPC Staff stated that new sales under ENGA were continuing and "the indications are that there is plenty of gas available, more than in fact can be sold under the present restriction." In the Matter of: Emergency Gas Requirements Group, March 30, 1977 Conference Transcript at p. 250, 256. Thus, it appears very likely that significant volumes of natural gas would be available to Consumers if needed to serve non-boiler fuel loads.

Moreover, with its large storage capacity, Consumers may have the capability to buy volumes of gas in excess of present needs and store it for later use. In the FPC proceeding cited above, Consumers or its subsidiaries sponsored exhibits indicating that Consumers had 13 storage areas under its control with maximum storage capacity of 224.662 Bcf and maximum designed deliverability of 2,681 MMcf/day. With these large storage areas at its disposal, Consumers may be able to buy large volumes of natural gas under ENGA and store it for use in serving high priority customers this fall or winter.

PEG submits that the changed circumstances regarding alternative supplies of natural gas is a most important factor which FEA should consider in determining whether to continue the interim order granting a complete feedstock allocation to Consumers' SNG plant.

6/ Prepared statement of Richard L. Dunham, Chairman Federal Power Commission, Before the Subcommittee on Energy and Power of the Committee on Interstate and Foreign Commerce of the House of Representatives, at p. 2 (April 5, 1977).

V. POLICY OBJECTIVES TO BE FURTHERED BY THE PRESENT REQUEST

PEG has discussed above the new facts and changed circumstances which justify rescinding the December 31st Order. In addition to making its order square with the facts as now known, PEG believes that FEA's rescission of the order in question would also produce the following beneficial developments.

1. Consumers Could Receive the Benefit of Its Investment in Offshore Supplies of Natural Gas.

The FPC order discussed above provided that:

> If at some future time NOMECO wishes to sell remaining reserves under the three subject lease blocks or additional reserves from other leaseblocks to Consumers, it should be allowed to do so if it can produce competent evidence of changed circumstances to support a finding that such volumes would in fact be dedicated to high priority end uses. Our decision today is limited in thrust to the facts of this case and should not be construed as signalling abrogation of our policy of encouraging companies to engage in responsible self-help efforts aimed at easing the impact of gas shortage.

Michigan Gas Storage Co., supra at p. 14-5.

If the FEA were to deny or sharply reduce the allocation of feedstocks to Consumers' SNG plant, the "changed circumstances" mentioned by the FPC would appear to have occurred. Without its SNG production, Consumers might be able to show that it needs the NOMECO gas to serve FPC priority 3 loads. In any event, without its SNG supply, Consumers will be in a much better position to receive the full benefits of its offshore investment.

It must be remembered that the FPC case discussed above is not an isolated application. Consumers owns an interest in several other offshore blocks which apparently have not been fully explored or developed. In its petition for rehearing of the FPC order of January 11, 1977, Consumers states that at present it has 52.5 Bcf of proved reserves and another 165 Bcf of probable reserves which would be affected by the FPC's decision. Consumers believes it has access to a large supply of gas with at least 18 years deliverability. Clearly, the FEA should aid Consumers' efforts to acquire this secure, long term alternative to its insecure and expensive SNG. FEA could best serve Consumers by rescinding the December 31st Order, thereby enabling it to acquire the NOMECO gas.

Such action would benefit Consumers' non-boiler fuel customers. The present supply of offshore gas is available to Consumers at $1.00 per Mcf. Future supplies will be available at the applicable nationwide rate plus transportation which will undoubtedly never reach the price of SNG. Even Consumers has characterized the offshore gas as "relatively inexpensive" as compared to its "expensive" SNG. See Consumers' Petition for Rehearing of the FPC Order at p. 1. By helping Consumers replace the expensive SNG with offshore supplies, the FEA will be aiding Consumers' customers.

Consumers' customers will also be aided by any purchases made by Consumers under ENGA. Even at $2.25 per MMBtu plus transportation, this gas will be cheaper than SNG at $3.25-3.50 (Consumers' November 1976 cost estimate). Thus, by encouraging Consumers to utilize alternative supplies of relatively inexpensive gas, FEA will help reduce the overall cost of gas to Consumers' customers, including PEG companies, while preserving scarce liquid hydrocarbons (propane, butane and other NGL's) for existing high priority users.

2. The National Energy Policy Is Promoted By Rescission of the December 31st Order.

It is widely recognized that the boiler fuel use of natural gas is a most undesirable use of a premium fuel and feedstock. Recognizing this basic fact, the FPC has forced the curtailment of boiler fuel usage before other usages of natural gas. The courts have upheld the FPC's findings in this respect. Cf. State of Louisiana v. FPC, 503 F.2d 844 (5th Cir. 1974); American Smelting and Refining Co. v. FPC, 494 F.2d 925 (D.C. Cir. 1974); Arkansas Power and Light Co. v. FPC, 517 F.2d 1223 (D.C. Cir. 1975). The FPC has also conditioned transportation certificates so that no gas from any source may be used for boiler fuel in a facility receiving gas from the offshore federal domain. Opinion No. 727, Docket No. CP72-6 (April 17, 1975).

By rescinding the December 31st Order, FEA will help reduce the wasteful use of natural gas as boiler fuel. Without SNG, Consumers will not be able to serve its large volume boiler fuel customers, all of whom have alternate fuel capability. This result is clearly in the national interest.

3. Refiners of Canadian Crude Oil Will Benefit from the Rescission of the December 31st Order.

The majority of the feedstock allocated to Consumers is a condensate which is considered crude oil under the Canadian Allocation Program. Consumers' SNG plant is regarded

as a first priority refiner and has received an allocation on that basis. Canada exports two types of oil, light and heavy. The light oil is exported in smaller volumes which are declining more rapidly than exports of the heavy oil. Consumers and seven (7) other first priority refiners out of 11 used only Canadian light oil in the base period.

It appears to PEG that access to Canadian light oil will become increasingly important to first priority refiners who by definition have no access to oil pipelines or ports. FEA can improve the access of these refiners to such oil by rescinding the December 31st Order. PEG submits that it is more important to supply light Canadian oil to the refiners dependent upon it, than to supply boiler fuel to large volume customers with alternative fuel capabilities. By terminating Consumers access to Canadian condensate, FEA will be ensuring that this increasingly scarce resource is used in the most efficient manner by those who have no alternatives.

4. FEA's SNG Feedstock Allocation Policy Will Be Furthered by Rescission of the December 31st Order.

Finally, FEA should seek to achieve the goals of its SNG feedstock policy. FEA's policy statement on SNG concludes that SNG is an inefficient use of resources in most instances and that FEA will implement a policy which discourages the allocation of scarce petroleum resources to manufacturers of SNG. By rescinding Consumers' allocation, FEA will certainly be furthering this policy. Since it is now apparent that all of the SNG is not necessary to serve "high priority" customers, there is no basis for continuing the interim feedstock allocation. This is particularly true where alternative gas supplies have increased dramatically since the interim order was issued. By curtailing its boiler fuel load and using alternative supplies of natural gas (both emergency purchase gas and the NOMECO supply), Consumers should be able to serve all existing high priority users.

VI. CONCLUSION

Pursuant to §205.9(d), one who files any request for action with FEA has a continuing obligation to provide FEA with new or newly discovered information relevant to the action requested. This requirement and the specific procedures for modification and/or rescission of an order indicate that FEA recognizes the value of re-examining specific orders in light of new evidence or changed circumstances. Presumably, such a re-examination is undertaken in order to ensure that the basis for issuing a particular order has not become outdated or been shown to be untrue. Cf. Algonquin Gas Transmission Company et al., Case Nos. FEX-0098 et al. (April 8, 1977).

In this case the basis for the December 31st Order has been shown to be incorrect. Consumers does not require SNG to serve high priority, non-boiler fuel customers. Moreover, alternative gas supplies are now available to Consumers in volumes and from sources not possible prior to adoption of the Emergency Natural Gas Act of 1977. There has obviously been a significant change in circumstances.

PEG has brought these facts to FEA's attention pursuant to its obligation under §205.9(d). PEG now requests that FEA utilize its established procedures to make the interim order allocating feedstocks to Consumers' SNG plant comport with the known facts. PEG submits that the December 31st Order must be rescinded since its basis is factually in error. If Consumers can show that it cannot acquire enough natural gas to serve high priority customers which do not have alternate fuel capability, a limited allocation of feedstocks might be in order. Without such a showing, however, there is no basis for any allocation.

Respectfully submitted,

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PETROCHEMICAL ENERGY GROUP

CERTIFICATE OF SERVICE

Baker & Botts certify that they are attorneys-at-law and are duly authorized representatives of the Petrochemical Energy Group for purposes of this proceeding. No representative of PEG has had any contact with any FEA official regarding the request for rescission made in the foregoing document. To PEG's knowledge, this matter is not presently pending before any FEA or state office or any court.

Baker & Botts certify that the foregoing document has been served by mail on the persons listed on the following pages. Pursuant to §205.133(c), each person receiving this Application may file comments regarding same within 10 days of receipt with Mr. Melvin Goldstein, Director, Office of Exceptions and Appeals, Federal Energy Administration, Room 8002, 2000 M Street, N.W., Washington, D.C. 20508.

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FEDERAL ENERGY ADMINISTRATION
WASHINGTON, D.C. 20461

JAN 25 1977

BAKER & BOTTS

DATE OF ORDER: DECEMBER 31, 1976

REQUEST OF: MR. P. D. ANDREA
CONSUMERS POWER COMPANY
212 WEST MICHIGAN AVENUE
JACKSON, MICHIGAN 49201

SUBJECT: ASSIGNMENT OF SYNTHETIC NATURAL GAS FEEDSTOCKS

MODIFICATION OF DECISION AND AMENDED ORDER
DATED DECEMBER 12, 1976

I. Procedural Statement

1. On December 12, 1976, the Federal Energy Administration (FEA) issued a Decision and Amended Order (December 12 Order) to Consumers Power Company (Consumers) assigning Consumers a base period use of 4,665,357 barrels of propane, butane or natural gasoline for synthetic natural gas (SNG) plant feedstock use in each calendar quarter of 1976 corresponding to a base period for its Marysville, Michigan, SNG plant.

2. The December 12 Order provided that Michigan Consolidated Gas Company be assigned as Consumers' base period supplier to supply 42,657 barrels of propane, butane or natural gasoline for each quarterly period corresponding to a base period, and that Dome Petroleum, Ltd., and the American Oil Company be jointly assigned as Consumers' base period supplier to supply 4,562,500 barrels of propane, butane or natural gasoline for each quarterly period corresponding to a base period. Any petition for an SNG feedstock allocation after December 31, 1976, was required to be filed on or before June 1, 1976, and to include information required by FEA regulations and the December 12 Order.

3. On June 1, 1976, Consumers submitted its petition (the petition) for the assignment of suppliers and establishment of a base period use of SNG feedstocks for periods

after December 31, 1976. The petition requested FEA to assign to Consumers on a permanent basis a base period use of 4,631,658 barrels of propane, butane, or natural gasoline for synthetic natural gas plant use for each quarterly period corresponding to base periods after December 31, 1976, for its Marysville, Michigan, SNG plant.

4. Upon the filing of the petition, FEA initiated a review to determine whether FEA should prepare an environmental impact statement under the National Environmental Policy Act of 1969 (NEPA), 42 U.S.C. §§4321 et seq., to determine whether the requested allocation, if granted, would significantly affect the quality of the human environment. At the present time, this review has not been completed.

II. Legal Authority

1. FEA is issuing this Modification of Decision and Amended Order (Modification) pursuant to 10 CFR Part 205, Subparts C and J, of the FEA's Administrative Procedures and Sanctions, and §211.29 and Special Rule No. 1 to Subpart A of 10 CFR Part 211, the Mandatory Petroleum Allocation Regulations, to amend the December 12 Order.

III. Findings and Analysis

Based on information contained in the petition, the December 12 Order and all available information relevant to Consumers' petition, the FEA has determined that:

1. Under the provisions of NEPA, FEA is responsible for reviewing each major Federal action to determine whether it significantly affects the quality of the human environment. In the event that such an action is found to have the potential for significantly affecting the environment, NEPA requires that an environmental impact statement be prepared. While it has been determined that, under FEA regulations, 10 CFR §208.4, an environmental assessment must be undertaken to determine the significance of the environmental effects of granting or denying Consumers' petition, FEA has not yet completed the required environmental review.

2. This modification of the December 12 Order is necessary to allow Consumers to meet its natural gas obligations to high priority customers until a final evaluation can be made by FEA of the June 1 petition based on all the criteria of 10 CFR §§205.35, 211.29 and Special Rule No. 1

to Subpart A of Part 211, including the impact on the environment, and until a new Decision and Order can be issued. FEA's continuing examination under these criteria is also closely related to its environmental review under NEPA. Thus, a final determination with respect to Consumers' June 1 petition must await the resolution of the environmental questions involved.

3. FEA estimates that it will require up to nine months' additional time to assess the environmental impact, if any, of granting Consumers' petition and if necessary, to prepare and circulate for public comment an environmental impact statement discussing the significant impacts of and alternatives to the requested assignment.

4. FEA has determined, based upon information contained in Consumers' June 1 application and subsequent submissions, that Consumers is continuing to experience significant curtailments of pipeline natural gas on its system and that projected natural gas curtailments to Consumers for the 1976-1977 heating season will equal and very likely exceed those for the 1975-1976 heating season. Consumers, therefore, will not be able to continue to supply many of its non-interruptible customers without a temporary extension of FEA's allocation of petroleum feedstocks for use in its Marysville SNG facility.

5. The allocation provided in the December 12 Order is therefore being extended for a period of nine months to permit completion of FEA's environmental review and to allow Consumers to continue supplying its non-interruptible customers. FEA believes that such an extension will preclude any environmental impacts which might otherwise result from a reduction in Consumers' allocation level during the interim and will also assure that Consumers will have sufficient feedstock available to continue operating its SNG facility.

V. Assignment Order

In consideration of the foregoing and pursuant to 10 CFR Part 205, Subparts C and J, and §211.29 and Special Rule No. 1 to Subpart A of 10 CFR Part 211, FEA hereby orders the following modification to the December 12 Order. The first ordering paragraph of Section IV, Amended Assignment Order, is hereby deleted and replaced by the new ordering paragraph 1 which reads as follows:

1.(a) Consumers Power Company, Jackson, Michigan, is assigned a base period use of up to 4,605,367 barrels of propane, butane, and/or natural gasoline for synthetic natural gas feedstock use for each calendar quarter corresponding to a base period for the period January 1, 1977 through September 30, 1977, for its Marysville, Michigan, SNG plant.

(b) Michigan Consolidated Gas Company is designated as Consumers' base period supplier for purposes of the assignment made in paragraph (1)(a) above for 42,857 barrels of propane, butane, and/or natural gasoline for each period corresponding to a base period;

(c) Bow Petroleum, Ltd., and the American Oil Company are jointly designated as Consumers' base period supplier for purposes of the assignment made in paragraph (1)(a) above for 4,562,500 barrels of propane, butane and/or natural gasoline for each period corresponding to a base period.

VI. Revocation, Modification, and Right of Appeal

This Modification Order is based upon the material validity of statements, allegations, and documentary material submitted by the applicant. It may be revoked or modified at any time upon a determination by FEA that the factual basis underlying the application is incorrect or on the basis of general regulatory provisions which the FEA may adopt.

In accordance with the provisions of 10 CFR, Part 205, an aggrieved party may file an appeal of this Decision and Order with the Federal Energy Administration. The provisions of 10 CFR, Part 205, Subpart H, set forth the procedures and criteria which govern the filing and determination of any such appeal.

Communications other than appeals regarding this assignment should be directed to the Office of Specialty Fuels and Products, Federal Energy Administration, 7000 H Street, N.W., Washington, D.C. 20461.

Effective immediately.

Barton R. House
Deputy Assistant
Administrator
Operations

Appendix B

MONTHLY REPORT OF COST AND QUALITY OF FUELS FOR ELECTRIC PLANTS

1. Company Plant Code	2. Report For	3. Reporting Company	4. Page Number
114500 - 2550	MO. 12 YR. 76	Consumers Power Company	1 OF 1

5. Plant Name	6. Plant Location
Thetford	Clio, Michigan

7. Name, Title and Address of person to be contacted concerning data entered on this form	Telephone No.
Edward G. Pulse, Oil Supply Coordinator, 1945 West Parnall Rd, Jackson, MI 49201	Area Code (517) Extension 788-1402

8. Signature of Official submitting this report	Title	Date Completed
	Director of Oil & Gas Supply	2/15/77

Line No.	TYPE PLAN (a)	PURCHASES TYPE (b) use code (1)	PURCHASES CONTRACT EXPIRES WITHIN 24 Mos. (Yes-No) (2)	FUEL TYPE use code (3)	COAL MINES ONLY TYPE use code (4)	COAL MINES ONLY DISTRICT Number & State (5)	SOURCE (6)	QUANTITY RECEIVED 1000 Tons 1000 Barrels 1000 Mcf (7)	QUALITY (AS RECEIVED) Average Btu of Coal per lb. Oil per gal. Gas per cu. ft. (8)	QUALITY (AS RECEIVED) To nearest 0.1 percent of: Sulfur (9)	QUALITY (AS RECEIVED) To nearest 0.1 percent of: Ash (10)	COST IN ¢ PER MILLION Btu (to nearest 0.1 cent) (11)
1	OT	F	Yes	NG			Consumers Power Company	479.6	1,000	-	-	183.3
2	OT	S	Yes	FO2			Rupp Oil Company, & Marathon Oil Co	23.9	140,000	0.40	0.04	238.1
3												
4												
5												
6												
7												
8												
9												
10												
11												
12												
13												
14												

MONTHLY REPORT OF COST AND QUALITY OF FUELS FOR ELECTRIC PLANTS

1. Company Plant Code: 114500 - 0500
2. Report For: mo. 12 yr. 76
3. Reporting Company: Consumers Power Company
4. Page Number: 1 Of 1
5. Plant Name: B C Morrow
6. Plant Location: Comstock, Michigan
7. Name, Title and Address of person to be contacted concerning data entered on this form: Edward G. Pulse, Oil Supply Coordinator, 1945 West Parnall Rd, Jackson, MI 49201
Telephone No.: Area Code (517) Extension: 788-1402
8. Signature of Official submitting this report:
Title: Director of Oil & Gas Supply
Date Completed: 2/15/77

Line No.	Type Plant (a)	Type Fuel (b)	Purchases: Type (c)	Purchases: Long-Term Contracts Expires Within 24 Mos. (Yes-No) (d)	Fuel Type (e)	Coal Mines Only: Type (f)	Coal Mines Only: District Number & State (g)	Source (h)	Quantity Received (i)	Quality (As Received): Average Btu or Coal per lb. Oil per gal. Gas per cu. ft. (j)	Quality (As Received): To nearest 0.1 percent of: Sulfur (k)	Quality (As Received): To nearest 0.1 percent of: Ash (l)	Cost in ¢ Per Million Btu (to nearest 0.1 cent) (m)
			use code (1)		use code (2)	use code (3)		For coal, show name of mine and county from which coal originated, if available. For oil, show supplier and refinery or port of entry. For gas, show pipeline (supplier) or distributor, producing area by state, or port of entry. (4)	1000 Tons 1000 Barrels 1000 Mcf (7)				
1	S	S	Yes	FO6				Lakeside Refining, Enterprise Oil, Rupp Oil, Murphy-Miles, Total, Industrial Fuel	137.6	150,000	1.13	0.05	166.7
2	GT	F	Yes	NG				Consumers Power Company	184.3	1,000	-	-	176.0
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(22-95)

1056

MONTHLY REPORT OF COST AND QUALITY OF FUELS FOR ELECTRIC PLANTS

1. Company-Plant Code	2. Report Form	3. Reporting Company	4. Page Number
114500 - 2500	MO. 12 YR. 76	Consumers Power Company	1 OF 1

5. Plant Name	6. Plant Location
Straits	Mackinac, Michigan

7. Name, Title and Address of person to be contacted concerning data entered on this form	Telephone No.
Edward G. Pulac, Oil Supply Coordinator, 1945 West Parnall Rd, Jackson, MI 49201	Area Code (517) Extension 788-1402

8. Signature of Official submitting this report	Title	Date Completed
	Director of Oil & Gas Supply	2/15/77

Line No.	TYPE PLANT 1 ICGT (a)	PURCHASES TYPE use code (1)	PURCHASES CONTRACT EXPIRES WITHIN 24 Mos. (Yes-No) (2)	FUEL TYPE use code (3)	COAL MINES ONLY TYPE use code (4)	COAL MINES ONLY DISTRICT Number & State (5)	SOURCE For coal, show name of mine and county from which coal originated, if available. For oil, show supplier and refinery or port of entry. For gas, show pipeline (supplier) or distributor, producing area by state, pf, port of entry. (6)	QUANTITY RECEIVED 1000 Tons 1000 Barrels 1000 Mcf (7)	QUALITY (AS RECEIVED) Average Btu of coal per lb. Oil per gal. Gas per cu. ft. (8)	QUALITY (AS RECEIVED) To nearest 0.1 percent of: Sulfur (9)	Ash (10)	COST IN ¢ PER MILLION Btu (to nearest 0.1 cent) (11)
1	GT	F	Yes	NG			Michigan Consolidated Gas Company	126.2	1,000	-	-	113.7
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(22-55)

MONTHLY REPORT OF COST AND QUALITY OF FUELS FOR ELECTRIC PLANTS

1. Company-Plant Code	2. Report For	3. Reporting Company	4. Page Number
114500 - 1000	MO. 12 YR. 76	Consumers Power Company	1 of 1

5. Plant Name	6. Plant Location
Gaylord	Gaylord, Michigan

7. Name, Title and Address of person to be contacted concerning data entered on this form	Telephone No.
Edward G. Pulse, Oil Supply Coordinator, 1945 West Parnall Rd, Jackson, MI 49201	Area Code (517) Extension: 788-1402

8. Signature of Official submitting this report	Title	Date Completed
	Director of Oil & Gas Supply	2/15/77

Line No.	TYPE PLAN (a)	PURCHASES TYPE (b)	CONTRACT EXPIRES WITHIN 24 Mos. (Yes-No) (2)	FUEL TYPE use code (3)	SHIPMENTS DAILY TYPE use code (4)	SHIPMENTS DAILY DISTRICT Number & State (5)	SOURCE For coal, show name of mine and county from which coal originated, if available. For oil, show supplier and refinery or port of entry. For gas, show pipeline (supplier) or distributor, producing area by state, or port of entry. (6)	QUANTITY RECEIVED 1000 Tons 1000 Barrels 1000 Mcf (7)	QUALITY (AS RECEIVED) Average Btu of Coal per lb. Oil per gal. Gas per cu. ft. (8)	QUALITY (AS RECEIVED) To nearest 0.1 percent of: Sulfur (9)	QUALITY (AS RECEIVED) To nearest 0.1 percent of: Ash (10)	COST IN ¢ PER MILLION Btu (to nearest 0.1 cent) (11)
1	GT	1	Yes	NG			Michigan Consolidated Gas Company	432.2	1,000	-	-	155.2
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(12-75)

MONTHLY REPORT OF COST AND QUALITY OF FUELS FOR ELECTRIC PLANTS

1. Company-Plant Code: 114500 - 2550
2. Report For: MO. 1 YR. 77
3. Reporting Company: Consumers Power Company
4. Page Number: 1 OF 1
5. Plant Name: Thetford
6. Plant Location: Clio, Michigan
7. Name, Title and Address of person to be contacted concerning data entered on this form: Edward G. Pulse, Oil Supply Coordinator, 1945 West Parnall Rd, Jackson, MI 49201
Telephone No. Area Code (517) Extension: 788-1402
8. Signature of Official submitting this report
Title: Director of Oil & Gas Supply
Date Completed: 3/14/77

Line No.	TYPE PLANT J IC GT (a)	PURCHASES TYPE use code (1)	PURCHASES CONTRAC EXPIRES WITHIN 24 Mos. (Yes-No) (2)	FUEL TYPE use code (3)	COAL MINES ONLY TYPE use code (4)	COAL MINES ONLY DISTRICT Number & State (5)	SOURCE For coal, show name of mine and county from which coal originated, if available. For oil, show supplier and refinery or port of entry. For gas, show pipeline (supplier) or distributor, producing area by state, or port of entry. (6)	QUANTITY RECEIVED 1000 Tons 1000 Barrels 1000 Mcf (7)	QUALITY (AS RECEIVED) Average Btu of Coal per lb. Oil per gal. Gas per cu. ft. (8)	QUALITY (AS RECEIVED) To nearest 0.1 percent of: Sulfur (9)	QUALITY (AS RECEIVED) To nearest 0.1 percent of: Ash (10)	COST IN ¢ PER MILLION Btu (to nearest 0.1 cent) (11)
1	GT	F	Yes	NG			Consumers Power Company	753.8	1,000	-	-	204.3
2	GT	S	Yes	FO2			Marathon Oil Company, Rupp Oil Company Enterprise Oil & Gas Company	37.7	141,500	.40	.04	261.6
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1059

MONTHLY REPORT OF COST AND QUALITY OF FUELS FOR ELECTRIC PLANTS

1. Company-Plant Code	2. Report For	3. Reporting Company	4. Page Number
114500 - 0500	MO. 1 YR. 77	Consumers Power Company	1 OF 1

5. Plant Name	6. Plant Location
B E Morrow	Comstock, Michigan

7. Name, Title and Address of person to be contacted concerning data entered on this form	Telephone No.
Edward G. Pulse, Oil Supply Coordinator, 1945 West Parnall Rd, Jackson, MI 49201	Area Code (517) Extension 788-1402

8. Signature of Official submitting this report	Title	Date Completed
	Director of Oil & Gas Supply	3/14/77

Line No.	Type Plant & SC GT (a)	PURCHASES Type use code (1)	PURCHASES Contract Expires Within 24 Mos. (Yes-No) (2)	Fuel Type use code (3)	COAL MINES ONLY Type use code (4)	COAL MINES ONLY District Number & State (5)	SOURCE For coal, show name of mine and county from which coal originated, if available. For oil, show supplier and refinery or port of entry. For gas, show pipeline (supplier) or distributor, producing area by state, or port of entry. (6)	Quantity Received 1000 Tons 1000 Barrels 1000 Mcf (7)	Quality (As Received) Average Btu of Coal per lb. Oil per gal. Gas per cu. ft. (8)	Quality (As Received) To nearest 0.1 percent of Sulfur (9)	Quality (As Received) To nearest 0.1 percent of Ash (10)	Cost in ¢ Per Million Btu (to nearest 0.1 cent) (11)
1	S	S	Yes	FO6			Lakeside Refining, Total, Inc, Enterprise Oil, Rupp Oil, Murphy-Miles, Industrial	120.7	150,000	1.12	.04	220.7
2	GT	F	Yes	NG			Fuel and Asphalt Company; Consumers Power Company	214.4	1,000	-	-	204.3
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(22-55)

1060

MONTHLY REPORT OF COST AND QUALITY OF FUELS FOR ELECTRIC PLANTS

1. Company-Plant Code: 114500 - 2500
2. Report Form: NO. 1 YR. 77
3. Reporting Company: Consumers Power Company
4. Page Number: 1 OF 1
5. Plant Name: Straits
6. Plant Location: Mackinac, Michigan
7. Name, Title and Address of person to be contacted concerning data entered on this form: Edward G. Pulse, Oil Supply Coordinator, 1945 West Parnall Rd, Jackson, MI 49201
Telephone No. Area Code (517) Number 788-1402
8. Signature of Official submitting this report
Title: Director of Oil & Gas Supply
Date Completed: 3/14/77

Line No.	TYPE PLANT (2 LETTER CODE)	PURCHASES TYPE	PURCHASES CONTRACT EXPIRES WITHIN 24 Mos. (Yes-No)	FUEL TYPE	COAL MINES ONLY TYPE	COAL MINES ONLY DISTRICT Number & State	SOURCE	QUANTITY RECEIVED	QUALITY (AS RECEIVED) Average Btu of Coal per lb. Oil per gal. Gas per cu. ft.	QUALITY (AS RECEIVED) Sulfur (Round to nearest 0.1 percent of)	QUALITY (AS RECEIVED) Ash (Round to nearest 0.1 percent of)	COST IN ¢ PER MILLION Btu (to nearest 0.1 cent)
	(0)	use code (1)	(2)	use code (3)	use code (4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	GT	F	Yes	NG			Michigan Consolidated Gas Company	97.8	1,000		-	178.1
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For coal, show name of mine and county from which coal originated, if available.
For oil, show supplier and refinery or port of entry.
For gas, show pipeline (supplier) or distributor, producing area by state, or port of entry.

(22-35)

1061

MONTHLY REPORT OF COST AND QUALITY OF FUELS FOR ELECTRIC PLANTS

1. Company-Plant Code: 114500 - 1600
2. Report For: MO. 1 YR. 77
3. Reporting Company: Consumers Power Company
4. Page Number: 1 OF 1
5. Plant Name: Gaylord
6. Plant Location: Gaylord, Michigan
7. Name, Title and Address of person to be contacted concerning data entered on this form: Edward G. Pulse, Oil Supply Coordinator, 1945 West Parnall Rd, Jackson, MI 49201
Telephone No. Area Code (517) Extension: 788-1402
8. Signature of Official submitting this report
Title: Director of Oil & Gas Supply
Date Completed: 3/14/77

Line No.	Type Plant (a)	Purchases Type (1)	Purchases Contract Expires Within 24 Mos. (Yes-No) (2)	Fuel Type (3)	Coal Mines Only Type (4)	Coal Mines Only District Number & State (5)	Source (6)	Quantity Received 1000 Tons 1000 Barrels 1000 Mcf (7)	Quality (As Received) Average Btu of Coal per lb. Oil per gal. Gas per cu. ft. (8)	Quality (As Received) To nearest 0.1 percent of: Sulfur (9)	Quality (As Received) To nearest 0.1 percent of: Ash (10)	Cost in ¢ per Million Btu (to nearest 0.1 cent) (11)
1	GT	1	Yes	NG			Michigan Consolidated Gas Company	136.4	1,000	-	-	158.4
2	GT	S	Yes	FO2			Rupp Oil, Osceola Refining, Marathon Oil Company	26.6	141,000			278.1
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(22-55)

1062

MONTHLY REPORT OF COST AND QUALITY OF FUELS FOR ELECTRIC PLANTS

1. Company-Plant Code	2. Report For	3. Reporting Company	4. Page Number
4920001-0600	MO. Dec. YR. 1976	The Detroit Edison Company	1 Of 1

5. Plant Name	6. Plant Location
Hancock	Walled Lake, Mi.

7. Name, Title and Address of person to be contacted concerning data entered on this form: Robert Paoletti, Director - Reports and Statistical Analysis, 2000 Second Avenue, Detroit, Michigan 48226 — Telephone No. Area Code (313) 237-8029 Extension:

8. Signature of Official submitting this report	Title	Date Completed
Robert W. Johnson Jr.	Controller	2-8-77

Line No.	TYPE PLANT (a)	PURCHASES TYPE use code (1)	PURCHASES CONTRACT EXPIRES WITHIN 24 Mos. (Yes-K) (2)	FUEL TYPE use code (3)	COAL MINES ONLY TYPE use code (4)	COAL MINES ONLY DISTRICT Number & State (5)	SOURCE For coal, show name of mine and county from which coal originated, if available. For oil, show supplier and refinery or port of entry. For gas, show pipeline (supplier) or distributor, producing area by state, or port of entry. (6)	QUANTITY RECEIVED 1000 Tons 1000 Barrels 1000 Mcf (7)	QUALITY (AS RECEIVED) Average Btu of Coal per lb. Oil per gal. Gas per cu. ft. (8)	Sulfur To Nearest 0.01% (9)	Ash To Nearest 0.1% (10)	COST IN ¢ PER MILLION Btu (to nearest 0.1 cent) (11)
1	GT	F	Yes	NG			Consumers Power Co., Jackson, Mi.	550	1,028	-	-	198.5
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MONTHLY REPORT OF COST AND QUALITY OF FUELS FOR ELECTRIC PLANTS

1. Company-Plant Code	2. Report Form	3. Reporting Company	4. Page Num.
492000-0600	MO. Jan. YR. 1977	The Detroit Edison Company	1 OF 1

5. Plant Name	6. Plant Location
Hancock	Walled Lake, Mi.

7. Name, Title and Address of person to be contacted concerning data entered on this form
Robert Paolgtti, Director - Reports and Statistical Analysis, 2000 Second Avenue, Detroit, Michigan 48226
Telephone No. 237-8029 Area Code (313) Extension

8. Signature of Official submitting this report	Title	Date Completed
Edward Johnson	Controller	3-14-77

Line No.	TYPE PLANT (a)	PURCHASES TYPE (b)	PURCHASES CONTRACT EXPIRES WITHIN 24 Mos. (Yes-No) (2)	FUEL TYPE (3)	COAL MINES ONLY TYPE (4)	COAL MINES ONLY DISTRICT Number & State (4)	SOURCE (6)	QUANTITY RECEIVED 1000 Tons 1000 Barrels 1000 Mcf (7)	QUALITY (AS RECEIVED) Average Btu of Coal per lb. Oil per gal. Gas per cu. ft. (8)	QUALITY (AS RECEIVED) Sulfur To Nearest 0.01% (9)	QUALITY (AS RECEIVED) Ash To nearest 0.1% (10)	COST (In ¢ PER MILLION Btu (to nearest 0.1 cent) (11)
		use code (1)		use code (3)	use code (4a)		For coal, show name of mine and county from which coal originated, if available. For oil, show supplier and refinery, or port of entry. For gas, show pipeline (supplier) or distributor, producing area by state, or port of entry.					
1	GT	F	Yes	NG			Consumers Power Co., Jackson, Mi.	230	1,026	-	-	208.7
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Appendix C
Michigan Gas Storage Co., et al.
Docket No. CP74-322, et al.
Hearing Ex. No. 49 (MEB-16)

Certified Copy

SEP 5 1975

FEDERAL POWER COMMISSION
Docket No. CP74-322, et al.
Hearing Ex. No. 49
Date Identified 7-30-75
Date Admitted 7-30-75

CONSUMERS POWER COMPANY

INDUSTRIAL CUSTOMERS' MONTHLY

EXISTING ALTERNATE FUEL CAPABILITY

CONSUMERS POWER COMPANY

SUMMARY OF COAL EXISTING ALTERNATE FUEL CAPABILITY VOLUMES(MCF)

1974

	Category 2	Category 3	Category 4	Category 5	Category 6	Category 7	Category 8	Category 9	Total
Jan	0	53,822	0	101,115	0	29,466	35,028	0	219,431
Feb	0	46,993	0	314,891	0	0	129,911	0	491,795
Mar	0	48,359	0	265,239	3,404	0	0	0	317,002
Apr	0	22,281	107,339	651,578	0	0	0	0	781,198
May	0	21,844	63,378	737,836	0	0	0	0	823,058
Jun	0	30,931	53,313	683,036	0	0	0	0	767,280
Jul	0	30,125	53,633	697,302	0	0	0	0	781,060
Aug	0	42,111	66,605	762,435	0	0	0	0	871,151
Sep	0	52,254	48,239	725,757	0	0	0	0	826,250
Oct	0	39,073	70,059	370,744	0	24,299	0	0	504,175
Nov	0	52,584	60,657	280,648	15,068	0	0	0	408,957
Dec	0	38,473	66,885	318,230	0	30,502	50,244	0	504,334
Total	0	478,850	590,108	5,908,811	18,472	84,267	215,183	0	7,295,691

BCS/vm
7/11/75

CONSUMERS POWER COMPANY

SUMMARY OF OIL EXISTING ALTERNATE FUEL CAPABILITY VOLUMES(MCF)

1974

	Category 2	Category 3	Category 4	Category 5	Category 6	Category 7	Category 8	Category 9	Total
Jan	0	310,737	224,704	773,509	87,659	49,110	155,096	0	1,600,815
Feb	0	314,491	118,341	498,148	0	0	372,892	0	1,303,872
Mar	0	359,290	267,070	498,871	54,312	0	0	0	1,179,543
Apr	0	423,759	159,018	597,398	121,282	0	210,432	319,220	1,831,109
May	0	334,510	239,799	942,906	132,150	0	214,644	359,817	2,223,826
Jun	0	392,482	185,217	718,102	80,552	53,426	241,898	305,746	1,977,423
Jul	0	421,984	262,618	570,100	78,665	57,766	499,576	0	1,890,709
Aug	0	412,483	230,349	822,067	85,528	46,795	229,752	306,734	2,133,708
Sep	0	329,266	232,175	759,557	129,881	0	434,738	0	1,685,617
Oct	0	452,496	65,235	1,005,756	126,311	107,391	483,536	0	2,240,725
Nov	0	352,780	145,506	1,242,782	156,721	0	212,087	334,309	2,444,185
Dec	0	367,355	198,018	809,368	141,732	50,836	452,013	345,776	2,365,098
Total	0	4,471,633	2,328,050	9,238,564	1,194,793	365,324	3,506,664	1,971,602	23,076,630

BCS/vm
7/11/75

Attachment C

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY ADMINISTRATION

In re:	)	Case No.
	)	
NORTHERN ILLINOIS GAS COMPANY	)	(SNG Feedstock Allocation)
Aurora, Illinois	)	

CERTIFICATE OF SERVICE PURSUANT
TO 10 C.F.R. §§205.23 AND 205.33

Pursuant to 10 C.F.R. §§205.23 and 205.33, the undersigned hereby certifies that he has mailed a copy of the Further Supplemental Comments of the Petrochemical Energy Group filed on March 22, 1977 in this proceeding to each of the persons on the attached service list.

Furthermore, by a copy of this certification attached to the comments, each of these persons is notified that comments may be submitted regarding these Further Supplemental Comments within 10 days to Mr. Finn Neilsen, Office of Product Allocation, Specialty Fuels Branch, Federal Energy Administration, Room 6318, 2000 M Street, N.W., Washington, D. C. 20461.

Tucker W. Peterson

Tucker W. Peterson
Baker & Botts
1701 Pennsylvania Avenue, N.W.
Washington, D. C. 20461

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March 22, 1977

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Northern Illinois Gas Company
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Chairman
Illinois Commerce Commission
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Executive Vice President
Purvin & Gertz
2600 One Main Place
Dallas, Texas 75250

Mr. John Doty. President
Illinois LP-Gas Association
P. O. Box 740
Rock Falls, Illinois 61071

Mr. L. R. Billett
Assistant Vice President, Supply
Northern Illinois Gas Company
East-West Tollway at Route 59
Post Office Box 190
Aurora, Illinois 60507

Mr. Robert Cole, Staff Executive
Industry-Government Relations
General Motors Corporation
General Motors Building
3044 West Grand Boulevard
Detroit, Michigan 48202

Northern Illinois Gas Company
P. O. Box 190
Aurora, Illinois 60507
Attn: Mr. George T. Jones

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY ADMINISTRATION

In re:	)	Case No.
	)	
NORTHERN ILLINOIS GAS COMPANY	)	(SNG Feedstock Allocation)
Aurora, Illinois	)	

FURTHER SUPPLEMENTAL COMMENTS
OF THE PETROCHEMICAL ENERGY GROUP

Recognizing the continuing obligation under FEA Regulations (10 C.F.R. §205.9(d)) to provide the Federal Energy Administration in this proceeding with any new or newly discovered information that is relevant to this proceeding, the Petrochemical Energy Group (PEG) respectfully submits the enclosed order of the Federal Power Commission (FPC). As the certificate of service (also enclosed) verifies, the undersigned has served all persons known to be parties to this proceeding and has notified each person of the opportunity to comment on this further supplemental information.

The attached FPC Order (Finding And Order After Statutory Hearing Issuing Certificates Of Public Convenience And Necessity, Granting Petitions To Intervene And Continuing Exemption) establishes beyond question that in the midst of one of the worst winters on record, and in spite of the claims of drastic curtailments of natural gas supplies to high priority users, NI-Gas is deferring delivery of 160 MMcf per day of natural gas during the winter (12 Bcf aggregate for period December - March) for redelivery to NI-Gas during the summer to serve low priority customers.

The volumes of natural gas which NI-Gas has consented to reschedule equals the total design output of NI-Gas' SNG plant and shows conclusively that NI-Gas does not require SNG to serve high priority customers even during the winter heating season. Moreover, the FPC order shows that NI-Gas will be paid more than $1.00 per Mcf for consenting to this rescheduling. The net result of NI-Gas' "arrangement" therefore, undisclosed by NI-Gas in any of its prior submissions to the FEA, would appear to be that (1) SNG costing $3.00-3.50 is being produced and sold to NI-Gas' high priority customers, while (2) natural gas costing much less is being rescheduled to serve low-priority customers, and while (3) NI-Gas alone appears to benefit at the expense

of its customers. There is nothing to indicate that the $1.00 rescheduling charge is being passed on to NI-Gas' customers, or that NI-Gas could not satisfy its high priority customers' requirements with cheaper alternatives than SNG.

Indeed, it can be noted that NI-Gas regularly participates in the weekly meetings of the Emergency Gas Requirements Group under Emergency Natural Gas Act Administrator Dunham. On March 9, 1977, the Group met to discuss the provisions of Order No. 6. In Order No. 6, Administrator Dunham stated that until April 30, 1977, the term "emergency supplies" permitted to be purchased under Section 6 of the Emergency Natural Gas Act of 1977 will be defined as gas necessary to enable the purchaser to serve uses other than those specified in Priorities 4 through 9 of the FPC Order No. 467, i.e., boiler fuel, and industrial uses with alternate fuel capabilities. Therefore, no pipeline or distributor, such as NI-Gas, may contract to purchase emergency supplies under Section 6 if, contemporaneously with execution of the contract, the pipeline or distributor is delivering, directly or indirectly, any gas for Priority 4 through 9 uses. NI-Gas at the meeting urged the lifting of these restrictions apparently because it had acquired additional supplies of gas through SNG, which permitted them to make lower category sales. See Transcript, Emergency Gas Requirements Group, Conference held March 9, 1977, pp. 223-224.

With this additional proof, we call upon FEA to deny NI-Gas' feedstock allocation request in total. There can no longer be any doubt that while existing nonsubstitutable, high priority users of propane, butane and other liquid hydrocarbons are being denied allocations by the FEA, NI-Gas has been granted massive allocations, as a new, nonhistorical, low priority user, so that it can serve boiler fuel customers with alternate fuel capability and can provide service to new customers. This is directly contrary to sound public policy and to FEA regulations, both as to NI-Gas' existing SNG plant and its proposed new SNG plant.

Respectfully submitted,

BAKER & BOTTS

By Tucker W. Peterson

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Attorneys for
PETROCHEMICAL ENERGY GROUP

March 22, 1977

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

JURISDICTION: SECTION 1(c)

Before Commissioners: Richard L. Dunham, Chairman;
John H. Holloman III, and James G. Watt.

Northern Natural Gas Company	)	Docket No. CP76-355
Natural Gas Pipeline Company of America	)	Docket No. CP76-390
Northern Illinois Gas Company	)	Docket No. G-10632

FINDINGS AND ORDER AFTER STATUTORY HEARING ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY, GRANTING PETITIONS TO INTERVENE, AND CONTINUING EXEMPTION

(Issued March 1, 1977)

On April 29, 1976, Northern Natural Gas Company (Northern) filed in Docket No. CP76-355 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing a rescheduling of gas deliveries to Northern Illinois Gas Company (NI-Gas) under existing contract demand entitlements, the delivery of natural gas to Natural Gas Pipeline Company of America (Natural) for transportation and exchange to effectuate the rescheduling of NI-Gas deliveries, and the construction and operation of metering facilities in Mills County, Iowa, to receive gas from Natural as part of the rescheduling arrangement. On June 10, 1976, Natural filed in Docket No. CP76-390 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the transportation and exchange of natural gas over its existing facilities in order to implement Northern's rescheduling arrangements. On June 18, 1976, NI-Gas filed in Docket No. G-10632 a petition for a Commission declaration continuing the exempt status of NI-Gas under Section 1(c) of the Natural Gas Act notwithstanding the implementation of the proposed rescheduling arrangements by Northern. These proposals are more fully set forth in the applications in Docket Nos. CP76-355 and CP76-390 and the petition in Docket No. G-10632.

NI-Gas, a public utility subject to the jurisdiction of the Illinois Commerce Commission, presently purchases 127,250 Mcf of natural gas per day from Northern under Northern's

Rate Schedule PL-1. Under authorization granted in Docket No. CP75-336, Northern is presently in the second year of an existing rescheduling arrangement with NI-Gas. 1/ Northern herein proposes to make certain alterations in its existing rescheduling arrangements so as to increase the amount of gas involved and to use Natural's facilities to aid in the delivery of gas to Northern and the redelivery of gas to NI-Gas.

Northern, with NI-Gas' consent, proposes to amend its existing rescheduling arrangements to provide that, during each of the 1976-77 and 1977-78 heating seasons, Northern may reduce deliveries of gas to NI-Gas by an aggregate volume of 12,000,000 Mcf at a daily rate, as allowed by NI-Gas, of up to 160,000 Mcf. Northern will return an equivalent volume of gas to NI-Gas during the summers of 1977 and 1978. The winter and summer periods are defined in the amended agreement between Northern and NI-Gas dated March 29, 1976, as those periods from October 1 through March 31 and April 1 through September 30, respectively. The amended agreement further specifies that NI-Gas will reduce its takes by up to 3,000,000 Mcf per month during each winter period in the months of December through March at daily rates as determined by NI-Gas in its sole judgement. Northern may request NI-Gas to reduce its takes during October and November, and these volumes would be credited to the reductions NI-Gas would be required to take during December through March.

Northern is currently curtailing deliveries of gas under its current contract demand requirements during the winter heating seasons. Northern estimates that, even with the proposed rescheduling of NI-Gas' volumes which will provide Northern with additional volumes of gas during the winter heating season, it will be deficient by 40,000 Mcf per day in 1976-77 and 101,000 Mcf per day in 1977-78 in meeting its existing contract demand requirements on peak days during the winter period. No new sales or attachment of new customers by Northern are proposed herein.

1/ Order issued September 30, 1975 (54 FPC ____).

In order to accommodate a portion of the proposed rescheduling of deliveries and redeliveries of gas to NI-Gas, Northern has entered into an exchange and transportation agreement dated April 8, 1976, with Natural. Natural in Docket No. CP76-390 proposes to implement this agreement by providing delivery of up to 4,500,000 Mcf of gas during the 1976-77 winter period to Northern at a daily rate not to exceed 160,000 Mcf. Deliveries to NI-Gas by Natural will then be reduced by the volumes delivered to Northern. During the summer period Northern will deliver to Natural for the account of NI-Gas up to 90,000 Mcf per day during April, 145,000 Mcf per day during June and up to 200,000 Mcf per day during the months of June through September. Northern, in its sole discretion, may elect to continue this proposed arrangement with Natural for the period, October 1, 1977, through October 31, 1978. Natural proposes to redeliver gas to NI-Gas in the summer period for the account of Northern through existing facilities and interconnections.

In order to effectuate the exchange and transportation arrangement with Natural, Northern proposes to construct two additional 12-inch meter runs at its existing interconnection with Natural in Mills County, Iowa. Its present meter capacity at such interconnection approximates 95,000 Mcf per day but with the proposed facilities will increase to 200,000 Mcf per day. The estimated cost of these facilities is $134,810 which will be financed from funds on hand and extensive bank loans.

Northern has agreed to pay NI-Gas a monthly charge of $1,020,000 as adjusted to reflect NI-Gas' actual cost of storage service from Natural from the previous year. The existing rescheduling arrangement which began in 1975 is rendered at a monthly charge equivalent to $1.02 per Mcf which reflects NI-Gas' actual cost of storage from Natural during 1974. This method of calculating a rescheduling charge has been continued for the proposed amendment and amounts to $1.32 on an Mcf basis for the first year. This adjusted charge utilizes rates proposed in Natural's rate filing in Docket No. RP74-96 presently in effect subject to refund.

Natural proposes to charge Northern a rate of 12 cents per Mcf for transporting and redelivering gas to NI-Gas during the summer period, with a minumum annual bill of $270,000, which is equivalent to transporting 2,250,000 Mcf of gas over the 335-mile distance to NI-Gas. This rate is based upon cost of service factors, excluding cost of purchased gas and storage operations, underlying Natural's proposed rate components in Docket No. RP75-108.

NI-Gas filed a petition in Docket No. G-10632 requesting a continuing exemption under Section 1(c) of the Natural Gas Act. NI-Gas' operations are conducted solely within the State of Illinois and the rescheduling agreements provide that NI-Gas' participation is contingent on a continued exemption. Similar arrangements with Northern and NI-Gas have been on-going for several years; 2/ however, the existing arrangements involve the payment of money to NI-Gas for the first time. We believe that the benefits to Northern from this proposal are significant in this period of gas shortages and for that reason will approve the instant proposal. We are concerned though with the ever-increasing permanence of these purportedly extra-ordinary temporary arrangements and the increasing involvement of NI-Gas in the sale of services in interstate commerce. Accordingly, the Commission will examine any future rescheduling arrangements of the instant type.

Since the instant proposals involve only a minor amount of new construction and would utilize for the most part existing facilities, the Commission finds that approval of these proposals does not constitute a major Federal action significantly affecting the quality of the human environment.

By letter order of August 17, 1976, a temporary certificate was issued to Northern in Docket No. CP76-355 and NI-Gas' exemption was continued on a temporary basis pending final action on its petition.

2/ Order issued November 26, 1975, in Docket No. CP76-40, et al. (54 FPC ____).

After due notice by publication in the Federal Register of the proposals by Northern in Docket No. CP76-355 on May 13, 1976 (41 FR 19771), by Natural in Docket No. CP76-390 on June 23, 1976 (41 FR 26612), and by NI-Gas in Docket No. G-10632 on July 19, 1976 (41 FR 29759), petitions to intervene in one or more of the subject dockets were filed by NI-Gas, Wisconsin Gas Company, the Brick People, et al., Iowa Public Service Company and North Central Public Service Companies, Inc. (NCPS). 3/ All allege that they have a direct interest in these arrangements among Natural, NI-Gas, and Northern; however, the Brick People are the only interveners who specifically raise an issue. In their petition, the Brick People state their objection to the rescheduling proposal to the extent that the arrangements might allow Northern's distributor customers to add new residential, commercial and small industrial customers. The Brick People are not opposed to the rescheduling arrangements to protect existing high priority markets of Northern but raise the question whether the distributor customers of Northern should be allowed to attach new loads as a result of additional gas. The Brick People request that a condition be attached to any authorization in the instant proceeding which would prohibit any of the gas from being used by a distributor to serve new customers. Both NI-Gas and Northern filed responses to the Brick People's request, protesting that the Brick People's request is without merit and should be rejected. This issue has been raised in a prior curtailment proceeding. 4/ The issue is so broad that the Commission believes the problem of growth is more appropriately handled in Northern's curtailment case where the persons affected by such issue are parties to such proceeding and the record necessary for decisional purposes is better developed. Northern's permanent curtailment plan is currently subject to an evidentiary hearing where such an issue can be explored and developed. In view of the limited term of the instant proposals and the pendency of Northern's curtailment case in Docket No. RP76-52, et al., the Commission will deny the Brick Peoples's request but without prejudice to such issue's being raised in Northern's curtailment proceeding in Docket No.

3/ Untimely petition.

4/ Southern Natural Gas Company, Docket Nos. RP74-6 and RP72-74, Opinion No. 747-B issued May 21, 1976 (55 FPC ____).

RP76-52, et al. No further petitions to intervene, notices of intervention, or protests to the granting of the applications and petitions have been filed.

At a hearing held on December 15, 1976, the Commission on its own motion received and made a part of the record in this proceeding all evidence, including the applications, petition and exhibits thereto, submitted in support of the authorizations sought herein, and upon consideration of the record,

The Commission finds:

(1) Northern Natural Gas Company, a Delaware corporation having its principal place of business in Omaha, Nebraska, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of April 6, 1943, in Docket No. G-280 (3 FPC 967); and Natural Gas Pipeline Company of America, a Delaware corporation having its principal place of business in Chicago, Illinois, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of October 13, 1942, in Docket No. G-235 (3 FPC 830).

(2) The services and facilities hereinbefore described, as more fully set forth in the applications in Docket Nos. CP76-355 and CP76-390, involve the transportation of natural gas in interstate commerce subject to the jurisdiction of the Commission and the performance of such services and the construction and operation of facilities therefor are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Northern and Natural are able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The proposed construction and operation of facilities and exchange and transportation of natural gas by Northern and Natural are required by the public convenience and necessity and certificates therefor should be issued as hereinafter ordered and conditioned.

(5) In view of the present temporary nature of NI-Gas' proposed operations with regard to the subject rescheduling arrangements and Northern's need for supplies of gas during the winter heating season, the petition for a continued exemption from the provisions of the Natural Gas Act pursuant to Section 1(c) thereof and the Regulations of the Commission pertaining thereto should be granted for the limited purposes herein proposed.

(6) Good cause exists for accepting the late petition of NCPS to intervene filed in this proceeding and participation by all interveners may be in the public interest.

The Commission orders:

(A) Certificates of public convenience and necessity are issued to Northern Natural Gas Company and Natural Gas Pipeline Company of America in Docket Nos. CP76-355 and CP76-390, respectively, authorizing the construction and operation of facilities and the transportation and exchange of natural gas in interstate commerce to implement the rescheduling of deliveries to NI-Gas, as hereinbefore described and as more fully described in the applications in these proceedings, upon the terms and conditions of this order.

(B) The certificates issued by paragraph (A) above and the rights granted thereunder are conditioned upon Northern's and Natural's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (c)(3), (c)(4), (e) and (f) of Section 157.20 and in Part 154 of such Regulations.

(C) The transportation, exchange and facilities authorized herein shall be abandoned upon termination of the rescheduling arrangements at the close of the 1977 summer delivery season.

(D) The transportation rate proposed by Natural for the services to be rendered to Northern is approved conditioned upon the outcome of the proceeding pending in Docket No. RP75-108 and any charges collected above and beyond the rate finally established by the cost components in the proceeding in Docket No. RP75-108 shall be refunded pursuant to the regulations of the Commission concerning refunds.

92-911 O - 77 - 69

(E) The proposed payment by Northern of charges to NI-Gas for the instant rescheduling of gas deliveries is approved conditioned upon the outcome of the proceeding pending in Docket Nos. RP74-96 and RP75-108 and any charges collected above and beyond the rates finally established by the cost components in such proceedings shall be refunded pursuant to the regulations of the Commission concerning refunds.

(F) The petition by NI-Gas in Docket No. G-10632 for a declaration of continuing exemption from the provisions of the Natural Gas Act and orders, rules and regulations of the Commission is granted; however, future arrangements of similar nature may require authorization under the Natural Gas Act.

(G) The authorization granted herein is without prejudice to the development of the Brick People's concerns, as hereinbefore described and as more fully described in their petition to intervene, in Northern Natural Gas Company's permanent curtailment proceeding in Docket No. RP76-52, et al.

(H) The petitioners to intervene are permitted to intervene in the proceedings in which they filed petitions, subject to the rules and regulations of the Commission; Provided, however, that participation of such interveners shall be limited to matters affecting asserted rights and interests as specifically set forth in the petitions to intervene; and Provided, further, that the admission of such interveners shall not be construed as recognition by the Commission that they might be aggrieved because of any order of the Commission entered in these proceedings.

By the Commission.
(SEAL)

Kenneth F. Plumb,
Secretary.

HOWARD M. METZENBAUM
OHIO

Attachment D

United States Senate

WASHINGTON, D.C. 20510

February 8, 1977

The Honorable Richard L. Dunham
Chairman
Federal Power Commission
825 North Capitol Street
Washington, D. C. 20426

Dear Mr. Chairman:

The natural gas crisis and the resulting present curtailments of these supplies to Ohio industries and schools have prompted my writing to request that the Federal Power Commission initiate an investigation into recent actions taken by the Columbia Gas Transmission Corporation.

On January 11, 1977, Columbia Transmission received approval from the FPC to enter into the intrastate gas market to purchase deficit supplies for delivery to its distribution customers. The purchase price of these emergency supplies will cost approximately two to four times the price of interstate gas customarily purchased by Columbia. Before permitting Columbia Transmission to pass these extra costs on to consumers, I believe that the FPC should carefully investigate the circumstances which necessitated these emergency measures.

It is my understanding that on September 27, 1976, Columbia Transmission notified its wholesale customers that the October curtailment plan, amounting to 21.2 bcf., was being cancelled. Columbia Transmission has since indicated that this decision was based upon its opinion that it had a surplus of gas reserves in storage on October 1, 1976, and upon a forecast for a mild winter similar to the past two seasons. As a result of the decision to lift curtailment, Columbia Transmission sold an excess 20.7 bcf. of gas reserves that could have been stored for the winter heating season. Much of this gas was sold to industrial users which had ready access to alternative fuel sources. By reason of this sale, and a pre-existing shortfall in their reserves as of November 1, 1976, Columbia Transmission was approximately 24 bcf. below the shortage level considered necessary to begin the peak winter season.

The direct impact of Columbia Transmission's imprudent decision is being presently felt by Columbia Gas of Ohio

which in late January announced that Ohio industries and schools must close their doors to conserve scarce gas supplies. These closings are expected to continue until relief is obtained from the severe colder temperatures. In addition to these closings, Columbia Gas of Ohio has announced strict curtailment plans for the remainder of the winter season which could affect thousands of Ohio industries.

I have serious doubts as to the wisdom of Columbia Transmission's decision to sell off substantial shortage reserves prior to the peak winter season. In my mind, these acts, at the very least, constitute poor business judgment, the effects of which should not be paid for by the consumer. I, therefore, urge that the FPC exercise its authority pursuant to section 5 of the Natural Gas Act and issue an order to Columbia Transmission to show cause why it should not be prohibited by the FPC from passing on to the consumers the additional costs incurred by reason of its own errors in judgment.

Warm regards,

Howard M. Metzenbaum
United States Senator

HMM/kw/je

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Senator Howard Metzenbaum, Complainant	)	
v.	)	Docket No. RP77-35
Columbia Gas Transmission Corporation, Defendant	)	

NOTICE OF COMPLAINT

(February 17, 1977)

Take notice that on February 11, 1977, Senator Howard M. Metzenbaum (Complainant), United States Senate, Washington, D.C. 20510, filed in Docket No. RP77-35 a complaint pursuant to Section 1.6 of the Commission's Rules of Practice and Procedure (18 CFR 1.6) and Section 5 of the Natural Gas Act requesting the Commission to issue an order directing Columbia Gas Transmission Corporation (Columbia) to show cause why it should not be prohibited from passing on to the consumers additional costs incurred by reason of its own errors in judgment, all as more fully set forth in the complaint on file with the Commission and open to public inspection.

It is stated that on September 27, 1976, Columbia notified its wholesale customers that its October curtailment plan, amounting to 21,200,000 Mcf, was being cancelled, based on Columbia's opinion that it had a surplus of gas reserves in storage on October 1, 1976, and upon a forecast for a mild winter. Complainant states that as a result of the decision to lift curtailment, Columbia sold an excess 20,700,000 Mcf of gas reserves and that much of such gas was sold to industrial users which had ready access to alternative fuel sources. Complainant further states that by reason of this sale, and a pre-existing shortfall in its reserves as of November 1, 1976, Columbia was approximately 24,000,000 Mcf below the shortage level considered necessary to begin the peak winter season.

Complainant asserts that the impact of Columbia's actions stated above is being felt by Columbia Gas of Ohio (Columbia Gas) which announced in late January that Ohio industries and schools must close in order to conserve scarce gas supplies,

which closings are expected to continue until temperatures moderate. Columbia Gas, it is further asserted, has announced strict curtailment plans for the remainder of the winter season which could affect thousands of Ohio industries.

It is stated that on January 11, 1977, Columbia received approval from the Commission to enter into the intrastate gas market to purchase deficit supplies for delivery to its distribution customers at a cost of approximately two to four times the price of interstate gas customarily purchased. Complainant states that he has serious doubts as to the wisdom of Columbia's decision to sell off substantial shortage reserves prior to the peak winter season, and maintains that these acts, at the very least, constitute poor business judgment, the effects of which should not be paid for by the consumers. Complainant, therefore, proposes that the Commission issue an order to Columbia to show cause why it should not be prohibited from passing on to the consumers such additional costs.

Any person desiring to be heard or to make any protest with reference to said complain should on or before February 28, 1977, file with the Federal Power Commission, Washington, D.C. 20426, a petition to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 1.8 or 1.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a petition to intervene in accordance with the Commission's Rules.

Kenneth F. Plumb
Secretary

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Before Commissioners: Richard L. Dunham, Chairman;
Don S. Smith, John H. Holloman III,
and James G. Watt.

Senator Howard Metzenbaum, Complainant	)	
v.	)	Docket No. RP77-35
Columbia Gas Transmission Corporation Defendant	)	

ORDER INSTITUTING INVESTIGATION AND HEARING
PRESCRIBING PROCEDURES, AND GRANTING INTERVENTIONS

(Issued March 31, 1977)

On February 11, 1977, United States Senator Howard M. Metzenbaum filed a letter requesting that this Commission order Columbia Gas Transmission Corporation (Columbia) to show cause why it should be permitted to pass on to its customers the additional cost incurred by reason of Columbia's alleged errors in judgment resulting in purchases of expensive emergency gas supplies during the past winter. Senator Metzenbaum's letter was treated as a complaint by the Commission and was immediately forwarded by the Commission's Secretary to Columbia for response within 15 days. Columbia's response in the form of an affadavit by William H. Howard, Senior Vice President, was filed with the Commission on February 28, 1977

Public notice of the complaint was issued by the Commission on February 17, 1977, providing for protests or petitions to intervene to be filed on or before February 28, 1977. Timely petitions to intervene have been filed by the Columbia Gas Distribution Companies and the Consumer Federation of America. Untimely petitions to intervene have been filed by The Cincinnati Gas & Electric Company and The Union Light, Heat and Power Company; the State of Louisiana; the Public Utilities Commission of Ohio; the Ohio

Public Interest Research Group; Ohioans for Utility Reform, Inc.; Ohio State UAW-CAP Council; Pennsylvania Gas and Water Company; the Division of Consumer Counsel of the Office of the Attorney General of Virginia; the Commonwealth of Virginia; Congressman Don J. Pease, and Congressman Thomas A. Luken. The above-named petitioners have demonstrated an interest in this proceeding and their participation is in the public interest. The petitions to intervene shall accordingly be granted.

In his complaint, Senator Metzenbaum requests the Commission to investigate actions by Columbia which allegedly constitute poor business judgment and which necessitated the purchase by Columbia of additional expensive emergency supplies during the past winter. Specifically, the complaint alleges that Columbia cancelled its October system-wide curtailment of 21.2 Bcf, based on its opinion that there would be a surplus of gas in storage as of October 1, 1976, and upon its forecast of mild winter weather, and also that cancellation of October curtailment resulted in excess sales of 20.7 Bcf during October to industrial users with alternate fuel sources. The complaint further states that by reason of these excess sales, and a pre-existing shortfall in reserves as of November 1, 1976, Columbia began the peak winter season with a shortage in storage inventory of approximately 24 Bcf. The complaint further alleges that these actions caused Columbia Gas of Ohio, Inc., a distributor affiliate of Columbia, to close schools and industries in Ohio in January 1977, and to announce increased curtailment levels for the remainder of the winter. Therefore, Senator Metzenbaum urges the Commission to require Columbia to show cause why it should be permitted to flow through to its customers the additional costs incurred through its own alleged errors in judgment.

In its response of February 28, 1977, Columbia argues that its actions during the past winter were prudent and consistent with the public interest. Columbia states that it did temporarily suspend curtailments from September 27, 1976, through the end of October, 1976, but that its actions were justified under the circumstances. In September, according to Columbia, its storage fields were being filled

ahead of schedule. Purchases and production in the Appalachian area had been reduced to the minimum practical level, and the schedule of deliveries from its affiliate, Columbia Gulf Transmission Company, had been adjusted. Due to depressed market demands and physical limitations on the ability of storage fields to absorb additional injections, Columbia states that it was forced to cutback on takes from its pipeline suppliers commencing September 20, 1976, and that it suspended curtailment to avoid further irreparable loss of available flowing gas supply.

Columbia denies that suspension of curtailment resulted in excess sales of 20.7 Bcf during October. Data submitted by Columbia allegedly show that its customers' takes during the disputed period " . . .were actually less than they would have been entitled to under the normal operation of Columbia's curtailment plan . . .". Columbia further states that the volume taken by its customers during October, 96,349 MMcf, while considerably above the volume anticipated, was still below their aggregate entitlement under the curtailment plan. Also, Columbia asserts that its storage deficiency as of November 1, 1976, resulted from unusual volumes of high priority sales due to unanticipated cold weather during October, and not from poor business judgment in suspending curtailment.

Based upon a review of the record in this proceeding, including the complaint and the response of Columbia, the Commission finds that the issues raised in the complaint cannot be finally resolved based solely on the present pleadings and the representations of the parties. The Commission finds that a formal hearing should be held for the purpose of investigating all relevant issues pertaining to the allegations set forth in the complaint, and that all parties, including the Commission staff, should have the opportunity to present evidence in support of their recommendations following investigation. The Commission's final decision will be based upon the hearing record. Columbia shall provide all necessary data for purposes of the present investigation and hearing.

In setting this matter for hearing, the Commission intends to review available remedies under the Natural Gas Act. Should the ultimate outcome warrant, we will apply those that are appropriate in the circumstances. The Commission's jurisdiction over Columbia's general rate filings and purchase gas cost adjustments provides full protection to Columbia's customers and ultimate cosumers. Columbia's current general rate increase was filed in Docket No. RP76-95, on April 29, 1976. By order issued May 28, 1976, the Commission suspended that rate increase for five months and permitted it to become effective on November 1, 1976, subject to later refund with interest if so ordered. Columbia's current PGA rate increase, filed on January 29, 1977, was accepted and permitted to become effective on March 1, 1977, by letter order of March 1, 1977. This filing reflects changes in Columbia's current costs of purchased gas based upon the prices to be paid as of March 1, 1977, imposed upon volumes for the twelve months ending October 31, 1976. The filing also provides for recovery through a surcharge of any additional amounts credited to Columbia's deferred account through December 31, 1976. Any other increases in purchased gas costs, including costs incurred through additional or continuing emergency purchases, are credited to the deferred account and cannot be collected until a new PGA filing is made and considered by the Commission.

The Commission finds:

It is necessary and proper in the public interest and in carrying out the provisions of the Natural Gas Act that a hearing be held for the purpose of investigating the allegations set forth in the complaint of February 11, 1977.

The Commission orders:

(A) Pursuant to the authority of the Natural Gas Act, particularly sections 4, 5, 7, 8, 14, 15, and 16 thereof, and the Commission's rules and regulations, a hearing shall be held in this proceeding for the purpose of investigating and determining the allegations contained in Senator Metzenbaum's complaint of February 11, 1977, against Columbia.

(B) Columiba's response to the complaint filed on February 28, 1977, shall be incorporated as a part of the record of this proceeding.

(C) A Presiding Administrative Law Judge, to be designated by the Chief Administrative Law Judge pursuant to 18 CFR 3.5(d), shall convene a prehearing conference in this proceeding on April 11, 1977, at 10:00 a.m., EST, in a hearing room of the Federal Power Commission, 825 North Capitol Street, NE, Washington, D.C. 20426, for the purposes of establishing procedures for the investigation and hearing to be held pursuant to this order. The Presiding Judge shall be authorized to modify all procedural dates and to establish further procedures as may in his judgment be required for purposes of the investigation and hearing pursuant to this order. The Presiding Judge shall also be authorized to rule upon all motions except motions to consolidate, sever, or dismiss, as provided for in the rules of practice and procedure.

(D) The above-named petitioners are hereby permitted to intervene in this proceeding subject to the rules and regulations of the Federal Power Commission; Provided, however, that participation of such intervenors shall be limited to matters affecting asserted rights and interests as specifically set forth in the petitions to intervene, and, Provided, further, that the admission of such intervenors shall not be construed as recognition by the Commission that it might be aggrieved because of any order or orders of the Federal Power Commission entered in this proceeding.

(E) The Secretary shall cause prompt publication of this order in the Federal Register.

By the Commission.

(S E A L)

Kenneth F. Plumb,
Secretary.

FILED
OFFICE OF THE SECRETARY
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FEDERAL POWER COMMISSION

February 25, 1977

SENATOR HOWARD METZENBAUM v.
COLUMBIA GAS TRANSMISSION CORPORATION
DOCKET NO. RP77-35

AFFIDAVIT OF W. H. HOWARD
ON BEHALF OF
COLUMBIA GAS TRANSMISSION CORPORATION

My name is William H. Howard, and I am Senior Vice President of Columbia Gas Transmission Corporation. The purpose of this affidavit is to answer allegations contained in the February 8, 1977, letter of Senator Howard M. Metzenbaum to Chairman Dunham concerning Columbia's alleged "imprudent decision" of temporarily suspending curtailment on its system from September 27, 1976, through the end of its summer season, the impact of such decision upon Ohio schools and industries, and his call for an investigation as to whether Columbia should be allowed to recover the price of certain emergency supplies purchased by Columbia for its customers.

On September 27, 1976, Columbia temporarily suspended curtailments to its customers until the end of the 1976 summer season, i.e., October 31. The several circumstances existing at the time were determinative of Columbia's decision to suspend curtailments and therefore must be thoroughly reviewed.

On the first of September, Columbia was well ahead of schedule in filling its storage fields to the top capacity of 590 Bcf. The schedule for September 1 was 546 Bcf, while the actual volume in storage was 557 Bcf. The increasing difficulty of injecting gas into storage fields late in the injection season as the pressure builds up is an operating fact confronted every fall. During September, Columbia was already taking its purchases and production in the Appalachian area at the minimum practicable level, and it had adjusted the schedule of deliveries from its affiliate, Columbia Gulf Transmission Company, in order to enhance to the maximum extent Columbia's continued ability to receive all available supplies and to inject gas into storage over the remainder of the summer season. Columbia Gulf's system was line packed on weekends, when market requirements are reduced, with greater deliveries being scheduled on Monday through Friday. This helped to maintain maximum rates of storage injection.

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As the month of September progressed, Columbia encountered increasing difficulties in its ability to utilize available levels of deliveries from its suppliers. In fact, due to depressed market demands and the physical inability of Columbia's storage fields to absorb additional injections, Columbia was forced to cut back its takes from its Southwest pipeline suppliers by approximately 95,000 Mcf per day from September 20 through September 27, 1976, the day that its curtailments were suspended. Some of these supplies were permanently lost to Columbia and its customers because they could not be made up before October 31.

Columbia concluded that it would be poor business practice and not in the best interests of its customers to continue curtailments while cutting back on available flowing gas supply, especially when such cutbacks of gas could not be husbanded for future use. Such a course of action would be untenable. Therefore, suspension of curtailment seemed both necessary and appropriate. Before so doing, however, Columbia canvassed its customers to determine how much additional gas they might purchase if curtailments were suspended. This action was essential to determine what exposure, if any, a suspension of curtailment would have on Columbia's ability to reach maximum volume on or before November 1, 1976.

Columbia operates under a seasonal curtailment plan under which customers have specified authorized volumes for the summer season (April-October). In the middle of September, we had determined where our customers were, and where we anticipated they would be, with respect to taking such authorized volumes. At that time, the vast majority of our major customers had taken deliveries either less than or equal to their authorized volumes for the first five months of the summer season. By September 27, 1976, the customers' aggregate deliveries were less than their authorized volumes for the period April-September, 1976, by approximately 9 Bcf. Only two customers--Baltimore Gas and Electric Company (Baltimore) and Commonwealth Natural Gas Corporation (Commonwealth)--indicated that they would be able to make additional sales if curtailments were suspended, and they estimated such additional sales at only approximately 1 to 1.3 Bcf.

As we evaluated the situation at that time, the added sales which would result from a suspension of curtailment could not be large and certainly not nearly sufficient to offset the cutbacks we knew would be required in Columbia's

purchases from its pipeline suppliers. As it turned out, despite the coldest October in history in Columbia's service area, Baltimore and Commonwealth actually only took additional volumes totaling 1.4 Bcf over what they would have been entitled to take if Columbia had not suspended curtailment.

Sen. Metzenbaum's letter alleges that Columbia sold an excess of 20.7 Bcf as a result of its decision to suspend curtailments during the month of October. However, an examination of Exhibit No. ___ (WHH-1) reveals that Columbia's customers' overall takes during that period were actually less than they would have been entitled to under the normal operation of Columbia's curtailment plan, assuming no suspension of curtailment. This exhibit compares the customers' entitlements assuming no suspension of curtailment with their actual purchases during that period.

As previously noted, Columbia operates under a seasonal curtailment plan. At the end of September, the amount of gas available to its customers for the remainder of the 1976 summer season consisted of three components: (1) their authorized volumes for the month of October; (2) any of their authorized volumes not taken during the months April through September, 1976; and (3) a 2% seasonal overrun which is permitted under the curtailment plan, which totals 8.8 Bcf for all customers. Adding these three components, Columbia's customers were entitled to take 97,366 MMcf during the month of October, assuming that Columbia's curtailment had remained in effect. In fact, Columbia's customers only took 96,349 MMcf during October. While this volume is considerably above the amount that Columbia anticipated that its customers would take during October, it was still below the aggregate amount to which they would have been entitled to take had curtailment not been suspended. Therefore, there is absolutely no factual basis to support Sen. Metzenbaum's assertion that Columbia's decision to suspend curtailments resulted in its selling an excess 20.7 Bcf of gas during October. Instead, the greater than anticipated deliveries were within the seasonally authorized volumes, which were necessary to serve high priority heating markets which resulted solely from the extreme record-breaking cold weather experienced in October, as I will describe below. Overall, Columbia's customers would have been entitled to all the gas actually delivered in October, even if curtailments had not been suspended.

Columbia's gas sendout and storage projections, which historically have been based on normal weather, continued on schedule, despite colder than normal weather during the first part of October. On October 10, Columbia had 587.4 Bcf in storage, which is only 2.8 Bcf (or 0.47%) below total storage capacity, or essentially full. However, the weather turned severely cold throughout Columbia's service area, and during the last 16 days of October, Columbia experienced an overall degree day deficiency (DDD) of 376, which was 179 DDD's or 91% colder than normal during this period. The winter period really started on October 16 rather than the nominal or planned November 1, and overall the month of October was 215 DDD's colder than normal. Columbia's temperature sendout studies indicate that an additional 97.6 MMcf is delivered for each DDD. Thus, of Columbia's overall storage deficiency of approximately 25 Bcf experienced on November 1, 1976, some 21 Bcf (97.6 MMcf x 215) was attributable to the colder than normal weather experienced during October. Thus, Columbia's storage deficiency as of November 1 resulted from unusual volumes of high priority sales due to the cold weather, and not from any poor business judgment in suspending curtailment.

By the middle of November, Columbia was still experiencing weather which was considerably colder than normal, and with a 30 day forecast of colder than normal weather, it was decided that protective action should be taken to bolster our storage position in order to protect the high priority users during the latter part of the winter. Thus, on November 17, 1976, Mr. Richard A. Rosan, Executive Vice President and General Counsel for the Columbia Gas System, wrote a letter to Mr. Drexel D. Journey, the Commission's General Counsel, describing Columbia's storage and curtailment situation, and requesting an opinion as to Columbia's ability to make emergency purchases of gas pursuant to Section 2.68 of the Commission's rules. Mr. Journey responded the following day with a letter which included this statement:

> ". . . it is my opinion that current and foreseeable conditions on the Columbia Gas system warrant the use of Section 2.68 of the Commission's Statement of General Policy and Interpretations for the acquisition of emergency gas supplies."

Thus, whatever "approval" was given to Columbia to enter the intrastate gas market to purchase deficit supplies was

given on November 18, 1976, rather than January 11, 1977, as alleged by Sen. Metzenbaum's letter.

Mr. Rosan's letter stated that Columbia intended to buy approximately 20 Bcf of gas on the best terms available pursuant to Section 2.68 of the Commission's rules. While Columbia originally lined up approximately that amount of emergency supplies, all of these arrangements were on a best efforts basis. Due to cold weather experienced in the Southwest and Midwest over the past three months, these emergency suppliers have had difficulties in meeting their own market requirements, and thus have only been able to deliver approximately 7 Bcf of the 20 Bcf originally committed to Columbia.

Columbia has been fortunate in procuring other emergency supplies from Canada, Algeria, Alaska, the West Coast and intrastate markets, pursuant to the Natural Gas Act and the Emergency Natural Gas Act of 1977, during the past 40 days. However, such volumes were purchased in order to alleviate the emergency created by the extremely cold weather throughout the Columbia service area over the entire winter to date, especially January, and do not in any way relate to our October experience. Illustrative of this are the facts set forth in my testimony presented in Columbia's Docket No. CP77-126 presented before the Commission in the latter part of January, 1977. At that time Columbia had already withdrawn 172 Bcf of the 211 Bcf scheduled from storage over the entire winter, leaving only 39 Bcf of storage turnover remaining. Thus, on January 23, 1977, Columbia's volume in storage was 89 Bcf below schedule. Our posture on January 23 was such that the volume remaining in storage of 393 Bcf was at the level we would expect to occur on or about March 15, under normal conditions. Furthermore, considering the takes by our customers to that time and the remaining volumes available to them out of their winter season entitlements, it was projected that even with normal weather conditions during February and March, our customers would be over 8 Bcf deficient in meeting their Priority 1 requirements.

Sen. Metzenbaum alleges that the direct impact of Columbia's decision to temporarily suspend curtailment in late September is presently being felt by Ohio industries and schools which have been shut down because of a lack of gas. I wish to point out that Columbia's Form 16, filed with this Commission on September 30, and prepared during the summer, showed a total delivery to its customers during the 1976-77 winter season of 632 Bcf, including 211 Bcf

rage. Columbia now plans to supply 646 Bcf to its s during the present winter season. Thus, notwith- its October experience and initial storage defi- Columbia will be able to provide its wholesale rs with even more than the anticipated seasonal of gas as reflected in its September 30, 1976,

lumbia has no control over how its customers sche- eir deliveries to consumers or how its customers e the gas they receive from Columbia. If these rs, such as Columbia Gas of Ohio, Inc. or Dayton Light Company, or any other customers, do not have ent seasonal gas remaining for industrial and school t is because the unusual cold weather has increased tial and other essential Priority 1 requirements to ent that there is insufficient gas left for industry ools. During the month of November, Columbia ex- ed 876 DDD's (or 35%) colder than normal weather in vice area. During December, our DDD's were 1178) colder than normal, and in January our DDD's were r 42%) colder than normal. These past November and were the coldest ever experienced on Columbia's . December was the fifth coldest in the past thirty and was only a few DDD's short of being the third . Columbia also notes that industries and schools s adjacent to Columbia's service area have also osed for lack of gas. Thus, there is no basis for tzenbaum's charge that Columbia's suspension of ment for a brief period this fall in any way con- i to the present shortage of gas to industries and in Ohio. This shortage was created by the cold --pure and simple.

also wish to take strong issue with the suggestion . Metzenbaum's letter that Columbia should not be ed to recover the purchase costs of certain of its y supplies during this winter. As I have described the extremely cold weather experienced in Columbia's area throughout this winter placed the pipeline and tomers in a dire situation. Columbia has taken inary efforts in order to secure additional emer- ppliers for its system to alleviate the natural gas y in Ohio and elsewhere on its system. Without rgency deliveries, it is entirely possible that the severe weather experienced during the period, 28-30 service of essential Priority 1 consumers ave been severely jeopardized. There is no issue ing Columbia's managerial judgment involved during

the crisis of this winter, which was caused by unprecedented weather and the resulting demands of four million Priority 1 consumers served by Columbia, a substantial portion of which are located in Ohio.

In conclusion, Columbia was faced with a situation in late September of 1976, where it could not in good conscience continue to curtail deliveries to its customers while cutting back upon gas takes from its pipeline suppliers which could never be regained. Under the curtailment provisions in Columbia's FPC Gas Tariff, and also as required by its public service obligations, Columbia has a duty to supply its customers all available volumes of gas up to their authorized entitlements, and under no circumstances should curtailments be imposed while irretrievable cutbacks of available supplies by Columbia are being experienced. If the 1976-77 winter had turned out to be normal or warmer than normal, Columbia might have expected criticism for not making as much gas as was available to avoid unemployment. We would be subject to an accounting before this Commission and perhaps even censure if we had curtailed our customers unnecessarily. Columbia's decision was prudent and fully consistent with the public interest when viewed in the context of our total supply situation and the authorized seasonal volumes of its customers in late September, 1976.

Respectfully submitted,

William H. Howard

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COMMISSION

February 25, 1977

SENATOR HOWARD METZENBAUM v.
COLUMBIA GAS TRANSMISSION CORPORATION
DOCKET NO. RP77-35

AFFIDAVIT OF W. H. HOWARD
ON BEHALF OF
COLUMBIA GAS TRANSMISSION CORPORATION

My name is William H. Howard, and I am Senior Vice President of Columbia Gas Transmission Corporation. The purpose of this affidavit is to answer allegations contained in the February 8, 1977, letter of Senator Howard M. Metzenbaum to Chairman Dunham concerning Columbia's alleged "imprudent decision" of temporarily suspending curtailment on its system from September 27, 1976, through the end of its summer season, the impact of such decision upon Ohio schools and industries, and his call for an investigation as to whether Columbia should be allowed to recover the price of certain emergency supplies purchased by Columbia for its customers.

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Attachment E

Calendar No. 863

94TH CONGRESS
2D SESSION

S. 3422

[Report No. 94-907]

IN THE SENATE OF THE UNITED STATES

MAY 12, 1976

Mr. PEARSON (for himself, Mr. BELLMON, Mr. BROOKE, Mr. FANNIN, Mr. HOLLINGS, Mr. INOUYE, Mr. MAGNUSON, Mr. STEVENS, and Mr. STEVENSON) introduced the following bill; which was read twice and referred to the Committee on Commerce

MAY 19, 1976

Reported by Mr. MAGNUSON, with amendments

[Omit the part struck through and insert the part printed in italic]

A BILL

To regulate commerce to assure increased supplies of natural gas at reasonable prices for consumers, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled, That this Act may be cited as the "Natural Gas Act Amendments of 1976".

SEC. 2. The Natural Gas Act (15 U.S.C. 717 et seq.) is amended by (1) striking out section 24 thereof (15 U.S.C. 717w); and (2) amending section 1 thereof by redesignating subsections (a), (b), and (c) as subsections (b), (c), and (d), respectively, and inserting therein the following new subsection:

"(a) This Act may be cited as the 'Natural Gas Act'."

"COMMISSION JURISDICTION OVER SYNTHETIC NATURAL GAS

"SEC. 27. The provisions of this Act shall apply to any plant *(except to any proposed plant that proposes to use, in whole or in part, crude oil, residual fuel oil, refined petroleum products, natural gas liquids or condensate, or natural gas liquid products as a feedstock)* for the manufacture of synthetic natural gas, to any sales or transportation of such synthetic natural gas, and to any person owning or operating such plant: *Provided,* That such jurisdiction shall not, as a result of the operation of this section, include the feedstock of such plant: *Provided further,* That if any such person or predecessor in interest was bona fide engaged in the ~~transportation~~ *production, transportation,* or sale of synthetic natural gas, subject to the jurisdiction of the Commission on the date of enactment of the 1976 Amendments, the Commission shall issue a certificate required under section 7 of this Act without requiring further proof that the public convenience and necessity will be served by such operation, and without further proceedings, if application for such certificate is made to the Commission within 90 days after the date of enactment of the 1976 Amendments. Pending the determination of any such application, the continuance of such operation shall be lawful: *And provided further,* That such

jurisdiction shall not preempt State laws, rules, and regulations regarding natural resource development, conservation, and environmental protection, or any other proper exercise of State police powers.

"NATURAL-GAS CONSERVATION

"SEC. 28. (a) Except as provided in subsections (c) and (e) of this section, the Commission shall by rule prohibit boiler fuel use of natural gas affecting commerce ~~not initially contracted for prior to~~ *supplied pursuant to any delivery arrangement in effect or contract initially executed after* May ~~10,~~ *12*, 1976, unless, upon petition by the user the Commission determines for the subsequent 12 month period that—

"(1) alternative fuels, other than propane, are not available to such user; or

"(2) it is not practicable or feasible to utilize such alternative fuels at the time of such Commission determination.

"(b) Except as provided in subsections (c) and (e) of this section, boiler fuel use of natural gas ~~contracted for~~ *supplied pursuant to any delivery arrangement in effect or contract initially executed* prior to May ~~10,~~ *12*, 1976, for the purpose of generating electricity shall be terminated by the user of such natural gas at the expiration of such con-

Mr. GAMMAGE. I have another question that I have asked of virtually every panel who appeared before this committee.

I intend to ask it of every panel coming down the pike.

On the first day of the hearings before this subcommittee, Dr. Schlesinger, in response to my question regarding the intrastate allocation authority provided for in the new plan stated that they would use it only under dire emergency situations, comparable to what occurred this last winter or worse. I take small comfort in that in view of the fact when we were debating the emergency natural gas bill, and it included an intrastate allocation provision relating to Hinshall gas, that intrastate gas that travels in interstate pipelines, that they did not want the authority and had no intention of ever using the authority and in fact this last winter were never called upon to use it because adequate supplies were made available and in fact in some cases supplies in excess of what the interstate pipeline system could carry were involved.

I would like your response to this.

As I understand it, three States, Texas, Oklahoma and Louisiana, contain a little over two-thirds or approximately two-thirds of the petrochemical industry in this country. I think Texas has some 46 percent standing alone. These are all producing States which for natural reasons have developed a very heavy dependency upon natural gas, both as boiler fuel and as a foodstock.

How does the petrochemical industry respond to the proposed allocation authority?

Mr. DEVINE. May I say Ralph Kienker of Monsanto testified at length on this and I might resubmit for the record his remarks.

Mr. GAMMAGE. I think he was going to provide us with some additional remarks.

Mr. DEVINE. I can provide what he said and I will be pleased to provide it.

[The following statement was received for the record:]

COMMENTS REGARDING: AUTHORITY TO ALLOCATE INTRASTATE GAS UNDER THE EMERGENCY NATURAL GAS ACT OF 1977

BY

RALPH W. KIENKER, ENERGY AFFAIRS DIRECTOR, MONSANTO COMPANY

Gas not dedicated to interstate commerce should not be included in the emergency allocation process under the Emergency Natural Gas Act of (ENGA).

Last winter, when the Emergency Natural Gas Act (ENGA) was passed, it had a provision for voluntary emergency sales which supplemented existing FPC emergency sale regulations. Great cooperation was given the Administration in locating supplies and transferring them to the interstate market from the intrastate market. More emergency gas was available under ENGA than the interstate pipelines could take.[1] Yet, Section 416 of the President's bill eliminates the ENGA voluntary sales provision and, instead, extends mandatory allocation to the very people who voluntarily helped last winter.

Equally telling is that the mandatory allocation provisions of ENGA—those dealing with interstate gas—*were never used.*

Also, it should be recognized that there was more gas burned as electric utility *boiler fuel*[2] between October and December of this winter[3] in the States who are the

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[1] Transcript, Meeting of Emergency Gas Requirements Group (industry and consumer representatives appointed to advise ENGA Administrator Dunham on administration of ENGA) March 30, 1977, pp. 255-256, 261.

[2] We do not mean to single out electric utility boiler fuel for use. It is cited here because data on utility fuel use is collected and published by the Federal Power Commission.

[3] FPC, "Monthly Fuel Cost and Quality Information," April 8, 1977, pp. 16-17.

net importers of gas than the entire amount of emergency gas injected into the interstate system under ENGA through early April of this year.[4] Vast quantities of this gas were sold under interruptible contracts—meaning that alternate fuel capability was installed.

Finally, if distributors and interstate pipelines are led to believe that the federal government will simply confiscate gas supplies from the intrastate market if "needed," then the incentive to husband supplies, to fill storage to capacity, to enforce curtailment priorities, is lessened. If ENGA is extended to the intrastate market, next year there will be many pipelines who will follow a burn now, worry later philosophy. We would recommend that, if ENGA is to be extended at all, the provisions of §6 be extended. This is the best, most productive short-term solution while the objectives of the National Energy Act are being attained.

Mr. GAMMAGE. In response to Mr. Flug's exchange with Mr. Stockman, I would like to address this to Mr. Flug. It is my understanding that some 80 to 85 percent of the exploration and discovery of new reserves at this point in time is conducted by unaffiliated independents either going into joint ventures and development or selling their finds to producers and pipelines. Some 90 percent of the exploration being done now, new holes drilled is being done in areas that have only about 30 percent, of where our new unfound resources are thought to be.

Those in the industry attribute this directly to the fact that in those 30 percent areas the finds are cheaper. They know they are there. The drilling costs are less and what-have-you, and to go into the new frontier areas containing a probable 70 percent of our resources, they are reluctant to go there because of the price factor, because of the additional cost of drilling, when you start talking about going 15,000 feet or deeper, where the cost multiplies geometrically.

Mr. FLUG. With regard to the role of the independents, we emphasize that heavily. That is one of the reasons we supported the Smith amendment last year. We were willing to try deregulating the small independents, to see what that would do, at the same time keeping the large integrated producers under control since they don't need that kind of artificial incentive. The House went along with that. Unfortunately, the Senate was not so minded.

As far as the success ratios are concerned, they vary wildly. I am looking at the Texaco report, which said that on its drilling in 1,491 wells they had a success ratio of 88 percent. I don't know whether they are finding the easy stuff or what.

Mr. GAMMAGE. I think that is the answer, 90 percent of the drilling is in 30 percent of the area.

Mr. FLUG. But I have had people from other large companies say they never drill for gas without finding it. That may mean they are only going in the safe areas, but it also means their return——

Mr. GAMMAGE. The speculation is less and the cost is less. Where is the incentive for them to go and drill that 70 percent that they are not going after?

Mr. FLUG. I think it reflects an inherent problem with companies the size of Texaco and Gulf. I think there is just as much bureaucracy as——

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[4] Statement of Richard L. Dunham, Chairman, Federal Power Commission, before the Subcommittee on Energy and Power, Committee on Interstate and Foreign Commerce, United States House of Representatives, April 5, 1977, p. 3.

Mr. GAMMAGE. Eighty to 85 percent of the total drilling is conducted not by Texaco and Gulf, but by independents?

Mr. FLUG. That is right, and we want them to get a fair return too, Mr. Chairman.

Mr. DINGELL. The Chair observes the time of the gentleman from Texas has expired.

The Chair recognizes counsel for questions.

Mr. DEMAREST. Mr. Hueter, before he left, Mr. Gore requested me to ask a question of you for the record. In your testimony you indicated that gas ovens are used for the baking of bread and that natural gas is absolutely essential for that purpose. Mr. Gore wanted to know why electric ovens were not a feasible alternative.

Mr. HUETER. Today among the wholesale bakers in excess of 90 percent are direct-fired gas ovens. These ovens are very large. They are very expensive, and to replace them in a hurry would be tremendously unfeasible. There are electric ovens. The electric ovens, I am advised, in addition to being more costly than gas-fired ovens, also utilize in excess of 30 percent more energy. It is a less efficient oven. There are only a few electric ovens owned by wholesale bakers in the Nation today. Maybe fewer, three or four or five.

Mr. DEMAREST. You indicated that it was not feasible to convert. You were talking in economic terms, in terms of the cost of conversion, rather than in terms of the practicability of using these electric ovens, I take it?

Mr. HUETER. Well, first of all would be the cost. Second is the time element and third, of course, is the cost of operation thereafter.

Mr. DEMAREST. Thank you very much.

Mr. HUETER. That additional cost, of course, would have to be passed on to the consumer.

Mr. FOLLETTE. I would like to make a statement with regard to fuels in food processing. I think in terms of changing fuels it is not just a question of a technological situation. There has to be an evaluation of the product, not only from the organoleptic side, but from all of the other potential deleterious effects. This is not a short term evaluation. It takes considerable research to know whether an alternate fuel will work in such an instance.

Mr. DINGELL. Gentlemen, I have listened to all your comments with considerable interest. I am not certain how many of you support the bill with or without amendments. Perhaps you might indicate. Do you favor the bill with or without amendments insofar as the natural gas pricing section is concerned?

Mr. FOLLETTE. We favor the elimination of incremental pricing except for boiler fuel. In other words, the high priority use should be for anything other than boiler use.

Mr. FARMER. As far as the entire bill is concerned, Mr. Chairman——

Mr. DINGELL. Specifically the natural gas section.

Mr. FARMER. With regard to the incremental pricing and the natural gas section, as indicated in my remarks earlier, I am trying to understand the purpose of it, against the background of rates based on cost of service.

Mr. DINGELL. There is obviously a difference in rates based upon cost of service.

Mr. FARMER. Conversion or conservation or to give a low price to the consumers. I don't know what the intent of it is. The most likely one is to have the cost at a rate which will encourage conversion to other fuels. I look at it from the viewpoint of the glass industry. We can't use coal.

Mr. DINGELL. I have no quarrel with your comments. Apparently you do not favor part D.

Mr. FARMER. No, sir.

Mr. DEVINE. It would be for you to judge, sir, whether to amend it or to begin again. It is a technical question.

Mr. DINGELL. I am trying to see what kind of consensus we have. You have all expressed reservations. Do you favor the bill with or without amendment, or do you oppose it?

Mr. DEVINE. Amended as we spoke, we would favor it.

Mr.DINGELL. And your comments were directed principally——

Mr. DEVINE. In summary we would say that we would prefer deregulation as to how you price natural gas. We would not encourage the construction of additional SNG plants. If you are going to use incremental pricing at all, we would apply it to boiler fuel but not to feedstocks or process uses.

Mr. DINGELL. Mr. Flug.

Mr. FLUG. I have very mixed feelings on parts of this and very unmixed feelings about others. On the price of natural gas, I have unmixed feelings. I think it is outrageous; the wellhead price.

Mr. DINGELL. That hardly indicates support.

Mr. FLUG. On the idea of, I guess, user taxes, which is directly involved in—although I don't see how you can separate it really from your whole thinking about this—and on the incremental pricing again I have mixed feelings. I am not sure about the demand elasticity. I want to see evidence it will make some difference before I come down hard in favor of it.

On incremental pricing obviously if that is a way of insuring in a sense lifeline rates to the residential user, that is good, but if it is also a way of hiding tremendous inflationary impact on the economy and making the consumer pay indirectly rather than directly, I am not sure that is so good, but at least for the time being I am for incremental pricing.

Mr. HUETER. The bakers' concern is with availability rather than price. Therefore, as I stated, we do not object to incremental pricing providing the baking industry is assured a steady flow of natural gas. This past winter many, many bakeries were shut down because of lack of gas and that is a very costly proposition, both to the consumer and to the company.

Mr. DINGELL. I would like to direct this question to Mr. Flug. Mr. Flug, you criticized $1.75 new gas price and $1.45 for the rollover price on old contracts. Now, could you give us some comment as to which of these prices you regard as creating the greater consumer impact, which you find more objectionable and why?

Mr. FLUG. I tried in my efficiency effort in a chart to separate out what I think the impact to be. I see in the first year both the interstate rollover and the intrastate rollover and the new gas

application, as well as the windfall built into the section all to be in the same order; that is, in the range of $1 billion. Being as conservative as I am, I left the 770 windfall constant across the 10 years although I suspect in some of the early years it will actually rise. The one, of course, that goes up the most is the new gas price. That is the application of the new gas price to increasing amounts of new gas.

Mr. DINGELL. This question is directed to Mr. Devine.

Mr. Devine, you indicated that you, and I suspect other industrial users, support deregulation. On the subject of incremental pricing you have indicated that you have strong reservations. Incremental pricing will constitute no higher price to those who would be getting natural gas under incremental pricing than they would pay if there were total deregulation, and the price might be lower. Can you explain this anomaly to me, please?

Mr. DEVINE. We supported incremental pricing in the context of encouraging us to move to the use of other fuels for generating steam. We opposed it where there was no substitute that was feasible. We have in effect incremental pricing in Texas, which is a free market. We are paying over $2.

Mr. DINGELL. I don't believe you have incremental pricing in Texas, unless you go out and buy your gas directly from a producer. If you buy it on a long-term contract from a pipeline you don't have incremental pricing. If you get your gas in Texas from a pipeline, you get your gas on a contract which sets the price at which the pipeline provides you the gas. You don't get incremental pricing unless your contract specifically so provides.

Mr. DEVINE. All I meant by that was where we are paying a high price for gas, we are moving rapidly in boiler conversion to coal.

Where we are paying a low price for gas, we do not have the incentive to do so.

Mr. DINGELL. We have an anomaly. You favor deregulation on the ground it provides additional supply. I think Mr. Hueter makes the same point.

On the other hand, you indicate strong opposition to incremental pricing where the level would be little different, I suspect, from a price level under deregulation.

Mr. DEVINE. We prefer deregulation. We feel that is a preferred solution to the problem. We feel the market will clear this more effectively than a bureaucracy in trying to sort out all these issues.

Mr. DINGELL. Are you telling me then that you don't object to incremental pricing?

Mr. DEVINE. I am saying that we prefer deregulation. If you choose to use incremental pricing, we feel you should encourage us to go where we can find that fuel. We feel each fuel should carry its share of the mail.

Mr. HUETER. I think I must go back to our original statement. Without gas, regardless of the price, a baker cannot operate and there is no bread on the shelves for the consumers.

Mr. DINGELL. We have no quarrel on this. You favor deregulation but oppose incremental pricing. Incremental pricing provides the blessings that you say exist with deregulation. I am curious how you and Mr. Devine favor the blessings of deregulation which you say

gives more supply, but at the same time you do not favor incremental pricing, which does not impose the higher price on the fellow who might have less ability to meet the cost.

Mr. HUETER. You misunderstand me. I say the bakers have no objection to incremental pricing, providing they are assured of a steady supply and an adequate supply of natural gas for operation.

Mr. FARMER. With deregulation we have calculated about 7.5 to 8 percent of the gas supply would constitute new gas coming in from a deregulated new interstate market. That cost would be rolled into the total cost of gas charged to all consumers on the basis of the actual average cost of gas to that system.

When you are dealing with incremental pricing, you have removed the incentive for exploration and development and getting the new reserves into the system. All you are doing is shifting around the cost within the available gas supply and charging some consumers more for the gas than you are charging other consumers. I view that as a difference between incremental pricing and deregulation of new gas.

Mr. DINGELL. The Chair yields to the gentleman from Texas.

Mr. KRUEGER. Mr. Chairman, it seems to me the difference between incremental pricing and deregulation is that in one instance there is a hope for additional recovery—that is through deregulation—whereas in the other there is not.

Secondly, in incremental pricing although there is a higher price, that price, of course, is borne by one sector of the consumers rather than the others, and so I don't see that there is necessarily any logical inconsistency on your part. However, I thank the Chair for yielding.

Mr. DINGELL. Gentlemen, you have been a very patient panel. You have waited long; you have testified very patiently and been very helpful to the committee. I apologize to you for any inconvenience we have occasioned you and I thank you for your appearance.

If you have any further comments with regard to the substance of the bill, or technical suggestions with regard to the language, which may affect the technical functioning of the bill, the committee will be glad to receive them.

If there is no further business to come before the subcommittee at this time, the subcommittee stands adjourned until 10 o'clock tomorrow morning.

[Whereupon, at 7:40 p.m., the subcommittee adjourned, to reconvene at 10 a.m., Wednesday, May 18.]

NATIONAL ENERGY ACT

WEDNESDAY, MAY 18, 1977

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY AND POWER,
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE,
Washington, D. C.

The subcommitttee met at 10 a.m., pursuant to notice, in room 2322, Rayburn House Office Building, Hon. Richard L. Ottinger presiding, Hon. John D. Dingell, chairman.

Mr. OTTINGER. The Subcommittee on Energy and Power is resuming its hearings on H.R. 6831, the National Energy Act, with particular focus on title I, part D, relating to natural gas.

We have with us today to focus particularly on economic issues raised by the President's proposals on natural gas, a panel consisting of Edward Erickson, Professor of Economics and Business, North Carolina State University; Garry DeLoss, Public Interest Research Group; John W. Wilson, of John W. Wilson and Associates; and S. David Freeman, Energy Policy and Planning Office.

Gentlemen, we are pleased to have you here. Have you agreed on any order of proceeding among yourselves?

We will start with Professor Erickson. We are pleased to have you with us. Why don't you pull over the microphone?

I will include the full statement of each of you in the record and you may proceed either by reading your statement or by summary.

STATEMENTS OF EDWARD W. ERICKSON, PH.D. PROFESSOR OF ECONOMICS AND BUSINESS, NORTH CAROLINA STATE UNIVERSITY, ON BEHALF OF THE NATURAL GAS SUPPLY COMMITTEE; JOHN W. WILSON, JOHN W. WILSON AND ASSOCIATES; GARY DeLOSS, PUBLIC INTEREST RESEARCH GROUP; AND S. DAVID FREEMAN, ENERGY POLICY AND PLANNING OFFICE, EXECUTIVE OFFICE OF THE PRESIDENT

Mr. ERICKSON. My understanding is that what we will do is very short statements and then there will be a question and answer period and a give and take between yourselves and the panel; is that correct?

Mr. OTTINGER. That is correct.

Mr. ERICKSON. Fine, because I think it is in that give and take that we get the most productive kind of activity.

My name is Professor Edward Erickson. I am professor of economics and business at North Carolina State University.

I am here this morning on behalf of the Natural Gas Supply Committee. I think it is important to note for the record that although I am essentially an academician and I conceive my contribution here in that manner, I have been a consultant for the Standard Oil Company of California, for Exxon, for Standard Oil Company of Indiana, and I am a member of the National Petroleum Council.

Also, I would like to include for the record the fact that I am a member of the board of directors of a public interest law firm, Tax Analysts and Advocates, and past chairman of the board of that firm. That firm is engaged in suits against firms, including Standard Oil Company of California, Exxon, Standard Oil Company of Indiana, and others. So that I believe I take a rather balanced point of view towards the whole energy situation.

Now, the summary of the major points that I have with regard to H.R. 6831 is that 6831 is presumably a legislative embodiment of the national energy plan.

From my point of vieww, the national energy plan is—not emphasize, italicize—not a national energy solution. The national energy problem is a result of the cumulative and compound effects of oil and gas price regulation. The national energy plan expects at several places to extend oil and gas price controls. The national energy plan also speaks of avoiding windfall profits for the United States oil and gas industry and of not paying tomorrow's prices for yesterday's discoveries.

With regard to prices, supply and "windfall profits," several points are of interest. These include, first, that the real price United States suppliers receive for old natural gas, adjusted for inflation and the loss of depletion, is now somewhat below what new contract prices were in 1954. That is hardly a windfall profit. The price United States suppliers receive for "old" oil also adjusted for inflation and the loss of depletion, is now almost 25 percent below the 1969 domestic reference price used by the Cabinet Task Force on Oil Import Control. That is hardly a windfall profit.

In terms of real economic incentives, the new gas price, if you are wiling to make a guess as to what the cumbersome price determination process might be in H.R. 6831, it is equivalent to $4.06 per barrel in 1969 dollars adjusted for the loss of depletion. I hardly find that an incentive price.

The extension of natural gas wellhead price regulation to the new gas supplies in the intrastate market is in effect a roll-back of actual prevailing prices and the reasonable price expectations upon which exploration and drilling costs have been incurred. We have in the United States domestic oil and supply situation, an example of a place where a market has worked, where things are going smoothly and have gone well. That is the intrastate market.

My conception of H.R. 6831 is that it cannot stand to see success and it wants to extend the failure of the interstate market to the intrastate market as well.

The extension of natural gas wellhead price regulation to expiring contracts in the intrastate market amounts to a roll-back of intra-

state prices with attendant capital losses and disincentives for new supplies. The "new" gas pricings of H.R. 6831 amount to a roll-back of reasonable expectations concerning prospective FPC new gas price determination, with a consequent inhibition of new supply.

In addition, the restrictive definition of "new" gas eliminates substantial potential supplies. I regard the windfall profit issue as a smoke screen which prevents us from moving on to what would be worthwhile social policy.

H.R. 6831 carries within itself a self-fulfilling prophecy of continued attrition of domestic gas and oil supplies.

I do not advocate tying the price of natural gas to the controlled price of oil, particularly lower tier old oil. In terms of energy supply and demand, consider the price of gasoline as a reference point.

In order for energy prices to reach levels consistent with the price of gasoline in the neighborhood of $1 per gallon— holding taxes, refinery margins and distribution costs constant—it would require across the board—no hanky-panky, phony distinctions of old oil, new oil, oil two and a half miles away, and oil a thousand feet deeper than this or that, but a barrel is a barrel—crude oil prices on the order of $25 to $30 per barrel.

On a straight Btu basis, and this is a conservative measure I am using here, using the 5.8-to-1 rule, this would imply natural gas prices of $4 to $5 per Mcf, or taking the lowest possible bound, or in the neighborhood of $3 per Mcf in the field.

Now I cannot promise you how much gas would be forthcoming at $3 per Mcf in the field, but I am confident there is a potential supply response.

In terms of the value of energy to the American society and the U.S. economy, what it does for us and allows us to do, energy is a good buy at these prices. In addition, there is apt to be considerable domestic supply response at prices between current U.S. controlled levels and higher prices.

In a nutshell, what H.R. 6831 does, as an embodiment of the national energy plan, is say to American consumers, either through mandatory controls or through taxes, we want you to behave as though energy prices were in these ranges, but we do not want to have the supply forthcoming that, if those prices were available to producers, would be available.

The implicit premise of the national energy plan is that it is appropriate to pay these prices for energy prices to foreign suppliers, but not to U.S. producers of oil and gas.

It is correct that about 75 percent of U.S. energy requirements are supplied by oil and gas.

Here is the next step that so many people seem to overlook. Domestic oil and gas are produced by domestic oil and gas companies. If we are going to rely on the kind of system that has made America the kind of society that it is, we have to rely on the oil and gas companies to do the job for us.

The national energy plan is preoccupied with the question of "windfall profits" for U.S. oil and gas companies, even where such "windfalls" do not exist. In order for domestic oil and gas to make their appropriate contribution to the U.S. energy balance, it is necessary for adequate price incentives to exist. H.R. 6831 does not

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contain such incentives. At the very least, a crucial element of a constructive and forward-looking national energy policy is deregulation of the wellhead prices of new natural gas supplies.

Thank you.

[The attachment to Mr. Erickson's prepared statement follows:]

PRICE CALCULATIONS TO

ACCOMPANY THE TESTIMONY OF

PROFESSOR EDWARD W. ERICKSON

I.	Constant dollar old gas price adjusted for the loss of percentage depletion	
	1977 old gas price	29.5¢/MCF
	1954 dollars (29.5 ÷ 2.22)	13.3¢/MCF
	adjustment for loss of percentage depletion	- 1.9¢/MCF
	equivalent old gas price	11.4¢/MCF
	1954 new contract price	10-20¢/MCF
II.	H.R. 6831 new gas price in constant 1969 dollars and adjusted for the loss of percentage depletion	
	1977 H.R. 6831 new gas price	$ 1.48/MCF
	Conversion to constant 1969 dollars ($1.48 ÷ 1.82)	0.81¢/MCF
	adjustment for loss of percentage depletion	-0.10¢/MCF
	equivalent H.R. 6831 new gas price	0.70¢/MCF
	conversion to oil equivalent	x 5.8/MCF/bbl.
	H.R. 6831 new gas "incentive price" in 1969 constant dollar oil equivalent	$ 4.06/bbl.

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III. The price of domestic old oil in constant 1969 dollars adjusted for the loss of percentage depletion

old oil ceiling price	$ 5.25/bbl.
conversion to constant 1969 dollars (5.25 ÷ 1.82)	$ 2.88/bbl.
adjustment for loss of percentage depletion	$ 0.40/bbl.
old oil ceiling price in constant 1969 dollars and adjusted for the loss of percentage depletion	$ 2.48/bbl.
Cabinet Task Force on Oil Support Control 1969 reference price	$ 3.30/bbl.
($2.48 ÷ $3.30) x 100	75%

Notes to the calculations:

Wholesale Price Index (1967=100)

1954	= 87.6	194.3 ÷ 87.6 = 2.22
1969	= 106.5	194.3 ÷106.5 = 1.82
April, 1977	= 194.3	

For a discussion of the depletion allowance and the user cost of capital, see Edward W. Erickson, Stephen W. Millsaps and Robert M. Spann, "Oil Supply and Tax Incentives," Brookings Papers on Economic Activity, 2:1974, pp. 449-478.

Mr. OTTINGER. Thank you very much, Mr. Erickson.
Mr. DeLoss or Mr. Wilson, which of you gentleman want to go?
Mr. Wilson, we will recognize you.

STATEMENT OF JOHN W. WILSON, PH.D.

Mr. WILSON. Mr. Chairman and members of the committee, regulation of the field price of natural gas, as practiced by the Federal Power Commission during the last eight years, has contributed substantially to diminished gas production in major producing areas throughout the United States.

On this point I agree with Erickson. But I think that our agreement essentially stops there because the conclusions and the implications that I draw from this are considerably different than the implications drawn by Erickson. Also, the dual interstate-intrastate standard of price control, that has also contributed substantially to the shortage of natural gas in the United States market, I view that as an ancillary factor in comparison with the impact which the Federal Power Commission's nature of regulation, not regulation itself, but the way it has been implemented by the Federal Power Commission has contributed to the shortage.

I view the elimination of the intrastate-interstate dichotomy as a major positive aspect of the administration's bill. But this does not mean that the fundamental underlying reasons for regulation are invalid.

The problem has been one of inadequate and misdirected regulation and insufficient tools for regulators to work with. To respond to these problems through deregulation as Erickson suggests, whether directly or in de facto form, that is, "regulating" on the basis of commodity value as the administration suggests, is 180 degrees off the mark. The natural gas-producing industry is so thoroughly integrated through joint ventures and partnerships that "free market" pricing is a mirror image of the pricing mechanism in a pure monopoly.

The top 20 firms, which account for over 70 percent of the industry's supply, are tied together with each other, and with many smaller so-called independents, through an all-pervasive and seamless web of joint ventures and partnerships which bind their interests as surely as merger eliminates competitive rivalry.

Firms which have the major portion of their assets committed to joint venture partnerships with their purported market rivals compete only in the sense that Ford competes with Mercury or Kilmer competes with Jurgenson. That may be a fine way to attempt to maximize the profits of the gas-producing "team," but it is simply not an industrial structure which affords any protection to the consumer or which serves the public's overall interest in economic efficiency and in equitable income distribution. That is why deregulation will not work, by whatever name we call it.

By definition, deregulation would lead toward free markets, but that is mere semantics. Freedom in that context would mean little more than the unrestrained ability or freedom of gas producers to collectively extract what the market will bear—the full commodity value—the full monopoly price.

Natural gas supplies today are not restrained by a lack of economic incentive. Rather, although prices already greatly exceed costs, incentives to restrain output have been created by regulatory procedures which have provided for regular and periodic price increases which make it far more profitable to speculate by withholding gas from the market than to profit immediately from its sale.

What sensible businessman would liquidate an investment which is appreciating in value at a compound annual rate of 30 to 50 percent per year? Keep in mind that we are talking about natural gas prices that have gone from 18 cents at the beginning of the 1970s to prices that exceed $2, in some cases $3 at the present time. Yet, this is precisely the regulatory approach that has been imposed on the natural gas-producing market during the last half decade.

Under these circumstances, there is no wonder that new gas supply commitments have declined, with each decline giving rise to new arguments for further price escalation, and each of these, in turn, further reinforcing speculative expectations. I think it is clear already that the recommendations of the administration for $1.75 wellhead prices are simply creating further expectations of that nature. It is not satisfactory to the producing industry, it is not

going to provide the incentive, but it certainly is going to cost consumers.

In absolute terms, incentives are more than adequate. Only insofar as current prices do not reflect the gas-producing industry's full expectation as to the ultimate level at which prices may stabilize, are incentives insufficient.

You have heard that at a minimum that is at a crude oil price of $25 a barrel, or a natural gas price of $4 or more. Incidentally, I have heard figures that are well above that.

Arco has indicated that it expects the price of natural gas to rise to over $6 as a result of the Alaskan LNG imports to the lower 48 States. Inadequate Federal regulation, as it has been practiced thus far in the 1970s, is, in my opinion, the root cause of the speculative fervor which has forced energy prices to rise to unprecedented levels.

Under these circumstances it is, I believe, unreasonable to posture a singular choice between deregulation and a continuation of the misguided regulatory practices of the past. Frankly, semantics aside, I think the administration's plan with regard to natural gas pricing comes pretty close to a deregulation formula. So that is being offered.

Neither solution is desirable and, frankly, if that is the choice there is not much to choose from. Regulatory reform which recognizes the fundamental noncompetitive character inherent in the structure of the natural gas-producing industry is the essential first step.

In contrast to a successful regulatory effort with respect to other industries such as public utilities, regulation of natural gas producers has been a scissors with one blade. The ability to establish prices without the authority to require performance. The Interior Department has had the explicit responsibilty for requiring performance, like the Federal Power Commission, within the context of an unregulated intrastate market and a thoroughly integrated producer cartel, doomed producer regulation under the National Gas Act a failure from the outset. The previous administration simply failed to do its job. Whether the current department is going to do better of not, simply remains unseen at the moment.

The answer now, however, is not to capitulate by turning our back on the problem, but to create better tools and to strive for a better structural environment in which ultimate industry performance may be expected to improve.

Current arguments to the effect that producer incentives have declined; commodity value is a proper regulatory standard; commodity value regulation will protect consumer interests; are simply incorrect within the context of the natural gas producing industry as it is structured.

The price of natural gas has jumped more than tenfold in the last six years. Rather than being an incentive to greater production, production has declined. The reason, of course, is the way in which this tenfold price increase incentive was provided.

In practice, the repeated increases served merely to further encourage additional expectations of almost limitless price increases in the immediately foreseeable future. Producers responded

rationally by waiting. They are still waiting, even though incentives are now at an all-time high, and it seems clear that the proposed legislation will again fail to fully achieve their expectations, thus leading to further waiting. Consequently, there will be a substantial cost to consumers in the form of escalating energy costs, very substantial costs, billions of dollars, but increased production is not a likely result of this any more this time than it was in 1971 when the price went from 18 cents to 26 cents.

As for the commodity value concept, there seems still to be a basic lack of the fundamental realization that a commodity's value is a function of the market in which that commodity is sold. In other words, if a market is monopolized or cartelized, the market value will be the monopoly price. Only if a market is competitive, which the natural gas producing industry clearly is not, will the commodity value be fair and reasonable.

To suggest, as the producers have that consumers will be protected in moving toward a commodity value price ceiling, is identical to saying that consumers will be protected if we move toward a pure monopoly price. The two concepts are identical. That solution is simply wrong, it is even antisocial. But it is the direction in which the petroleum industry would have us move, and the administration's natural gas regulation reforms are leading us.

Thank you.

Mr. DINGELL. Thank you, Doctor.

Mr. DeLoss.

STATEMENT OF GARY DELOSS

Mr. DELOSS. Thank you, Mr. Chairman.

I apologize for the delay in the delivery of my statement. It should be here any time. But in the meantime I have a carbon I can speak from very quickly.

President Carter's gas pricing proposal shares the basic weakness of his energy plan—the rhetoric is not supported by the proposed policies. Specifically, the promise to prevent an inequitable transfer of income from consumers to natural gas producers is contradicted by the choice of OPEC-influenced gas prices which permit windfall profits.

Let us look at some of the rhetoric first. Some of my favorite language in the National Energy Plan reads: "The energy producers . . . should not be allowed to reap large windfall profits as a result of circumstances not associated with either the marketplace or their risk-taking. The fourfold increase in world oil prices in 1973-1974 and the policies of the oil-exporting countries should not be permitted to create unjustified profits for domestic producers at consumers' expense (p. 28)."

And later in the plan, President Carter says, "although producers need incentives for exploration and new development, pricing policies should not give them windfall profits unrelated to their economic contribution. If producers were to receive tomorrow's prices for yesterday's discoveries, there would be inequitable transfer of income from the American people to the oil and gas producers, and producers' profits would be excessive (p. 30)."

And in Dr. Schlesinger's testimony here last week:

"We reject the proposition that unconstrained prices in an alleged free market—where prices are set by foreign producers and supplies are subject to the pressures of unlimited demand—is the only answer to the current problem. Beyond the point at which price increases produce necessary incentives and resources, they produce windfall profits, inflationary pressures, and perhaps even recession—not necessarily more gas."

Needless to say, these words are music to my ears. I have used similar language in testimonies before this subcommittee and in other forums over the past three years. It is gratifying to hear the President and his energy advisers agree that deregulation leads to OPEC, or monopoly, pricing of American energy, not a free market price; and to hear them warn of the macroeconomic consequences of permitting domestic energy producers to charge the OPEC price—inequitable transfer of wealth, inflation, and recession.

Unfortunately, judging from the natural gas pricing structure proposed by President Carter and Dr. Schlesinger, they do not appear to understand that these consequences are not merely prospective dangers. The influence of the OPEC oil price on domestic energy prices has already caused an inequitable transfer of income from consumers to domestic energy producers, and massive inflation, and recession.

Natural gas producers, for example, have received billions of dollars of increased revenues, much of which can fairly be characterized as windfall profits, over the past four years. These revenue increases are displayed in the table below.

Revenue Increases for Natural Gas Producers
(Source: Bureau of Mines)

Year	Marketed Gas Production	Value at Wellhead	Average Value per mcf
1972	22.5 tcf	$4.2 billion	18.6 cents/mcf
1973	22.6	4.9	21.6
1974	21.6	6.6	30.4
1975	20.1	8.9	44.5
1976(est.)	19.9	11.6	58.0

As the table displays, annual revenues to the gas producers have risen from $4.2 billion in 1972 to $4.9 billion in 1973, $6.6 billion in 1974, $8.9 billion in 1975, and $11.6 bilion in 1976.

The Bureau of Mines numbers in that area for 1976 are still in their estimate stage. As the table displays, annual revenues to gas producers have risen by $7.4 billion since 1972, an increase of 176 percent.

Another way to look at the effect of the price increases is that the gas producers have received a total of over $15 billion more over the past four years than they would have received if annual revenues had stayed at their 1972 level. Oil revenues have risen drastically since 1972 as well. Oil producers received $11.7 billion in 1972, $13.1 billion in 1973, $21.5 billion in 1974, $24.5 billion in 1975, and about $25 billion in 1976. Thus annual oil revenues have increased by $13.3 billion since 1972, an increase of 113 percent. These increases in annual revenues mean that the oil producers have received a total of over $37 billion more over the past four years than they would have received if annual revenues had remained at their 1972 level.

In short, OPEC-influenced price increases for domestic oil and gas have caused an income transfer of about $50 billion from consumers to oil and gas producers over the past four years. If coal price increases are added, the total rises by several billion dollars, and the inflationary and recessionary effects of the energy price increases have created further income transfer effects.

Given this recent historical context, several comments about the economic effects on consumers from President Carter's proposed natural gas pricing policy follow.

First, consumer concern about natural gas pricing cannot be bought off by protecting residential gas users from the effects of the $1.75 per Mcf price for new gas through incremental pricing of such gas to industrial users. Consumers will still be injured by the transfer of income, inflation, and recession that could have been avoided by a more just price. Consumers do not want to pay the OPEC monopoly price to domestic producers of natural gas under the guise of regulation.

Second, the unregulated $2 per Mcf price for some intrastate gas sales and the $1.42 per Mcf regulated price for new gas established by the Federal Power Commission last year are not legitimate starting points for choosing a single national regulated price for new gas. Both the $2 price and the $1.42 price are OPEC-influenced prices. Hence any defense of the proposed $1.75 price for new gas as a compromise between these OPEC-inflated prices is unacceptable.

Third, rationalization of the $1.75 price as the Btu equivalency of the average price of domestic oil is unacceptable because that price has been influenced greatly by the OPEC oil price.

Fourth, creation of a single national regulated market for natural gas should not be purchased by bribing gas producers and producing States with monopoly profits from OPEC-influenced gas prices.

Finally, a gas pricing policy that conforms to President Carter's espoused principle of denying windfall profits to producers will begin with the cost-based prices of 56 cents per Mcf recommended by the FPC Office of Economics and 61 cents per Mcf recommended

by the FPC Bureau of Natural Gas in early 1976. With some allowance for inflation over the past year, that means a cost-based price for gas would be about 75 cents per Mcf today.

If the Congress must go beyond a cost-based price to a political price, or "judgmental price" in Dr. Schlesinger's words, in order to gain a majority vote to create a single national regulated market for natural gas, the starting point should be 75 cents, not $1.42, and the chosen price should be defensible as something less than the bribe to gas producers represented by the $1.75 in the Carter plan.

Thank you.

Mr. OTTINGER. Thank you very much, Mr. DeLoss.

Mr. Freeman is here from the White House staff on energy. He was asked to come without a prepared statement, but we thought it would be very useful for him to comment on the attacks on the President's program which come from such diverse directions on this panel. Therefore, we would welcome anything you might have to say.

STATEMENT OF S. DAVID FREEMAN

Mr. FREEMAN. Thank you, Mr. Chairman. I am delighted to be here.

In a sense, we draw some comfort from the attacks from spokesmen for the producers and consumer representatives. There is no price that one can propose for natural gas that would be high enough to satisfy the producer or low enough to satisfy the consumer. So that we have heard this morning tangible evidence of the fact that it is a most difficult issue, and one where complete satisfaction of one's interest and one's deeply felt beliefs, is perhaps not feasible in a democratic government attempting to reach judgments and conclusions and provide, at long last, some certainty. Mr. Wilson, I think, correctly diagnosed as one of the ills of this problem, the great uncertainty about prices; the hope on the part of producers for prices tomorrow that perhaps induce them not to produce today.

We have, in a sense, a cross-roads in history. This issue of natural gas pricing has been the subject of fierce debate, at least since 1954. My own personal opinion is that the pricing system that was in effect in the fifties and in the sixties served the Nation well in those years. But whether one believes that the system was good or bad in the past is relatively unimportant. It served us in another era. We now face a situation where historical costs are really not an accurate gauge of what incentives, and indeed what the costs may be, of discovering the remaining oil and gas resources.

I should like to make a couple of points before we move into general discussion.

One point is that I do not think the balancing of the natural gas supply and demand situation will occur primarily from pricing decisions on the supply side. We have been debating this issue for a number of years. During the last 5 years of the debate the price of natural gas has gone from 25 cents to $1.42 per Mcf, but production has not increased, in fact it has decreased.

It is time I think that the Nation faced up to the geological facts of our natural gas resource. Our plan is addressed primarily to the

demand side, where the greatest opportunity for balancing natural gas supply and demand exists.

Our plan would, in a sense, shift to coal 3 to 4 trillion cubic feet a year of natural gas now being burned in boilers and make that gas available for household consumers and consumers who cannot use other sources of energy.

We will do well with the incentives that we provide or any other incentives that anyone can dream up to find the remaining natural gas at a pace that will match the pace at which existing reservoirs are being depleted. In the seventies, we have had tangible evidence that the resource base does not respond sufficiently to prices to overcome the depletion. It is time to face the reality of the natural gas resource base.

That is not to suggest that in another era, when we move to a level of energy pricing that will bring synthetics and Devonian shale and the tight gas and perhaps the methane in the geopressurized brine, that we will not have sizable additional resources.

In terms of pricing levels which exist today or which would reasonably contain inflation, we deal with a very limited natural gas resource. And the ability to find that resource is contained by legitimate necessary environmental constraints, such as the Secretary of Interior announced yesterday, in terms of a leasing program that will not enable the coastal States to participate and to plan the developments in the coastal zone so that recreation resources, which must last for the ages, can be preserved.

We are dealing with a one-time crop in natural gas, and it will supply a fair share of our needs for the rest of the century. But one of the problems with the debate over pricing and supply is that we have not really looked at the trade-off between the short term and the medium term. We failed to recognize that no matter how high the price, the natural gas resource can only supply a limited share of our needs, and can be found only at a pace that will roughly offset the depletion of existing reservoirs.

Balancing the natural gas budget is going to occur primarily by our efforts on the demand side, by the weatherization program that we have proposed, by the coal-switching program, and by other pressures to put the natural gas that we have to its highest and best use, and to eliminate the large percentage of it that goes out the windows and up the chimneys and burned in boiler fuel. The remaining gas in the ground, hopefully, we will find at a pace that will offset depletion.

In terms of incentives, it is difficult for me to seriously consider arguments that suggest that the $1.75 per Mcf price for new natural gas does not provide generous incentives for the discovery of the remaining resource.

In my opinion, completely and suddenly overnight decontrolling new natural gas is tantamount to decontrolling all of the gas. The natural gas pipelines have a huge appetite for natural gas and the ability to roll the price in with their existing lower-priced old gas. They can afford to pay prices of $5, $6, perhaps even $7 an Mcf. They can pay a price that is high enough, when averaged in with their existing gas, that the total of their gas supply would be equal

to the price of competing fuels. If one advocates sudden, overnight decontrol of new gas, I think one has to be candid and forthright and state that one is willing to accept the consequences of a price so high that it would be tantamount to decontrolling all of the gas.

Our program is a first step toward the deregulation of natural gas. It is a step that will provide all of the incentives needed to bring out the existing resource.

In addition, we will provide special prices in areas where higher incentives appear to be needed. But there is no need to enable producers to obtain tomorrow's prices for resources found yesterday, where the cost and the built-in impact on the economy would be terribly inflationary and where our experience during the 1973-74 embargo showed us that costs tend to shoot up to reach prices.

I think that we therefore are earmarking the increased prices in a way that will result in the discovery of new resources rather than providing additional inflation.

Thank you, Mr. Chairman.

Mr. KRUEGER. Thank you, Mr. Freeman.

There are always time constraints both on us and on you. I wonder whether we might begin, while I await the return of one or two other members, whether we might begin with something like giving each panelist three minutes, which I shall rigidly enforce on you, to comment on some of the testimony of the other panelists.

I suppose we might as well begin in the same order as the panelists themselves have spoken, which would be to begin with Dr. Erickson.

Dr. Erickson, if you would like three minutes to look at some of the comments of any of the other members of the panel, and then we shall go on down the line in the same sequence.

Mr. ERICKSON. I think Dr. Wilson's reference to Sonny Jurgenson as a quarterback for the Washington Redskins is an indication of how in tune he is with the state of competition in the oil and gas industry. It is a highly competitive industry. The joint ventures that exist are part of the vehicle of that competition which permits entry of smaller firms into the offshore activity.

Withholding, I regard that to be essentially hot air; the investigations of withholding have not come up with anything. You cannot make natural gas out of hot air. The sooner we get rid of the withholding argument, the better off we will be.

There is a certain amount of schizophrenia in the administration and in Mr. DeLoss's comments with regard to the OPEC price.

The OPEC price is the current opportunity cost of additional energy consumption to the United States economy. That is a fact of life, we have to learn to live with that. The longer that we try and delude ourselves that that is not the case, the worse it will be.

If the administration is right that the world oil market is getting tighter, that is not a monopoly price. That is the competitive price, or it is moving in the direction of the competitive price for the replacement costs of additional worldwide energy supply. Some people happen to be in a very favorable position and they earn substantial economic rents as a result of those facts of life, Saudi Arabia in particular. Some people are smarter than others, too.

There are some things we can do things about and things we cannot.

Now, with regard to decontrol, and rolling in prices, and what is often referred to as the blip, there are two possible solutions to that.

One is that that only can happen as a result of the extraordinarily inefficient and cumbersome way we price natural gas in regulated public utilities. At the distribution end we could reform that problem.

Another is that I would go along with David and say yes, maybe what we ought to do is deregulate across the board and in a real forward-looking policy would have said we will deregulate across the board, let all United States energy prices, old and new, whatever, become equal to the opportunity costs of additional energy consumption in the United States, but we will impose an excess profits tax on an excise basis with a plow-back provision in it to enable us to increase domestic energy supply capacity.

Thank you.

Mr. KRUEGER. Your three minutes are up.

The next person is Mr. Wilson, three minutes.

Mr. WILSON. Thank you.

I am going to respond to Erickson briefly just by stating that I do not think there is anybody else here that would agree with him that the merger of interests through joint venture, through corporate integration, through acquisition, will promote competition. He and I have been around on this many times. I just do not see it; I do not think the law sees it. The merger between interests, the joining of interests is not something that is going to promote competition.

With regard to Dave Freeman's arguments, as I understand them, he is saying let's not be obsessed with these pricing schemes built into the administration package; what we are trying to do is offer a demand-side plan and the objective is conservation.

The point is, Dave, that price is the tool that you are recommending for the implementation of a conservation program. So it is proper to focus on price; it is not an obsession, it is the subject of your proposal. It is therefore imperative to focus on price and to determine what the objective is that your price is aimed at, and whether the solution is likely to be achieved.

You say that the producers probably will not be satisfied with any price. Well, think of the consequences of that conclusion. Think of the consequence of that conclusion with respect to what the implications are for consumers and what the implications are for natural gas supply.

Think further about your statement that what the administration's plan is is a first step toward total deregulation. What sort of implications do you think that holds for withholding as opposed to moving now?

If I were a producer and a representative of the administration made that announcement to me, I would say, that is a perfect reason not to do anything to change my plan at the immediate time; this is just a first step, I am going to wait until we get there. So I think that the whole idea is just absolutely bankrupt.

With regard to one point that you made I certainly do agree—that is the notion that the deregulation of the price of new gas is

tantamount to total deregulation. That is implicit in the recommendations of the FPC with regard to North Slope pricing of Alaskan gas; they have said, let's price this gas at the incremental value to the pipeline, which would then roll it into ultimate customers. That is where we are getting ideas of $4 and $6 natural gas, which are then going to become the ceiling for natural gas from conventional producing areas.

The whole thing is an unending escalator. We are on it, you are simply taking the next step, the same kinds of policies that were offered to us over the last six years. The results are not going to be any different.

Mr. KRUEGER. Your time has expired.

The Chair recognizes Mr. DeLoss.

Mr. DELOSS. I have basically two points I want to raise with Mr. Erickson.

First, if he does see joint ventures as easing entry into the offshore development market, I wonder if that means that he would restrict joint ventures to the small companies and not permit the major companies to engage in joint ventures.

Two, I think it is possible to defend objections to OPEC pricing of American energy. It seems to me that, generally speaking, the energy market has been an administered market historically for decades. I think it was very interesting to hear Dr. Schlesinger make that kind of description last week because it has been a long time since someone in the executive branch acknowledged the facts of life here.

There has been a worldwide cartel of one variety or another for decades. We have had administered pricing in this country through the regulation of supply, through demand prorationing by the producing States, and through the regulation of imports during the 1960s and I think that Dr. Schlesinger correctly characterized the situation when he said if there is going to be an administered price, better that our government should administer it than a cartel of foreign governments.

Unfortunately, as I note in my testimony, I do not think the administration's price really carries out the logical conclusion that would follow from that rhetoric. I think that the price they have chosen is much too influenced by the OPEC cartel price and that we could do much better.

Mr. KRUEGER. Thank you, Mr. DeLoss.

Mr. Freeman.

Mr. FREEMAN. Ed Erickson and I have disagreed on a number of issues, but I have always admired his forthrightness and candor in expressing his points of view. I think it helps the committee to have people like Ed and the others on the panel who wil speak their minds freely and clearly.

I am glad that he acknowledges that the decontrol of new gas is tantamount to total decontrol and that he really advocates deregulation across the board. The problem with that approach, of course, and it was the approach that was suggested by the past administration, is the enormous, horrible inflation that it imposes on the economy and the ripple effects of that inflation, and indeed the depressing effect on it.

In terms of Mr. Wilson's comments that our plan deals with the price to the consumer as a tool for conservation, that is entirely correct; but we are dealing with the price to the consumer through taxes on the industrial consumer of natural gas.

The point that I was making is not that the price to the producer is unimportant—it is quite important to have the incentives to discover the gas that remains—but that we should not have undue expectations about what is forthcoming, whatever price we decide. In terms of balancing the supply and demand of natural gas, the main help has to come from conservation and conversion to coal.

We have carefully designed our program on natural gas to protect the household consumer and the small user of natural gas who in a sense is stuck with their gas furnace, through the weatherization program and through the rate design features of our proposal to shift the higher cost of natural gas on to industrial consumers.

Now the criticism about creating uncertainty by stating that our program is a first step toward decontrol, that is just not fair criticism. The program is very specific, it lays out precisely what the pricing will be over the foreseeable future and the first step toward deregulation is simply by linking the price of natural gas to the price of oil so that over time—and it will probably be a period of a decade—these commodities have been very, very far apart—they will come together.

Mr. KRUEGER. Thank you.

I thank the panel. The panel is far more gifted at constraining itself than the members of the committee are.

The Chair now recognizes the members in the order in which they appeared in the committee.

The gentleman from Indiana, Mr. Sharp.

Mr. SHARP. It is always helpful when we have a panel which has a consensus. It makes it easier for us in judging some of these questions.

I would like to ask this question, which several have commented on, but I am trying to get a little clearer answer out of each of the panelists.

Mr. Wilson has said to us that the present situation in the bill simply leaves us in a position that it may pay the investor to either wait on his investment to produce or may pay him to go elsewhere. Under the present situation you go to the intrastate market instead of interstate market or you go abroad.

Is that a significant problem with the present? And is it a significant problem with the bill?

Mr. WILSON. That is my position. I think it would be best for Messrs. Freeman and Erickson and DeLoss to comment on it and maybe I will have something to say.

Mr. SHARP. I would appreciate it if you would hold your answer since I am limited in time.

Mr. FREEMAN. I agree with John Wilson. One of the major problems today is the uncertainty over what the price will be. A year ago when the President of the United States was advocating decontrol, I could understand why producers of natural gas would wait. Our program provides certainty of price for the foreseeable future.

Mr. SHARP. Yes, but how about after? It certainly doesn't at the time the price controls are scheduled to go off on oil. We leave all those decisions after 1981 up in the air.

Mr. FREEMAN. Our program includes legislation which we will send up at the appropriate time to extend price controls on oil indefinitely. Our program is to continue price controls on oil and natural gas for the foreseeable future until we have a competitive market in the world so that we do not need price controls. The price of natural gas is fixed by a formula and a person has every incentive to produce and bring their gas to market because there will no longer be any vintaging. The natural gas that they bring to the market will receive the applicable price in each year in the future. So they have absolutely nothing to lose and everything to gain by bringing their gas to market sooner.

Mr. SHARP. Mr. Erickson?

Mr. ERICKSON. Well, I want to comment both on what John said and what David just said.

If David means that price controls are going to go away when there is a break in the world price of oil, that means never. I would be glad to detail my answer to that.

Mr. SHARP. That is all right, I tend to agree with you.

Mr. ERICKSON. Contrary to what David says, I see us with our foot in the door to more vintaging rather than less.

Mr. SHARP. But now the question though is: Do they now wait and not make investments to produce because it is better to wait or better to invest elsewhere and will that be the situation under the program of the President? I am asking you is that a real problem and really, for you, I am asking: Does deregulation solve that problem?

Mr. ERICKSON. Deregulation solves that problem.

Mr. SHARP. Why does it solve the problem?

Mr. ERICKSON. I would have to in all candor say that there probably are some strange timing decisions being made with regard to development of existing properties. However, if you look back to 1973, I spent some time in Baton Rouge pouring through the records of the Louisiana Public Service Commission trying to figure out what the intrastate price was at that time.

Now at that time as far as I could tell from the submissions to various intrastate pipelines for the passthrough cost to their customers, the price was around 60 cents heading towards 85 cents. And it has gone up as you know substantially since then.

Now at that same time I was engaged in doing some econometrics for the Brookings' Panel on Activity with regard to economic incentives. One of the things I discovered, and I don't think we ought to put too much emphasis on econometric results, however, these results are consistent with what we generally know. One of the things I discovered was that it takes about 7 years for 50 percent of the supply response to occur.

Now in the——

Mr. SHARP. So we don't have to worry? I don't understand.

Mr. ERICKSON [continuing]. In the intrastate——

Mr. SHARP. My time is running out.

Is it your judgment that is not a serious problem with the waiting or investing elsewhere?

Mr. ERICKSON. My judgment is it is not a serious problem particularly compared to the alternatives, which are worse.

Mr. KRUEGER. The time of the gentleman from Indiana has expired.

The gentleman from Michigan, Mr. Stockman, is recognized for 5 minutes.

Mr. STOCKMAN. I would like to pursue a point raised that concerns me too. That is your argument that if we would have overnight decontrol of gas, if we did nothing else, we would probably touch off a bidding war on the part of interstate pipeline buyers and other buyers that could drive the price up a high as $6 an Mcf. I think that would be true if we deregulated gas and did nothing else. It seems to me that is the only condition under which your statement is true. But I think in making that assertion or proposition you ignored many other points in your own plan or the Administration's plan which I think would mitigate against that.

No. 1, you are going to have a considerable reduction in demand especially from the intrastate market, because you have a mandatory program for switching boilers and other very large existing boiler fuel users. So some of the demand from the market is going to be reduced.

Second is what the incremental price provides.

Now the argument about this bidding escalation essentially revolves around the fact that the incremental supplies, new gas supplies, are going to be rolled into the existing structure and you will have no demand response on the part of the users because they won't feel the full price. But according to the program that you proposed, you are going to load that extra cost, which would be very considerable if we get up into the range you are talking about, onto those users which are most demand-responsive. So it seems to me that although we have heard a lot of figures about the cost of fuel conversion, using other fuels, they don't seem to be in the range of $5 to $6. That is another thing that would reduce some of the demand in the market. And as a result of these two things, it seems to me that the condition under which your argument would be true really don't hold.

I am wondering whether you would comment on that?

Then you have the incentives and your taxing program and excise tax and so forth in terms of voluntary conversions and you have the new source controls which would mean major new consumers coming on line in the whole program which also would be adding to the demand for natural gas. If you take all those things into consideration, it seems to me you have a somewhat different market condition than that in which your argument would possibly be true.

Mr. FREEMAN. Yes, Mr. Stockman, the points you raised are well worth discussing. As you recall, I said that a sudden and complete deregulation would cause these prices to in a sense "go through the roof." The factors that you mention do not mitigate that. As you will note, our coal conversion program is realistic. It recognizes that it takes several years to draw up the blueprints and order the

equipment to convert a powerplant that now uses natural gas to convert to coal. The taxes on the utilities don't go into effect until 1983. We must begin today an all-out coal conversion program, but we must not delude ourselves into believing that the power plants in the Southwest or in other parts of the country can be converted suddenly. Demand is not going to disappear soon, and that factor will not mitigate the demand.

The other point is the incremental pricing point. We have a considerable cushion of low-priced natural gas for the industrial consumers at the moment. Even if one applies the incremental pricing provisions of our bill, we still have a lot of gas available for industry that will cost 50 cents, 75 cents an Mcf, that can be averaged in, so that the point in rolling in——

Mr. STOCKMAN. Not with the excise tax.

Mr. FREEMAN. But the excise tax itself goes ito effect gradually over a number of years.

Mr. STOCKMAN. The excise tax if I remember right would raise the base costs to $1.05 right now, the beginning of this year.

Mr. FREEMAN. In 1979, and that would be applicable to industrial consumers. But there is a very, very large cushion for absorption of higher prices. If you recognize that the gas that is purchased, the new gas—and this is the point that a number of people who favor decontrol make—would be 5, 6, or 7 percent of the total supply each year. If you just apply some simple arithmetic one can absorb a very, very high price for this new gas for a number of years.

Mr. STOCKMAN. It would be 5, 6, or 7 percent of the total supply available, but not of the total supply available to the demand-sensitive users under incremental pricing. The other thing is these $5, $6, or $7 contracts couldn't possibly be for the normal duration, 10 or 20 years. You might get some spot buying for a very short period of time but it seems to me if you expect the conversion and the conservation program to work no rational buyer would go out and buy $5 for——

Mr. KRUEGER. I am sorry, the time of the gentleman has expired.

I was going to wait until the end of the sentence, but it was a very long sentence.

The Chair now recognizes the gentleman from New Jersey, Mr. Maquire, for 5 minutes.

Mr. MAQUIRE. Thank you, Mr. Chairman.

I was not here when you made your opening comments, gentlemen. I apologize for that. I am interested in some of the statements made by Professor Erickson.

First, Professor, do I take it, having quickly looked through your paper, that you would do nothing about the intrastate market in terms of a national energy policy?

Mr. ERICKSON. Let me say that in principle I agree that the interstate and the intrastate market ought to be merged, but they ought to be merged by turning the interstate market into the same kind of market that the intrastate market is, rather than the other way around, yes.

Mr. MAQUIRE. I thought that was the answer. I just wanted to make sure.

Mr. ERICKSON. And let me pick up on an answer to Mr. Sharp.

The bottom line was——

Mr. MAQUIRE. On my time?

Mr. ERICKSON. I am sorry.

Mr. MAQUIRE. Go ahead.

Mr. ERICKSON. The bottom line of that long involved thing was that while prices were going up substantially in the intrastate market, there was a considerable supply response and that acted to mitigate the price rise in the intrastate market and in fact caused some backing off in prices there and that is what I would expect.

Mr. MAQUIRE. Mr. Freeman, some industrial and utility gas and oil users, particularly in the Northeast where we have serious air pollution problems, will be exempted from coal conversion orders for environmental reasons.

Isn't it unfair to tax them under those circumstances for continued oil and gas use?

Mr. FREEMAN. I don't think so, Mr. Maquire. The taxing provisions on natural gas are designed to encourage both conservation and conversion. The language that industrial people tend to speak in is dollars. If the price of natural gas goes up, they will have much sharper incentives to make additional investments to use less of the gas in their factories even though they do not switch.

They will also have the incentive——

Mr. MAQUIRE. Wait a minute. If you don't switch to coal, how do you use less gas?

Mr. FREEMAN. There are various technologies, waste heat recuperators. I can't go through all.

Mr. MAQUIRE. You are saying a list of conservation measures.

Mr. FREEMAN. Yes, conservation measures that are not economical at today's prices would be economical at the tax prices.

Mr. MAQUIRE. You are not concerned about the disparity between the tax that is going to be paid by someone who can't switch to coal, and the tax that is not going to be paid by someone who can switch to coal, as a result of the administration's environmental policies, which I believe are very desirable, but if you are looking for a national, unified policy, I wonder if this would make sense.

Mr. FREEMAN. I believe that it does. We do not concede that these industries that could not convert to raw coal would not have a coal-based option to convert to. Low Btu coal gasification, and other technologies may enable them to have coal energy in a gaseous form if their plants require that. The message that we are trying to send is that by the mid and late 1980s the natural gas and oil resources will be so scarce and so expensive and so necessary for other uses that one needs to have all segments of industry make preparations to use less and to move to a coal-based source. We believe that putting the tax on the industrial users of natural gas while protecting the homeowner who cannot make these switches, is the most equitable policy.

Mr. MAQUIRE. Mr. Wilson and Mr. DeLoss, have you had an opportunity to look at some of the calculations that are attached to Professor Erickson's testimony in terms of the "real price" that U.S. suppliers receive for old natural gas, and do you have any comments on those calculations, if you have had a chance to review them?

Mr. WILSON. I have just looked at them very briefly, and have not had a chance to go over them in any great detail, but clearly they are based upon the assumptions that Erickson makes and the starting points that he uses, and by making those assumptions carefully and choosing the starting points with care, a preordained result can be obtained, but I would be glad to take a look at them in detail and submit some comments for you if you would like.

Mr. MAQUIRE. Which diverges from the facts as you understand them.

Mr. WILSON. Not diverges from the facts specified, but diverges from the facts evolved if one started from a different beginning point.

Mr. MAQUIRE. Could Mr. DeLoss respond to that as well, Mr. Chairman, or not?

Mr. KRUEGER. Briefly. I am trying to be very evenhanded.

Mr. DELOSS. Basically this choice of number here reminds me of a study that was done and much popularized around the Congress about 2 years ago called the Nathan Study on Oil Pricing which indicated that oil was so costly to produce that every producer in the country that was finding new oil was producing it at a loss, and I recall seeing an oil company spokesman quoted in Fortune magazine subsequently, I believe, saying "Oh, well, these guys like to have a little fun once in a while with numbers," and I think that you can do that very easily with numbers in this area. That is why in my own testimony I chose to look at the gross revenues, and how they have increased over recent years, because I think it is very difficult to disguise what is happening when you look at that number.

Mr. ERICKSON. That is not fun with numbers. 1954 was when the *Phillips* decision occurred. 1977 is now. The wholesale price index is what it is. And 29.5 cents is the old gas price and that is it.

Mr. KRUEGER. You may have your chance in the future.

At this time the Chair recognizes the gentleman from Texas, Mr. Gammage, for 5 minutes.

Mr. GAMMAGE. Mr. Chairman, I was not here for the original testimony, so at this time I would like to yield up my time to Mr. Stockman.

Mr. KRUEGER. The gentleman from Michigan has 4 minutes and 45 seconds.

Mr. STOCKMAN. Thank you.

Mr. Freeman, I am very curious about some of the numbers within the energy plan, particularly as they relate to natural gas. In your projections you indicate that natural gas production without the plan would be about 16.4 trillion cubic feet in 1985, and with the plan you would have 17.6 trillion cubic feet. I am wondering what that is based on, in light of the fact that—this is table IX on page 96. I am wondering what that was based on, the elasticity assumptions and so forth in light of the fact that the FEA's 1977 energy outlook suggests the following: That with the continuation of the current regulatory system we would have 16.6 trillion cubic feet of production in 1985, which corresponds completely with your figure for without plan, but that under a deregulation program, we could get production up to 21 trillion cubic feet, substantially

higher, almost 6 trillion cubic feet, and 4 trillion cubic feet above what would come even from the limited incentives in your plan.

It seems to me that what you are talking about, No. 1, is 4 trillion cubic feet of gas that is potential energy supply that we are going to forgo, and that if we assume the demands, underlying demands, in the economy remain, that is going to have to come primarily out of, a), imported oil which certainly I don't think is consistent with the Administration's plan or, b), out of coal, and even with the best pollution control and emissions control devices we have today, that is going to mean a lot more sulfur in the air. It is going to mean a lot of extra costs to the economy and to consumers, because the cost of converting Btu's out of coal with all the add-ons and associated expenses are certainly much higher than they are for natural gas.

I am wondering if you would comment on that, and give me some indication of how you rationalize those projections because I think they came out of the same computer.

Mr. FREEMAN. Yes, Mr. Stockman. As the record no doubt already reveals, I am not an economist, and I am——

Mr. STOCKMAN. Are you a geologist?

Mr. FREEMAN. No, I am a lawyer with an engineering background, and I don't purport to have complete knowledge of what went into the FEA computer models. Certainly not in the past, and not completely in the last few months. I will comment on your question in this way. Our judgment is that the pricing formula approach that we have will approximate a maximum production. It is not just the $1.75 per Mcf price. One has to put great weight on the special pricing provisions where we have identified that all drilling below 15,000 feet——

Mr. STOCKMAN. But presumably that is included in your model—

Mr. FREEMAN. Yes.

Mr. STOCKMAN. [continuing]. because you made these predictions for 1985 under conditions stated in the plan.

Mr. FREEMAN. I am not familiar with an estimate that suggests that there may be 4 trillion cubic feet more. I think a similar question was perhaps put to Dr. Schlesinger, and we are going to provide an answer for the record, and I can only give you that. If I could just make this comment, I have listened to and observed numerous model studies of gas supply. I think if one goes back and checks out the various estimates, Paul MacAvoy has made a number of them, and a number of other people, we will find that there is a considerable margin of error in those estimates in the past.

Mr. STOCKMAN. Let me just say this. I understand that you can't answer the question, but the point is we have heard from a number of people yesterday, and we have two economists here today who are very concerned about the impact on the consumer.

Now the fact is that if you forgo this natural gas, say, at $2 or $3, or whatever the market price would turn out to be, you are going to be asking consumers to pay $4, $5, and $6 equivalence for imported LNG, for synthetic gas, or for converted coal, and we are concerned about the total cost to the economy, and the cost of producing the energy supplies that we need in order to keep the economy growing and so forth.

It seems to me, that your plan is very anticonsumer when we get down to it, when we look at the alternative, which would be the higher cost synthetics, and so forth.

Mr. FREEMAN. Our position is that our plan will achieve maximum production.

Mr. KRUEGER. The time of the gentleman from Texas who has been yielded to by the gentleman from Michigan has expired.

The Chair now recognizes himself for 5 minutes.

Mr. Freeman, I was planning actually to pose this question to our next panel, which is specifically concerned with environmental questions, but I think since you are the only administration witness today, that I would like to pose a problem to you, because in my judgment, the proposal which the President presented and the discussion that I have had with represenatives from what may be the Department of Energy have not in any way recognized realistically the environmental tradeoffs involved in the policy that has been proposed, and I am going to give a brief statement and then ask your comment on it, Mr. Freeman.

Mr. FREEMAN. Yes, sir.

Mr. KRUEGER. One of the largely unnoticed aspects of natural gas deregulation debate I think has been environmental consequences of using substitutes for gas. Natural gas is the one fuel that can be produced, transported and burned without serious damage to the environment, whereas any substitute is far more environmentally destructive. These substitutes are, of course, principally coal and nuclear.

Natural gas may displace these fuels directly if it is burned in electric utility boilers, or indirectly if it is burning coal relieving the need for electrical generation. The natural gas wells can be drilled with so little environmental damage that they are virtually unnoticed, and there is a friend of mine who made a statement many years ago that the way to produce the most contented cows was to have them rub their backs up against an oil derrick. I think that there might have been some truth in that.

In any case, cattle certainly do graze very near to gas wells and sometimes they graze profitably there.

Once natural gas is produced it can be transported to a point probably more easily, given our existing transportation system, than almost anything else that we have. Clearly we have rail problems. Clearly we will have some harsh debate over the transportation of coal by slurry pipeline, particularly from people who need that water as they see it for agricultural purposes.

Now nuclear fuel obviously also poses some problems in transportation, so I want just to quantify some of the potential advantages from increased production of natural gas.

It obviously is flexible enough to be used either as a fuel for a utility burner or in the home. If we consider just one area of emissions, that is sulfur dioxide, if through increased incentives we were to add 1.5 trillion cubic feet of additional natural gas, which would be only about 7 percent of what we used this year if we could adjust 1.5 trillion, then that gas would displace enough coal, according to the research my staff has done, to prevent the introduction of 800 million pounds of SO_2 into the air. This is true even if the coal is burned in a boiler equipped with the best sulfur removal technology available.

Now 800 million pounds of additional SO_2 is a fairly substantial amount.

I think that what this means is that while I think that the price for natural gas is important I think incentives are important, I think the principles are important, but I also think that there are enviromental tradeoffs, and I think that without looking at some of those tradeoffs, we are really shortsighting the American consumer, and I have taken a bit over 3 minutes, but I wonder whether you would comment on that, because I personally found absolutely nothing in the President's proposal, and have had nothing in my discussions with people in the Department of Energy, that really recognizes these tradeoffs.

Mr. FREEMAN. Mr. Krueger, I agree with you. As a matter of fact, my own independent research on the subject back in 1974 led me to the conclusion in a book that I authored that onshore natural gas is by far our most environmentally benign source of energy. It has almost no environmental drawbacks, and compared to almost any other source of energy, except perhaps for solar energy, one has major environmental advantages. Even offshore in areas where we know we can drill such as in the Gulf of Mexico, the natural gas resource, in terms of a large source of current energy, is our No. 1 candidate from an environmental point of view. So that I think your point is extremely well taken.

We feel that our program is deigned to achieve the maximum production of natural gas for the foreseeable future. The point of the special pricing provisions is that it is not necessary to provide a $2.5 or $3 price for all the natural gas in order to achieve incentives for the gas that is deep down. If one examines the incremental cost of pricing all the gas high enough to achieve that last 5 or 10 percent, one finds that that last 5 or 10 percent is going to cost a whole lot more than imported energy. We do make a distinction between the $1.75 and the other more costly sources of gas which will have to command a much higher price which we will provide as an incentive and achieve full production.

Mr. KRUEGER. Thank you very much for your answer.

We are due to have another panel in 10 minutes. I think the appropriate thing perhaps to do would be to recognize Mr. Sharp for 2 minutes if you have any additional questions, and Mr. Stockman for 2, and then we will try to recognize staff.

Mr. SHARP. Let me ask very quickly, Mr. Freeman, and maybe the other two would like to comment on this.

The presumption is that we are going to make gas available for residential use as a higher priority, and I think the implication is that they will be protected in terms of price, not that the price won't go up, but that somehow it won't go up as fast as the industrial.

My question is if in fact the other half of the program is successful, that is to try to get the utilities, boiler fuel users and everything off of the gas lines as possible, which I understand will take a couple of years, won't the unit costs first of all go up to pay for the pipeline and the distribution system for the residential at a faster rate than at present?

Secondly, won't the incremental costs which the residential is protected from for a couple of years, as that goes on to the business, suddenly come on in a big way to the residential user, and so aren't we perhaps putting the residential user in a position where he appears to be protected for 1, 2, or 3 years, and then suddenly is going to find gas prices going up rather dramatically?

Mr. WILSON. Could I comment on that?

Mr. KRUEGER. I request that the comment be restricted to 45 seconds.

Mr. WILSON. The residential users protection is elusive because he pays the price that the industrial user ultimately charges for the product that is going to be made with the higher cost fuel.

Mr. DELOSS. Could I comment? The essence of my testimony is that consumers are concerned about the macroeconomic impacts, not just the pocketbook impacts on their residential utility bills, and we should be concerned about income transfer, inflation and recession. The economic impact statement that the White House put out on their plan does not even comment on what the natural gas pricing provisions will do in the way of economic impacts, and they should be required to focus on that, and focus on them very thoroughly.

Mr. FREEMAN. Could I answer the question that was put to me, Mr. Chairman.

Mr. KRUEGER. I am sorry, I don't know it was put to you.

Yes, I am sorry, there were 6 seconds left.

Mr. FREEMAN. The price of natural gas to the household consumer is going to go up, but we are going to ameliorate that glide path, so that there will be no problem of entrapment as you suggest. It will just be a question of the prices going up more slowly than they otherwise would. As for industrial products, at least the household consumer can either buy them or not buy them. As for his gas bill, he has got to pay it.

Mr. KRUEGER. Thank you.

The gentleman from Michigan, Mr. Stockman, is recognized for 2 minutes.

Mr. STOCKMAN. Mr. Freeman, I hate to go back to the point, but the fact is that your projections show an 8 percent increase in production with your general Btu related cap and then your special pricing provisions for the deep and remote and so forth, an 8 percent increase over the base case which assumes currently regulatory policy. I am not convinced at all that that is the maximum additional production that we can get in light of other estimates that have been made using different supply elasticities, using the same supply elasticities but different policy. That is No. 1.

Second, what I understand about your special pricing provision is that it is going to have very little impact for this reason: When you are talking about deep production, 15,000 feet or below, you are talking about a $10 million cost for drilling. You are talking about a much lower probability rate in terms of finds. You are talking about much greater uncertainty as to the geologic formations you are going to find. They drilled a number of wells that produced rather vigorously for a couple of months and then just dried up, so the risk factor is very large.

What I understand is that if there is no certainty ahead of time as to what the range of the price might be for that risk exploration, very little of it is going to go on. The procedure set up in your bill as a case-by-case determination by the FPC, as far as I can read it, or whoever will be delegated that authority, it seems to me that the higher the risk, and you would agree with me I am sure that when you get into deep drilling and other remote sources the risk factors go up, the greater the certainty you need before you take the risk as far as price, but your special pricing provisions will move in just the opposite directions and leave producers with great uncertainty as to what price they are going to be able to receive for the higher risk gas that they are going to find.

Mr. FREEMAN. Your questions are very good and they help us bring out points.

I hope you are right. I would be inclined myself to think that we may achieve greater production than our plan suggests. We tried to be conservative in what we hoped to achieve. There has been an awful lot of overpromising on the natural gas issue and we picked the lowest number we thought we could achieve. But our program is designed to maximum production.

As for the special pricing if we did it the way you suggested you would be correct. But our intention is to announce in advance a much higher price.

Mr. STOCKMAN. Can you indicate what that might be? Do you have any idea?

Mr. FREEMAN. We haven't looked at that. That would be done by the administrator in charge but certainly the price would have to be announced in advance, and it would have to be considerably higher than $1.75 for the deep drilling. And with that system it seems to me that we could get the drilling and get the gas.

Mr. KRUEGER. At this time I would ask the panel whether they would be willing, while members go to cast their vote on the school lunch program, a consumer issue, to respond to questions from the staff. I would ask that 5 minutes be given initially to Mr. Schroeder, and then 5 minutes be given to minority counsel, and then probably at the end of that time we will have some members back who will be glad to claim some time for themselves.

Mr. SCHROEDER. Thank you, Mr. Chairman.

I want to get into what has been raised a couple of times, the macroeconomic aspects of the natural gas pricing issue.

Would all of you, if you would care to respond, agree that as a general principle if higher prices were to be offered for natural gas, and if those higher prices were to produce a substantial increase in the supply of natural gas, arguably that supply increase would displace crude oil imports, so that at least the potential exists that a substantial increase in natural gas discoveries would lower our net energy bill, thereby providing a net benefit to consumers and to the economy as a whole?

Mr. ERICKSON. That is precisely correct, and because of the importance of the United States in the world oil market it would also have a restraining effect upon the world price of oil. That was one of the problems with David's answer. He was confusing cost to the economy with cost to consumers. Any amount of money that we

pay for imported oil is a net loss to the economy, whereas if we paid higher prices for natural gas to domestic natural gas producers that is an international economic transfer.

Mr. FREEMAN. Certainly the major thrust of our program is to reduce oil imports, for a number of reasons. As a noneconomist, I would like to ask Mr. Erickson if he is really testifying that there is zero return of the money for imports. Certainly there is a considerable recycling of those funds, I would not want to get on the other side of that argument, but I am sure he would not want the record to indicate that he felt that there was no recycling of funds.

Mr. ERICKSON. That is correct.

Mr. WILSON. I think there is a very heroic assumption in the question that you ask. The assumptiom is that there is a substantial price elasticity of supply. Mr. Stockman got into this with some of the other witnesses earlier.

The evidence is not there. People like Erickson, people like MacAvoy, people like Erickson's co-author, Bob Spann, have written articles on econometric research over the period of the last 5 or 6 years. If you go back and look at what is projected by these people in 1972, 1973, 1974, you will see that if only the price of natural gas would go to 45 cents or 50 cents by 1978 or 1979 we will have twice as much gas as we require in this country.

Now that is absurd, but that is the kind of number juggling, econometric modeling, that has been done that has created the confusion that exists in the minds of some of these policymakers, that if only we increase the price of natural gas, we will increase supplies sufficiently enough to meet our needs for eliminating the environmental degradation that is associated with coal or enough to preclude the need for high cost energy imports.

In fact it isn't true. Gas prices have gone up by a multiple of 10 in 6 years. Where is the supply elasticity? It is not there.

Mr. SCHROEDER. Perhaps in order to afford Mr. DeLoss an opportunity to answer the previous question, I could redefine it because I think that he could provide a useful comment.

Would you agree that the issue related to the macroeconomic benefit or cost of higher natural gas prices really pivots on the question of whether there is a supply response? If you assume that there is a significant supply response, then the potential exists for net economic benefit? If, on the other hand, you assume there will be no significant supply response, then the result of higher prices is much more inflationary, paying more for the same amount of a commodity. Therefore it would represent a net economic loss or cost?

Mr. WILSON. I think you are right on the money except you don't have to make an assumption. You have got empirical evidence, and you have got a situation here in which it is acknowledged that this is a first step. We are told that it is a significant first step, and that somehow, because of a moratorium announcement or something like that, we can expect producers to respond this time. We have had moratoriums associated with gas price increases before. The producers don't believe it.

If this legislation is enacted, nobody is going to believe a moratorium. They are going to know, and I say this with due respect, that

Mr. Krueger and others are going to introduce legislation in the next session of Congress to further increase the price of natural gas beyond that which this administration recognizes at this time. It is just another temporary step, no matter what is said at this point. The expectation of future increases is going to exist.

Mr. DeLoss. A couple of quick comments.

No. 1, even if there is a supply response to an increased price, and if that creates a positive macroeconomic effect, the real question is what should be the price increase that elicits the supply increase, and how should it be decided? And I think that as I indicated earlier, since we are in that situation where the price is going to be administered, it ought to be administered through some very careful judgment by the government.

Secondly, the negative macroeconomic impacts of a sharp price increase for gas are much less speculative than these supply increase responses, and I have indicated three of those that I think people should be very concerned about today, income transfer, inflation and recession.

Using John's language again, we have a lot of empirical evidence about those consequences over the last 3 to 4 years, and so I think that you should always keep that very prominently in mind, that there is very little speculation about those macroeconomic impacts.

Finally, you should always remember that all of energy policy really can be defined as investment guidance policy, and we should be careful how much investment we guide into a variety of supply options, when guiding investment into conservation options is a less speculative investment opportunity, and more environmentally benign even than natural gas, which was just described as very environmentally benign.

I think that the conservation program in the Carter plan, for example, is much too weak. It is self-described as moderate or minimal. It is not a strong conservation plan. Therefore it is not guiding sufficient investment away from energy production and into energy conservation. Energy conservation is really a source of energy. Conservation investments effectively produce energy. We could be "mining" and "drilling" for energy in existing buildings all over the country right now with a mandatory retrofit program.

Mr. Schroeder. Thank you.

Mr. Freeman, do you care to comment?

Mr. Freeman. I just have one comment.

I think we ought to be aware of the extraordinary high costs of marginal production if it is included in the base price. For example, if we could obtain 10 Mcf at $1.75, but if we went to $2.25, assume that we had a 10 percent increase and you got 11 Mcf, if you make the arithmetical calculation you will find that that additional Mcf costs $7.25 an Mcf.

Our proposal would be to have the base price of $1.75, and pick up that extra Mcf through a special price that would be a rifle shot to reflect the higher cost source. It would provide a total cost to the economy and to the consumer considerably lower, and obtain the same amount of gas.

Mr. Schroeder. Professor Erickson, with that background could you tell us some of the results of your analysis.

Mr. ERICKSON. What David has just articulated is precisely the philosophy that over the last 23 years has gotten us into a serious mess with the regulation induced shortage of natural gas. It is not a rifle shot, it is a peashooter and it doesn't have a pea in it.

On top of that with regard to macroeconomic effects the most severe economic effects again flow from the regulation and shortage of natural gas, the unemployment associated with plants closing down and dislocation effects. Those are the things that I think we should be concerned about.

Mr. SCHROEDER. What does your model project as the short- and the long-term price response to deregulation?

Mr. ERICKSON. It is very difficult to use an econometric model, which was estimated on data for 20 and 30-cent natural gas to predict supply response in the $2 to $3 range. I have done some work for the Office of Technology Assessment of the Congress with regard to the potential from Devonian shale where we didn't use an econometric approach. We used an engineering economic approach looking at data from about 500 wells in three different areas.

It looks to me there that very conservative numbers are that with prices in the $2 to $3 range we could be picking up by the early 1980s at least 1 trillion cubic feet a year. We don't need a special program for Devonian shale. What we need is deregulation across the board.

Mr. SCHROEDER. There is a substantial body of economic literature which suggests that the long run equilibrium natural gas price would be pegged to the replacement price of oil, the oil import price.

Do you see any merit in that argument?

Mr. ERICKSON. It would be influenced by it in an unregulated market. However, I am not sure that it would be pegged to it. Oil and gas have separate supply and demand curves from oil. The intrastate market right now is clearing at prices below the Btu equivalent for oil. It is difficult to say. The premium fuel qualities of natural gas, if the interstate market were integrated with the intrastate market on an unregulated basis might make the price of natural gas above the Btu equivalent for oil.

Mr. SCHROEDER. You think that in the long run it could stay significantly above the oil import equivalent prices?

Mr. ERICKSON. That is possible, yes.

Mr. SCHROEDER. I have questions for Mr. DeLoss and Mr. Wilson.

How do you respond to the argument that cost-based regulation, no matter how effectively, or accurately, or equitably done, will nevertheless result in excessive levels of demand by virtue of the price of substitute fuels, and will thereby insure in the long run an imbalance in the natural gas market?

Mr. WILSON. All commodities in an economic environment are scarce. That is the definition of an economic good. Otherwise it doesn't extract a price. In a competitive market there would be no problem. We wouldn't be sitting here debating about whether we should be talking about market value as the standard or whether we ought to be talking about cost, because the two would be equal. That is the beauty of the way a truly competitive market works out. There will be either entry or exit from the market. There will be supply and demand responses until a partial equilibrium is

achieved in that market, at which the price that is paid representing the commodity value is equal to the cost of the product.

Now that solution completely disappears when you interject monopoly control on the supply side of the market. We have got that in petroleum. We have got it in a broader spectrum than in petroleum with regard to energy markets. It permeates into coal, uranium and the other fuels that the oil companies have gotten into, and it certainly pertains to natural gas. So now we have got a problem, and the problem is that cost and value don't coincide, and you are going to have a disequilibrium problem between supply and demand.

As a utopian, which I am not anymore, I was 5 years ago, my solution to that was to enforce the antitrust laws, and bring about a situation in which supply and demand can come into balance in an equilibrium position so that value and cost can be identical. Jim Halverson at the Federal Trade Commission tried to do that 4 or 5 years ago. He was a Republican who understood what a free market and competition really meant. He was blocked by the White House. He was blocked by the administration. The same kinds of things blocked efforts in the Democratic administrations in the 1960s and in the 1940s and the 1930s. The political power of the oil industry is too great to bring about that utopian situation, so now you have to grapple with how do you allocate in an environment in which the market mechanism is not going to bring about an equilibrium.

The approach of Erickson is to say forget about income distribution. Let's assume that that is neutral, and worry about allocative efficiency. Let the price mechanism allocate the resource in a way that reflects the value of the commodity, and income distribution be damned.

From an economic point of view, that is a bad solution. I think that you have to be concerned about income distribution, and you have to go to an incremental pricing structure reflecting marginal costs in a fashion that equates the total revenue requirement with total costs in much the same way that this committee is perceiving going about the solution of pricing the electric utility industry, where you have a disequilibrium but it works the other way. It can be done. The methodology exists but the solution is not to forget about income distribution and go to commodity value and thereby capitulate rather than solve the problem that is introduced by the monopolistic element in the marketplace.

Mr. DeLoss. Just a brief answer.

I think that to the extent that I could accept price as a conservation measure, that of course I would argue that the government should capture the economic rent instead of allowing the domestic energy producers to capture that economic rent via the process of using the OPEC price or the monopolistic price for domestic energy reserves. Certain elements of the administration's plan are very obviously based on that concept.

Mr. Schroeder. Thank you.

Mr. Maguire. The gentleman from Texas, Mr. Collins.

Mr. Collins. Thank you, Mr. Chairman.

Mr. Freeman, what do you determine the Btu equivalency of coal to be today in terms of price?

Mr. FREEMAN. I believe that that is around $1.10, but I am not certain of that, sir. I am just kind of guessing.

Mr. COLLINS. How did they arrive at that figure? Dr. Schlesinger gave that the other day and I understand that you are the technical authority on the staff.

Mr. FREEMAN. I do not make that claim, no, sir. I was out of town the day he testified, but I believe that if you take the long-term contracts for coal—this information was supplied to us, and we could double check it—that the price of coal is on a Btu basis considerably lower than the price of oil today.

Mr. COLLINS. The figures I had seen were $2.50, and we suddenly come up with $1.10. We have never had this figure before.

Mr. FREEMAN. The Btu equivalent of course of new crude oil is in the neighborhood of $2.25 or $2.50, but coal, if you look at the long-term contracts——

Mr. COLLINS. You are talking about present production costs on present coal.

Mr. FREEMAN. Yes. I think that number reflects all of the existing contracts.

Mr. COLLINS. You are not taking averages, are you?

Mr. FREEMAN. Yes, sir.

Mr. COLLINS. We are talking about 1977.

Mr. FREEMAN. Perhaps we misunderstood your question.

Mr. COLLINS. I am sure glad we got this clarified, because we are talking about 1977 prices on gas, aren't we?

Mr. FREEMAN. The $1.10 figure probably does represent an average. You are interested in the Btu equivalent of the new contracts for coal.

Mr. COLLINS. If all the double talk we are getting in these hearings is like that we are going to have a hard time getting the facts. I am sure glad you raised this question. We are talking gas, oil, coal, solar today.

Mr. FREEMAN. Correct.

Mr. COLLINS. When they told me what it cost, what I have been pointing out, and I always was under the impression that the reason that gas is having such a hard time is because we have so far underpriced it that we have encouraged people to buy it. In other words, Btu count, industry has a tremendous incentive to buy gas, and if we priced it up higher, we would discourage them from trying to buy it.

In other words, that goes back to the open market.

Mr. FREEMAN. I think that we are together on that principle, Mr. Collins. I don't know for sure what the $1.10 Btu of coal, whether it is equivalent to new contracts or the average. I will check that out

Mr. COLLINS. Give us those old figures.

Mr. FREEMAN. Yes, sir.

Mr. COLLINS. Because coal is where we all want to go.

Mr. FREEMAN. Yes, sir.

Mr. COLLINS. I agree with you completely. We have over 200 years of reserves and we all want to go to coal.

Mr. FREEMAN. There is perhaps some confusion about the coal prices, because the spot market for coal temporarily shot up for a while, and those prices became rather high. I think though that the

long-term contracts have gone down. The $1.10 figure may very well reflect new, long-term coal contracts, but it certainly needs to be double checked.

Mr. COLLINS. Mr. Chairman, I would like to ask unanimous consent to leave the record open at this point for the Btu equivalency on coal, in terms of the spot price in 1977.

Mr. KRUEGER. Without objection, it is so ordered.

[The following information was received for the record:]

Question: What are the current prices of coal to the electric utility industry?

Answer: The question can be answered in two ways. What are the electric utilities paying for coal delivered to the utility, and what are they paying for coal at the mine?

According to the Federal Power Commission (FPC) in December 1976, the most recent month for which data are available, the average delivered cost of spot market coal was 92.4 cents per million Btu. The average delivered cost for contract coal was 85.5 cents per million Btu.

Unfortuntately, the information on coal prices at the mine is not as well documented as are the FPC data. *The Wall Street Journal* reports spot coal prices per ton weekly based on a sampling of eastern coal companies, but the Btu content is not noted. In the May 24, 1977 edition, the spot price quoted for steam coal was from $17 to $22 per ton at the mine. If one assumed a heat content of 12,000 Btu per pound, the spot price would range from 71 cents to 92 cents a ton at the mine.

Mr. COLLINS. That is the new price today, 1977.

Mr. FREEMAN. Spot as well as long-term contracts.

Mr. COLLINS. Either way. If it is more favorable to take the long-term I will be glad to see that.

Mr. FREEMAN. I will try to obtain both for you, yes, sir.

Mr. COLLINS. Thank you very much, Mr. Freeman.

Mr. KRUEGER. The time of the gentleman has expired.

At this time the Chair intends to recognize first those members who have not had any opportunity to question, that is the gentleman from Louisiana and the gentleman from Tennessee. Then I will return to the gentleman from New Jersey who has one set of further questions he wants to ask, but I will try to conclude this panel if at all possible by 12 o'clock so that we will only have delayed the next panel half an hour.

I haven't checked the audience, but I assume that our 11:30 panel is here, and we will try to get that next panel going at 12, so I shall be fairly rigorous in adhering to the 5-minute rule.

I believe that Mr. Moore was here earlier, so I will first recognize the gentleman from Louisiana, Mr. Moore, for 5 minutes.

Mr. MOORE. Thank you, Mr. Chairman.

I have a question directed at Mr. DeLoss and Mr. Wilson.

I understood your testimony at the very beginning, of course, discounting price elasticity or price producing increased product. The Federal Power Commission, Stanford University, Federal Energy Administration, Institute of Gas Technology, which I believe is at the University of Illinois, have econometric models to show there is price elasticity response as the Federal Government has tried to reflect in its bill and the FPC has tried to reflect in the past. You have given us your opinions and thinking.

Do you have any econometric models that we can compare to those we have before us?

Mr. WILSON. Sir, I was the Chief of Division of Economic Studies at the FPC from 1971 through 1973. Consequently, I am very familiar with the FPC's econometric model.

Mr. MOORE. The one they used for 770-A?

Mr. WILSON. Yes, I am. I am also familiar with the Khazzoom model which was built earlier in 1969 and I am familiar with the whole generation of FPC models as well as other models that have been developed by Ed Erickson, by Paul MacAvoy, by SRI and so on. They are all based on assumptions. They have all produced projections that are wrong. If we would have believed those models over the course of the last 5 years while these same issues and same debates were raging before congressional committees, then today we would have three times as much natural gas supply as we can possibly require at an average price of well under $1 an Mcf. They don't work. The assumptions don't work. The industry is not looking at current price. They are looking at price that is speculative for the future.

Mr. MOORE. You have models to give us, is that correct, that you have worked up that are based on proper assumptions and proper information?

Mr. WILSON. I have not got an econometric model because I don't believe that the historical data, the empirical data that is necessary to do that kind of work can be used to build one. Econometric models are built from historical data. If you were to build one right now you would see that supply elasticity is negative. The higher you raise the price, the less is brought forth.

Mr. MOORE. The only recent one we have is April 14, 1977, from FEA. It does show price elasticity works. Their model is continuing to work.

Mr. WILSON. No, it doesn't show it works. It shows a speculative elasticity model. Come back in 3 years and see whether it works.

Mr. MOORE. Mr. DeLoss, do you have any such models or are you taking a similar approach that these things are all wrong and we should pay no attention to them?

Mr. DELOSS. I certainly would associate myself with John's statement. I am glad we have somebody here with his experience to respond to your question. I think that on this problem maybe there is a consensus here between at least three of the panelists. Part of the problem is predictability, and it is not so much that we disbelieve that there is a price and supply relationship, but that we would like to see producers and potential producers face a predictable price situation.

I am not sure how firm that predictability can be, because as John noted there will always be somebody coming back with a bill next year to change the price. I think it would be nice to supply some predictability. The question is which price do you choose to elicit supply? That is what my testimony goes to, not the econometric models.

Mr. MOORE. Then you don't have one either.

Mr. DELOSS. No, I am suggesting that to the extent that there is a price-supply relationship, the debate is not so much over whether that relationship exists, but over which predictable price to establish to permit that mechanism to operate.

Mr. MOORE. Mr. Freeman, I wondered, looking towards the future, if you would look back. You have had a long history working with energy regulation, I believe. In looking back over the history of

the situation that we have progressed from the regulation of interstate gas to now, the regulation of oil, the regulation of intrastate gas, I am wondering if this scheme of things is going to work unless we also extend regulations eventually to perhaps coal, to keep them in a proper Btu equivalency, and maybe even some day solar. I would like to have your guesstimate of where we are headed and if you don't think that is a proper thought that we may well be headed in that direction.

Mr. KRUEGER. The Chair will recognize Mr. Freeman for a response to the question. That is the last question from Mr. Moore.

Mr. FREEMAN. Mr. Moore, I certainly don't think so, and I certainly hope not. The coal resource is relatively abundant, and the coal industry is workably competitive, with efforts on the part of the antitrust department and with perhaps legislation it can remain competitive. There is no need in the foreseeable future to have to regulate coal.

Our hope is that by a phase-out action with oil and gas, we can restore some semblance of balance to supply and demand, and go back to a competitive economy in the energy industry by bringing coal, solar and supplemental sources in. Our objective is to work our way out of regulation. Certainly there is nothing that I know of that would suggest that we should extend price controls to coal. That industry can and should continue to be very, very competitive.

Mr. KRUEGER. Thank you.

The Chair now recognizes for 5 minutes the gentleman from Tennessee, Mr. Gore.

Mr. GORE. Thank you, Mr. Chairman.

Thank you all for your testimony.

I have read your prepared statements very carefully, and I look forward to reading your statements in the record, Mr. Freeman.

I wanted to ask you, Professor Erickson, some questions about your economic theory.

What leverage does the consumer of natural gas have on the price of natural gas?

Mr. ERICKSON. The consumer of natural gas as an individual has no leverage at all.

Mr. GORE. No leverage at all?

Mr. ERICKSON. However, the market demand, which is a summation of all those consumers, industrial, residential and commercial, operates against the market supply. In that place where you have a free market, the intrastate market, the market price is now in the neighborhood on an average basis of about $1.80 per Mcf.

Mr. GORE. We have established that the consumer has absolutely no leverage on the price paid for natural gas. What incentive does the pipeline have to pay the lowest price available?

Mr. ERICKSON. A pipeline is in the business of selling natural gas, ultimately in competition with other fuels, and they want to have their pipeline full.

Mr. GORE. What other fuels does the pipeline put in its pipeline?

Mr. ERICKSON. In competition in end use markets with other fuels, with coal, with oil and electricity. Natural gas pipeline puts only natural gas in its pipeline.

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Mr. GORE. So they have an indirect incentive to try to prevent people from switching to alternative fuels, correct?

Mr. ERICKSON. That is correct.

Mr. GORE. But their primary incentive is to keep their pipeline full.

Mr. ERICKSON. That is correct.

Mr. GORE. Now as an economist, and I am not one, and I will hasten to add that caveat, are you familiar with the concept of tie-in sales and monopoly theory?

Mr. ERICKSON. Yes, I am.

Mr. GORE. You correct me if I am wrong in summarizing that theory. If you have a large and powerful monopoly which has the ability to set whatever price it can extract from a captive market, if that monopoly then sells an additional service or good over which they themselves do not have a monopoly of production, then that is the use of monopoly power to shove an additional product down the throats of their captive consumers.

Is that a fair statement of the theory? I know it is a little roughshod.

Mr. ERICKSON. It is a little roughshod. The fundamentals are that on the assumption, and it is an assumption, that someone has monopoly power, he can only use that monopoly power once. If he has got it with product X and he tries to use it on product Y, he loses some of it with product X.

Mr. GORE. If he has a monopoly on product X and he attaches product Y, say, product Y makes up 20 percent of the total cost of the combined product, he has a monopoly over product X, the consumer has nowhere else to go, in order to buy product X, the monopolist insists that the consumer buy product Y in conjunction with product X, then that is the use of the monopoly power over product X to force consumption of product Y at whatever price the producer of product X sets, correct?

Mr. ERICKSON. If there also happen to be products Z and W, electricity and coal, there is competition across there, and that is why you can only use the same monopoly power once, assuming that it exists again, and that is an assumption I would not buy with regard to the U.S. oil industry.

Mr. GORE. It is fair to state that the consumer of natural gas faces a monopoly situation insofar as the distribution network is concerned?

Mr. ERICKSON. The distribution network of natural gas?

Mr. GORE. Right.

Mr. ERICKSON. That is a regulated monopoly, yes.

Mr. GORE. Right, and 75 percent of the value of the final product which is sold is made up of transportation charges, correct?

Mr. ERICKSON. In rough terms.

Mr. GORE. In rough terms. I know that there is some disagreement about how accurate that figure is, so the remaining 25 percent roughly involves the value of the good which is transported, the natural gas.

Mr. KRUEGER. The time of the gentleman has expired. The witness will be allowed to respond and then we will proceed to the next questions.

Mr. ERICKSON. Can I talk with you after?

Mr. GORE. I will be glad to.

Thank you, Mr. Chairman.

Mr. KRUEGER. Thank you.

Our numbers grow.

The Chair recognizes the gentleman from Ohio, Mr. Brown, for 5 minutes.

Mr. BROWN. Thank you, Mr. Chairman.

Mr. Freeman, in response to the last question that Mr. Moore asked, you said something about the program phasing out control of oil and gas. I am somewhat at a loss on that because it seems to me that it anticipates price controls on natural gas, both interstate and intrastate for the first time indefinitely, and also continues the controls on oil prices beyond the present exploration for oil, though I am not sure how that is accomplished.

How do you phase out control of oil and natural gas?

Mr. FREEMAN. You are correct, our policy is set forth in the plan. It contemplates continued price controls over both oil and natural gas indefinitely. The price control system is phased out in the sense that we have equated oil and natural gas on a Btu equivalent basis. As we have more and more brand new oil in the system, we are pricing it at a level roughly equivalent to a price that may in the future represent a semblance of competition in the market.

We are hopeful that as the years proceed and we balance the demand for gas with the supply and bring coal and alternative fuels in, that we can move to a competitive marketplace. The President has indicated this was a first step in that direction.

Mr. BROWN. Then will you phase out controls at that point, when your program gets in balance?

Mr. FREEMAN. Mr. Brown, if I may finish.

I think it is contingent upon a situation in the world market, which is setting the marginal price of energy, where we feel that we are not in a sense at the mercy of a cartel, where there is a balance of supply and demand in the world market. We are hoping to move in that direction through our program of conservation and increased supply, and we hope that other nations will emulate us.

Mr. BROWN. I heard the words but what is the answer to my question?

Mr. FREEMAN. The answer?

Mr. BROWN. Are you going to phase out controls; is that your ambition or is it not, to phase out?

Mr. FREEMAN. Our program is to continue controls as long as they are needed to protect the consumer interest and avoid undue inflation.

Mr. BROWN. So there is nothing in this legislation that phases out controls, is that right?

Mr. FREEMAN. No, sir, there is not.

Mr. BROWN. Okay.

Could you answer why you put a different price on new oil and new gas with reference to attempting apparently to stimulate the production of those two products? The price of new new oil or whatever the terms are that are being used now, newly discovered oil, is close to the current market price, $11.28, but the price for new new gas is much lower than that——

Mr. FREEMAN. Correct.

Mr. BROWN. [continuing]. in terms of oil equivalency price?

Mr. FREEMAN. I think the short answer to that question, Mr. Brown, is that those prices reflect history and the fact that in an attempt to avoid undue inflation and windfall profits to the producing industry, that we felt that a Btu——

Mr. BROWN. Could you explain to me how they reflect history because gas costs more in the marketplace than oil does?

Mr. FREEMAN. The history is that the price of natural gas has been regulated on a historical cost basis and the price of oil has not.

Mr. BROWN. So this reflects historical regulation, is that right?

Mr. FREEMAN. Historical prices in the marketplace, historically reliance by consumers all over the country on natural gas. And it reflects a fact that the price of new natural gas has increased on a percentage basis, if anything, more rapidly than oil. It reflects the fact that we are going to a price that roughly reflects the average decontrolled price intrastate; it reflects a price higher I think——

Mr. BROWN. I do not think that is true, with all due respect. I am sorry. How do you get to that?

Mr. FREEMAN. I think if you take the average prices in the intrastate market before the winter emergency of this winter—and discount that as an aberration—I think you will find that the price, especially as it moves upwards very sharply, is roughly equivalent to intrastate prices, give or take a few cents.

Mr. BROWN. Did you give us the source for that for the record?

Mr. FREEMAN. I think we will supply the average intrastate prices in 1976, yes.

Mr. BROWN. Then could you please provide for the record the PIES computer run for the following scenarios: the 1980 reference case which is not included in our report to the national energy plan, 1980 reference case with deregulation, 1985 reference case with deregulation and the assumptions that went into the gas supply figures for the Carter plan as to the intrastate prices, where did you get those assumptions and what are they? And the prices under section 406(b) of part D.

Mr. FREEMAN. Yes, sir, we will supply everything we have.

[The following information was received for the record:]

Question. Using the same model that provided "fuel balances by sector" on Page 96 of the Plan, provide domestic supply figures for:

1980 Reference Case

1980 Reference Case with Deregulation

1985 Reference Case with Deregulation

Answer: Attached for your information is a copy of the PIES output for the 1980 Reference Case. No runs were made for the National Energy Plan analysis which involved the Reference Case with deregulation.

Question. Provide assumptions that went into the chart for the "1985 with Plan" gas figures as to:

a) Intrastate Prices

b) Prices under Section 406(b) of the bill.

Answer: The following assumptions were made with respect to natural gas pricing in the Charter Plan:

(1) The distinction between interstate and intrastate markets disappears under the Plan for all newly discovered gas. Such gas is assumed to be priced at no more than the Btu related price of domestic crude oil to refineries (excluding the crude oil equalization tax);

(2) The roll-over of contracts for committed reserves in the interstate markets is assumed to occur according to current FPC practice for interstate gas;
(3) All other uncommitted interstate gas is assumed to be priced at $1.45 plus inflation;
(4) All other intrastate gas is assumed to be priced at the Btu related price.

Mr. BROWN. I want to find the—the reason for the question is to find out what you had on which those assumptions, which in some cases I think were faulty, were made.

Mr. KRUEGER. The time of the gentleman has expired.

What I shall do, and if anybody else walks in they can ask questions of the next panel, I will recognize Mr. Maguire for three minutes, Mr. Stockman for one minute to pose a question to which he will ask a written response, and one minute to the minority counsel for the same purpose.

Mr. MAGUIRE. Before my time begins, I wonder if I might ask if we could have a provision for the record to be left open so that, for example, Mr. Wilson might comment on some of the things Mr. Erickson has said, as I indicated I wanted him to do in the early testimony, or Mr. Erickson on what any of the others have said or any of them on what any of them have said.

Mr. KRUEGER. Fine. We will hold the record open in accordance with the request just made.

Mr. MAGUIRE. Thank you, Mr. Chairman.

Mr. Erickson, you have talked about roll-backs in relation to what you call reasonable expectations.

Mr. Wilson, you have talked about prices greatly exceeding costs.

Do either of you have data that you can present to this committee on what it now costs onshore, offshore, under variable conditions, to produce a thousand cubic feet of natural gas?

Mr. ERICKSON. That cost varies depending on what thousand cubic feet of natural gas it is. For newly discovered gas in the Federal Power Commission proceeding now underway, Docket No.RM77-13, those numbers will be available for the Congress. But I do not think they will be available in time to submit for this record.

Mr. MAGUIRE. What was the last set of numbers that you saw with respect to any additions to our natural gas supply?

Mr. ERICKSON. $1.61.

Mr. MAGUIRE. Cost?

Mr. ERICKSON. Yes.

Mr. MAGUIRE. Cost?

Mr. ERICKSON. That was in opinion 770-A.

Mr. MAGUIRE. Mr. Wilson, what do you have on that subject?

Mr. WILSON. I have a recent audit that was done I believe by Price Waterhouse of the books of the Gulf Oil Company, which was supplied to us in conjunction with an investigation by the New York State Legislature Task Force on Natural Gas that shows a figure of some 27 cents for Gulf Oil Company in 1976.

I could supply that.

Mr. MAGUIRE. Would you?

Mr. Erickson, I recall from having read the record that the producers in the Louisiana offshore area indicated to the FPC in 1971 that if they raised the price from 13 cents to 16 cents there would be plenty of supply.

Mr. DeLoss is telling us today that any cost-based calculation has to start at no higher than 75 cents per Mcf. If you are not talking about what may be in the opinion 770 which is in a court challenge in terms of reading the market today, including new gas, did you disagree with that?

Mr. ERICKSON. 75 cents?

I certainly would disagree with that.

Mr. MAGUIRE. What would be your average number?

Mr. ERICKSON. For newly discovered natural gas, of natural gas that would be an increment to the supply.

Mr. MAGUIRE. That is not precisely the question.

Mr. ERICKSON. It is increments to supply in which we are ultimately interested.

Mr. MAGUIRE. All right, answer that.

Mr. ERICKSON. It is that in the intrastate market I am sure that people are being very disappointed in discovering gas at $2.75 or $3 an Mcf, which they are selling because the market will only permit that at prices below their costs.

Mr. MAGUIRE. You are telling me they are selling it below cost?

Mr. ERICKSON. Absolutely. Their sunk costs are sunk, of course.

Mr. MAGUIRE. Does Mr. Wilson agree with that, that they would be selling gas below gas?

Mr. WILSON. In intrastate markets?

Mr. MAGUIRE. Yes.

Mr. WILSON. Absolutely not; gas is being sold well above cost in intrastate markets, especially in San Antonio.

Mr. KRUEGER. The time of the gentleman from New Jersey has expired.

Is there any specific request for comments in writing that you wish to make at this time, any specific request of the panel.

Mr. MAGUIRE. I would like the data that they could provide us on cost, because we have had two hours of discussion with nobody referring to or giving us any figures. I find that rather astonishing.

Mr. BROWN. Will the gentleman yield?

Mr. MAGUIRE. I do not think I have any time.

Mr. KRUEGER. At this time the Chair recognizes Mr. Stockman for one minute to pose a question.

Mr. STOCKMAN. Mr. Freeman, in discussion we were having with Mr. Collins before talking about the Btu equivalency of coal, I would like to ask for additional information because I do not think that discussion got to the real point.

What you were talking about was the fuel acquisition price or equivalency for coal, but obviously you cannot merely buy coal and burn it. There are going to be a lot of associated costs that have to go into that calculation.

The equivalency for coal if you are using it as a boiler fuel, for instance, has to take into account storage costs which you do not have with gas, containment costs such as putting the shed over the coal piles, and controlling emissions, has to take into account the emissions costs, for precipitators, scrubbers and so forth, it has to take into account the disposal cost of the sludge, whatever the out-by-product is, maybe even structural modification; finally, boiler retrofit because you cannot use it for coal.

All of those have to be folded in so you can get the relative equivalency, that is the use price equivalency as opposed to the equivalence.

Secondly, going beyond that, the use price equivalency, Btu, is going to vary with the end use. For boilers, as I have indicated, as a replacement fuel, boiler replacement fuel, all of those things would be taken into account; as a replacement fuel for processed heat where you are using direct flame applications you imply a conversion technology, you use gas, so you are going to have even higher cost there.

Finally, the third category would be as a feedstock replacement. Btu equivalency there is talking basically about liquefaction, and that is in terms of $30 or $40 per barrel equivalent.

I would like to see some numbers that the administration has on Btu equivalencies in use terms, not the fuel cost application because that is irrelevant.

Mr. FREEMAN. May I comment?

It is not irrelevant to the producer.

Mr. STOCKMAN. To the producer, but to the user?

Mr. FREEMAN. There are two aspects.

Mr. STOCKMAN. To the economy it is relevant, because the relevant final factor is what it is going to cost the economy to produce certain Btu's of energy.

[The following information was received for the record:]

Question: Mr. Stockman asked Mr. Freeman to provide a discussion and some illustrative numbers as to the Btu equivalency of coal, oil and natural gas as alternative fuels.

Answer: (The figures used are illustrative, and not official estimates of the Administration). Clearly, the relative cost of alternative fuels to the consumer includes factors other than the direct comparative cost on a Btu basis of the raw fuel. Since oil and gas are comparable in cost of exploration development and production to the consumer, Btu equivalency is a rational measure of the price the producer should receive. But different fuels have associated with them different plant design features, environmental protection requirements, fuel inventory and storage aspects and conversion cycle efficiences, all of which affect the relative cost to the consumer of the end-use energy derived from the combustion of these alternative fuels. In addition, these many factors and their associated costs vary from one end-use application to another including non-combustion applications e.g. chemical feedstocks.

As used in this discussion, Btu equivalency means that fuel cost in dollars per Btu which would produce an equal amount of end-use energy (or feedstock) after taking into account the different (a) conversion facility capital and

operating and maintenance costs, (b) fuel inventory and storage requirements, (c) conversion efficiencies and (d) heat stream clean-up and waste disposal costs associated with converting that fuel to the desired form of end-use energy.

The following illustrative example is provided. We assume two 800 MWe net electric power generation plants--one oil-fired and one coal-fired. The oil-fired plant consumes low-sulphur oil delivered to the plant site at $16 per barrel which at a heat content of 5.8 million Btu/bbl is a delivered fuel cost of $2.76/million Btu. Coal, with a heat content of 13000 Btu per pound or 26 million Btu per ton, costing $71.26 per ton would provide an equivalent delivered fuel cost.

However, the oil plant capital cost, since the plant is simpler, does not need a flue gas scrubber, and requires less expensive fuel receipt and storage facilities, costs about $350/Kw. The equivalent net capacity coal plant equipped with a flue gas scrubber and lifetime storage capability for the scrubber sludge would cost about $520/Kw. The oil plant has a heat rate of about 9200 Btu/Kw-hr. The coal plant due to scrubber parasitic load and other factors has a heat rate of about 9600 Btu/Kw-hr. The oil plant operation and maintenance (O&M) costs are about 0.15¢/Kw-hr. The coal plant O&M costs

including limestone for wet scrubber operation and transport of ash and scrubber sludge to an appropriate waste disposal site is about 0.4¢/Kw-hr.

Considering those differences, what must the delivered cost of the coal be for the coal plant to produce electric power at the same cost as that from the oil-fired plant? Or, in other words, what is the Btu equivalency of coal in this hypothetical situation?

The cost of power is calculated as follows:

Power cost ¢/Kw-hr. =

$$\frac{\text{Capital Cost X Annual Fixed Charge Rate}}{\text{Plant Siting X Capacity Factor X 8760 Hrs./Yrs.}}$$

+ Fuel cost $¢/10^6$ Btu X Heat Rate Btu/Kw-hr.

+ O&M cost ¢/Kw-hr.

At an annual fixed charge rate of 15% and a plant capacity factor of 0.65 power cost from the hypothetical oil-fired plant and delivered oil cost would be 3.61¢/Kw-hr.

The delivered coal cost to provide electric power at the same cost from the coal-fired plant would need to be $\$1.92/10^6$ Btu or $49.83/ton.

This illustraties that in the case of electric power production, the Btu equivalency of coal costs is about

$\frac{\$1.92}{\$2.76}$ or about 0.7 the cost of low sulfur oil.

Similar Btu equivalencies can be developed for other applications of coal, oil or natural gas. If, for example, oil or natural gas were being used as an energy source for a process heat application wherein high temperature heat in which little particulate matter or poorly burned combustion products could be tolerated, the equivalent price of raw coal would be lower. A heat exchanger to isolate the coal combustion products from the process heat stream might be needed where, instead, the hot combustion gases of the oil or natural gas fuel could be directly applied. Similarly, if close control of flame temperature and size were a requisite of the end-use application, coal systems would require lower priced coal to be equivalent. In such applications, the Btu equivalency of coal could be 60 percent of the price of oil, or 50 percent, or even less dpending on the specific requirements and related equipment needs.

Finally, if the coal, oil or natural gas is to be used as feedstock to a chemical process, the specific chemical make-up of the coal and its contaminants or the need for a much greater degree of preprocessing of the coal could result in a wide range of Btu equivalencies. FEA does not have specific data on these latter examples to provide specific well-founded illustrations of these Btu equivalencies.

Mr. KRUEGER. I think my understanding was there would be responses in writing to any further questions. So if anyone on the subcommittee has any further questions they wish to pose to the panel in writing, we would ask the assistance of the panel in responding, if you would.

Might I receive an indication from the panel that they would be prepared to respond?

Mr. ERICKSON. Absolutely.

Mr. FREEMAN. To the best of our ability.

Mr. KRUEGER. All heads nod in the affirmative, let the record show.

We wish to thank the panel for its helpful testimony and its endurance.

[The following letters were received for the record:]

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SCHOOL OF AGRICULTURE AND LIFE SCIENCES

SCHOOL OF LIBERAL ARTS

DEPARTMENT OF ECONOMICS AND BUSINESS
BOX 5368 ZIP 27607

May 23, 1977

The Honorable Phillip Sharp
U.S. House of Representatives
Washington, D.C. 20515

Dear Congressman Sharp:

I am sorry I was so inarticulate with respect to your question concerning how well markets could be expected to work under deregulation of new gas. Please accept my apology for using up so much of your time with such a rambling answer. I am glad that Congressman Maguire was gracious enough to allow me to give you a more succinct answer.

The best evidence concerning how well natural gas markets could be expected to work to bring supply and demand into balance comes from the unregulated intrastate market.

When circumstances in the world energy market began to change, prices in the intrastate markets took off. I remember doing some digging in the summer of 1973 in Baton Rouge to get a feel for the Louisiana market. Prices were then in the 50-65 cents/Mcf range, and were clearly heading higher. But the intrastate market got considerable supply response. President Carter is correct in his observation that -- with the exception of offshore -- most new supplies in recent years have gone to the intrastate market. That is what one would expect under the price differentials which have existed.

The intrastate market is now clearing and supplies equal demands, including industrial demand. The only way that this happy situation can also occur in the interstate market is under deregulation of wellhead prices.

The question of how well natural gas markets could be expected to work is also related to the problem of reserve estimation and the allegations of speculative withholding. In that regard, I am enclosing a short piece, "The Fact and Fancy of Natural Gas Reserve Estimates," which I recently did. It is written in a popular vein, but I hope you find it interesting.

I hesitate to predict what supply response would be under deregulation. I do not believe that econometrics can do much more than give one a feel for what the range of the correct answer would be. The situation in recent years has been too

North Carolina State University at Raleigh is a constituent institution of The University of North Carolina.

chaotic and regulation restricted to put much faith in statistical price elasticity studies. My own feeling, based on years of work in this area, is that the U.S. could again produce 20-25 Tcf in the lower 48 states. I also think that this rate could be sustained for a considerable period of time.

Two additional points are relevant here. First, a full supply response will depend upon the industry having timely access to all OCS areas. Second, even if I am wrong and we are unable absolutely to increase natural gas production, there will still be a supply response. The 5 Tcf per year which prevents output from sliding still further to 14 Tcf (from the present rate of about 19 Tcf) must be considered an incremental supply. I think that we can do better than that, but the only way to tell is to deregulate and give it a try.

Because of time constraints, we were unable fully to develop all of the ideas and topics which came up. One of these was the relationship of deregulation of new gas to the deregulation of all gas. As I recall, Dave Freeman proposed that deregulation of new gas was tantamount to the deregulation of all gas. Dave also asserted that there would be no supply response under deregulation. I think that these positions are incompatible.

Producers could only use new gas supplies to lever a more rapid rollover of old gas contracts than would otherwise occur if there were in fact a new gas supply response.

Some old gas contracts could be expected, over a period of time, to rollover to higher prices. This is a complicated area, but there are a number of points that need to be made:

1. Old gas prices are protected by contract, and pipelines have an incentive in terms of competitiveness at the demand end of the pipeline to keep old gas prices low.

2. It would require the availability of new gas before much rollover could occur.

3. But the more new gas there is available, the less leverage a supplier of new gas would have, and the less rollover there could be expected to be.

4. To the extent there is rollover, the proper signals for decentralized, individually initiated, non-authoritarian, price induced conservation are given to natural gas users.

5. Both new gas supplies and rollover of old contracts inhibit the tendency for there to be a "blip" in the price of gas.

It is my hope that enough new gas -- both from new discoveries and reallocation from expiring intrastate contracts -- would be available to the interstate market so that the weighted average price of interstate natural gas would move steadily, over a fairly short number of years, toward the new gas price.

Another topic we did not have a chance to develop in full was the macroeconomic effects of new gas deregulation. In my opinion, the macroeconomic effects of new gas deregulation must be compared to the effects of its most likely alternative -- a continued and expanded regulation induced shortage under the Administration proposal.

The events of last winter showed how severe the effects of such a shortage can be. In this regard -- paradoxical as it may sound -- it is important to note that for many users deregulation would result in a reduction in natural gas prices. This is because, in the extreme, the price of natural gas is infinite for those users who are curtailed and cannot get natural gas. At the very least, the appropriate shadow price of natural gas for curtailed users is the price of alternative fuels, where such fuels are available and appropriate for their use or production process.

As you know from my several appearances before the Subcommittee, I am a strong advocate of deregulation of the price of new natural gas supplies. I think it is economically sound. I hope it is politically feasible. I firmly believe that it is in the best interest of the country.

Respectfully yours,

Edward W. Erickson

Edward W. Erickson
Professor of Economics and Business

EWE/lsn
Enclosures

cc: The Honorable John Dingell
The Members of the Subcommittee on Energy and Power

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DEPARTMENT OF ECONOMICS AND BUSINESS
BOX 5368 ZIP 27607

May 23, 1977

The Honorable Andrew Maguire
U. S. House of Representatives
Washington, D.C. 20515

Dear Congressman Maguire:

You raised several questions on Wednesday, May 18, which could not be fully explored because of time constraints. Since the record has been left open, I would like to take this opportunity to respond to your concerns. In addition, I would like to take this opportunity to thank you very much for your generous permission to use some of your time to respond more fully to Congressman Sharp.

With regard to cost, I think that it is erroneous to try to think about "the cost" of natural gas supplies. There is a wide array of costs. If drillers knew beforehand which prospects were going to be low cost, they would drill only those prospects. The large number of exploratory dry holes tells us how difficult it is to make such a before-the-fact determination. There are even substantial numbers of development dry holes.

It is the whole idea of "the cost" as it is embodied in cost based regulation which is responsible for the current regulation induced shortage of natural gas in the interstate market.

Nevertheless, the FPC regulatory procedure involves cost estimation on an aggregate average basis. In Opinion 770-A, the FPC found the cost of gas to be $1.6116 per Mcf. (See p. 93 of Docket RM75-14, Opinion No. 770-A, for this calculation.)

If the FPC costing procedures are applied to the current experience of natural gas producers, producers are reported to be incurring costs of at least $2.40/Mcf in the production of gas. This estimate is detailed in a motion to the Commission to establish interim national rates under Dockets Nos. RM77-12 and RM77-13. A copy of the motion and the calculations upon which it is based are attached.

But I must emphasize that the mistaken idea that there is a "the cost" is a fundamental error. Since our colloquy, I have had the opportunity to talk with an independent operator from

West Texas. He told me about a recent exploration drilling program he has conducted on a ranch in western Shackleford County, Texas.

In that drilling program, about $1,200,000 was spent drilling wells in the search for gas. For some of the financial backers, this is their only venture to date in oil or gas exploration. Only one well was successful, and that well is a very modest success. It has an initial production capability of about 100 Mcf per day. It is not a strong well, and may have a life of only three or four years. Given the expected production decline, this well may produce about 100,000 Mcf over its life. Without taking into account the time value of money, the simple average cost of gas from this $1,200,000 drilling program is $12 per Mcf. ($1,200,000 divided by 100,000 Mcf equals $12/Mcf.)

It is important to note that there is yet no pipeline connection to this well because its volume of production is too small to justify laying a line. (Some industry critics, I suppose, would call this "withholding".) The operator hopes that additional drilling on nearby properties will discover enough gas to justify laying a pipeline which could also pick up this gas.

This is an example which could in general be repeated many times on the basis of this and other operators' similar experiences. It is calculations such as these which illustrate the illusiveness of the idea of "the cost" of gas.

The problem is to provide adequate price incentives to encourage operators to take the risks associated with ventures such as the one described above in the hope that they will have sufficient successes to justify the effort. Since H.R. 6831 is in fact a price rollback bill, it does not provide such incentives. That adequate price incentives can work well is demonstrated by the market clearing experience in the intrastate market.

You were also concerned about the possibility of gas now priced at 26 cents being granted a price of $1.45 under the provisions of H.R. 6831. I believe that the 26 cent gas to which you referred is actually 29.5 cent gas under Opinion 770-A. Be that as it may, I believe that H.R. 6831 states that renegotiated prices for gas from expiring interstate contracts shall not exceed $1.45 per Mcf. What the price would actually be is left to the President's discretion. Since it is unlikely that the President will spend his time setting prices for individual gas contracts, it is reasonable to suppose that this matter will actually be handled by an administrative delegate of the President. This whole clause (Section 406(b)) is akin to a kind of special relief provision. The industry experience with administrative "special relief" does not suggest much upward price flexibility from this source.

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In addition, under H.R. 6831, such relief would not occur until the contracts had expired. This would not occur until sometime in the neighborhood of 1990, or later. For such relief to occur, it would require that there be some gas still flowing from these contracts. Given the rate at which the industry is producing from existing reservoirs to meet demands, there might not be very much, if any, gas left under these contracts at the time they expire.

Under deregulation of the wellhead price of new gas, there could be some rollover of existing contracts to higher prices upon supplies of new gas initially becoming available. In this connection, you may wish to see my comments in my letter to Congressman Sharp, a copy of which is enclosed.

You also asked some of the other panel members if they would like to comment on the price calculations contained in my testimony. There was not much of a substantive response. Because of your interest in those calculations, I would like to take this opportunity to explain the basis for my judgment that H.R. 6831 amounts to a price rollback for intrastate gas and prospective new gas in the interstate market.

The price of new gas under H.R. 6831 is unfortunately tied to the controlled price of domestic oil. This raises the question of what the H.R. 6831 price for new gas would be in the second quarter of 1977. Using the National Energy Plan, the wellhead components calculate to $1.48 per Mcf, as follows:

$$
\begin{aligned}
\$11.28 \times 36\% &= 4.06 \\
5.25 \times 50\% &= 2.63 \\
13.50 \times 14\% &= \underline{1.89} \\
& \quad 8.58 \div 5.8 = \$1.48/\text{Mcf}
\end{aligned}
$$

This number appears to be the best number to use until the Administration spells out its calculations. What the price of new gas would be under H.R. 6831 is just one of many instances in which the quantitative base for the Administration prosposals appears to be quite soft.

There may also be a transportation allowance in the H.R. 6831 new gas price. It is difficult to tell what this might be because of the ambiguities in the Administration proposal, but it could be on the order of 10.5 cents per Mcf. If this 10.5 cents per Mcf is included in the H.R. 6831 new gas price, that price becomes $1.585 per Mcf for the second quarter of 1977. That price is still a rollback for the intrastate market and reasonable expectations of what an FPC cost based price might be in Docket No. RM77-13.

If the $1.585 figure is used as the starting point in my calculation II of Attachment A to my testimony, the new gas price in H.R. 6831 translates into an oil equivalent of $4.35 per barrel in 1969 dollars. This is hardly a very vigorous approach to elicit new supplies to solve what the President, and common sense, assures us is a serious crisis.

You also raised the question of joint ventures in exploration. As you know, the Interior Department has administratively prohibited joint ventures in OCS bidding among the ten or so largest firms. Joint bidding ventures among large and small firms are still permitted.

My research has led me to the conclusion that joint ventures are pro-competitive. They have facilitated the entry of smaller firms into the risky high cost, high technology OCS area. In addition, there is absolutely no credible evidence that joint bidding ventures among the largest firms have had any anticompetitive effects. There have been a number of studies of the rate of return to OCS activity. All show it to be in the competitive range. In connection with joint ventures and the rate of return to OCS activity, you may wish to look at pages 58-61 (and especially footnote 24 on page 59) of my attached paper, "Charges of Domestic Energy Monopoly: the Dog in the Manger of U.S. Energy Policy."

The U.S. energy industries are highly competitive. This includes the oil and gas industries in general, and joint bidding in OCS lease sales in particular. Were we to deregulate the well-head price of new gas, we could expect a competitive supply response which would benefit the whole nation.

Respectfully yours,

Edward W Erickson

Edward W. Erickson
Professor of Economics and Business

EWE/lsn

Enclosures

cc: The Honorable John Dingell
The Members of the Subcommittee on Energy and Power

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DEPARTMENT OF ECONOMICS AND BUSINESS
BOX 5368 ZIP 27607

May 25, 1977

The Honorable David Stockman
U.S. House of Representatives
Washington, D.C. 20515

Dear Congressman Stockman:

It was a pleasure to testify before the Subcommittee on Energy and Power on Wednesday, May 18. I am sorry that time constraints prevented us from having a direct discussion of some of the issues which concern you. However, since the record is still open, I would like to take this opportunity to respond to one of the questions you raised. That question is the relation of the U.S. energy situation to the world oil market.

The U.S. regulation induced shortage of natural gas spills over into an increased U.S. demand for oil imports. The U.S. demand for oil imports is aggravated by the fact that we insist upon paying U.S. oil producers artificially low controlled prices,* rolling in domestic oil with higher cost imported oil, and domestically selling the resulting mix on the pretext that it only costs us the weighted average price.

The regulatory sleight of hand involved in suppressing U.S. natural gas prices contributes substantially to an export drain associated with selling wheat, computers, caterpillar tractors, airplanes, soybeans, etc. worth approximately $14.00 per barrel in equivalent value to subsidize U.S. oil consumption which we value at only about $11.00 per barrel. This is a pure and simple economic waste.

The natural gas price rollback provisions in H.R. 6831, will induce additional U.S. demands for imported oil, and at controlled domestic crude oil prices, additional economic waste. This waste is independent of whether the dollars which we pump out into the world economy are "recycled" to buy U.S. products on our export account. In fact, this "recycling" is the mechanism by which

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* See calculation III of Attachment A to my testimony of May 18. The real price of old oil is now about 25 percent below what it was in 1969.

the waste is facilitated.

This is a balance of payments problem. But it is an accounting truism that the balance of payments must balance. The way that this happens is that we borrow money to finance the increased level of oil imports which our regulation induced shortage of natural gas induces. By not adequately encouraging the development of the full domestic potential of U.S. oil and gas production, H.R. 6831 will put unnecessary pressure on the U.S. demand for imported oil -- and therefore, as well, on the world price of oil.

Our oil import bill makes us poorer in real terms. By regulatory restriction, we deny ourselves access to a domestic national resource. As a consequence, our real national income is lower than it otherwise would be.

Respectfully yours,

Edward W. Erickson

Edward W. Erickson
Professor of Economics and Business

EWE/lsn

cc: The Honorable John Dingell
The Members of the Subcommittee on Energy and Power

NORTH CAROLINA STATE UNIVERSITY | AT RALEIGH

SCHOOL OF AGRICULTURE AND LIFE SCIENCES

DEPARTMENT OF ECONOMICS AND BUSINESS
BOX 5368 ZIP 27607

SCHOOL OF LIBERAL ARTS

May 25, 1977

The Honorable W. Henson Moore
U. S. House of Representatives
Washington, D.C. 20515

Dear Congressman Moore:

In your May 18 colloquy with Dr. John Wilson, you discussed the availability and usefulness of econometric models of natural gas supply. Dr. Wilson mentioned some econometric modeling which Bob Spann and I have done. Because of time constraints, I was unable to comment myself on that work. Since the record is still open, I would like to take this opportunity to comment.

The basic econometric modeling work which Professor Spann and I have done is reported in several papers. These are:

"Price, Regulation and the Supply of Natural Gas in the United States," Regulation of the Natural Gas Producing Industry (Baltimore, Johns Hopkins, 1972), pp. 192-218, (edited by Keith Brown), (with R. M. Spann).

"Joint Costs and Separability in Oil and Gas Exploration," in Energy Modeling, Art, Science, Practice, M. F. Searle, editor (Baltimore: Resources for the Future, 1973), pp. 209-250 (with R. M. Spann).

"Supply Response in a Regulated Industry: the Case of Natural Gas," The Bell Journal of Economics and Management Science, Vol. 2, No. 1 (Spring 1971), pp. 94-123, (with R. M. Spann).

"Oil Imports, The Wellhead Price of Natural Gas, Energy Policy and Joint Costs in Oil and Gas Exploration," in Energy Policy Evaluation, Dilop R. Limaye, editor (Lexington: Heath, 1974), Chapter 10, pp. 115-123 (with R. M. Spann). Also abstracted in Michael S. Macrakis, editor, Energy: Demand Conservation and Institutional Problems (Cambridge: MIT, 1974), p. 536.

"Balancing the Supply and Demand of Natural Gas," Balancing Supply and Demand for Energy in the United States (Denver: University of Denver, 1972), pp. 91-106, (with R. M. Spann).

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Much of this work is quite involved in an economic and statistical sense, and I will not burden you with the technical details. However, with the benefit of hindsight, it is possible to summarize our findings as follows:

- The principal solution to the natural gas shortage in the United States must be new discoveries of non-associated natural gas.
- The supply of new discoveries of non-associated natural gas responds to the price of non-associated natural gas and can be considered separately from the supply of oil.
- There is a significant positive supply response of drilling activity and non-associated natural gas discoveries to increases in the price of natural gas.
- It is impossible to project supply response in the $2.00 to $3.00 per Mcf price range upon the basis of econometric estimations which rely upon price data in the 20¢ to 30¢ per Mcf.

The natural gas pricing provisions contained in H.R. 6831 amount to a price rollback for at least the intrastate natural gas market. The most straightforward interpretation of the interstate pricing provisions in H.R. 6831 also suggest that here as well there is a price rollback from reasonable expectations. These pricing provisions will act as a disincentive for new natural gas supplies. This is not what the United States needs. Rather than extending regulation to the intrastate market and compounding the shortage of natural gas, the unregulated intrastate market should serve as a model for more appropriate legislation. Such legislation would involve deregulation of the wellhead price of new gas supplies. In my opinion, the U.S. resource base is sufficient to maintain or expand natural gas supplies. The administration proposal as embodied in H.R. 6831 will, in my judgment, cause continued attrition in U.S. natural gas production.

Respectfully yours,

Edward W. Erickson

Edward W. Erickson
Professor of Economics and Business

EWE/lsn

cc: The Honorable John Dingell
The Members of the Subcommittee on Energy and Power

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DEPARTMENT OF ECONOMICS AND BUSINESS
BOX 5368 ZIP 27607

May 25, 1977

The Honorable Albert Gore, Jr.
U.S. House of Representatives
Washington, D.C. 20515

Dear Congressman Gore:

It was a pleasure meeting you on Wednesday the 18th. I am sorry that the calendar was so crowded that we did not have an opportunity fully to develop the questions you raised. Perhaps we will have another opportunity. In any event, I would like to take this chance to respond in more detail to some of your concerns.

You raised the question of tie-in sales under a monopoly situation. I am not sure where you were going with that line of inquiry because our time ran out. But it seems to me that you could have been moving toward either or both of two possible areas.

The first is the question of the diversification of oil and gas companies into coal and other energy supply activities.

The second is the question of the ability of companies with new gas supplies to use the promise of access to those supplies as a lever to achieve a rollover to higher prices of gas sold under old contracts at low, historical prices.

With respect to the issue of tie-ins with coal, I do not think that this is a problem. The oil companies which are most intensively into coal production -- Conoco and Occidental -- are relatively small firms in the oil industry. The evidence is that they have expanded their capacity and output faster than the coal industry on average. This is a competitive response.

In addition, Exxon and others have taken positions in western coal reserves. In order for these companies to realize anything from their coal holdings, they will have to produce coal (under appropriate environmental conditions). We need more coal output.

The production of coal by Exxon, or any other oil company, is a competitive market response to the social desirability of additional U.S. coal output as reflected in the price of coal.

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Were any oil company to attempt to hold back on coal production as a device to protect its oil and gas production, the history of the industry indicates that some other company or companies would move aggressively to take up the slack. The result would be that the first company would be a loser on both its oil and gas and coal position.

Were any oil company to attempt to force a tie-in sale of oil or gas with coal, or vice-versa, it would be unsuccessful for two reasons. First, both the oil and gas and coal markets are highly competitive and no company has the monopoly power necessary to force a tie-in sale.

Second, if such an attempt to force a tie-in sale were undertaken, there would be an aggressive response from other potential sellers of both coal and oil and gas which would undercut the tying firm. Again, the result would be that the first company would be a loser on both its oil and gas and coal production.

In addition, there is a further problem with the whole idea of tie-in sales. Even if we grant, for purposes of argument only, that some firm somewhere has monopoly power in either oil, gas or coal, that firm would be foolish to try to extend its monopoly power from one fuel to the others. A firm can only use the same monopoly power once. Given the uncertainties, dynamics and effectively competitive conditions of U.S. energy markets, an attempt to extend an assumed monopoly power in one fuel market to other fuels markets would likely result in a dissipation of that assumed power with a consequent economic loss to the firm which attempted the tie-in sale.

I must, however, reject the assumption that U.S. oil and gas firms have any monopoly power. It is an unrealistic assumption. I have attached a recent paper of mine, "Charges of Domestic Energy Monopoly: The Dog in the Manger of U.S. Energy Policy." I began analyzing the U.S. oil and gas industry in the early 1960's when I was a graduate student at Vanderbilt University. In my opinion, despite misinformed and nonanalytical contentions to the contrary, the U.S. petroleum industry is very effectively competitive.

The second general area where you might have concerns regarding tie-in sales is in the natural gas market itself. As you know,

sales in the interstate natural gas market involve a complicated scheme of vintaging of gas supplies. The whole concept of vintaging is an attempt to socially monopsonize the U.S. supply of natural gas. That is, through FPC regulation, society has set itself up as a monopoly buyer of interstate natural gas.

But this ill-fated attempt at systematic price discrimination against U.S. natural gas producers has created a substantial shortage of natural gas supplies in the interstate market.

Under conditions of shortage, it is in the joint interests of producers, consumers who wish to have additional gas supplies, and the nation for the price of gas sold in interstate commerce to be higher than regulated levels.

This applies to all gas. A user who wishes to consume additional gas cannot distinguish molecules of gas from one vintage or another at the point of use. Were the price of natural gas to be higher, price induced, voluntary, cost-effective conservation would encourage natural gas supplies to flow to their highest valued uses.

Thus, in terms of the conservation ethic, rollover of old gas contracts to higher price levels is a social benefit.

In addition, the historical record of the industry in terms of financing itself from internally generated funds, together with federal and state taxes on additional revenues, both suggest that the principal applications of such revenues would be in new exploration and production activities and as payments to public treasuries. Therefore, in terms of the environmental ethic associated with additional supplies of clean natural gas, roll-over of old contracts to higher prices is a social benefit. Also, in terms of balancing the budget and providing funds for other worthwhile public activities, rollover of old contracts to higher prices is a social benefit.

Nevertheless, there is concern regarding the rollover of old natural gas contracts to higher prices in terms of its potential effect upon consumers. In this connection, several points are of paramount importance:

1. There can only be rollover of old contracts to the extent that new gas supplies are available. New gas supplies are what we are after.

2. Producers will be able to rollover old gas contracts only during the transition in which there continues to be a shortage of gas. Perpetuation of the regulation induced shortage of natural gas in the interstate market intensifies the prospective rollover problem.

3. Many people are concerned about a "blip" in the price of new gas under deregulation. The "blip" may occur because pipelines are able to roll-in higher priced new gas supplies with lower priced old gas supplies. To the extent pipelines permit old contract rollover, they jeopardize their end-use market position based on a roll-in strategy.

4. Those users who are denied access to natural gas because of the regulation induced shortage are forced to use higher priced or less cost-effective substitute fuels. Thus, "consumer protection" amounts to the subsidization of one set of users by another. Because the regulation induced natural gas shortage is so large, pervasive and widespread, this willy-nilly cross-subsidization ultimately costs all of us.

I am much more confident in decentralized market action to sort out these conflicts in an orderly and socially effective way than I am in the ability of additional layers of administrative control and bureaucracy -- however enlightened -- acceptability to solve the natural gas shortage which previous controls have in fact created.

In the current shortage situation, there is a potential for other conflicts. It is also possible that your question regarding tie-in sales is connected to the reports of a "finders fee" having been paid by a Tennessee pipeline to a producing affiliate. I am not familiar with the specifics of that particular case. But I do know that to the extent there may have been anything improper about such a deal, it is a symptom of the regulation induced shortage.

Consumers, all consumers and users, will ultimately be better protected from unnecessary costs and shortages by allowing the competitive natural gas supply market to work.

The intrastate market is now clearing. Supplies equal demands, including industrial demands. There is little doubt that if interstate demands were allowed to compete on a price basis with intrastate demands, prices in the intrastate markets would be higher than current levels. But this is preferable to extending the shortage conditions which exist in the interstate market to the intrastate market through the price rollback provisions contained in H.R. 6831.

In a separate letter to Congressman Maguire, a copy of which is enclosed, I have detailed the calculation which indicates that H.R. 6831 is a price rollback to somewhere in the neighborhood of $1.48 to $1.58 per Mcf.

Current prices in the intrastate market average about $1.80 per Mcf, with some as high as $2.25. The intrastate market works. It was the source of 400-500 Bcf of emergency sales volumes to the interstate market during the winter of 1976-77. Were I more cynical, I would say that one of the intents of H.R. 6831 is to destroy the one clear example of the correct solution to our interstate natural gas shortage problems.

Instead, I simply submit that the natural gas pricing provisions of H.R. 6831 are a tragic mistake. A really courageous stand would have been for President Carter to take the initial step necessary to begin to rectify the consequences of decades of maladroit natural gas ceiling price controls. Such a step would have been to immediately follow through on his campaign pledge to Governors Boren, Edwards and Briscoe and to have proposed deregulation of the price of new natural gas.

You also inquired about the world price of oil. In my opinion, it is a technical misnomer to refer to OPEC as a "cartel." Cartels restrict output by formally allocating output among their members. No such formal allocation exists for OPEC. Nor do the major oil companies provide a prorationing mechanism. Rather, it is more appropriate to regard OPEC as a dominant price leadership situation, and Saudi Arabia is the dominant price leader.

Saudi Arabia has shown a willingness and ability to absorb the effects of swings in world demand and the outputs of other OPEC

members by adjusting -- both downwards and upwards -- its own rate of output.

The implication of this Saudi behavior is that it is unrealistic to base U.S. energy policy upon the implict or explicit expectation that there will be a break in the world price of oil. In this regard, I was distressed to hear David Freeman explain that the Administration position on deregulation of U.S. natural gas markets depended upon a more competitive world oil market. A more competitive world oil market is quite apt to be one in which prices will be substantially higher and Saudi Arabia is just another supplier.

My views on the structure and behavior of the world oil market are contained in a paper "Nations, Companies and Markets: International Oil and Multinational Corporations," a copy of which is enclosed. The current two and three tier pricing flap within OPEC may be regarded as an ingenious gambit by the Saudis to shift the burden of temporary world excess capacity onto other members of OPEC.

Over recent years, the U.S. demand for imported oil has, on a rough one-to-one basis been about equal to the total Saudi output of oil. Last winter, when the U.S. demand for imported oil jumped from seven million barrels per day to ten million barrels per day, the incremental three million barrels per day was greater than the total individual outputs of either Kuwait, Algeria, Iraq, Abu Dhabi, Libya, Nigeria, Indonesia or Venezuela.

Oil is a substitute for natural gas. The price rollback provisions of H.R. 6831 will perpetuate and worsen the U.S. natural gas shortage. This will spill over into increased U.S. demand for imported oil. One of the best ways to assure the tight world oil market which the Administration fears is to pass H.R. 6831 as it is presently formulated.

Conservation alone will not do the job -- not without severe mandatory restrictions on energy use. The reaction to the gas guzzler and standby gasoline taxes suggest how well such authoritarian measures as, say, ten gallon per week gasoline rationing would be received.

The Administration seems to be schizophrenic on the question of the relation between the world oil market and U.S. oil and gas prices. On the one hand, they warn us of a prospective tight world oil market with higher prices. The world price of

The Honorable Albert Gore
May 25, 1977

Page seven

oil is the principal component of the minimum social opportunity cost of increased U.S. energy consumption.

But on the other hand, the Administration is not willing to see the U.S. oil and gas industry receive prices for developing new domestic oil and gas supplies which are equal to the costs to the economy of the goods and services -- wheat, computers, caterpillar tractors, soybeans, airplanes, etc. -- which we must export to pay for the oil imports. Price rollbacks for natural gas increase our dependence on imported oil and aggravate this economic waste.

You also asked about the U.S. supply of coal. The U.S. has tremendous coal resources. But coal resources are not an economic supply. The idea that the supply of coal is demand limited -- that the domestic supply curve of coal is a clothesline that stretches from here to infinity at a constant price -- is a crucial component of the Administration thinking. I have no first-hand knowledge of the cost structure of the U.S. coal industry.

But I can offer you a parallel observation. Seven or eight years ago, there were many -- myself included -- who thought that the world supply curve of oil was such an infinitely constant clothesline at $2.00 per barrel. We were rudely surprised.

In just over seven years it will be 1985. I hope that we -- the American public -- are not as rudely surprised with regard to the economic costs of mining and using U.S. coal. But if we are, the consequences of having discouraged the full development of the domestic U.S. oil and gas potential -- as does H.R. 6831 -- will be the more severe.

Respectfully yours,

Edward W. Erickson

Edward W. Erickson
Professor of Economics and Business

EWE/lsn

Enclosures

cc: The Honorable John Dingell
The Members of the Subcommittee on Energy and Power

Mr. KRUEGER. We are prepared now for the next panel.

Mr. Lee White, the Consumer Federation; Mr. Ernst Habicht of the Environmental Defense Fund; Mr. Morton Simons, Simons and Simons, and Mr. Marvin Hicks, Executive Director, Northeast Oklahoma Public Facilities Authority.

Gentlemen, if you would come forward at this time, please.

STATEMENTS OF LEE WHITE, CONSUMER FEDERATION OF AMERICA; ERNST R. HABICHT, JR., PH.D., ENVIRONMENTAL DEFENSE FUND; JAMES MARVIN HICKS, EXECUTIVE DIRECTOR, NORTHEAST OKLAHOMA PUBLIC FACILITIES AUTHORITY; AND MORTON SIMONS, SIMONS & SIMONS

Mr. MAGUIRE [presiding]. The committee will come to order.

The first witness is Lee White, representing the Consumer Federation of America.

Mr. White, you have a statement?

Mr. WHITE. Yes, I do. Unfortunately, it is not in written form. I would appreciate, however, the opportunity to submit for the benefit of the subcommittee and the staff some fairly specific recommendations that I will undertake to implement some of the points that I hope to make orally.

Mr. MAGUIRE. The record will be left open for that statement.

Mr. WHITE. Thank you.

Mr. MAGUIRE. Will you proceed with your oral statement?

Mr. WHITE. Yes.

At the outset let me indicate that the Energy Policy Task Force of the Consumer Federation of America is a coalition. We have included within our groups labor organizations, farm organizations, the rural electric cooperatives, municipal electric distribution systems, municipal gas distribution systems, United States Conference of Mayors, Consumers Union, a number of other assorted groups.

In any large coalition of that sort it is evident that not every group will share every view. However, I think on the basis of a recent meeting of our organization, it was clear that there was great disappointment in the product of the Carter administration insofar as natural gas pricing is concerned.

We made practically a career out of our being opposed to what the Ford and Nixon administrations had proposed and had hoped and expected that there would be much more in the Carter proposals that would get our support. Quite frankly, there are some very useful and very positive aspects of the Carter administration's National Energy Act as it relates to natural gas. Particularly do we think it is long overdue to have extended controls to the intrastate market. The existence of those two markets separately has been one of the most mischievous factors in the entire natural gas situation that exists in the country.

Similarly, we support the idea that is not new, but nevertheless important, that is that the older gas, the lower-priced gas, ought to be reserved for residential and small commercial customers. This principal was involved in both of the bills that were passed by the House and the Senate last year, and we are glad that it is now a part of the program.

Obviously, in light of some of the conflicting statements made by President Carter when he was a candidate, we were pleased at least there was not a recommendation that there be deregulation of new natural gas.

We oppose strenuously, however, the use of the capped approach or the Btu equivalency approach.

As I listened to Mr. Freeman, it is hard not to feel sorry for somebody who is trying to come in the middle and who gets beat on both sides. But that does not mean that because he is being beat on both sides, or the administration is, that they are necessarily correct.

We strongly urge that the whole concept of cost-based regulation is far and away the most equitable system to use. It has within it the elements of consumer protection, and this is of course what we are about, and it is consumer protection. There are 40 million American families at the end of the network; they can perhaps, a

very few, switch to some other fuel, but for the most part we who have gas furnaces and gas stoves and hot water heaters are captives in the classic sense. We need to be protected.

To the extent that we are talking about allocating a scarce resource or a resource that we know is going to become even more scarce, we strongly urge there be positive and affirmative measures rather than using price. We believe price to be one of the most regressive techniques for rations and allocation that there is.

As a consequence, we strongly urge that the subcommittee reject the notion of $1.75 or any other Btu equivalency. I think no consumers that I know, no responsible consumer groups believe that any fuel ought to be underpriced. But we also believe we have to be protected against exorbitant prices when we have no alternatives.

We continue to believe that the natural gas producing industry is not workably competitive. We know about the linkage between the petroleum companies and the natural gas producing companies because they are one and the same. In the producing area, the gas producing area in this country it is a small handful of major corporations, names like Exxon, Gulf, Texaco, Phillips, that dominate the reserves.

We urge, therefore, that not only do we go back to, or continue the cost-based regulation, but that some of the elements of the Carter package be taken singly and looked at.

For example, we are led to believe that there should be an incentive for new gas. Yet the Carter package calls for $1.45 for expiring contracts, gas that could have been produced for costs that would yield a 15 to 18 percent profit at 26 cents, by the testimony and the actions of the producers themselves. To permit those expiring contracts to turn now to $1.45 is an unwarranted transfer of funds from the consumer to the owners of those reserves, most of which, if I may say, happen to be on public lands.

We do have a number of additional specifics, but let me just hit one more before I yield up my time.

The Carter bill says in the event that the Court of Appeals which has before it an appeal, and incidentally, the Consumer Federation of America is one of the appealing parties, claiming that the $1.42 rate set in order 770 is illegal, in the sense it is not supported by evidence.

The Carter proposal said it does not make any difference what the court says, we are going to stick to that price. That strikes us as an astonishing recommendation from an administration that presumably believes in procedures, judicial review, and fairness.

So I hope that this particular item will receive the attention of the subcommittee.

There is, of course, more but I think it is important to hit these basic points. With that I am prepared to yield any other time I may have.

[The additional material referred to follows:]

COMMENTS OF
CONSUMER FEDERATION OF AMERICA
RELATING TO THE "NATIONAL ENERGY ACT"

Part D of the "National Energy Act", which is discussed below, relates to among other things the pricing of natural gas.

Section 401(a) sets forth certain findings and purposes of the new proposed legislation relating to natural gas. This section attempts to restate the history of natural gas in a way which does not accurately reflect the true events. For example, Section 401(a)(3) provides that "the Congress enacted the Natural Gas Act of 1938 to provide protection for consumers and to provide a regulatory structure through which interstate pipelines could be assured a fair return of return." First, it should be observed that the Natural Gas Act was not passed to "assure" pipelines a fair rate of return but to limit pipelines which because of their uncontrolled monopoly power, were able to charge exorbitant rates, to a fair rate of return. Secondly, the Natural Gas Act in 1938 expressly provided that it was to regulate "natural gas companies." In the first case to reach the Supreme Court on the proper interpretation of the Act, involving Hope Natural Gas Company, the Supreme Court held that the term "natural gas company" applied to the production operations of a company as well as its interstate transportation of gas functions. This holding that the Gas Act extended to products, albeit at that time, they were interstate pipelines

engaged in production operations, was confirmed by several other Supreme Court decisions during the 1940's. It was clear from these cases, that Congress from the outset had intended for the Act to apply to wellhead operations. The only issue left open at that time was whether a company that was in the production operation of natural gas, but was not at the same time engaged in the interstate transportation of natural gas, would be subject to regulation. This issue was decided in 1954 by the United States Supreme Court in the first Phillips case which simply ruled that a so-called "independent" producer of natural gas was also a "natural gas company" within the meaning of the Natural Gas Act as enacted by Congress in 1938. Thus, the Phillips case in 1954 was not a radical departure from any prior interpretation of the Natural Gas Act by the Courts. As indicated, the Courts had held from the very beginning that the Act was intended to apply to the production of natural gas at the wellhead. In the early cases, the Supreme Court also made it quite clear that the Act was primarily designed to protect consumers against exploitation by natural gas companies.

Section 401(a)(4) states that "in 1954, the Supreme Court held that the Natural Gas Act applied to the wellhead sale of natural gas in interstate commerce, subjecting producers selling interstate gas, but not intrastate gas to a reasonable rate of return regulatory standard based on a determination of historic production costs." Here again, this section of the proposed bill is inaccurate. The 1954 decision by the Phillips case did not hold that producers selling interstate gas "but not intrastate gas" were subject to regulation under the Natural

Gas Act. In fact, the question as to whether the Natural Gas Act applies so as to prevent discrimination by natural gas companies operating in intrastate commerce against interstate users has never been definitively ruled upon by any court. At the present time, that issue is now before the United States Court of Appeals for the District of Columbia Circuit in an appeal from the Commission's Order No. 533. In that case, the Federal Power Commission ruled that it lacked jurisdiction over the intrastate market to prevent discriminatory activities by natural gas companies. That holding of the Commission, made in 1975, is now being challenged in an appeal taken by the American Public Gas Association and the Consumer Federation of America to the United States Court of Appeals. The issue before the Court is whether or not the Natural Gas Act prohibitions against "undue discrimination" apply to the intrastate activities of natural gas companies. The case is scheduled for oral argument before the Court on May 9, 1977.

Secondly, the Supreme Court in the 1954 Phillips case did not hold that producers subject to regulation at the well-head under the 1938 Natural Gas Act were subject to a regulatory standard "based on a determination of historic production costs." In subsequent cases involving the setting of wellhead rates, the Supreme Court has held that the standard of "just and reasonable" rates set by Sections 4 and 5 of the Natural Gas Act is a

broad, flexible standard designed to provide the incentive needed to produce new supplies of natural gas, but no more than an adequate incentive for that purpose. The Supreme Court has recognized that "non-cost" items may be considered by the Federal Power Commission in setting wellhead rates. This standard of "just and reasonable" rates under the Natural Gas Act has been hammered out by a long-line of decisions by the United States Supreme Court. Clearly, any change to a new standard would likely invoke an entirely new process of litigation to determine the scope and meaning of the new standard.

Section 401(a)(5) states that "the differential between the price of natural gas and oil has widened with the continuation of cost-based regulation of natural gas,[and] the four fold rise in world oil prices in 1973 and 1974..." Oil prices have increased because of "artificial" situations caused primarily because of the OPEC cartel. The artificial increase in oil prices has no relationship to the price of natural gas produced from domestic fields, many of which are on offshore lands owned by the United States Government. In the meantime, the price of natural gas has not been held down during the past eight years. In fact, the Federal Power Commission, under the appointments of industry-oriented personnel, has granted one round of rate increases after another to set ever-escalating pleateaus of new high prices for natural gas. In 1971, the major oil company producers of natural gas entered into a stipulation in the Southern Louisiana Area Rate Case that a 26¢ per Mcf wellhead price for

new gas would provide them with all of the incentive required for them to produce natural gas from the major area through 1977. The industry-dominated Federal Power Commission subsequently has scuttled this industry-sponsored and Court-approved settlement agreement and has set rates which first escalated to 52¢ per Mcf and finally in Opinion No. 770 and 770-A to $1.42 at the wellhead, despite the industry's earlier representations that 26¢ provided them adequate incentive. Under these circumstances, it is patently erroneous to contend that the price of natural gas has been held down by the Federal Power Commission "with the continuation of cost-based regulation." We would also be remiss in not observing that an oil shortage, by which we mean that domestic consumption had exceeded domestic production, has developed in this country in recent years though oil prices were historically unregulated, so it is clearly wrong to attribute so-called gas shortage to cost-based regulation of production rates.

Section 401(a)(6) provides that "as a result, the incentives to find new natural gas have declined along with the proved reserves of natural gas." Here again, this is an erroneous statement of fact. There has been absolutely no showing that the incentives to find new natural gas have, in fact, declined. Nationwide figures indicate that in 1973 and 1974, as well as 1975, the footage of successful new gas wells drilled were the greatest in the nation's history. The curious thing about this successful drilling, however, is that the companies were reporting

very little new findings. The "proved reserves of natural gas" have been reported only by an industry-dominated committee of the American Gas Association. The AGA proved reserves estimates have been attacked by independent studies and analyses as inaccurate and dramatically understated. The validity of the AGA reserves estimates is now a central issue in the pending case before the United States Court of Appeals involving the Federal Power Commission's establishment of a $1.42 Mcf wellhead rate. Accordingly, it cannot now be said accurately that "the proven reserves of natural gas" have declined.

Section 401(a)(8) provides that "a new system of natural gas pricing is needed that recognizes the costs and risks associated with finding future supplies of natural gas as well as the commodity value of substitutable fuels." This statement erroneously ascribes to the view that somehow natural gas prices have been too low under the present regulatory scheme. As indicated previously, the industry-dominated Federal Power Commission has undertaken many techniques to seek to increase the price of natural gas above its costs, including a fair return, to the industry, including any appropriate "non-cost" items deemed allowable under the intepretations by the United States Supreme Court. For example, in Opinion No. 770-A, the Federal Power Commission added a component of 43.5¢ based on assumed Federal income tax costs that the producers would

would pay. This item is under challenge in the United States Court of Appeals, and CFA is there contending that the evidence indicates that the industry does not now pay Federal income taxes due to various tax gimmicks, and very likely, will continue in the future to avoid paying any Federal income taxes on their natural gas producing operations. Therefore, a substantial part of the present $1.42 rate is not cost-justified. It seems inconceivable that the Presiding could call for a "new system of natural gas pricing" that would ask for higher prices than that which the present industry-dominated Federal Power Commission has established, when the present $1.42 rate is clearly improper and excessive in many respects. The provision for a new system of gas pricing to recognize "the commodity value of substitutable fuels" merely repeats a contention that the major oil companies engaged in the natural gas business has been making for many years, in each instance up to this time unsuccessfully. The industry has objected to cost-based pricing or any other regulated method of subjecting it to receiving only a "reasonable return" on its investment. The technique which the industry has so strongly lobbied for over the years has been that gas should be priced at the "commodity value of substitutable fuels." In every case to reach the Courts, including the United States Supreme Court, this standard has been definitively rejected as not consistent

with the mandate of the Natural Gas Act of 1938 "to protect consumers against exploitation by natural gas companies." To now have this same standard embodied in the President's "National Energy Act" is shocking to consumers.

Section 401(b) provides that the purposes of this part are "(1) to bring the natural gas market back into better balance by reducing the demand for natural gas and increasing the supply through the establishment of an incentive based pricing approach for new natural gas...." The basic concept involved here is erroneous. The attempt at "reducing the demand for natural gas," by setting artifically high prices, which unduly burden consumers who are already overburdened by extremely high energy bills as a result of the just completed winter heating season is patently fallacious. Rather than trying to use drastic price increases to reduce the demand for natural gas which because of a number of factors including its clean burning characteristics, is relatively inelastic as to high priority users, demand should be reduced by a fair allocation plan which allocates the gas to the desirable uses. Any attempt to accomplish this through new high prices merely unnecessarily burdens the already overburdened consumer.

Section 402(a)(5) defines the term "new natural gas" as gas which is produced from a new lease on the Outer Continental Shelf or which is produced other than on the Outer Continental

Shelf from a new well, the completion location of which is 2.5 miles or more from an old well or (ii) "the completion location of which is at a depth of 1,000 feet or more in excess of the depth of the completion location of any old well ... provided that the completion location "... is not in the same producing zone as the completion location of any such old well." This definition seems to reject a definition of "new natural gas" recently adopted by the Federal Power Commission in Opinion No. 770-A. In that decision, the Commission refused to agree to an industry proposal that gas could receive the new gas price merely because there was a "recompletion of an old well to a new level of depth." The Commission's decision in Opinion No. 770-A would in effect be reversed by the language of this section.

Section 402(b) states that "[t]he President shall have the authority to define, by rule, the terms used in this [definitional] part in a manner consistent with the purposes of this part". Since "this part" contains, among other things, the definitions of "Btu related price," "inflation adjustment," "new natural gas," "old natural gas," etc. this delegation of virtually unbridled authority to the President (which in turn will undoubtedly be delegated to the Secretary of Energy) in effect gives the Secretary authority to re-write the Act and to set rates at any level applicable to whatever vintage of gas he chooses. Perhaps more than any

other section of the proposed legislation, this empitomizes the "politicizing" of the ratemaking process.

The bill in Section 403, Section 404, Section 405, Section 406, Section 408, and Section 410 authorizes the President to establish "by rule" certain prices for old and new gas, and to take certain other actions with respect thereto. These provisions are in conflict with the present provisions of the Natural Gas Act authorizing the setting of prices only by decision of an independent regulatory commission, i.e., the Federal Power Commission. The provisions also appear to conflict with the provisions of the proposed Energy Organization Act, S. 826, which would transfer the functions of the Federal Power Commission to a new Department of Energy and allocate those functions at the discretion of the Secretary of Energy between an independent Board of Hearings and Appeals and the Administrator of the Economic Regulatory Administration. Nothing in the proposed Organization Act bill, S. 826, vests any jurisdiction in the President to determine natural gas rates. To the extent that regulatory functions to adjudicate gas rates are vested in the Board of Hearings and Appeals under the proposed Organization Act, it would clearly be inconsistent to seek to vest such powers in the President, as proposed in the "National Energy Act." The setting of rates for natural

gas, new or old, should not be determined by Presidential (or any other) rulemaking. CFA strongly believes that natural gas wellhead rates, as well as all the other ratemaking functions of the FPC, should be undertaken by an independent board in an evidentiary-type ajudicatory proceeding with the full right of cross-examination. To the extent that such an independent adjudicatory board is established within the Department of Energy, it should have jurisdiction to establish natural gas rates only after full evidentiary hearings. Ratemaking is an essentially adjudicatory process, and for the Secretary of Energy, or his delegate, to determine rates without full evidentiary hearings and absent the "just and reasonable" standard set forth in the Natural Gas Act would improperly convert the ratemaking process from its present quasi-judicial nature to a political function. The net result would be the loss of confidence of the American consumer in the rate-setting process.

Another section of the Act contains a definition of the requirements of an evidentiary hearing which should be applied to the setting of natural gas rates. Section 502 (a)(14) defines an "evidentiary hearing" as one

> "...which includes notice to, and an opportunity for, participants to present direct and rebuttal evidence and to cross-examine witnesses and which results in a written decision based upon evidence appearing in a written record of the proceeding, and ... which is subject to judicial review."

No less of a standard should apply to the crucial matter, from the consumer viewpoint, of setting wellhead rates.

Section 404 relating to the establishment of a maximum lawful price for sales of new natural gas provides that the President shall, by rule, establish such price based on "a price equal to the current Btu related price." The current Btu related price is defined as the average per barrel crude oil acquisition costs for refineries in the United States for the most recent quarter divided by a factor of 5.8. Section 404 thus completely abandons the existing "just and reasonable" regulatory standard of the Natural Gas Act as interpreted by the courts and substitutes in its place a standard whereby natural gas will be priced by reference to oil prices. Nowhere in the "National Energy Act" are there any standards for the pricing of oil. Thus, Section 404 would subject American consumers to continual escalating prices on new domestic supplies of gas based upon an undefined ceiling, which in turn could depend in large part upon the actions of the OPEC cartel. This is unacceptable to American consumers.

In the fact sheet from the White House preceding the "National Energy Act", it was estimated that the initial price of new natural gas would be set at $1.75 per Mcf at the wellhead. Such a price is greatly in excess of the highest price which the Federal Power Commission has prescribed for new gas in Opinion 770 of $1.42. The Federal Power Commission's $1.42 price is now under review by the United States Court of Appeals for the District of Columbia Circuit. The CFA and other consumer groups have sought to demonstrate there that

many of the components of the $1.42 price are excessive. Thus, to increase the price for new gas to $1.75 as proposed in Section 404, and to thereafter have it pegged to the price of oil subject to increase through action by the OPEC cartel, is completely unjustified.

Section 405 applies to the setting of a maximum price for sales of old gas under existing contracts. It provides that the maximum ceiling should be either the contract price or the price that was determined just and reasonable by the Commission and was in effect on April 20, 1977 "(without regard to any appeal of such determination pending on April 20, 1977)". This provision directly seeks to nullify the pending appeal of the Opinion 770 case before the United States Court of Appeals by CFA and a large of group of consumer interests. The case has been thoroughly briefed by all parties and oral argument was held before the Court on March 23-24, 1977. In view of the fact that the Court of Appeals has not rendered a decision on the matter at this time, it would be improper for the Congress to establish a rate for old gas set by the Commission currently under appeal. Furthermore, such action by Congress would circumvent the authority, if not the dignity, of the Court. The bald attempt to cut off the appeal rights of the large group of consumers seeking redress from the Commission's Opinion No. 770-A, in addition to being an unjustified

slap in the face of the judiciary branch of government, is inimical to the interests of the American public.

Section 406 authorizes the establishment of a maximum price for producers of old natural gas under a new contract. Section 406(b) provides that in the case of old natural gas which is committed to interstate commerce on April 20, 1977, or which is produced from a new well or a new lease, the maximum price shall not exceed $1.45 per Mcf. This provision would apply when a contract relating to such old gas expires and is renewed by a new contract. This provision would permit producers an even higher price for old gas than that which the Commission allowed in its recent Opinion No. 770-A. Under the terms of that opinion, when old gas contract expire, producers are entitled to certain higher prices. For example, Opinion No. 770-A provides that old gas priced under area rate regulation at 26¢ per Mcf since it was discovered and drilled prior to 1973) would be entitled to a rate of 52¢ per Mcf simply upon the expiration of the contract and the entering of a new contract between buyer and seller. This provision in Opinion No. 770-A has been attacked on appeal by a large group of consumer interests as improper because it, in effect, would allow the doubling of the price for gas despite the fact that the original price was cost-based and no additional costs of any magnitude were incurred by the producer, other than the

price of the ink required to sign a new contract. The "National Energy Act" provision would allow that old gas to escalate not to just 52¢, but to go to $1.45 per Mcf. This is directly contrary to even the Commission's liberal ruling in Opinion No. 770-A. This is presently estimated to have an annual impact of $1.3 billion, 1/ which monies will represent clear, windfall profits to the producers because they have not been required to incur any new costs, but will receive the additional monies simply through the happenstance of the expiration of their existing contracts. Under the present Natural Gas Act, Section 7(b), no producer may abandon any sale to interstate commerce merely because his contract expired. Thus there is no reason why such gas should not continue to be sold to the interstate users at prices already determined to be just and reasonable for such flowing gas since such prices will return to the producers all of their costs of whatever nature, plus a fair rate of return, and avoid the windfalls resulting from per se excessive rates called for by Section 406(b).

Section 406(c) provides that in the case of old natural gas which has not been dedicated to interstate commerce, it shall be entitled to the price for new natural gas, i.e. the conservatively estimated $1.75 resulting from the application of the standard of the "current Btu equivalent price" for oil. By establishing a higher price for gas that has been withheld

1/ Source: FTC Data

or not previously dedicated to the interstate market (i.e., $1.75) as distinct from gas from old contracts that had been previously committed or dedicated to interstate commerce (i.e., $1.45), the bill not only insures windfall profits for the sellers of this old, low cost gas but in addition, discriminates in favor of those producers who have willfully declined to supply gas to the interstate market. The estimated annual impact of this provision is $1 billion. 1/

Sections 406(b) and (c) also would apply to shut-in gas which, if previously committed to interstate commerce, would get $1.45 under Section 406(b) and, if uncommitted as of April 20, 1977, would get the "Btu equivalent" price of $1.75 under Section 406(c). (A dollar impact of this provision is being worked up but is not presently available.)

Section 408 of the bill would authorize special pricing provisions "if the President determines that such special price is necessary to provide incentives for the production of [high cost] natural gas ...." Under the present decisions by the United States Supreme Court relating to the setting of wellhead prices, provision is made whereby producers can seek to establish a special exception from an applicable wellhead rate where costs justify such an exception. These provisions

1/ Source: Bureau of Mines Data.

of the existing law are completely adequate, CFA believes, without the need to establish new special legislation in this regard. A further problem with Section 408, is that it lists situations in which special high rates might be set to include "in depths of more than 500 feet of water" and "more than 15,000 feet below the surface of the earth." These are completely inadequate criteria for determining whether or not a special price should be required. The facts indicate that some of the most prolific producing wells have resulted from depths of more than 500 feet of water or at depths of more than 15,000 feet below the surface of the earth. While the costs of these wells may be more, the average cost per Mcf (i.e. the unit cost) of the gas produced from these wells may very well be substantially below that of a shallow well. The key issue is the determination of the cost per Mcf produced. Factors such as depth of more than 500 feet of water or more than 15,000 feet below the surface of the earth are but one part of the equation, specifically the numerator, necessary to the determination of that key matter. CFA believes that "special pricing provisions" should apply only when producers can establish that the costs per Mcf produced is such that the revenues under existing prices will be insufficient to cover all costs, including a fair rate of return.

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Section 408(c) requires the Federal Power Commission to increase any prices previously set by it to the extent permitted by the terms in the contract, to "cause an inflation adjustment in such prices...." The amount of the adjustment is defined in Section 402(a)(20). It appears unnecessary for Congress to enact any mandatory increases by means of an automatic inflation factor, when such an increase would not have been permitted under prior rulings of the Commission and there is no evidence of any relationship between the inflation factor and the cost of producing the flowing gas in question.

Section 409(a) provides that the new high prices directed by the Act "shall be deemed just and reasonable" and may not be disallowed by the Commission under the terms of Section 4 and 5 of the Natural Gas Act. The problem is that Sections 4 and 5 of the Natural Gas Act provide for "full hearings" to establish proper "just and reasonable" natural gas rates and contemplate the production of full evidence by the producers as a condition precedent to their obtaining rate increases. All of those procedures designed to protect consumers would be swept aside by the new Act in its direction that the new national gas rates will be established not on the basis of any evidence of costs or fair rate of return or other factors traditionally considered appropriate by the United States Supreme Court for wellhead regulation, but by the establishment of an essentially "political" wellhead rate, without the need for any proof or

evidence by the industry to justify the new rate levels. Similarly, Section 409(b) provides that the Commission may not deny a certificate of convenience and necessity under Section 7 of the Natural Gas Act on the basis of price "if such price is not in excess of the maximum lawful price" to be established under the Act. This provision also would set aside the long line of decisions by the United States Supreme Court which require the FPC in granting a certificate to determine whether or not the price that would be charged under the certificate as an initial price is in line with the "just and reasonable" standards of Section 4 and 5 of the Natural Gas Act.

Section 410(a) provides that "[a]ny rule promulgated by the President ... shall be enforceable to the same extent and in the same manner as a regulation, or rule, promulgated under the Emergency Petroleum Allocation Act of 1973." It is not clear why the Act refers to the enforcement provisions of Emergency Petroleum Allocation Act rather than the Natural Gas Act. Furthermore, nothing in Section 410 or any other provision describes procedures relating to judicial review of any new rate set by the President (or his delegate). It would appear that even under the ratemaking provision of the Act as proposed, the judicial review provisions of Section 19 of the Natural Gas Act should apply to any rate-setting actions, and any attempt to cut off or terminate the right of judicial review of rate-setting decisions by the President or the Department of Energy

or the Federal Power Commission, as the case may be, would not be in the public interest. The need is to have rates which result from and hence reflect the integrity of the adjudicatory process and thereby gain the deserved confidence of the American people. Rates established by partisan political processes, such as by rule issued by the President (or his delegate) without evidentiary hearings and without any right of judicial review, will be immediately recognized by the American people as arbitrary and untrustworthy. The result would be a breakdown in confidence in the processes of government. Since setting of rates takes property, i.e., money, from the pockets of inflation-weary consumers and transfers that money to the pockets of the gas-company producers, it is imperative that due process be accorded the consumer in a full, fair adjudicatory proceeding. This is not provided in the "National Energy Act" for natural gas rates or in the earlier Energy Organization Act, S. 826. 1/

Section 412(a) provides that "[t]he Commission may grant abandonment under Section 7(b) of the Natural Gas Act at any time prior to the committing or dedication of natural gas for interstate commerce." This appears to amend the present standard of Section 7(b) of the Natural Gas Act, which is an important safeguard for consumers served by interstate pipelines. Under existing Section 7(b) of the Natural Gas Act, gas dedicated to interstate commerce may not be abandoned without a hearing

1/ As noted above, however, §502(a)(14) of the National Energy Act provides for evidentiary hearings for the less important rate design proceedings under Part E.

and a showing by the producer that such abandonment is in the public interest and will not injure the interstate users. It would appear that Section 412(a) would radically change that standard for no apparent reason and in the face of overwhelming evidence that Section 7(b) has served to protect consumers from the abuse of monopoly power by producers and pipelines.

Section 414 relating to the "incremental pricing of natural gas" provides that any portion of the average cost of natural gas delivered after the enactment of the Act which exceeds the average cost of natural gas to the pipeline company during the most recent 12 calendar months ending before enactment of the Act shall be allocated in the rates and charges to low priority uses, i.e. all uses other than residential and small commercial. This provision appears to be designed for the beneficial purpose of requiring that the incremental high cost of the new gas supplies would be allocated to low-priority users, and not be shouldered by the high-priority residential and small commercial customers. While such a provision is beneficial to consumers, clearly the implementation of such a provision in the pipeline rates to its many distributor-customers will be a very complex and difficult task to accomplish. One provision in Section 414(a) apparently could wipe out the benefits to residential and small commercial users. It states that the incremental pricing formula to low-priority users will

not apply "if such allocation would result in rates or charges for such uses equal to an amount no greater than the reasonable price (as determined by the President) of substitute fuels." Substitute fuels could constitute any exotic fuel that might be available, such as imported LNG. In any event, the exception appears to be a loophole which could negate the entire incremental pricing scheme to the detriment of the heavily burdened residential and small commercial customers.

The provisions of Section 415 authorizing regulation under the Natural Gas Act of synthetic gas appear beneficial and in the public interest.

Section 416 would amend the "Emergency Natural Gas Act of 1977". The first group of amendments would make the allocation authority of the President in Section 4 of the Emergency Act applicable to any pipeline, whether that pipeline was an interstate or intrastate pipeline. While this is a beneficial change, it is not substantially different from Section 4 of the present Emergency Act, which permitted the President to order during a national emergency any intrastate pipeline to transport interstate gas. Accordingly, this change appears merely procedural, rather than of any real substance. A major omission from the amendments, as well as from the original Emergency Act, was to give the President the power to make an

allocation of gas during a national emergency from any "producer" as distinct from a pipeline. If producers have available supplies of natural gas, there would appear to be no reason why the President should not allocate those supplies of natural gas during a national emergency to prevent closings of factories or the cure (or assist) other emergency situations. The omission of allocation authority over producers is a major loophole in the Emergency Act and in the amendments proposed in Section 416 of the "National Energy Act."

Section 416(5) would amend Section 4(a)(1) of the Emergency Act by striking out "April 30, 1977" and inserting in lieu thereof "April 30, 1979." There would appear to be no adverse effect by extending the President's authority to allocate natural gas during an emergency for an additional two-year period.

While the amendments in Section 416 to the Emergency Natural Gas Act of 1977 do not so state, it appears that there is no amendment proposed to Section 6 of the Emergency Act. That section permitted the President to authorize any interstate pipeline or distribution company to purchase gas at rates during the emergency in excess of the ceiling rates established under the Natural Gas Act. It thus appears that Section 6, which authorizes such emergency sales only until August 1, 1977 will expire by its own terms. This is beneficial. Any attempt to extend the emergency authorization of Section 6 of the Emergency

Natural Gas Act of 1977 would be contrary to the best interests of American consumers. Experience has shown that if there is establishment of a procedural loophole whereby producers may obtain a rate in excess of established national rates, this inevitably results in little gas being sold at the established rate. For example, the procedures used by the Federal Power Commission in authorizing limited term sales, optional pricing procedures, and emergency sales, all at prices in excess of the established "just and reasonable" wellhead rate, resulted in virtually all quantities of natural gas that were sold to interstate consumers in recent years being priced under those loopholes provisions. The same would be true for any new ceiling rates established under the National Energy Act if a loophole existed whereby producers could obtain more than the ceiling. Accordingly, it is imperative that Section 6 of the Emergency Natural Gas Act of 1977 not be extended, and hence, CFA supports the President's decision to terminate this loophole provision in the 1977 Emergency Natural Gas Act.

Mr. MAGUIRE. Let me just ask if Morton Simons has arrived? If he has, he may join the panel.

Our next witness is Ernst Habicht, Environmental Defense Fund.

Mr. Habicht.

STATEMENT OF ERNEST R. HABICHT, JR.

Mr. HABICHT. Thank you, Mr. Chairman.

I would like to summarize my written remarks.

I start out by noting that each pipeline carrying gas in the country has two ends; they are physically tied together, but they have no economic relationship to each other that can be observed under present policies on natural gas.

Current policies on gas promote the consumption of that fuel and discourages conservation. They discourage rational State energy policies regarding gas. They discourage the production of geologically conventional but expensive gas. They certainly inhibit obtaining good information about unconventional geologic gas. And, perhaps least observed, current policies waste both capital and other fossil fuels through uneconomic investments in exotic gas supplies and encourage the further importation of liquid fuels.

Each of these items deserves great elaboration. We simply do not have time for it today.

But it seems to me a successful policy on natural gas has to couple the horse of economic efficiency to the cart of social equity. And we have to pay attention to both ends of the pipelines.

The Carter proposal to impose taxes on flowing gas and rebate those taxes in part, or entirely, to gas consumers makes good sense. It lets consumers know what the real cost of gas is; that is to say, the opportunity costs of gas, while at the same time it provides them with capital to use gas more efficiently.

It is as if—and perhaps this is a suggestion you might want to entertain—we could set up an entitlements program for gas use in the United States. Each customer, using gas, who today has a property right in gas, could trade that property right, efficiently, at a value for the gas traded equal to the opportunity cost of not having gas at all. That would permit much more economic flows of gas in our economy, provide people with the capital to conserve gas, and get gas under the burners of those who could not otherwise acquire that fuel unless they moved to Texas or Oklahoma or Algeria.

We seem to recognize only those interests who are presently enjoying gas service, but steadfastly ignore interests who really do not know how badly they are being abused by current policies.

The costs to a residential customer who cannot get gas today are very frequently the costs of electric heat. That is a price for space conditioning two to three times the cost of gas in the intrastate market today.

We do not hear anything from the innovators who are going to come forth and help us solve our problems once gas prices make good sense. That is how the economy of this country came to be so strong, through the use of a sound market mechanism to encourage innovation and invention, and through employing new technologies as rapidly as possible.

Of course, we do not hear anything from the taxpayers who are being asked again and again to set forth subsidies to provide new uneconomic gas supplies. These taxpayers are being abused both through the Federal income tax code and higher property taxes. Some exotic facilities are being financed with municipal revenue bonds. To do that sort of thing on the scale it is going on now and in the future will sure drive up everybody's property taxes throughout the country. Yet no one will know that the reason taxes are going up is that they are subsidizing the energy industry.

In summary, there are four elements of a successful natural gas policy. Insofar as is possible, prices paid by all consumers for natural gas should reflect the replacement costs of that fuel. To effect this reform we must impose taxes on flowing gas and see to it that gas rate designs make good economic sense. Revenues derived from such taxes, or from rates premised on the replacement costs of gas must be rebated equitably so that gas users have the capital for making cost-minimizing investments.

We simply have to get away from rolled-in pricing which disguises the prices of uneconomic gas supplies and which permits gas utilities to waste gas, waste oil, and to make $5 or $6 gas or more and

average these costs with cheap flowing gas. That is where the economy is bleeding—importing naphtha, turning it into gas and selling it at a price of $1.50 when its real costs are three times as great.

The inter- and intrastate gas markets have to be integrated. In accomplishing this task, we must insure that unfulfilled demand in the former does not drive prices in the latter to unconscionably high levels. Thus a lid on flowing gas prices paid producers must be imposed in such a manner as to avoid dramatic contractual price escalation when the entire nation can bid effectively for instrastate gas. This seems to be a relatively straightforward matter to accomplish.

We must establish a market system which would permit one customer to buy gas from another as well as satisfy other parties affected by the transaction. A "finder's keepers" rule for conserved gas must be included.

We must deregulate the price of new gas. If this be done by phases, the near-term cap on prices ought to be dictated by a natural gas target price equal to the Btu equivalent price of imported petroleum substitutes for gas. In effect, we are already paying close to this price, through unnecessarily high levels of imported fuels, but have not yet recognized it.

There are some useful guidelines to a successful gas policy. We should not overlegislate the industry where regulation or market price activities will produce a more efficient outcome. We should not predicate gas prices on upward moves in the future. We ought to test each policy instrument so that it is neutral as to price in the future.

We ought to recognize that there are peculiar institutional constraints on some energy users and let state regulatory authorities have the options to deal with these. Consider, for example, the landlord-tenant situation in a building master-metered for gas. Some of these buildings of course are rent-controlled. We ought to permit utilities to come into those situations and provide investment capital for the conservation of gas where no other party has any incentive to effect such a gas saving investment. Such investments might go into the rate base to be expensed in accordance with how the benefits and the costs are actually going out into the economy.

We have to quit subsidizing new gas from conventional or unconventional geologic sources—through the tax laws and other measures—relative to conserving gas. We have to treat the two energy sources on an equivalent basis. There is no little demon that can distinguish molecules of methane from a new gas field, from a coal gasification plant, or that gas freed up from houses and burners having inefficient usage today. There is no physical distinction to be made of that gas and there should be no economic distinction whatsoever. Indeed, since conserved gas is the cheapest resource and environmentally the most beneficial, we ought to be subsidizing that relative to all other sources.

Thank you very much for the opportunity to appear before you.

[Mr. Habicht's prepared statement follows:]

Testimony of Ernst R. Habicht, Jr., Ph.D., Director
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Before the House Interstate and Foreign Commerce Committee
Subcommittee on Energy and Power

May 18, 1977*

Mr. Chairman and Members of the Subcommittee:

Thank you for your invitation to appear before you today. My name is Ernst R. Habicht, Jr. and I am employed by the Environmental Defense Fund, Inc. (EDF) as Director of the EDF Energy Program. As the copy of my attached resume indicates, for nearly six years I have sought to render our energy policies more sensible.

Introduction

My endeavors are focused on energy technology, economics and environmental impacts. My colleagues and I have been particularly heavily involved in analyzing and reforming the pricing and investment policies of regulated energy suppliers, principally our electric and gas utilities through which flows over half of all the energy in the U.S. economy. Our goal is to minimize the total social costs of energy production and consumption.

To implement the reforms we seek, EDF has intervened in numerous state and federal regulatory proceedings during the last five years. At first, the reforms we advocated met with sharp resistance. But starting in 1974, utility regulatory authorities began to adopt our ideas. By quietly but forcefully advocating some very good ideas at the appropriate time and place, much of what was thought revolutionary when we first suggested it has become the conventional regulatory wisdom. Indeed, one of my former colleagues is now the Vice Chairman of the New York Public Service Commission and another has just been confirmed as Chairman of the Wisconsin Public Service Commission.

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* The reader is referred to my testimony before the House Committee on Science and Technology of April 7, 1976 and before that Committee's Subcommittee on Energy Research, Development and Demonstration (Fossil Fuels) of February 24, 1976.

Because of EDF's unique internal structure and heavy reliance on outside technical and economic experts, we have developed an interdisciplinary and unique perspective on the nation's energy dilemma. I hasten to add that we are not interested in making arguments where there is no possibility for reform; rather, we seek to identify common interests between disparate groups and thus move energy policies in a direction that will minimize both environmental and economic costs.

Our Senseless Natural Gas Policy

Current federal policies regarding natural gas have seven major effects, no one of which is sensible. These are:

1. To promote gas consumption;
2. To discourage gas conservation;
3. To discourage rational state regulatory policies;
4. To discourage the production of geologically conventional gas;
5. To inhibit attaining good information concerning the costs of geologically unconventional gas;
6. To waste both capital and fossil fuels through uneconomic investments in exotic gas supplies; and
7. To encourage the further importation of liquid fuels.

Each of the above items deserves far greater elaboration than our limited time today permits. But the main features of our current gas policy are best highlighted by some specific examples.

First, current rate designs laid down by the Federal Power Commission and state regulatory authorities are enormously promotional of gas consumption. In particular, the declining block rate design conveys the impression that the more we consume the cheaper the gas will become. While this was indeed true for several decades, it has become an historical curiosity and to continue to rely on declining block rates, especially during periods of peak seasonal demands for gas, is utterly irrational. Perhaps the most perverse outcome of this policy is that, through the mechanism of rolled-in pricing, coupled with declining block rates, we wind up selling synthetic natural gas at a price of between 1/4 and 1/2 of its actual costs.

Second, we are doing almost everything we can imagine to discourage gas consumers from using that fuel more efficiently. Obviously, the way we price gas is an incentive to consume, not to conserve. Also the Federal Power Commission's policies for allocating gas among a shrinking array of industrial consumers creates further disincentives to conserve gas. Few industrial gas users would invest in gas-saving projects when to do so has little or no impact on the timing or severity of their curtailment. And no rational state regulatory authority is going to encourage investment in gas conservation knowing that the FPC is quite likely to allocate the cheapest "saved gas" to another region of the nation. Thus, current policies to effect conservation of natural gas are premised almost entirely on altruism.

Third, through wellhead price controls established at a level below the cost of alternative fuels (i.e., below the opportunity costs of gas -- which would reasonably be expected to determine the market clearing price for that fuel), we have discouraged the exploration and production of gas. This is sorely exacerbated by a climate of uncertainty coupled to an expectation that the "regulated" price is likely to climb each year. Why look for gas this year when it's quite likely the price will be higher next year? This is the mirror image of promising homeowners a tax rebate for investments in insulation at some indefinite point in the future: intelligent gas users are not going to invest in insulation this year if they think they will get a tax rebate for such an investment next year.

Fourth, current policies compel the gas utility industry to make some of the least sensible investments in gas supplies devised by twentieth century man. Again and again, the Congress has been beseeched to subsidize gas-producing technologies which could not meet a market test. Perhaps the least rational of these is the Lurgi process -- a technique for turning coal into gas that is over four decades old. We are also converting imported refined petroleum feedstock into natural gas and importing liquified natural gas, both of which, with increasing frequency, are sold at prices far below their actual costs.

Fifth, while there may be enormous gas resources left to tap, we have no idea just what they will cost to produce. Current policies have the effect of subsidizing the sale of extraordinarily expensive gas while withholding potentially cheaper gas from the marketplace. In no way can this be in the interests of gas users, the environment or those who invest in gas supply ventures, including federal income taxpayers who increasingly are a source of utility investment capital.

Only with a complete understanding of how current gas policies drive us to uneconomic, inefficient and environmentally destructive uses of both capital and natural resources can we properly evaluate a more sensible policy. It is also important for us to understand that there are at least three major interests whose views will not be adequately expressed to the Congress or the Administration.

The first group is growing and consists of many individuals and firms who simply cannot get gas at any price. By far the most numerous are residential and commercial customers who must tum to number two oil, propane or electricity for domestic space and water heating. Most of those who must resort to electricity are condemned today to use antiquated, inefficient and ridiculously expensive technologies in place of gas. There are also potential industrial gas users who cannot locate their facilities near the markets for their products because natural gas is unavailable to them there. Instead, they must either move to a gas producing state or take their operations abroad in order to obtain a firm supply of feedstock.

The second, least visible group consists of those who will solve our problems when energy prices become rational. These are our innovators -- individuals, small firms and large corporations -- whose very inventiveness is a function of these prices. It is their efforts that will present us with a vast array of new technologies, about which we know virtually nothing today, permitting us to reduce the operating costs of energy using devices. Innovation will also permit us access to both traditional and exotic forms of energy at lower cost and with less environmental damage than anyone presently envisages.

The third, potentially most visible but least informed group consists of taxpayers at virtually every level of govemment. It is this group which is already supplying a good deal of poorly utilized investment capital for the energy industry. And it is upon this group that a large burden of many uneconomic proposals for future gas supplies is likely to come to rest.

The Goals of a Sensible Natural Gas Policy

It is with the understanding that present policies regarding natural gas promote consumption, discourage conservation and stifle innovation and that those most aggrieved by present policies are least likely to be heard from that we can set forth four essential goals of a sensible national policy regarding natural gas:

1. Insofar as is possible, prices paid by all consumers for natural gas should reflect the replacement costs of that fuel. To effect this reform we must impose taxes on flowing gas and see to it that gas rate designs make good economic sense. Revenues derived from such taxes -- or from rates premised on the replacement costs of gas -- must be rebated equitably so that gas users have the capital for making cost-minimizing investments. And, if gas users are to make intelligent decisions, we must abolish the persistent understating of gas costs inherent in rolled-in or average cost pricing, regardless of the source of new gas supplies;

2. The inter- and intrastate gas markets must be integrated. In accomplishing this task, we must insure that unfulfilled demand in the former does not drive prices in the latter to unconscionably high levels. Thus a lid on flowing gas prices paid producers must be imposed in such a manner as to avoid dramatic contractual price escalation when the entire nation can bid effectively for intrastate gas;

3. We must establish a market system which would permit one customer to buy gas from another as well as satisfy other parties affected by the transaction. A "finder's keepers" rule for conserved gas must be included. Though gas consumption has become

a property right, it is a peculiar one in that gas cannot now be traded among existing or potential users. Interestingly, if this sort of transaction were permitted, after a few years we would have a much better idea of the market clearing price for gas; and

4. We must deregulate the price of new gas. If this be done by phases, the near-term cap on prices ought to be dictated by a natural gas target price equal to the Btu equivalent price of imported petroleum substitutes for gas. In effect, we are already paying close to this price -- through unnecessarily high levels of imported fuels -- but have not yet recognized it.

While no element of the program I suggest is novel to the Congress or the Administration, together my suggestions may come as a surprise. I repeat that my conclusions regarding a sensible natural gas policy are set forth after an exhaustive examination of just how natural gas producers, utilities and consumers are motivated under prevailing policies.

Some Useful Guidelines

There are several overriding features to a successful energy policy. First, we should not make the mistake of legislating the expectation of everlastingly high (or low) prices. Each element of the policy ought to be tested and found neutral with respect to long run price increases or decreases.

Second, we ought not legislate what is inherently a regulatory, or especially, a marketplace function. Frequently, it takes many years, even decades, to perceive the adverse impacts of an ill-chosen policy instrument. For example, the consequences of regulating wellhead prices for natural gas did not make themselves felt significantly for many years after their imposition.

Third, we must recognize that there are special institutional constraints on some energy users, the burden of which can only be eliminated by expanding the array of options available to them. For example, numerous gas consumers rent commercial

or residential space in structures which are master-metered. For them, as well as for a number of financially strapped municipal and state governments, one of the best ways to minimize costs is to permit gas utilities to incorporate at least a portion of gas-conserving investments in their own rate bases. These investments should be expensed in accordance with how the benefits and costs are actually incurred. State regulatory authorities must have the flexibility to devise and adopt energy policy instruments suited to the peculiar circumstances at hand.

Fourth, each policy instrument must be tested and determined to be at least neutral with respect to conventional gas supplies on the one hand and gas conservation on the other. We can no longer afford to discriminate against investments which would permit more efficient utilization of present gas supplies. This is especially the case since conserved gas is by far the cheapest of any gas supplies or substitutes we have at hand. Indeed, in consideration of the environmental and other benefits of energy conservation, we should be discriminating in its favor.

To put my testimony into a broader context and to convey my impressions of our current and proposed energy policies, especially as they concern natural gas, I have attached my brief analysis entitled: "Toward A Visible, Workable Energy Policy." I must note regretfully that time has not permitted a more comprehensive analysis and I express our sympathies to Committee members and staff who are working under formidable constraints in evaluating an extremely complex legislative package.

Again, thank you for the opportunity to set forth our views on a sensible natural gas policy.

EDF is a nationwide coalition of scientists, lawyers and economists dedicated through litigation and involvement in administrative government proceedings to the preservation and improvement of environmental quality. It is supported by an active membership of some 45,000 citizens.

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May 18, 1977

TOWARD A VISIBLE, WORKABLE ENERGY POLICY

by Ernst R. Habicht, Jr. *

The United States already has an energy policy, albeit an invisible one. It consists of a set of regulatory practices and tax provisions, based on the underlying economic premise that energy is cheap and abundant and will grow more so in the future. Regulatory precedents and the tax code have expanded over the years, yet few recognize what an enormous influence they have on both demands for energy and on selection of technology for new energy supplies.

This invisible policy made good sense during most of the Twentieth Century. Technological advances and increasing economies of scale caused substantial decreases in the real cost of energy until the mid-1960's. Declining block rates for sales of gas and electricity did not merely reflect accountants' costs of service; as long as real energy costs were falling, they at least crudely conveyed useful economic information about the future. Our invisible energy policy worked reasonably well for most of our lives.

But it doesn't work any more. Since the early 1970's, the real costs of energy have risen sharply and the price of some energy forms may continue to rise. In no way do current policies reflect this. For example, utilities are investing growing sums in petroleum conversion plants, operating twelve months a year, to produce synthetic natural gas. As we average in the costs of this gas, we effectively sell

* Mr. Habicht directs the energy program of the Environmental Defense Fund, a group which places considerable emphasis on economic analysis.

imported oil at a third of its cost. Running an air conditioner now commonly costs many utilities three to five times as much as it does the owner of the appliance. Thus, while our invisible energy policy once made sense, it no longer does.

Over half the energy we consume, or roughly 70 percent of non-transportation energy, flows through our utilities. Their consumer prices are directly regulated at the state or municipal level through rate designs that, in general, have not changed over the past decade. These rates, of course, are predicated on cheaper and cheaper energy. Yet now new electricity or gas production costs far more than the average prices charged consumers.

To promote industrial capital formation we increasingly rely upon investment tax credits and accelerated depreciation. These are especially important elements in financing our most capital-intensive activities such as electricity generation. But now energy production is using so many tax dollars that, when an electric utility reduces its construction program, the principal recipients of the savings are neither its stockholders nor its customers but the federal income taxpayers! One investor-owned gas company has even managed to finance a new $100 million synthetic gas plant with tax exempt bonds. And we just marketed nearly three times as many of these kind of bonds to move oil out of Alaska. These subsidies thoroughly obscure the growing costs of energy but surely contribute to our burgeoning taxpayer revolt.

Synthetic gas plants, nuclear power plants, off-shore drilling rigs, Arctic pipelines and liquified natural gas tankers are extremely expensive even in comparison to traditional energy producing activities. To finance our increasingly capital-intensive energy supply technology we find we must reach beyond income tax subsidies to loan guarantees, all-

events tariffs, ratepayer surcharges and guaranteed energy price floors. For eliciting new energy supplies or dampening energy demands, these instruments are poor substitutes for meaningful market tests. Moreover, in comparison, they are devastatingly inflationary. We ought to recognize, too, that we are allocating capital to costly projects while passing up far cheaper resources to be found simply by using more efficiently the electricity and fossil fuels already in production.

Despite rapid growth in energy consumption, especially in recent decades, the per capita energy demands of Americans in 1976 were only 1.65 times those of 1915 and only 2.4 times those of 1850. The reason for these surprisingly small increases is that there has been an enormous amount of energy conservation associated with moving from a cord wood and animal feed energy economy through coal to oil, natural gas and electricity. For example, the diesel locomotive is nearly six times as efficient as the coal burning steam locomotive -- surely a major reason for the latter's disappearance. Since oil substituted for only a small part of the coal when we turned to diesels, 83 percent of the energy to run the nation's railroads was conserved!

Total energy consumption figures can be very misleading. A very considerable portion of past GNP growth has resulted from improved efficiency of energy use, much of which stemmed from switching from one fuel type to another. This compels us to take a fresh look at what energy conservation is all about. There are no physical distinctions between hydrocarbons or electricity made available through new production or freed up through more efficient consumption -- the end products are identical. Any rational society would invest in available energy supplies in the relative order of their economic merit. But our invisible energy policy precludes rational investment priorities.

We now know enough to formulate a new energy policy. First, the price of energy to consumers must reflect its replacement costs, as it did for so many years. Only then

can intelligent decisions be made to achieve optimum efficiency of buildings, appliances, autos, machines and work schedules. Most importantly, only when prices are sensible, can the enormous innovative talents of the private sector focus productively on the problem. And the taxes which move prices in the right direction can be rebated in an equitable fashion to permit energy users to minimize their own costs.

Second, if we continue to subsidize energy production, we must subsidize energy conservation and new energy technologies. Because of perverse institutional discrimination, numerous energy industries are not the beneficiaries of the largess of our tax laws and regulatory practices and may be even further impeded by taxes on labor.

Third, we must give energy producers incentives to look for new oil and natural gas which are commensurate with their replacement costs. In recent years we have subsidized expensive synthetic or liquified natural gas with one hand while creating disincentives to drill for and produce cheaper gas with the other. It is by no means clear that the interstate pipeline companies are more deserving of incentives -- or will make more efficient use of them -- than the traditional natural gas producers. Absent the aggresive participation of these producers, we have no way of knowing the extent of conventional gas reserves or the costs of producing those vast quantities of gas locked up in geologically unconventional reservoirs.

Our two-tiered natural gas market, the creature of an outdated regulatory vision, is exceedingly difficult to render rational without severe and lasting impacts on both industrial and residential consumers. To integrate successfully the inter- and intrastate gas markets we must insure that unfulfilled demand in the former won't send prices in the latter skyrocketing. We must also establish a workable white market for gas to permit consumers to rationally allocate gas around the nation until the market clears.

And we must give producers of new gas the signal they have been waiting for. If their profits prove excessive we can always tax them -- something we cannot do to OPEC.

The consequences of any new energy policy for inflation, unemployment and GNP growth must be measured against the impacts of perpetuating a policy whose foundations have been wrecked by a natural gas vacuum and a rising tide of foreign oil. Should we recycle dollars in our own economy or let the world money markets determine our fate? Until we predicate our energy policy on the rising real costs of future energy supplies that policy will be increasingly determined for us by OPEC.

Sensible energy prices will have the biggest impact on parts of our economy that have not yet developed. A host of people and companies will go to work, develop new products and make a profit when we stop discriminating against the efficient use of energy. We will hear little from them as the debate rages for most will not recognize their opportunities until we quite discouraging energy conservation and novel energy technologies.

The Carter Administration's proposed new comprehensive energy policy builds on many of these realities and represents a meaningful step forward. Sooner or later we will recognize that the only important question is how rapidly we can replace our invisible, obsolete energy policy with one that works.

Mr. MAGUIRE Our third witness is Mr. Marvin Hicks of the Northeast Oklahoma Public Facilities Authority.

STATEMENT OF JAMES MARVIN HICKS

Mr. HICKS. Mr. Chairman, with your permission I will read a statement.

My name is Marvin Hicks and I am deeply honored to appear before this committee to make a statement in relation to the proposal to establish statutory ceiling prices on all "new" natural gas. I have to admit I am not an economist or professional engineer. The only qualification that entitles me to express an opinion on the subject is more than 30 years of managing the operation of municipal utilities and by being in contact with the small consumer almost daily during that period. Our utility operation is operated on the principal of only meeting actual expenses of operation and repayment of the indebtedness incurred to install the system. In that capacity I have had the same concerns and frustrations as the individual consumer, both as to consistency of supply and ability to pay the prices being charged for the commodity distributed.

The Northeast Oklahoma Public Facilities Authority, of which I am now executive director, is a State trust created to furnish natural gas to consumers in eastern Oklahoma which includes six cities and their surrounding areas, which is the area compromising Cherokee, Adair, Delaware, and Ottawa Counties of Oklahcma. The Authority does not engage in production but is obliged to purchase, as a sort of collective purchasing agent for the participating consumers, the gas, adding to the wholesale price only an amount to cover the expenses of distribution and debt service requirements.

We service 8,507 customers and have 378 miles of pipelines—including mains and service lines. Our gas is purchased from two sources. One is Oklahoma Natural Gas Company—an intrastate company—and the other is Cities Service Gas Company—an interstate company; and from July 1975 to June 30, 1976, we purchased approximately 1 billion cubic feet from the former and approximately 315 million cubic feet from the latter.

Oklahoma Natural Gas Company is regulated by the Oklahoma Corporation Commission and is permitted to pass along to the consumer increases in the cost of gas purchased monthly. Cities Service Gas Company is regulated by the Federal Power Commission. Exhibits A and B attached hereto reflect the difference between the price of gas purchased from an intrastate company and an interstate company whose prices are more closely monitored. You will also note the dramatic increase in the wholesale costs in the past few years.

The part that is not easily explained is that Oklahoma Natural Gas Company, which has a cost of fuel adjustment clause and utilizes it monthly, just in the last month gave the Welfare Department of the State of Oklahoma one quarter million dollars in what it terms excess profits. In addition, the stockholders of Oklahoma Natural Gas have seen their dividends more than double in the last couple of years. The generous gift of one quarter million dollars came about only because the State of Oklahoma is considering more stringent controls over State utility companies and has been extensively investigating these companies this year.

You have asked me here to testify concerning the impact of raising the cost of gas purchased by interstate companies to $1.75. I can only say that the State of Oklahoma this session voted to give all welfare recipients a subsidy of $5 per month to help defray utility costs which are already beyond the reach of many consumers in Oklahoma. Not too many years ago, Adair County, Oklahoma, which we service incidentally, was considered one of the most poverty stricken counties in the Nation. I know, from the steady flow of consumers in my office daily, what impact these high utility rates are having on people with fixed or low incomes.

Higher rates in Oklahoma will eventually result in the need for more subsidy for the poor whether it comes from the State or Federal level.

It is my personal opinion that some type of controls should be adopted that would allow the producers and wholesalers a fair return on their investment, but would also protect the consumers from excessive prices on a commodity so necessary to survive in our society today.

When I refer to excessive profits I refer to such companies as Oklahoma Natural Gas Company where they are giving excess profits away, but not in the form of lower rates to the consumer.

I reiterate my appreciation for being invited here and only hope I have stressed the seriousness of the problem as it affects the small consumers in Northeast Oklahoma.

[The attachments to Mr. Hick's statement follow:]

Northeast Oklahoma Public Facilities Authority

103 N. College Avenue
Tahlequah, Oklahoma 74464
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COMPARATIVE GAS COSTS RATES CHARGED BY

OKLAHOMA NATURAL GAS COMPANY

MONTH	RATE
June, 1962	.28676 MCF
July, 1962	.28733 MCF
August, 1962	.28719 MCF
September, 1962	.28891 MCF
October, 1962	.28931 MCF
November, 1962	.28848 MCF
December, 1962	.28633 MCF
January, 1963	.28924 MCF
February, 1963	.28639 MCF
March, 1963	.28602 MCF
April, 1963	.28617 MCF
May, 1963	.28769 MCF
June, 1963	.29104 MCF
July, 1963	.29273 MCF
August, 1963	.29140 MCF
September, 1963	.29893 MCF
October, 1963	.29940 MCF
November, 1963	.29907 MCF
December, 1963	.29908 MCF
January, 1964	.29499 MCF
February, 1964	.29398 MCF
March, 1964	.29209 MCF

MONTH	RATE
April, 1964	.29131 MCF
May, 1964	.29297 MCF
June, 1964	.29795 MCF
July, 1964	.29608 MCF
August, 1964	.29692 MCF
September, 1964	.30059 MCF
October, 1964	.29842 MCF
November, 1964	.29734 MCF
December, 1964	.29860 MCF
January, 1965	.29742 MCF
February, 1965	.29618 MCF
March, 1965	.29717 MCF
April, 1965	.29656 MCF
May, 1965	.29680 MCF
June, 1965	.29779 MCF
July, 1965	.29882 MCF
August, 1965	.29919 MCF
September, 1965	.29935 MCF
October, 1965	.29987 MCF
November, 1965	.29926 MCF
December, 1965	.29940 MCF
January, 1966	.29745 MCF
February, 1966	.29758 MCF

MONTH	RATE
July, 1966	.30003 MCF
August, 1966	.30133 MCF
September, 1966	.30084 MCF
October, 1966	.29977 MCF
November, 1966	.30038 MCF
December, 1966	.30193 MCF
January, 1967	.30010 MCF
February, 1967	.29939 MCF
March, 1967	.29794 MCF
April, 1967	.29735 MCF
May, 1967	.30136 MCF
June, 1967	.30277 MCF
July, 1967	.30323 MCF
August, 1967	.30461 MCF
September, 1967	.30057 MCF
October, 1967	.30635 MCF
November, 1967	.30293 MCF
December, 1967	.30266 MCF
January, 1968	.29936 MCF
February, 1968	.29781 MCF
March, 1968	.30006 MCF
April, 1968	.29928 MCF
May, 1968	.30155 MCF

MONTH	RATE
October, 1968	.31108 MCF
November, 1968	.30907 MCF
December, 1968	.31309 MCF
January, 1969	.32176 MCF
February, 1969	.32200 MCF
March, 1969	.32050 MCF
April, 1969	.32058 MCF
May, 1969	.32253 MCF
June, 1969	..32390 MCF
July, 1969	.32507 MCF
August, 1969	.32467 MCF
September, 1969	.32873 MCF
October, 1969	.32869 MCF
November, 1969	.33164 MCF
December, 1969	.33005 MCF
January, 1970	.32720 MCF
February, 1970	.32812 MCF
March, 1970	.32511 MCF
April, 1970	.32797 MCF
May, 1970	.32760 MCF
June, 1970	.32710 MCF
July, 1970	.32820 MCF
August, 1970	.32944 MCF

AMOUNT	RATE
January, 1971	.32961 MCF
February, 1971	.32922 MCF
March, 1971	.32711 MCF
April, 1971	.33005 MCF
May, 1971	.32921 MCF
June, 1971	.33184 MCF
July, 1971	.33431 MCF
August, 1971	.33609 MCF
September, 1971	.33630 MCF
October, 1971	.33750 MCF
November, 1971	.33750 MCF
December, 1971	.34245 MCF
January, 1972	.34109 MCF
February, 1972	.35947 MCF
March, 1972	.35293 MCF
April, 1972	.35595 MCF
May, 1972	.35995 MCF
June, 1972	.36141 MCF
July, 1972	.37203 MCF
August, 1972	.36774 MCF
September, 1972	.36529 MCF
October, 1972	.37333 MCF
November, 1972	.36589 MCF

MONTH	RATE
May, 1973	.44443 MCF
June, 1973	.44543 MCF
July, 1973	.46963 MCF
August, 1973	.46963 MCF
September, 1973	.48519 MCF
October, 1973	.50564 MCF
November, 1973	.50722 MCF
December, 1973	.51236 MCF
January, 1974	.51444 MCF
February, 1974	.50160 MCF
March, 1974	.50688 MCF
April, 1974	.52868 MCF
May, 1974	.56912 MCF
June, 1974	.58056 MCF
July, 1974	.62098 MCF
August, 1974	.60458 MCF
September, 1974	.62343 MCF
October, 1974	.62655 MCF
November, 1974	.67004 MCF
December, 1974	.67914 MCF
January, 1975	.67295 MCF
February, 1975	.67346 MCF
March, 1975	.70788 MCF

MONTH	RATE
August, 1975	.83484 MCF
September, 1975	.82201 MCF
October, 1975	.87182 MCF
November, 1975	.93181 MCF
December, 1975	.92953 MCF
January, 1976	.98822 MCF
February, 1976	.98676 MCF
March, 1976	1.04955 MCF
April, 1976	1.06122 MCF
May, 1976	1.04008 MCF
June, 1976	1.16522 MCF
July, 1976	1.25882 MCF
August, 1976	1.24035 MCF
September, 1976	1.23274 MCF
October, 1976	1.26642 MCF
November, 1976	1.30501 MCF
December, 1976	1.33595 MCF
January, 1977	1.33806 MCF
February, 1977	1.37693 MCF
March, 1977	1.39762 MCF
April, 1977	1.40391 MCF
May, 1977	1.43551 MCF

Northeast Oklahoma Public Facilities Authority

103 N. College Avenue
Tahlequah, Oklahoma 74464
Telephone 456-5021

COMPARATIVE GAS COST RATES COMPARED BY

CITIES SERVICE GAS COMPANY

MONTH	AVERAGE COST	BASE RATE	EXCESS RATE
June, 1971	.3042 mcf	.2842 mcf	.4063 mcf
July, 1971	.2884 mcf	.2842 mcf	.4063 mcf
August, 1971	.2871 mcf	.2842 mcf	.4063 mcf
September, 1971	.3202 mcf	.2842 mcf	.4063 mcf
October, 1971	.3257 mcf	.2842 mcf	.4063 mcf
November, 1971	.3636 mcf	.3390 mcf	.4510 mcf
December, 1971	.4298 mcf	.3390 mcf	.4510 mcf
January, 1972	.4313 mcf	.3390 mcf	.4510 mcf
February, 1972	.4337 mcf	.3390 mcf	.4510 mcf
March, 1972	.3965 mcf	.3066 mcf	.4287 mcf
April, 1972	.3835 mcf	.3066 mcf	.4287 mcf
May, 1972	.3553 mcf	.3066 mcf	.4287 mcf
June, 1972	.3066 mcf	.3066 mcf	
July, 1972	.3066 mcf	.3066 mcf	
August, 1972	.3066 mcf	.3066 mcf	
September, 1972	.3117 mcf	.3097 mcf	.4318 mcf
October, 1972	.3672 mcf	.3097 mcf	.4318 mcf
November, 1972	.4057 mcf	.3101 mcf	.4322 mcf
December, 1972	.4165 mcf	.3101 mcf	.4322 mcf

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MONTH	AVERAGE COST	BASE RATE	EXCESS RATE
June, 1973	.3585 mcf	.32920 mcf	.45130 mcf
July, 1973	.3342 mcf	.32920 mcf	.45130 mcf
August, 1973	.3349 mcf	.32920 mcf	.45130 mcf
September, 1973	.3564 mcf	.33740 mcf	.45950 mcf
October, 1973	.3727 mcf	.33740 mcf	.45950 mcf
November, 1973	.4184 mcf	.33740 mcf	.45950 mcf
December, 1973	.4435 mcf	.34590 mcf	.46800 mcf
January, 1974	.4506 mcf	.34590 mcf	.46800 mcf
February, 1974	.5002 mcf	.41860 mcf	.51860 mcf
March, 1974	.4948 mcf	.41860 mcf	.51860 mcf
April, 1974	.4895 mcf	.41860 mcf	.51860 mcf
May, 1974	.4462 mcf	.41860 mcf	.51860 mcf
June, 1974	.4448 mcf	.43200 mcf	.53200 mcf
July, 1974	.4324 mcf	.43200 mcf	.53200 mcf
August, 1974	.4688 mcf	.43200 mcf	.53200 mcf
September, 1974	.5061 mcf	.48270 mcf	.58270 mcf
October, 1974	.5300 mcf	.48270 mcf	.58270 mcf
November, 1974	.5488 mcf	.48270 mcf	.58270 mcf
December, 1974	.5609 mcf	.48270 mcf	.58270 mcf
January, 1975	.5591 mcf	.47680 mcf	.57680 mcf
February, 1975	.6017 mcf	.51970 mcf	.61970 mcf
March, 1975	.6117 mcf	.53140 mcf	.63140 mcf
April, 1975	.6020 mcf	.53140 mcf	.63140 mcf
May, 1975	.5919 mcf	.57350 mcf	.67350 mcf
June, 1975	.5735 mcf	.57350 mcf	
July, 1975	.5735 mcf	.57350 mcf	
August, 1975	.5338 mcf	.53400 mcf	

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MONTH	AVERAGE COST	BASE RATE	EXCESS RATE
September, 1975	.5425 mcf	.53400 mcf	.63400 mcf
October, 1975	.5800 mcf	.53400 mcf	.63400 mcf
November, 1975	.5994 mcf	.53400 mcf	.63400 mfc
December, 1975	.6362 mcf	.55430 mcf	.65430 mcf
January, 1976	.6390 mcf	.55430 mcf	.65430 mcf
February, 1976	.6748 mcf	.59520 mcf	.69520 mcf
March, 1976	.6668 mcf	.59520 mcf	.69520 mcf
April, 1976	.7719 mcf	.71950 mcf	.81950 mcf
May, 1976	.7689 mcf	.71950 mcf	.81950 mcf
June, 1976	.7530 mcf	.73640 mcf	.83640 mcf
July, 1976	.7364 mcf	.73640 mcf	.83640 mcf
August, 1976	.7756 mcf	.77560 mcf	.87560 mcf
September, 1976	.7801 mcf	.78010 mcf	.88010 mcf
October, 1976	.8411 mcf	.78700 mcf	.88700 mcf
November, 1976	.8654 mcf	.78700 mcf	.88700 mcf
December, 1976	.9791 mcf	.89520 mcf	.99520 mcf
January, 1977	.9827 mcf	.89520 mcf	.99410 mcf
February, 1977	1.0996 mcf	1.01640 mcf	1.11640 mcf
March, 1977	1.1038 mcf	1.02760 mcf	1.12760 mcf
April, 1977	1.0800 mcf	1.02760 mcf	1.12760 mcf

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Mr. MAGUIRE. Thank you, Mr. Hicks.

The 5-minute rule will be in force during the questioning.

Mr. Stockman.

Mr. STOCKMAN. Can I defer to Mr. Brown for the moment?

Mr. MAGUIRE. Surely.

Mr. BROWN. Thank you, Mr. Chairman.

Mr. Habicht, I am fascinated by your suggestion about the price of natural gas, and I would like to relate it to the question of gasification of coal.

Do you have any idea at what price gasified coal might be brought into the picture as a preference for natural gas prices?

Mr. HABICHT. I have been following the filings of various companies who propose to gasify one sort of coal or another, and the latest estimate I have seen exceeds $4.50 per Mcf at the tailgate of the operation. To that must be added transportation charges, but if you have a partly empty pipeline, those are very close to zero.

I would, however, caution you in using those numbers.

Mr. BROWN. Close to zero is marginal cost you are saying.

Mr. HABICHT. Yes, for transportation, but I caution you to note that most of these proposals assume a very, very high plant factor. These are capital intensive operations, and they are proposed to operate at 91 or so percent capacity factor. When they don't operate at as high a factor, the costs expand very markedly. If we assume that the outcome would be the same as for nuclear power which was promised to come on at 80 percent and is now in the 55 to 60 percent capacity factor range—then we can anticipate a price of about $6.

Mr. BROWN. The reason I asked the question is it seems to me that if there is a relationship within reaching distance between the real price of natural gas, and the price of gasified coal, we might be able to eliminate an economic step that is anticipated in this legislation, and that is the forcing of industries that have coal fired boilers, the utility industries, from switching from natural gas coal in the conventional form, and thereby eliminate some of the environmental damage and cost in terms of the scrubbers and so forth, that would be involved, and perhaps take out a whole generation of undesirable methods of energy usage.

Do you have any comment on that?

Mr. HABICHT. There is an intermediate step, but it involves making gas substitutes, not natural gas, from coal. In such a fuel switching strategy you could turn coal into low or intermediate heat content gas with I think greater reliability.

Mr. BROWN. Reducing the cost, dollar cost?

Mr. HABICHT. Exactly.

Mr. BROWN. And reducing the environmental damage in its combustion from hard coal; is that correct?

Mr. HABICHT. There is no question but that would be the case.

Mr. BROWN. And what is the price strength to that?

Mr. HABICHT. There we are looking at prices at $2.50 to $3 per Mcf on an equivalent BTU basis.

Mr. BROWN. That seems not to be irrational in view of the fact that recent filings before the Federal Power Commission have asked for prices in the $2.36 or $2.40 range, so we seem to be very close to the prospect of doing that.

Could you relate it to oil in any way for me?

Mr. HABICHT. The opportunity costs of gas are certainly those of imported oil. Where we don't have gas for large industrial customers, they must perforce use imported oil.

Mr. BROWN. I really was talking about, however low quality gasified coal.

Could you relate low quality gasified coal to oil for me?

Mr. HABICHT. In terms of price?

Mr. BROWN. In terms of price.

Mr. HABICHT. The price would be just above imported oil.

Mr. BROWN. And in terms of the environmental damage.

Mr. HABICHT. Probably greater, but very difficult to quantify, because we are looking at apples and oranges.

Mr. BROWN. Can it be managed with processes now known in terms of scrubbers and that sort of thing?

Mr. HABICHT. The big uncertainty, Congressman, is in toxic substances that are produced attendant to the conversion of coal to gas, or liquids. There is a history of occupational disease in the town gas industry, and while we ought to be able to get a good handle on those problems, there may be some sticky issues when we first get these technologies underway.

Mr. BROWN. But does that produce a product that in itself while damaging is either usable as a heat product or as a chemical product or some other product that might have an economic value?

Mr. HABICHT. Exactly.

Mr. MAGUIRE. The gentleman's time has expired but I will permit the gentleman to answer.

Mr. HABICHT. All of these effluents are toxic but they also have a fuel value so there is a clear economic incentive not to let these pollutants loose on the environment.

Mr. BROWN. Thank you.

Mr. MAGUIRE. Thank you.

Mr. Moore.

Mr. MOORE. Thank you, Mr. Chairman.

Would it be fair to say that as far as Mr. White and Mr. Hicks are concerned, that one of your concerns would be having an adequate supply of natural gas for consumers, and the consumers that Mr. Hicks in particular services?

Mr. WHITE. Yes. It is I am sure for both of us.

Mr. MOORE. Mr. Hicks, do you agree?

Mr. HICKS. Yes.

Mr. MOORE. Mr. Habicht, I think you also pointed out or it was pointed out from questions that certainly the burning of natural gas is superior from an environmental point of view to the fuels we use as resources per day in electric power?

Mr. HABICHT. With the exception that there are applications of active solar energy systems that are cleaner and cheaper.

Mr. MOORE. Sure.

Mr. HABICHT. Because they reduce the costs of the technology they are tied to, but generally I would agree with you.

Mr. MOORE. Mr. Hicks, I have some questions concerning your testimony that I would like to get information on. You indicate you buy your natural gas from two sources.

What price did you pay on the average per Mcf for your gas from Oklahoma Natural Gas last year?

Mr. HICKS. Sir, the current price that we are paying I said is adjusted monthly and the last price that I have in the exhibits that I presented before you is $1.44, but I was advised on my way to the airport that I had a notice from Oklahoma Natural which raised that 7 more cents, and that is 14 cents per thousand cubic feet in 3 months.

Mr. MOORE. What are you paying from Cities Service, the interstate supplier?

Mr. HICKS. From Cities Service the last gas we purchased was $1.08.

Mr. MOORE. Why the difference in price did you buy 1 billion cubic feet from Oklahoma and 315 million cubic feet from Cities Service?

Mr. HICKS. The three cities that is the small amount were not able to interconnect with one gas system; it is so far apart; it has to be from either Cities Service or Oklahoma Natural. It is not feasible to run a Cities Service gas to the Oklahoma Natural or vice versa, and on that point I don't think the gas would be available from Cities Service to pick up any additional customers anyway.

Mr. MOORE. Is Oklahoma Natural Gas a producer or a pipeline that distributes, a distributor?

Mr. HICKS. They are producers, distributors.

Mr. MOORE. They do both.

Mr. HICKS. Right.

Mr. MOORE. Is all the gas they sell what they produce or do they buy from other producers to mix?

Mr. HICKS. No, they produce and also purchase.

Mr. MOORE. Do you know what their acquisition cost is for the gas they are selling you now at $1.41? Do you know what they are paying for the gas?

Mr. HICKS. No, because they mix in the old gas, the new gas.

Mr. MOORE. Do you know what they are paying for the new gas?

Mr. HICKS. That report, sir, is not sent to me.

Mr. MOORE. You don't know.

Mr. HICKS. No, sir.

Mr. MOORE. We have heard testimony earlier from I believe that same company, is that not right, counsel, that gave the figure; they are saying their purchase cost on new gas is $1.45 to $1.50 in Oklahoma, the gas that they are buying?

Do you have any idea? You said you don't know what they are buying but do you know what anybody else is paying?

Mr. HICKS. I have been told they are paying $1.75 for new gas.

Mr. MOORE. They have paid as high as $1.75 for new gas?

Mr. HICKS. Yes.

Mr. MOORE. Which they have in turn rolled in with their other gas which keeps your price at $1.51.

Mr. HICKS. Yes. They roll in that with the cheaper price and then this is what they sell it to this authority for.

Mr. MOORE. No further questions, Mr. Chairman.

Thank you, Mr. Hicks.

Mr. MAGUIRE. Thank you.

Mr. Stockman.

Mr. STOCKMAN. Mr. White, your testimony has evoked two comments on my part and I would like to begin by inquiring of you whether you would have any objection if we renamed your organization to the proposal that it be renamed the Selective Consumer Federation of America, because it seems to me that if I understand your position right, and I make some deductions from it, that is exactly what we have involved.

Your position would consist of the following three factors: No. 1, that we continue historic cost based regulations, and of course that implies that there will be a continuation of the production trend decline for natural gas, 23 trillion cubic feet in 1973, we are down to 19 now, and all of the projections that have been made under a continuation of historic based cost/base regulations indicate it could be as low as 15 or 16 trillion cubic feet by 1985.

Secondly, you suggest that rather than relying on the market, we allocate the residual supply to the highest priority users, which would be the current residential consumers, customers.

Third, if we have any supplemental high cost supplies such as LNG, SNG or whatever, that that would be shifted onto the remaining low priority users if there are any remaining left on the system.

It seems to me that that is consumer protection for a very selective group of people, namely, those who have gas heating systems in their homes today, and who are on systems that have enough supply for the next 10 years to meet even those commitments, but I want to ask you about some other categories of consumers.

Mr. WHITE. Is there a question mark at the end of that?

Mr. STOCKMAN. There will be one.

What about the consumers who are on electric heat as opposed to gas heat, because if we force all utilities on a 100 percent basis even for peaking capacity to go to coal, the generation costs are going to rise and that means that while your consumers who are maintaining that 60 cents gas to heat their homes, while they are getting that, there are going to be some electric heating consumers who are going to be paying $6 which is the equivalent already, Btu equivalent, and it may rise even beyond that.

Second, what about the consumers whom I would call the general market basket good services, cars, processors, consumers and so forth, to the extent that we force as a result of this policy that we and you have outlined, those who need fuel for heat treatment and for other processes, even for boiler processes in the manufacturing process, to go to a much higher synthetic fuel cost or coal cost, you are going to raise considerably the price of every one of those items.

Thirdly, you have air consumers. The gentleman from Texas and I were doing some very rough calculations this morning. We concluded that if we go with the administration's plan or even worse, if we would go with the historic cost based regulation, you are going to have a $5 trillion difference in natural gas production in 1985. That is the equivalent of 4 or 5 billion pounds more of sulfur in the air, and the air consumers of course include almost everybody in this country.

Finally, you will have gas consumers undersupplied by utilities. There are some utilities even with complete conversion and the complete elimination of boiler and other low priority users who still won't be able to meet their load until 1985. To the extent that those pipelines are underutilized the carrier and amortization costs of those pipelines are going to have to be loaded onto the remaining residential consumers.

I am suggesting we can pick out many, many categories of consumers that would be hurt very seriously by what I think is the logic of your plan. Your position this morning, your statement, seems to me to only protect a very arbitrarily selected group of people, and those who have been lucky enough over the last 15 or 20 year to get into the low-priced gas game at an early date.

Would you care to respond?

Mr. WHITE. Oh, I would love to.

As far as the selective group, I don't perceive that if the administration's plan goes through, if the administration's plan as we would modify it goes through, there is anything to preclude new natural gas customers who are going to use it for residential purposes. It is not intended as I understand it to freeze the situation that exists today. There is not that kind of a freeze that nobody else can have it.

Basically the undergirding for that particular recommendation, and with a few modifications, I would say you have stated reasonably well, is that we are not going to have enough natural gas to meet all of the uses and purposes to which it could be put, and we do not believe it makes sense to use price as the allocating mechanism.

For example, the administration has proposed, and we have no objection, in fact we support the notion, that industrial uses will have to have a tax added.

Mr. STOCKMAN. We all support that.

Mr. WHITE. Okay. What we are talking about, we are trying to push people away from the use of natural gas.

Mr. MAGUIRE. The time of the gentleman has expired, so if you could complete your answer to the question.

Mr. WHITE. If we can use mandatory legislation or a phased-out period to have all of our industrial users move to alternative fuels. We recognize it is going to cost more. No consumer advocate expects really the world to go backwards or the prices to be turned back to an earlier time, but what we are talking about is the ability to handle today's situation.

We have hundreds of thousands of families today who have got bills for $500 or $600 for last winter for fuel and utility costs that they can't pay. We have got I think, while we are adapting to new conditions, to protect those people. One day that old gas is going to run out, and we know it, and yet we think that there ought to be a priority for those people who have not got the financial ability to switch, and regardless of what the President proposes or what Congress comes up with, natural gas is a declining resource, and we know that we can debate whether we are going to run out of it by the year 2010 or 2020 or 2040, but we are not going to have natural gas, and we will have to go through some adjustment and conversion.

As has been suggested, we will be using alternative techniques, and what I am talking about is short-term policy, as long as 10 or 20 years, and I think that is important to wrangle over right now.

Mr. MAGUIRE. We have been joined by Mr. Morton Simons of Simons and Simons.

Mr. Simons, would you like to make your remarks at this point, and we will proceed with the questions?

STATEMENT OF MORTON SIMONS

Mr. SIMONS. Yes, I would very much appreciate that.

I would first like to apologize for not being here earlier. Apparently when I was scheduled there was a mix up and I understood I was to be here tomorrow. I guess I was wrong, so here I am now.

First, I would like briefly to identify myself so you know where I am coming from. I have been practicing before the Federal Power Commission since 1953. I have a practice now that is almost exclusively Federal Power Commission and Federal Power Commission on appeal in the courts.

I have participated in most of the landmark cases that followed the Supreme Court's 1954 *Phillips* decision, and I have been involved actively in curtailment cases in recent years, which is the working out of the shortage that we face. I speak exclusively on behalf of myself and not on behalf of my clients.

My clients have included a variety of different types of consumers. I have represented gas distribution companies, local gas companies. I have represented and do represent States and State commissions. I have represented industrial users, and I have represented Members of Congress, but my views are strictly my own.

One of the factors that results when you have been around for a long time is you realize that all of the arguments that a lot of people think are new are really very old.

When we started out in producer regulation after 1954, it was very soon evident that there were two ways you could fix the price of natural gas. One was on a cost basis, cost plus a fair return to the producing company. The other was to let market prices fix it.

The difficulty with market prices was that there was not a free market. Since there was not a free market, it was necessary to go to cost. In a free market, cost and market price should approximate each other.

The reason that there is a difference between market price and cost is that we don't have a free market. It is a prime indication that we don't have a free market.

This was true in 1954. It is true in 1977. And I think it is going to be true as long as we are dealing with natural gas at all.

Now I would like to pay, as I guess everybody has done, customary respect to the concept of having a national energy policy and of wrapping everything up in one piece, of finding out how we are going to handle natural gas and oil and electricity. It certainly makes no sense to be taking people off gas, to put them on oil, when there isn't enough oil, and so on. We do need an integrated policy.

It is, however, a mistake to think that we don't have a policy today. We do have a policy today. It is the policy that has been

brought to us by, and is exceedingly profitable for, the energy companies. It is not so good for the public, because the supplies are inadequate and the prices constantly rise.

I want to direct my objections to this bill—to the gas portion of the bill, part D—to three sections, two of which are the heart of the bill, section 404, sales of new gas, and section 405, sales of old gas, and then I guess really just a personal pique at the findings in section 401, which purport to be history but are in fact a rewriting of history.

What is the matter with section 404, which is new gas pricing, is it ties the price of gas to the OPEC price for oil. There is no rational basis in the world for tying the price of our domestic production to what a foreign cartel fixes for oil. The problem with having a foreign cartel control our supply of energy is really twofold: One is they can cut it off at any time, but that really I think is less of a problem. The other problem is they can charge us any price they want. But it makes no sense to get out of that to charge ourselves for our own domestic production the same price that OPEC would charge us for oil on a Btu basis.

As I said, there are two ways, there always have been two ways you can fix the price of energy, fix the price of natural gas. One is on a cost basis, and it is perfectly clear that under the statute as it now exists, the Natural Gas Act, the only basis is cost plus fair return. Going to a market price standard is about the same as having deregulation. There is no real substantive difference.

With respect to old gas pricing, again the standard that is being used is to incorporate what the Commission has already done, escalating it a bit. Particularly objectionable is the provision of section 405(2) which would take away from the consumers their right of appeal of the Commission's Order No. 770. Order 770 raised the price of gas from 50 cents to $1.44. An appeal was taken. There was a lot of conflict as to what circuit it ought to be in, and it was finally held that the D.C. Circuit had venue. That court has heard oral argument, and I think most observers believe there is not a chance in the world that the $1.44 price can be sustained, because it is not based on any sort of sensible record or sensible findings.

Section 405(2) would just simply terminate the appeal. It hardly seems fair to the consumer to change the rules in the middle of the game. I don't see why there is such a manifest distrust of the courts of this country and of due process.

With respect to the findings section on natural gas, and wholly aside from the style of saying that natural gas was originally sold "at very low prices," which 401(a)(1) says, there is considerable question as to what is meant by "very low prices." Low compared to what? Low compared to what the cartel has set for us?

You go all through these findings, and they are basically factually erroneous. I think you get into deep trouble when you start rewriting past history. It was what Orwell warned about in "1984." If you can't live with facts, maybe there is something wrong with the way you are doing business, but don't try to rewrite past history. The findings in here are almost entirely incorrect, and it seems to me that you ought to have appropriate fact findings.

My basic objection, however, is to the standards that are being used. It should be realized—I am sure many witnesses have said this, and I think anybody who knows anything about this field agrees—that higher prices will not bring forth any additional supply. That is really not the contention of anybody when you examine it. When try to find out what additional supply you will get for the higher prices, you are told, really nothing.

The evidence on this point is overwhelming. In the last 8 years the price of gas has gone up from an average of 17 cents per Mcf to about four times that; about 68 cents or 70 cents is the current average price for all gas. But the supply has declined. In the prior 8 years the price was held steady at 17 cents. Yet the interstate supply increased by about 40 percent during that period.

You have the same history in oil: The price of oil has quadrupled since the OPEC cartel raised the prices in 1973; but domestic production has gone down.

Quite obviously, higher prices will not get you more gas. It does not depend really where you start on this. We have a finite supply as people have noted time and again. What you can do with the price is determine what you are going to pay. You cannot determine the volumes of gas you are going to get with the price. You can either set the price at 50 cents and you are going to get x amount of gas, whatever it is, 18 to 20 trillion feet at that level, or you can double the price, or triple or quadruple it and you will still get the same volume of gas.

So you should realize that whatever you do with price, you are not affecting supply at all. There are a lot of reasons for this, but the result I think is the same.

Now, what needs to be done——

Mr. MAGUIRE. Mr. Simons, I am going to have to interrupt you at that point. I have only six minutes to get to the floor for a vote. So if we could suspend for about 10 minutes and then when we come back you may complete your statement.

Mr. SIMONS. Very well, sir.

[Brief recess.]

Mr. MAGUIRE. Mr. Simons, would you complete your statement?

Mr. SIMONS. Yes. Thank you, Mr. Chairman.

There are two other general areas I would like to cover. One deals with the Emergency Natural Gas Act that was effective this past winter. I think that in a very real sense that act was a failure, that it served only to permit gas to flow in interstate commerce at exceedingly high prices, as high as $3.25, and I think that when you are given representations of what this bill or any other bill designed to soften regulation will do, you should recall that you were told at the time the Emergency Natural Gas Act was before you and you were considering putting a $2.25 lid, that it really wasn't necessary; there was sort of the implication that prices wouldn't go above $2.25. Yet, number one, they went up to at least $3.25, and, secondly, having gone to $3.25, the argument was then made by the oil industry that all gas should flow at $3.25.

This has been true from Day 1. I can tell you since at least 1955, when I got into the first producer cases, if there are two prices for natural gas, one and one plus-10 cents, every producer wants the

plus-10 cents. It doesn't matter whether you call it special or emergency or different or intrastate or whatever, there is always the push for the higher price.

The other thing, I indicated that by setting higher prices you are not going to bring forth new supply. I didn't develop the reason for that. The reason is quite simple. The industry finds it much more profitable. We have geared our system in such a way that it is more profitable—for them to produce less. The less they produce, the higher the price they get. Then they say in order to get rid of the shortage we need still higher prices.

But as long as you give higher prices so long as there is a shortage, you are never going to get rid of the shortage. It seems to me what is required, and it seems to me Barry Commoner the other day indicated what was required, was a new approach. This bill seems to write in the old approach, to do more of what has not been working.

I would suggest 3 steps, all of which have been suggested by others, but I think they should form the basis for a new and effective system.

One is enforcement of certificate obligations. And you, Mr. Chairman, are exceedingly familiar with the Gulf warranty case. That is a case where Gulf was delivering 350,000 Mcf a day as of a year ago. Last October, the Federal Power Commission finally got around to ordering them to live up to their certificate obligation to deliver 625,000 Mcf per day. As of March this year, they were up, they said, to 645,000 Mcfa day, an increase of almost 300,000 Mcf a day, and I want to tell you how much 300,000 Mcf a day is. One of my clients is the State of North Carolina and the North Carolina Utilities Commission. That entire State receives an average of 180,000 Mcf a day at the present time.

So by requiring producers to live up to their obligations, what was done with Gulf can work elsewhere. It requires a determined Federal agency to require that certificates be adhered to.

The second thing that can be done, and obviously this bill does it in part and it is necessary to any sort of approach to regulation, is to regulate the intrastate market. The Smith bill passed by the House did it a year or so ago. It should be done, and there is no reason to raise the price levels up to a $1.75 as part of that package.

Incidentally, when reference is made to the intrastate price, you are almost always told about some price of $1.75 or $2, or $2.25. You are very seldom given the average intrastate price, and it seems to me that that really is the price that you are going to have to look to. It is not the 1 or 2 percent highest priced gas that should fix the price for everything.

The third area, it seems to me——

Mr. MAGUIRE. What is that average price now?

Mr. SIMONS. I really don't know; I think it is a well-kept secret. I would point out that prior to the time of the OPEC cut-off in 1973, prior to the time of the acute shortages, the intrastate price was within a penny or two of the interstate price, and all through the 1960's and early 1970's, it was around 17 cents.

Now, the third point, it seems to me, where we need legislation or legislation could be helpful—and this picks up a proposal that was

made sometime back, over in the Senate, I think, by Senators Stevenson and Jackson—is the use of a TVA-type corporation to undertake exploration and production on the continental shelf and on Federal land to provide the necessary competition for this industry which is not motivated to increase production.

I think it would certainly be appropriate to provide that a TVA-type corporation would be operative only when supplies are below some sort of triggering level, whether that is 20 trillion a year deliveries, or production less than 20 trillion a year, or whatever. I don't think you need it necessarily as a permanent fixture, but at the point where the private companies are not doing the job that is necessary, and where they say that it costs too much—and that is frequently their excuse, they would rather get into other endeavors, or in other countries, rather than engage in domestic production—it seems to me that the government ought to step in with respect to gas and oil on government-owned lands to fill in the missing gap.

I would point out, too, and I guess this really is my final point, and this grew out, Mr. Chairman, of your Gulf hearings, we are told that the oil industry really isn't all that profitable. I saw a large editorial-type commentary in the Wall Street Journal of Monday, written by Dr. McCracken, and he said the oil industry is only earning 15 percent on net worth, or at least that is what they report. But the fact of the matter is they never tell you what they are earning on domestic production.

In the Gulf case you asked Gulf to provide you with data that would indicate what it was earning on its domestic production and whether at 21 cents per Mcf, which was its contract price, it would make or lose money. Its response to you was that they didn't have those figures and knew of no way to get those figures.

So if the oil industry tells you they are not making enough on domestic production, the appropriate response is how conceivably can they know when they say they don't have those figures?

One other point, instead of the Emergency Natural Gas Act, what should have been done was a better use of royalty gas by the government from offshore lands. That is already an existing power. The Secretary of Interior has the right to royalty gas, can use it as needed. That has been done, incidentally, by the State of New Mexico, with respect to its royalty gas, and that approach could take care of the emergency problems rather than the Emergency Natural Gas Act.

We do need a national energy policy. But the policy, at least so far as natural gas, that is enunciated in H.R. 6831 is only going to give you more shortages at higher prices.

Thank you.

Mr. MAGUIRE. Thank you, Mr. Simons.

A couple of questions, first for Mr. White and Mr. Simons. One of the criticisms of our regulated pricing of natural gas has been that it is based on historical, not on prospective cost. I wonder if you could tell us what you believe a fair price would be for a prospective as opposed to an historical calculation cost, and, secondly, something about how one would arrive at such figures?

Mr. WHITE. Mr. Chairman, it is accurate to say, as your question implies, that the traditional technique has been to find the average

cost in a test year and to use that as an indicator, and it is equally true that there will be certain situations, and obviously since you are seeking the average price, some are below and some are above or else there wouldn't be an average.

So what we have done in the past, I think, is to use a technology or methodology that has been relatively effective. I think implicit in your question is that now we are reaching into deeper formations, now that the easier gas has been found, it is claimed by the people who are in the gas-producing business that the old kind of, if you will, base of information is not running fast enough to get to these new costs.

I am not sure that that is the case, but if it is the case, I have suggested 5 years ago a solution. You may remember during World War II the United States said to suppliers of equipment, clothing, guns, munitions, everything, we don't have time to sit down and wrangle about the price. Go ahead and keep your records and come back to us with your records, and we will have an examination, and if you did not receive enough money, we will give you more. If you received too much, we will withhold it and even it out, a renegotiation technique.

Hopefully the Renegotiation Board, still in existence, will be resuscitated by the Carter administration, although it looks like there is a little doubt about it at the moment. I see no reason why anybody can't keep accurate records and come in, not like those Mr. Simons suggests, where they have one helluva time telling you the difference in how the costs were allocated. Allocated costs in regulated petroleum and natural gas resulted in every plant that was owned by an oil company being allocated to the gas side of it rather than to the oil side. So there are some accounting techniques.

But it seems to me it would be perfectly agreeable and to some extent it is incorporated already in the administration proposal—it says for anybody who can demonstrate a special problem, let them keep their records and come in and demonstrate conclusively in an adversary proceeding, that indeed their costs are so high, they need special relief. That provision was incorporated into the Federal Power Commission's first area rate case, the Permian Basin in August 1965. So there is nothing novel about it, and if the historical average costs don't work, I don't see any public policy that would prohibit anyone from coming in and demonstrating they need special relief and should get it.

Mr. MAGUIRE. Before we turn to Mr. Simons, you referred to the special pricing provisions of the proposed law which I want to also ask you about. In section 408, we have a provision which allows special pricing on a national, geographic or case-by-case basis, and, as I understand, it allows it in advance rather than after the cost data has been submitted, based on experience already occurred.

Now, do you find section 408 adequate as it stands for the purpose that you just described, or do you see possible difficulties there?

Mr. WHITE. I guess what you have done, Mr. Chairman, is to highlight the difficulty of testifying on this draft. There is one lot of it, and the sections that I have looked at seem to be, I don't know whether it is deliberate or inadvertent, but there is a lot of ambiguity woven into it.

To answer your question, my own instincts, biases and prejudices tell me I would rather have somebody come in after the fact rather than let the President make a prospective ruling on information and data and, above all, it seems to me it does meet another natural goal, and that is to get people making the investment, and if they know under the law they can come in and demonstrate in a proceeding where there is opportunity for cross-examination and other scrutiny of their reasons, sure, there is no consumer advocate I know of that wants to "do in" any gas producer, whether the biggest or the smallest. What we are hoping is that it doesn't work in reverse, that we get "done in."

Mr. MAGUIRE. Mr. Simons, do you have a comment on the prospective cost issue and the special pricing provisions of section 408?

Mr. SIMONS. Yes, I would like to address the latter one first, if I may.

The interesting thing about 408 is if you go to 408(b), it says that if there are special factors that the producer has, bears cost of transportation or liquefaction of the gas, the President, by rule, may adjust the price to reflect such cost. It is ironic that here where there are added costs, you determine the price by looking at costs. And, of course, looking at costs is the common-sense approach to all pricing.

I don't think it ought to be just restricted to the special case of transportation and liquefaction.

I think Mr. White's proposal is a good one. I think what you want to do is you want to be fair to the industry; you don't want to, or you don't need to, be more than fair to them, because to the extent you are, you are being unfair to the consumer.

I think that there does have to be to some extent, when you are fixing a prospective price, a certain element of arbitrariness. You do the best job you can on the facts you have. You attempt to make the adjustment to reflect what the prospective costs are. In that sense, it is not something that you have got a really 100 percent sure evidentiary basis, but the fact it is not 100 percent doesn't mean you should not go with the best you have, that you are 90 percent right. If what is needed to make it work is some sort of subsequent look, if you set the price at and there was some error in it, I don't have any problem with the renegotiation board-type procedure.

Mr. MAGUIRE. Would you set it? You are a knowledgeable person who has worked in the field for many years. If you had to sit here and establish a price, what would you say?

Mr. SIMONS. I have great faith in the hearing and decisional process. I think one thing might be to wait to see what the D.C. Circuit says it ought to have been in Opinion 770.

I think another approach, if you want a thumbnail approach, and since there are going to be all sorts of upward exceptions and never downward exceptions, would be to take the price that obtained prior to the time of the OPEC cartel influence on energy pricing, and trend that upward perhaps even generously for inflation since that time.

But what you want to remember is that the average price of gas in this country in September of 1973, not that long ago, was about

22 cents. Sure, there has been inflation; sure there are other costs. But it would seem to me something on the order of doubling of that certainly ought to be adequate as the first step to take account of where we are, and go from there.

I think it is up to the industry to demonstrate that they need higher prices. And I think every observer has noted that if you fix higher prices—and indeed as higher prices have been fixed—costs tend to rise to meet that price. The price of leases, for example, has gone up very markedly as the price has risen.

The lease sale prices are essentially a form of economic rent that has nothing to do with true cost. It is a cost that rises to meet the price. So you have to be careful about those kinds of costs.

But as I said, Mr. Chairman, I think whether you set the price at 35 cents or $2.35, you are really not going to get that much difference in the amount of gas.

Mr. MAGUIRE. I might say, Mr. Simons, the pencil calculations I made quickly in a recent hearing with Dr. Schlesinger, if I assumed a 25-cent price 5 years ago, let's say, and a 20 percent rate of return on investment, would be 20 cents cost and a nickel in profit on that 25 cents, and then you assume that 250 percent increase in costs over the 5-year period, it ended up with, let's say, $1.50 price, and that would calculate out to a 200 percent, as opposed to 20 percent, return on investment and a 2,000 percent increase in absolute profits even after you factor in a 250 percent increase in cost.

I have asked for a critique for those numbers as to whether or not they do or do not relate to reality. I assume you have deductions for the elimination in the depletion allowance and perhaps some other things. But does anybody want to comment on that little pencil scribble?

Mr. SIMONS. I think it is a sensible first step. It is obviously not the last step. I think it is a sensible first step, and it puts the burden on the producers or on Dr. Schlesinger to come up and explain why it is not so.

Mr. WHITE. If I may respond, also, to your question, Mr. Chairman, about where the price ought to be fixed, I get the impression from listening to Dr. Schlesinger and reading their energy plan, that they have selected what might be called a political price for natural gas. Otherwise, the criticism that was leveled at Mr. Freeman here this morning about why it is so high from one side and why it is so low from the other, simply there is no rationale that one can find for selecting that particular oil equivalency price except it comes out $1.75, although I gather with the Alaskan oil, it is going to go up to two bucks with the decision on Alaskan oil.

I think what you have to do in order to answer your question is make a very basic threshold judgment, and that is, should the price be fixed at some sort of politically acceptable level where the consumers who are screaming and the producers who are screaming all say, well, that isn't as bad as I thought it was going to be, but it isn't as good as it should be.

Or do what Mr. Simons suggested, which is to use the fundamental concept that natural gas is a commodity that requires the Federal Government to operate because the marketplace simply

cannot fix the price and decide that cost-based regulation conceptually is the way to go.

Then you come to your question, which is let's take a look at the cost. The Federal Power Commission has been doing that. Their judgment has been attacked; it has been argued before the Court of Appeals, and within the next 30 days or 60 days, there will be a decision whether or not the Federal Power Commission has discharged its obligation under the Natural Gas Act to figure out what the costs are and allow no more, plus reasonable return.

So if I were to counsel the committee, I would say that to me it is a perfectly satisfactory approach, and to those who say, yes, but it has gotten us into all this difficulty, I don't think so. I think it is the existence of the intrastate market, and I think it is also the expectations of deregulation being right around the corner, and it is hard to condemn anybody for holding back if he truly believes that the Congress may well deregulate.

A dollar seventy-five isn't deregulation, but to those of us who paid some attention to the costing, it seems like it is not only the first step, as Mr. Freeman said, it is a giant 3 or 4 steps toward deregulation.

Mr. MAGUIRE. Mr. Sharp.

Mr. SHARP. Well, thank you, Mr. Chairman.

I am sorry I unfortunately missed most of your testimony and was trying to read through what you have in writing at the moment. Given the vote, I think I will not ask any questions, and just listen.

Mr. MAGUIRE. Let us conclude the panel. I do want to say to Mr. Habicht, I found some of his proposals rather thought-provoking, and I intend to study his statement in greater detail.

I want to thank Mr. Simons for referring to the Gulf warranty case, which I worked on rather extensively last year. I think it is fair to say there were some outside questions not raised, and had Congress not pursued the matter vigorously, we would not be seeing a delivery of 300,000 Mcf per day from that source to meet its contract commitments.

I want to thank all of the members of the panel, including Mr. Hicks, who was not questioned extensively, but nevertheless we are very grateful for your statement, and we will resume at two o'clock.

[Whereupon, at 1:42 p.m., the subcommittee recessed, to reconvene at 2 p.m. the same day.]

AFTER RECESS

[The subcomittee reconvened at 2 p.m., Hon. Richard L. Ottinger presiding.]

Mr. OTTINGER. The hearings by the Subcommittee on Energy and Power on H.R. 6831, the National Energy Act, title I, part D, on natural gas, will continue this afternoon with a panel representing distribution companies.

We have with us Robert E. Seymour, Chairman of the Consolidated Gas Company; Arthur Seder, Chairman of American Natural Resources Systems; Alan Beringsmith, an economist, Pacific Gas and Electric Company; Charles F. Wheatley, Jr., General Counsel of

the American Public Gas Association; and O. C. Davis, President, Peoples Gas Company.

Gentlemen, we are pleased to have you with us this afternoon. As I understand it, by agreement with the witnesses, among the witnesses, Mr. Seymour is going to go first. What I would suggest, if there is no objection, with respect to each of the witnesses, we will put your entire statement into the record.

I would hope that particularly in the case of people who have very thick statements, like Mr. Seymour, that you would summarize the statement because of the time restrictions upon us. But, you may proceed as you desire.

STATEMENT OF ROBERT E. SEYMOUR, CHAIRMAN, CONSOLIDATED NATURAL GAS COMPANY AND CHAIRMAN, AMERICAN GAS ASSOCIATION; ARTHUR R. SEDER, JR., CHAIRMAN AND CHIEF EXECUTIVE OFFICER, AMERICAN NATURAL RESOURCES COMPANY; ALAN W. BERINGSMITH, ECONOMIST, PACIFIC GAS AND ELECTRIC COMPANY: O. C. DAVIS, PRESIDENT, PEOPLES GAS COMPANY; AND CHARLES F. WHEATLEY, JR., GENERAL COUNSEL, AMERICAN PUBLIC GAS ASSOCIATION

Mr. SEYMOUR. I am Robert E. Seymour, Chairman of Consolidated Natural Gas Company in Pittsburgh and Chairman of the American Gas Association.

I have already submitted for the record a much fuller statement of position on some of the points I am about to cover, as well as other items of concern in the legislation.

Mr. Chairman, there seems to be an attitude that, because natural gas production has in fact declined in recent years, a continuation of this decline is inevitable. The principal point I would like to emphasize to this committee today is that we in the gas industry believe these projections are wrong and that we are concerned that the administration's proposed energy plan does not provide, in several important areas, for sufficient incentives to increase domestic energy supplies.

First, I would remind the committee that natural gas now accounts for about 30 percent of this nation's total energy needs, that it is the largest component of domestically-produced energy. Indeed, President Carter has referred to it as "our most precious fuel."

Since the energy supply increases called for under the President's program are predicated on rather optimistic projections of energy conservation, any shortfalls in achieving these conservation goals will necessarily have to be met with imported energy. Furthermore, it will be very difficult to restrain the annual energy growth rate to the 2 percent rate proposed in the President's program without adverse impacts on the economy.

We in the gas industry firmly believe that it is not necessary or desirable to adopt such a pessimistic view with respect to our Nation's ability to continue to produce our domestic energy resources. With respect to gas, we believe that there are large recoverable supplies of conventional natural gas as well as substantial supplemental supplies that could be produced from coal gasification, SNG and LNG.

Virtually every recent analysis of remaining recoverable resources of natural gas have concluded that there are between 700 and 1200 Tcf of remaining conventional gas in the United Staes. At current consumption rates, this is between a 35- and 60-year supply. In addition, we project a very significant potential contribution from supplemental sources of gas.

Our projection of natural gas production from conventional natural gas supplies in the lower 48 States can, with deregulation of new gas and realistic public land leasing policies, be maintained well into the 1990s at approximately 20 quads per year, or approximately today's rate of production. This compares with administration projections of decline to some 17 quads per year as early as 1985.

A comparison of these estimates is set forth in Chart #1, attached to my written statement. Chart #2 refers to specific supplemental supplies, the six categories of which total some 14 quads in the year 2000. Our industry believes the projection of conventional lower 48 natural gas production is attainable, given the deregulation incentive and, indeed, each category of supplemental supply is attainable with Federal encouragement and no major project delays.

In view of the environmental, efficiency and costs advantages of natural and supplemental sources of gas, it is difficult to understand why the administration's program has relied for essentially all of its energy growth on increased electrification and direct use of coal. While we in the gas industry believe that all our domestic energy sources should be vigorously developed, we do not believe the administration's program recognizes the increased contribution that gas can make.

This is particularly important considering the capital requirements and additional costs that the American consumer will bear without natural gas development. For example, the annual costs to the consumer in 1976 dollars to provide the additional 3.1 quads of electric energy—a very optimistic projection—proposed by the administration for 1985 will be approximately $43 billion.

If the same amount of energy were supplied with deregulated natural gas, from LNG and from coal gasification, this annual cost is estimated at only $17 billion, and the coal use and environmental impact are also more favorable, as detailed in Attachment 8 to my full statement.

A major deficiency in the President's program is that it provides no real additional incentive for natural gas exploration and development. The administration's proposal to establish a $1.75 per Mcf national price ceiling extends the very price regulations into the intrastate market which have already proven to be a disincentive in the interstate market.

I firmly believe that the only workable way to increase domestic natural gas production is to deregulate the price of new natural gas and to provide a fair but stringent definition of what constitutes "new gas." Because only new gas would qualify for unregulated prices, the economic impact of such deregulation would be gradual and would amount to only about a 10 percent gas price increase per year over the next decade. This is because the majority of the gas produced during this period would still be old gas under a vintage price structure.

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While deregulation of new gas is the only pricing approach which can accommodate increased production costs, it is important to note that the administration's new gas ceiling of $1.75 discriminates against natural gas in that it provides less of an incentive than proposed for new domestic oil which would escalate over three years to the price of foreign oil.

Further, prices in the intrastate market for new and renegotiated contracts are already averaging more than $1.75 per Mcf. In fact, according to the FPC, 64 percent of these contracts were above the $1.75 limit in the first quarter of 1977.

Finally, the natural gas pricing proposals of the administration clearly violate the 7th principle enunciated by the President in his energy message that oil and gas prices should generally reflect the true replacement cost of energy. Considering that foreign oil is realistically our "swing fuel", we should be willing as a Nation to pay at least as much for developing domestic natural gas supplies as we are for importing oil.

As a concrete example, I want to state briefly my company's experience in the Appalachian area. Consolidated has been exploring, developing, producing and purchasing gas in the Appalachian area since the 1880s. Since 1969, when it became obvious that new domestic gas supplies from elsewhere were not going to be available, Consolidated increased its efforts in Appalachia despite rapidly escalating costs.

We have maintained production levels while the national production rate declined. Why? Because we have not been constrained by Federal regulatory price ceilings which discourage the tremendous capital investment and corporate commitment necessary to produce the gas. At this time, I would like to submit for the record an expanded discussion of Consolidated's experience in Appalachia.

Accordingly, I urge this subcommittee to adopt a proposal such as H.R. 2088, the Natural Gas Act Amendments of 1977, introduced by Congressmen Robert Krueger and Clarence Brown as the best vehicle to ensure adequate supplies of natural gas to meet our Nation's requirements.

I thank you for the opportunity to testify today. I will be glad to answer any questions the subcommittee may have.

[Mr. Seymour's prepared statement follows:]

TESTIMONY OF

ROBERT E. SEYMOUR
CHAIRMAN OF THE
CONSOLIDATED NATURAL GAS COMPANY
AND
CHAIRMAN OF THE BOARD
AMERICAN GAS ASSOCIATION

Before the

ENERGY AND POWER SUBCOMMITTEE

of the

HOUSE INTERSTATE AND FOREIGN COMMERCE COMMITTEE

A Perspective on the National Energy Act
May 18, 1977

I am Robert E. Seymour, Chairman of the Consolidated Natural Gas Company in Pittsburgh, Pennsylvania which serves a four state area that includes pipeline and distribution systems in Ohio, Pennsylvania, New York and West Virginia. I am also Chairman of the Board of the American Gas Association, a national industry association representing over 300 natural gas transmission and distribution companies. A.G.A. members serve over 160 million consumers and provide over 85% of the gas utility service in this country.

The energy crisis, which has faced and is continuing to face our country, whether measured in terms of a growing dependence on imported oil, or the actual shortage situations such as occurred this past winter, or on predicted future problems, is to a large degree a manifestation of the growing natural gas shortage. There is general agreement that this gas shortage is the result of the counterproductive Federal laws, regulations and policies which have kept gas prices regulated well below the minimum level that would promote exploration for and development of new supplies. In addition, the artificially low price of gas has encouraged its expanded use and has often led to wasteful consumption.

My major concern with the Administration's national energy plan is whether it can provide sufficient development of energy supplies to meet national energy requirements for the next 20 - 25 years. My concern is not a narrow, parochial one -- although increased natural gas supplies are, of course, a personal concern. My reservations with the national energy plan concern the broader question of the direction chosen for national consumption and production patterns for all domestic energy sources. Every shortfall in meeting the national energy objectives outlined in the President's plan will require a further increase in oil imports with the negative policy implications of increasing foreign source reliance and continuing deficits in our foreign balance of payments.

National energy shortfalls could be alleviated by maintaining U.S. production of natural gas at current levels of almost 20 Tcf per year, given the proper price incentives. There has never been a genuine exploration incentive for natural gas in the U.S. Natural gas went from the post World War II oil by-product stage directly into a stifling environment of field price controls in 1954. This led to a steady 16-year downward trend in exploration and development. It is an intolerable situation that there has not been at any time an effective exploration incentive for natural gas -- our nation's cleanest and most efficient energy source.

To correct this problem, the gas industry urges Federal and legislative actions to achieve goals detailed in the attached briefing package. Supplemental supply sources and the deregulation of new gas could play a major role in mitigating energy shortfalls and minimizing further increases in foreign oil imports. However, this possibility has evidently been rejected by the Administration

since by their own estimates natural gas production will drop to 16 Tcf per year in 1990 with their proposed pricing mechanism. This, we believe cannot benefit the American consumer, nor the nation as a whole.

Fuel Mix and National Goals

The President's program calls for overall energy growth of roughly 2% a year from 1976's level of 74 quads, creating demands for 92.8 quads by 1985 and 96.1 quads by 1990. While 2% national energy growth rate is an admirable goal, it may be very difficult to achieve without potential reductions in economic growth. When fuel balances by sector are reviewed, 10.0 of the additional 18.8 quads of projected energy growth between 1976 and 1985 are for electric generation. Of the remaining 8.8 quads of energy growth, 6.2 quads will have to be provided from direct use of coal in industry. Nuclear capacity will have to increase 400% between 1976 - 1985, and national coal production will have to double by 1985. (See Attachment 1) Prudent national policy should provide for greater domestic supply growth in natural gas in the event either demand exceeds supply or the large additional supplies from coal cannot be developed for supply or environmental reasons.

The Administration's plan may create a serious energy supply problem by setting ambitious goals for coal, nuclear and electrical power while inhibiting natural gas development which can only result in increasing reliance on foreign oil imports. Instead, it should be concentrating on ensuring a readily available supply of natural gas, to enable our nation to meet the national energy goal of reducing oil imports from a potential level of 16 million barrels a day to less than 6 million barrels.

The national energy goals call for an increase in coal production by more than 400 million tons by 1985. This objective appears optimistic based on the fact that the coal industry has developed only 20 - 25 major new coal mines in the past twelve years, not to mention transportation, mining restrictions, and environmental considerations. The nuclear power objectives of the plan may also be optimistic when the recent history of development in this industry is taken into account.

All of these factors seem to indicate that the Administration's plan is overly optimistic on the low side of consumption and the high side on production of coal and electricity. If natural gas and supplemental gas supplies are not developed to their full potential, additional shortfalls will have to be made up from imported oil.

Natural Gas Supply and Consumption

The Carter plan seriously inhibits the development of new natural gas supplies. The President's program will result in a significantly lower contribution from conventional and supplemental gas sources than with deregulation of new gas prices and a favorable government climate towards supplemental natural gas sources. Under a ceiling price for new gas (lower even than the new oil ceiling price), lower 48 state production is projected by the Administration to continue its decline, dropping to 17 Tcf by 1985 and 16 Tcf by the early 1990's. Liquefied natural gas imports, synthetic natural gas and coal gas are not expected, nor permitted, to make any contribution to supply in any significant amounts. As shown in Attachment2, the gas industry could provide roughly 6.6 quads of

additional energy by 1985 with deregulation above the 18.8 quads projected in the President's program. As mentioned, residential and commencial gas consumption increases are projected to average only 0.6% between 1976 - 1985. (The residential sector would grow 1.9% annually while the commercial sector would decline 1.2% annually) But, by 1990, the residential and commercial sectors are projected to consume almost 50% more natural gas than in 1985 (reaching an annual growth rate in this period of 8.3%). (See Attachment 2)

Those who suggest that a decline in the contribution of gas is inevitable should recognize:

- Proven reserves and potential gas resources, coupled with economically feasible supplemental gas supplies and a strong conservation ethic, are adequate to meet not only existing gas demands but even increased demand well into the next century.
- The potential for technological breakthrough with respect to gas energy is great and if it occurs would provide an almost unlimited supply of usable energy for most purposes. In this regard, one of the great potentials for nuclear energy might well be making hydrogen from sea water. This, in turn, could be the ultimate long-term, unlimited source of premium energy to be delivered through the efficient underground gas pipeline network now in place, and which is readily expandable.

Cost of Additional Electric Investment Vs. Gas

National electrification will prove extremely expensive for the American public and the nation. Based solely on requirements for gas and electricity, as indicated in the national energy plan, the nation will need by 1985 to produce for end-use an additional 3.1 quads of electricity. The annual consumer costs (in 1976 dollars) required to provide an additional 3.1 quads of electric energy by 1985 would total approximately $43 billion versus roughly $17 billion, if additional natural gas from deregulation were used instead of this electricity. (See Attachment 3).

Preliminary analysis, in Attachment 3 covering national costs of an additional 3.1 quads of electrical energy indicates substantial savings to the nation if natural gas were used as a substitute for the additional electric consumption. Residential consumers will pay nearly $11.2 billion more annually if our nation chooses to emphasize electricity rather than natural gas. For industrial customers, $15.6 billion annually would be saved by substituting natural gas for proposed additional electricity.

We are not herein depreciating the increased need for coal and nuclear-generated electricity. Indeed, if we are going to meet even the very modest energy growth rates through the year 2000, we will need to develop all our domestic energy sources to the maximum extent. But, again we cannot reconcile the Administration's plan with its complete lack of incentives for both natural and supplemental gas supplies when any alternate forms of energy are both more expensive to the consumer and less environmentally acceptable.

The proposed increase in electrical consumption which the President's plan fosters would prove costly. Natural gas can play a far greater role than the Administration envisions. Our industry stands ready to

make its contribution to our nation well into the 21st century. Our specific recommendations which will permit this to occur are as follows:

Natural Gas Pricing

A major deficiency in the President's program is that it ignores the necessity for increased development and production of natural gas. The Administration's proposal to set a national price ceiling is nothing more than an extension of the current policies that have proven so inadequate. (See Attachment 4).

The price ceiling concept is and has been unworkable because it sets a level above which prices cannot rise, even if production costs so warrant. With respect to the issue of whether there are additional significant supplies of conventional natural gas and whether these can be brought on at higher prices, it should first be recognized that all major estimates of potential gas resources, including those of the U.S. Geological Survey, indicate that there are between 700 and 900 Tcf of potential gas resources in the U.S. over and above current proven reserves of 216 Tcf. In addition, when the natural gas drilling activity in 1975 is compared with the geographical location and depth of potential resources, it clearly shows that present price regulation has not permitted adequate incentives for exploration and development in frontier areas. Over 90 percent of current drilling activity is onshore and at shallow to moderate well depths rather than offshore or at deep depths onshore where a major portion of the potential resource is estimated to be. To compound this trend, drilling that has existed since 1973 in the intrastate market which has contributed to a leveling off of the 16-year

decline in exploration drilling from 1956 to 1972, would be further rolled-back by the arbitrary $1.75 average price ceiling in the Administration's plan.

Evidence in the unregulated intrastate market clearly suggests that $1.75/Mcf is not sufficient. Since the intrastate market in the last year or so has shown signs of softening--that is, prices have even declined--a reasonable argument can be made that supply and demand have indeed reached equilibrium. If so, the statistics for new and renegotiated contracts in the intrastate market in 1976 show a range of "free market" prices between $1.50 and $2.35/Mcf, with an average of about $1.65/Mcf. Clearly a new gas ceiling at $1.75/Mcf would represent a rollback for approximately one-third of all the new and renegotiated contracts made during 1976, and the FPC reports two-thirds in the first quarter of 1977. It is difficult to see, therefore, how a $1.75/Mcf new gas price ceiling, which escalates at only 2 percent annually in real dollars, after taking out the assumed 5.5 percent annual inflation, represents any increased price incentive for greater gas development.

Deregulation of new gas would not lead to exorbitant increases in the cost of natural gas to the consumer. Residential consumer prices would rise slightly to compete with the prices of alternate energy choices, but remain price competitive with alternate fuels. The difference between the annual percentage increase in residential gas prices resulting from deregulation and that expected under continued FPC regulation is estimated to be, at most, about 10 percent per year dropping to less than seven percent through the 1980's. When the cost of replacement energy paid by residential users who would not have additional gas produced under deregulation is considered, the difference in annual percentage price increases is only 1% through 1990.

However, price is only part of the effect of deregulation. Most important is increased volume. Deregulation will make available about 4 Tcf more gas annually by 1985, increasing to over 5 Tcf by 1990, as compared to those volumes we would experience under continued regulation. Thus, the real issue is not the modest price increase, but whether adequate quantities of gas will be available at any cost.

The price ceiling concept further inhibits new exploration and production by creating an atmosphere of uncertainty as the Federal government and the Federal Courts incessantly debate the merits of any given raise in the ceiling price. The extended legal proceedings on FPC Opinion #770-A are an example of the problems the industry faces in making major production decisions based on rates that are subject to future refunding.

Immediate removal of federal controls on the wellhead price of new natural gas is the most realistic answer to the problem of increasing domestic production. It is widely recognized that the disparity in price between the intrastate and the interstate markets has to be eliminated, but this should be done by removing the long-standing, unworkable Federal price controls which have caused the problem. The removal of such controls serves a valid twofold purpose. It not only assures a maximization of efforts to produce and develop new gas supplies from frontier and hard-to-reach areas, but also creates a strong incentive to conserve and use our nation's premium fuel more efficiently without a complex Federal system of taxation and rebates.

There is gas to be produced given the proper economic incentive! In testimony delivered before this Subcommittee, Mr. Harry C. Kent, Director of the Potential Gas Committee, pointed out there remains to be discovered about 700 to 1,200 trillion cubic feet of natural gas. This figure is one and one-half times as large as the total previously discovered volume of natural gas in this country. While I would not dispute the fact that natural gas is a finite resource, I would quarrel strongly with the Administration's program which consigns Americans to large increases in the use of expensive electricity without also allowing the gas industry to do its part.

In fact, by continuing to hold the price artificially low, H.R. 6831 merely ensures that the Administration's dire predictions on natural gas supply will come true. An examination of supply projections reveals that the Carter proposal will result in decreasing supplies of gas. Attachment 4 indicates that by 1990 only 15.2 Tcf of natural gas would be available under H.R. 6831. This figure is nearly 5 Tcf less than the 20.1 Tcf available under deregulation.

Accordingly, I urge this Subcommittee to consider and adopt a proposal such as H.R. 2088, the Natural Gas Act Amendments of 1977, introduced on January 19 by Congressmen Robert Krueger and Clarence Brown as the best vehicle to ensure adequate supplies of natural gas to meet the nation's needs. Enactment of this legislation will increase exploration and production of natural gas resources in deep hard-to-reach areas requiring expensive technology, as well as increase supplies from frontier areas such as the Outer Continental Shelf.

A crucial aspect of any natural gas pricing legislation is the method of defining new gas. Such definition must provide the maximum incentive to find and produce "new" gas and give producers a clear indication and direction as to what gas will qualify for the new gas

price. Section 402(a)(5) of H.R. 6831 is fatally deficient in this regard because it narrowly defines "new" gas in so arbitrary and complex a manner that a great majority of new gas production would not qualify for the new gas price under this definition.

To eliminate this problem, I urge you to accept a "new" gas definition such as that contained in S. 2310 introduced by Senators James B. Pearson (R-Kans.) and Lloyd Bentsen (D-Tex.) which passed the Senate on October 22, 1975. Under that proposal, new gas was defined as that committed to interstate commerce for the first time on or after 1/1/75, or produced from wells on or after that date, or from wells begun in extensions of old reservoirs on or after that date. Roll-over interstate contracts would remain old gas but would receive a price set and modified every two years by the FPC based on specified criteria enumerated in S. 2310 Section 208 as it would have amended the Natural Gas Act by adding new Section 29. This new gas definition would give clear guidance to producers as to what gas would receive the higher price, while ensuring that gas qualifying for the price would actually be warranted by the higher cost of producing it.

In the alternative, if the Committee deems it desirable to focus on arbitrary limits of 2.5 miles or 1,000 feet as the Administration has done, we would strongly emphasize that the new gas definition should apply within a distance of 2.5 miles or less than 1,000 feet if it can be shown by pressure or other physical data that you are in fact in a new reservoir. Anything beyond these limits should be automatically designated "new gas" without reference to reservoir characteristics.

In summary, I can only emphasize again that increased natural gas production is essential to meet the nation's energy needs, especially in light of possible shortfalls in coal and nuclear energy supply use. Deregulation of the wellhead price of new natural gas along the lines of H.R. 2088, with the suggested refinements from the 1975 Pearson-Bentsen bill, would stimulate increased production while encouraging conservation by the free market price mechanism. I urge you to adopt legislation that will ensure the continued availability of our nation's premium fuel by deregulating the wellhead price of new natural gas.

Pricing Incentives for Hard-to-Reach Gas

Although I agree with the President's recognition of the difficulties of producing high-cost gas in hard-to-reach areas, I emphasize again that only the free market supply and demand process will encourage production of gas from deep onshore and offshore drilling. In addition to deregulated price, gas from tight formations and geopressured aquifers will need continued major research efforts. The main reason that gas reserve additions have continued to decline is because federal regulations have dictated through simple economics that the predominance of drilling and well completions take place in older, less risky, and less costly areas. In 1975 over 90% of all gas wells completed were onshore and at depths of less than 15,000 feet.

As these figures illustrate, gas is not being produced in the location of the major U.S. potential gas resources, which total between 600 and 900 Tcf in addition to proved reserves of 216 Tcf, because of economics. In 1975 only 4% of the total wells completed were offshore and an additional 3% were in deep onshore areas. About 90% of all gas wells completed in 1975 were in areas and at depths where only 30% of the estimated potential gas resource exists.

It is clear that the lack of economic incentive in the interstate market as a result of continued wellhead price regulation has been a sharp deterrent to the development of higher cost gas supplies in frontier areas. Opponents of gas deregulation in the Administration and Congress have been misled by statistics which have been interpreted to mean that our nation's gas depletion is near. This is not the case. Government controlled price levels have restricted exploration in high cost areas.

As availability of supplies tightened for Consolidated Natural Gas Corporation for example, we have increased our production efforts to find gas in the Appalachian area where drilling is costly but unregulated by the Federal government. In Ohio our company produces gas which costs already $1.75 Mcf at the wellhead. It is estimated that in Appalachia only about one-fiftieth of the potential well completions of deep gas, over 15,000 feet deep, have been completed. Reports indicate that such gas costs about $362 a foot to drill, perhaps the costliest in the Continental U.S.

There is increasing realization of the large volumes of natural gas which can be recovered from tight formations such as the Uinta Basin in Utah, the Green River Basin in Wyoming, the Piceance Basin of Colorado and the Devonian shales and low-permeability sandstones in the Middle and Eastern sections of the U.S. Estimates of this gas are speculative, but estimates of the in-place resource range from 1100-1200 trillion cubic feet of gas.

Much publicity has been given to gas recovery from geopressurized aquifers along the Gulf Coast. These are saline water reservoirs off Louisiana and Texas where the water pressure is higher at a given depth than the normal hydrostatic head. These salt brines start at depths of 5,000 to 15,000 feet and the methane content estimates range into the thousands of Tcf. The drilling costs of suitable wells for production of fluids run about $2 million per well to a depth of 15,000 feet. This already represents a cost of over $130 per foot, or three times the present average drilling cost. Hundreds of years supplies of gas might be found, but commercial feasibility depends upon higher gas prices and more research. However, the key point I am making is that with the ceiling set on new gas under the President's energy bill or the prospect of some as yet undefined price relief, it is unlikely -- even with research breakthroughs -- that this vast potential will be developed.

Incremental Pricing and Industrial Users Tax

The cost allocation of more expensive new gas and certain supplemental supplies to industrial users only, through the incremental pricing provision in the bill, sets a detrimental federal standard for the gas industry. We oppose any attempt to federally mandate this approach to industrial users only. Instead, we recommend this issue be left to the determination of State Public Utility Commissions in their ratemaking proceedings on gas utility rate filings.

We strongly urge the Congress to scrutinize this issue closely. Most arguments favoring incremental pricing are based on a modification of the classic economic theory of marginal cost pricing with incremental costs being charged to arbitrarily chosen classes of users--in this instance, the industrial users. But, we stress this approach is not applicable to the current situation in the gas industry since, almost without exception, the supplemental gas is not incremental. Instead, it represents the substitution for eventually declining traditional gas supplies,and it enables the industry to provide service to existing customers at traditional levels.

Incremental pricing will also have an inflationary impact on the cost of goods and services produced by industry, hiding from ultimate consumers the impact of energy price increases. Eventually, high priority residential and commercial users will pay higher prices for service as the high fixed costs of the gas system are spread over lower volumes of gas due to lower industrial load factors. Also, increased needs for storage capacity to supply the peak needs of

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increased residential and commercial use would exert an upward pressure on ultimate prices to the consumer. Indeed, the residential consumer of natural gas would, until the increment at ceiling price for low priority customers was reached, pay for natural gas at current rates plus inflation. This approach seems at considerable variance with the very ethic of the President's plan for having the American consumer pay the real price for energy to encourage all appropriate conservation.

The conservation impact of this proposal in conjunction with the industrial users tax is grossly overstated, and we want to focus on this issue for a moment. We support the phase out of burning gas for electrical generation and other major industrial boiler fuel uses in excess of 3 Mcf a day (essentially, FPC categories 8 or 9). Also, we think conversion to coal should be encouraged where feasible with proper safeguards reflecting necessary lead time, availability of fuel, economic justifications and environmental considerations. But, while we favor a phase out of boiler fuel uses as I've outlined, we urge use of appropriate incentives rather than punitive taxes. These would include appropriate tax credits and a utility "finders-keepers" provision in the bill for gas conserved in the utility's system.

We are vigorously opposed to the industrial users tax on natural gas, since it will not lead to any significant conversion before 1985, yet will cost industry, and eventually the consumer, $44 billion. (See Attachment 5). This revenue windfall to the U. S. Treasury should instead be plowed back into supply improvement measures, and not retained as part of the general U. S. revenues, by rebuilding the Carter proposal to place the emphasis on supply. This provision in

the legislation is fundamentally inconsistent with the recognition that natural gas is artifically priced below its true replacement cost. The tax only operates to increase the price for natural gas with little immediate impact on gas consumption and produces no incentive to increase supplies.

Our preliminary estimates show the industrial users tax will start out initially small in 1979, and rise to well over $1.50/Mcf on a national average basis by the mid-1980's. (See Attachment 6). Since the price of distillate is based on PAD District averages, it will not vary from region to region. The major impact of the users tax, therefore, will be to diminish regional differences in natural gas prices to industry, with a much more substantial impact in the present lower cost regions. For example, the tax will have a large effect in the southern U. S. where gas prices are relatively low. But, the tax will have little impact in the northern parts of the country where gas is currently higher priced because of transmission costs. (See Attachment 7).

The tax on use of gas will evidently not promote any basic changes in consumption patterns during the first few years. A comparison of gas prices including tax, versus coal price streams from an EPRI study (Fuels and Energy Price Forecasts, March 1977) along with the amortized cost of conversion to coal and increased operating costs, suggest an economic cross-over point for larger boilers of over 1500 Mcf/year will not be reached until almost 1985 under the Carter proposal. Substantial conversions will not take place until 1985--at which time, industry will already have incurred $44 billion of total direct costs of the tax. I also want to stress these preliminary calculations do not include, in the total direct cost of the tax on industrial gas users, such variables as the costs of environmental

constraints nor the costs of incremental pricing. Furthermore, there are other costs that bear further consideration such as the cost of coal conversion, the costs to residential consumers caused by under-utilization of the in-place pipeline system, costs associated with increased needs for storage capacity, and the expected heavy upward pressure on the price of coal because of increased demand.

Further, numerous industries use natural gas in processes which are not convertible to coal. At the very least, this will require that the exemption provisions in the natural gas users tax be expanded to exempt process uses of natural gas from the tax.

Gas Utility Rate Reform

The natural gas industry opposes the enactment of any legislation that establishes Federal authority over utility rates or sets Federal guidelines. Accordingly, I urge that you reject those parts of H.R. 6831, Title I, Part E, Subpart 4 which establish such Federal authority and guidelines. I base this recommendation on the premise that no Federal program could possible reflect the individual situations and needs peculiar to different regions of the country. The State Public Utility Commissions have the expertise and are better equipped to make decisions on the appropriate rate structure for their jurisdictions. The gas industry urges that this authority be left with the State PUC's which can be more responsive to local situations than the Federal Government.

Liquified Natural Gas (LNG)

The gas industry urges that unreasonable impediments to LNG importation be removed so that this safe supplement to domestic natural gas supplies can alleviate critical shortfalls during periods of peak

demand. Since provisions on LNG imports will be implemented by "administrative" actions, the gas industry will take a definitive position when the proposed detailed action is published in the Federal Register.

Synthetic Natural Gas (SNG)

Again, the industry urges that past unreasonable restrictions on feedstocks for liquid hydrocarbon SNG be removed. Comments on specific proposals will be forthcoming upon publication of proposed regulations in the Federal Register.

Extension of Emergency Natural Gas Act of 1977

The gas industry strongly urges that extension of the mandatory allocation authority not be included in a total energy package. This would formalize, perhaps permanently, a temporary solution that grew out of an extremely unusual winter situation.

In testimony before this Subcommittee on January 28, 1977, I supported the Emergency Natural Gas Act as a means to protect public health and safety, and to avert human suffering to the maximum extent possible. But I say now as I said then that mandatory allocation authority must not become a way of life in this already overregulated industry which delivers our nation's cleanest, most efficient and most critical fuel. Such authority does nothing to increase gas production. In fact, the mandatory allocation authority under ENGA Section 4 was not invoked by FPC Chairman Richard Dunham to meet last winter's shortages. Self-help measures by the industry and emergency purchases under ENGA Section 6 were sufficient to meet the high requirements brought about by the most severe winter in recorded history.

As a final point, I suggested that if an extension is passed, it contain only the ENGA Section 6 authorities, and that it be on a standby basis with an appropriate "triggering mechanism."

Energy Conservation Provisions

The gas industry has been and will continue in the forefront advocating and implementing positive conservation efforts. However, we are opposed to the Utility Conservation Program provisions of the legislation which would have the Federal government mandate State PUCs to require utilities to offer conservation programs. Instead, any utility conservation program should be done at the local level and left to the State PUCs to determine the scope based on local needs. State PUCs are more familiar with the inherent economic, supply, base load pattern, and climatological considerations in such programs. Also, they are better-equipped to review rate-making considerations and proper rate base treatment for these programs.

There are also antitrust and products liability problems with the legislation. Section 103 requires utilities to enter the retrofit installation business. While the gas industry supports the increased use of retrofits for conserving gas, there are serious problems in the proposals as stated:

Under Section 103, utilities must list and sell all available retrofit products, whether tested or untested, safe or unsafe, and whether they save gas or not. To do otherwise would invite antitrust litigation on the part of retrofit manufacturers or even the government. In addition, utilities must become the product liability insurers and guarantors of such devices when they are sold. To prevent this unfair result, the legislation should specifically require the State Regulatory Commissions to compile lists of recommended devices, and should exempt utilities from all antitrust, product liability and other liability relating to their installation and use.

There are also regulatory barriers to conservation programs. Section 107 removes contractual barriers to installing retrofit devices.

In fact, the barriers are more regulatory than contractual. Therefore, this section should be broadened by providing an exemption from Federal and State regulation of utility company participation in retrofit and other conservation programs.

I also would recommend these additional modifications to the legislation:

- Conservation efforts should apply to the specific utility providing heating service to the residential customer.
- The "finders-keepers" rule should be adopted so that gas conserved in a utility's service area could be utilized there.
- The financing service provision should be modified so that the utility can just offer to arrange financing through conventional, federal or state program sources.

Reserves Data Reporting System

As proposed, the Department of Energy would assume audit and verification of industry reserve data. The natural gas industry has repeatedly offered to assist the federal government in taking steps which might improve quality, accuracy, completeness, or acceptability of reserves estimates. Periodic reserves evaluation programs such as the FEA Operator Survey and Major Field Studies in 1975 have already established a baseline for such verification and audit. We suggest that close scrutiny be given to any reserves reporting program which is established to insure that it does not become an undue reporting burden on the industry by requiring new additional reporting procedures. Such a system should be based on established federal and state agencies rather than creating new, redundant, and expensive organizations both in the public and private sectors.

Coal Allocation Authority

The gas industry opposes the unnecessary extension of broad allocation authorities to the currently unregulated coal market. Under the Administration's proposal, the Administrator could divert coal from a supplier which might provide supplies to a coal gasification plant which is now in the planning stages.

This is another step in developing an undesirable Federal regulatory framework which must lead eventually to price controls if the allocation authority is to be used. This could only lead to shortages of yet another domestic fuel source.

I support the Administration's thinking in seeking more efficient uses of gas by phasing out of burning gas for electric generation and other major industrial boiler fuels uses, (those which use over 3 Mcf a day).

Being located, working and living in the heart of a major coal producing area, I know the reality of the obstacles facing the coal production and use goals set by the Administration. The capital costs for hundreds of new mines are tremendous. A one to two million ton mine could take two to three years to bring into production. Even if a certain utility ends up being able to burn coal under the Clean Air Act, the coal transportation costs or water requirements could prove a real problem. Coal-fired electricity already costs the consumer almost five times the fuel costs of natural gas. With costly pollution abatement equipment, transportation, and conversion costs, the consumer will bear the burden of increased utility bills.

I recommend using positive incentives, such as tax credits, to encourage conversion rather than implementing punitive taxes which are eventually borne by the ultimate consumer.

Coal Gasification

The more effective and sensible approach for substitute energy supplies, in many instances where coal conversion is either impracticable or where costs are exorbitant, is the commercial development of coal gasification. Compared to a major rehabilitation of our nation's rail beds to transport coal, the United States presently has over $100 billion invested in a national gas transmission, distribution ($51 billion) and end-user equipment system (at least $49 billion, of which $27 billion is for residential gas appliances). Utilizing this present pipeline system is much less expensive than creating new transportation systems or using the present facilities inefficiently at substantially less than full capacity.

Consolidated strongly supports the initiation of a coal gasification industry and such actions as are necessary to achieve early commercialization of high-Btu coal gasification. The gas industry agrees with the spirit of the Administration's policy that proven technology should not be subsidized, but we draw the important distinction between other technologies and high-Btu coal gasification by urging the Congress and the Administration to move forward with federal loan guarantees for U. S. commercial demonstration of first generation synthetic fuel technologies. This is because there are as

yet no operating, commercial scale, first generation technology plants in the U. S. Loan guarantees will encourage energy industries to overcome obstacles such as uncertainty of future petroleum pricing, environmental questions, government regulation, escalating costs and the most difficult constraint, financing needs. A full scale demonstration coal gasification plant costs about $1.3 billion. This cost is higher than the total net worth of most natural gas transmission and distribution companies.

The Administration and members of the Congress are increasingly recognizing the merits of coal conversion to high-Btu synthetic gas rather than electricity.

The following points highlight the conclusions reached in Attachment 8, "A Comparison of Coal Use for Gasification versus Electrification":

1. On the basis of efficiency of the utilization of the energy content of the coal, gasification of coal is estimated to be considerably more efficient than coal electrification:
   - Using conventional technologies at the residential end-use, the overall system efficiency is 36% for coal gas and 25% for electricity.
   - Using advanced technologies at the end-use (heat pumps), the efficiency advantage of coal gas is substantially higher in almost all regions of the country, with the advantage for coal gasification the the greatest in the most northern parts of the continental U. S. (66% for coal gasification versus 35% for coal electricity).

2. For the same quantity of useful end-use energy a coal gasification system will consume nearly 33% less coal than a coal-fired electric generation system.
3. From an environmental standpoint, coal gasification plants would result in significantly less air pollution, would generate less solid wastes, and would use far less water than a coal-fired electric power plant producing the the same amount of useful energy:

   - For comparable size plants, air emissions are between 9 and 12 times less for coal gasification, depending on the category.
   - With respect to water use, a coal gasification plant is estimated to consume 88% less water than a comparable coal-fired electric plant.

4. With respect to the cost of energy to the end-user, coal gasification has substantial advantages over coal electrification, even when advanced end-use technologies are employed:
   - For current technologies (i.e. using electric resistance heating and conventional gas furances), the average residential cost of energy used would be about $7/MMBtu for coal gasification vs. about $14/MMBtu for electricity from coal.
   - Using advanced space heating technologies (i.e. heat pumps), the cost of energy from gas produced from coal is between $4 and $5/MMBtu depending on the geographical area compared with $7 and $10/MMBtu for electricity for the same area.

5. With respect to plant capital investment, for the same amount of useful end-use energy a coal gasification plant requires about one-half the capital investment of a coal electric plant when both serve conventional residential end-use appliances.
   - For 250 Billion Btu/day, a coal gasification plant would cost about $1.3 billion whereas a coal electric plant would cost about $2.7 billion.

Energy Research and Development

While the Administration has moved to increase some gas related research efforts, less than 10% of ERDA's R&D budget for the coming year will be gas-related. This level of effort falls far short of the potential that gas offers in meeting our future energy needs.

Areas of gas related-research which should be expanded include:

1. Coal gasification including commercializing first generation as well as accelerating research and demonstration of second generation;
2. Enhanced gas recovery from tight formations;
3. Gas from geopressured reservoirs;
4. Fuel cells;
5. Gas heat pumps and high efficiency gas furnaces;
6. Industrial energy conservation
7. Solar heating and cooling
6. Fuels from biomass.

Finally, these increases in gas related research are especially justified in view of the inherent efficiency and environmental compatibility of natural gas supplemental gas production and delivery.

Mr. Chairman that concludes my testimony.

Testimony of

Robert E. Seymour

Chairman of the
Consolidated Natural Gas Company

and

Chairman of the Board
American Gas Association

Before the

Energy and Power Subcommittee

May 18, 1977

The following changes should be made in the prepared statement of Mr. Robert E. Seymour:

Page 10, first paragraph, fifth line

... gas. This figure is one to one and one-half times as large as the total...

Page 11, first paragraph, sixth line

... the date of enactment, or produced from wells on or after that date, or from wells begun...

Page 13, first paragraph, third line

... 700 and 900 Tcf in addition to proved reserves of 216 Tcf, because of...

Page 13, last paragraph, lines 5-9

... gas which costs already $1.75 Mcf at the wellhead. The total Appalachian potential has not really been defined because less than 10 deep gas wells over 15,000 feet, have been completed. Reports indicate that such wells cost about $5 million per well and are perhaps the costliest in the Continental U.S.

Page 16, first paragraph, lines 5 & 6

... fuel uses in excess of 3 MMcf a day (essentially, the lower FPC priority use categories). Also, we think conversion to coal should be encouraged where...

Page 17, last paragraph, lines 6 & 7

... suggest an economic cross-over point for larger boilers of 1.5 Bcf per year will not be reached until almost 1985--at...

Page 18, last paragraph, last line

... gas supplies can alleviate critical shortfalls.

Page 19, line 1

Since provisions on LNG imports will be implemented by...

Page 20, third paragraph, line 5

... ment. In addition, utilities would become the product liability...

Page 21, last paragraph, line 1

... As proposed, the Department on Energy would assume the auditing and...

Page 22, third paragraph, line 4

... which use over 3 MMcf a day).

Page 25, section 4, lines 10 & 11

... pumps), the end use cost of energy from gas produced from coal is between $4 and $5/MMBtu of ouput depending on the geographical...

Attachment 1

PROJECTED FUEL BALANCES BY SECTOR
(ADMINISTRATION ESTIMATES)

QUADS--10^{15} BTU

	1976 ESTIMATED	1985	1990
DEMAND	74	92.8	96.1
RESIDENTIAL & COMMERCIAL			
OIL	7.0	5.4	5.8
NATURAL GAS	7.8	8.2	12.2
ELECTRICITY[1]	12.6 (3.9)	16.8 (5.2)	17.0 (5.2)
COAL	0.2	0.0	0.0
TOTAL	27.6	30.4	35.0
INDUSTRIAL			
OIL	6.4	8.0	11.4
NATURAL GAS	8.8	9.0	6.3
ELECTRICITY[1]	8.4 (2.6)	14.2 (4.4)	15.6 (4.9)
COAL	3.8	10.0	4.9
TOTAL	27.4	41.2	38.2
TRANSPORTATION			
OIL	18.4	20.4	21.0
NATURAL GAS	0.6	0.6	0.4
TOTAL	19.0	21.0	21.4
ELECTRICITY			
OIL	3.2	2.6	2.5
NATURAL GAS	3.0	1.0	-
COAL	9.8	16.6	17.2
NUCLEAR	2.0	7.6	9.3
OTHER	3.0	3.2	3.6
TOTAL	21.0	31.0	32.6

[1] ENERGY REQUIRED TO PRODUCE ELECTRICITY; AMOUNT IN PARENTHESIS REPRESENTS ELECTRICITY DISTRIBUTED.

Attachment 2

NATURAL GAS SUPPLY AND CONSUMPTION PROJECTIONS

QUADS--10^{15} BTU

SUPPLY	1976 ESTIMATE	1985 A.G.A.	1985 PRESIDENT'S PROGRAM	1990 A.G.A.	1990 PRESIDENT'S PROGRAM
LOWER 48	18.8	20.0	17.0	20.1	16.4
SNG FROM PETROLEUM FEEDSTOCKS	0.3	1.2	0.5	1.2	0.5
COAL GASIFICATION	-	0.4	-	1.6	-
ALASKAN GAS	-	1.2	0.1	1.2	1.2
LNG IMPORTS	0.01	2.0	0.6	3.0	0.6
CANADIAN IMPORTS	0.9	0.6	0.6	0.6	0.2
TOTAL	20.0	25.4	18.8	27.7	18.9
CONSUMPTION					
RESIDENTIAL & COMMERCIAL	7.8		8.2		12.2
INDUSTRIAL[1]	9.3		9.6		6.7
ELECTRIC GENERATION	2.9		1.0		-
TOTAL	20.0		18.8		18.9

[1] INCLUDES NATURAL GAS CONSUMED AND LOST IN TRANSPORTATION.

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NATIONAL COSTS OF ADDITIONAL 3.1 QUADS OF ELECTRIC ENERGY

Category	Incremental Energy[1] Quads		Investment Costs $ Billions 1976			Annual Consumer Costs $ Billions 1976		
	Electric	Natural Gas	Electric[2]	Natural Gas[3]	Difference	Electric[4]	Natural Gas[5]	Difference
Residential & Commercial	1.3	2.0	44.0	5.5	38.5	18.2	7.0	11.2
Industrial	1.8	2.8	61.0	7.6	53.4	25.2	9.6	15.6
Total	3.1	4.8	105.0	13.1	91.9	43.4	16.6	26.8

[1] Electric consumption of 3.1 quads replaced by 4.8 quads of natural gas presumes 100% end-use efficiency for electricity and 65% end-use efficiency for natural gas.

[2] Costs for additional electric capacity (66% nuclear and 34% coal with scrubbers) based on $1.1 billion per 1000 Mwe nuclear and $900 million per 1000 Mwe coal where 1 quad electric requires 32.9×10^3 Mwe of electric capacity.

[3] 4.8 quads (1.4 Tcf LNG, 0.4 Tcf coal gas, 3.0 Tcf "new" gas from deregulation) requires investment of $5.2 billion for coal gas, $6.4 billion for LNG (U.S. investment), and $1.5 billion for "new" gas from deregulation (presumes FPC productivity of 300 Mcf/ft and costs per foot of $150 for high confidence, new horizon, deeper on and offshore drilling).

[4] Based on $14/MMBtu for incremental electric costs from new coal and nuclear steam electric plants.

[5] Based on $4/MMBtu for LNG, $5/MMBtu for coal gas, and $3/MMBtu for "new" natural gas from deregulation.

Attachment 4

IMPACT OF CARTER PROPOSAL ON LOWER 48 STATE NATURAL GAS PRODUCTION

	Annual Production (Tcf)			
	1978	1980	1985	1990
Offshore				
FPC 770A	4.1	4.4	5.0	5.2
Carter Proposal	4.1	4.4	5.4	5.8
Deregulation	4.1	4.6	5.7	6.0
Onshore				
FPC 770A	14.8	13.7	11.1	9.4
Carter Proposal	14.6	13.4	10.9	9.4
Deregulation	15.3	15.0	14.3	14.0
Total U.S. Supply				
FPC 770A	18.8	18.1	16.1	14.6
Carter Proposal	18.7	17.8	16.3	15.2
Deregulation	19.4	19.6	20.0	20.1

Attachment 5

DIRECT COST OF INDUSTRIAL GAS USERS TAX

Year	Weighted Unit Tax ($/Mcf)	Taxable Volume of Industrial Gas Use	Total Direct Cost of User Tax ($ Billions)
1979	$0.35	6.9	$2.4
1980	0.99	5.8	5.7
1981	1.09	5.7	6.2
1982	1.23	5.6	6.9
1983	1.33	5.6	7.4
1984	1.43	5.7	8.1
1985	1.64	5.4	8.9

Attachment 6

PRICE EFFECTS OF INDUSTRIAL GAS USERS TAX

Year	National Avg. Distillate Price to Industry	- Tax Adjustment	= Adjusted Gas Price To Industry*	= National Avg. Industrial Gas Price	+ Users Tax To Industry
1977		---			
1978		---			
1979	3.00	1.05	1.95	1.56	.39
1980	3.15	.40	2.75	1.65	1.10
1981	3.31	.35	2.96	1.75	1.21
1982	3.47	.25	3.22	1.86	1.36
1983	3.65	.20	3.45	1.97	1.48
1984	3.83	.15	3.68	2.09	1.59
1985	4.02	0	4.02	2.20	1.82
1986	4.22	0	4.22	2.35	1.87
1987	4.43	0	4.43	2.49	1.94
1988	4.65	0	4.65	2.64	2.01

*For users of 1500 MMcf/year (10^9 Btu/year), Section 4992 Section 4992(a)

REGIONAL INCREASES IN INDUSTRIAL GAS PRICES OVER FEA FORECASTS RESULTING FROM USER TAX

Region	1980 Industrial Gas Price Increases		1985 Increases
	Percent Over 1977 Price	Percent Over Expected 1980 Price	Percent Over Expected 1985 Price
1. New England	0%	0%	16%
2. New York/New Jersey	70	57	44
3. Mid-Atlantic	117	70	52
4. South Atlantic	182	124	72
5. Midwest	107	76	60
6. Southwest	141	57	84
7. Central	138	56	9
8. North Central	147	50	81
9. Western	64	5	39
10. Northwestern	86	32	59

ENERGY ANALYSIS

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A COMPARISON OF COAL USE FOR GASIFICATION VERSUS ELECTRIFICATION

Introduction

As a result of the increasing reliance by the U.S. on foreign energy sources in the past few years, there is considerable interest in significantly increasing the utilization of the large domestic resources of coal. To date, the primary focus of attention has centered on examining the potential of using more coal for increased electrification. While increased production of electricity is desirable in a number of applications, its additional contribution to overall U.S. energy supply will be limited by cost, efficiency, environmental, and other factors.

A major alternative method of using coal is the production of high Btu or pipeline quality synthetic gas from coal. While the technology for coal gasification has not been commercially demonstrated in the U.S., such applications are now feasible. Moreover, production of gas from coal offers the opportunity to make use of the existing gas pipeline transmission and distribution system in the U.S.

A major U.S. energy policy issue, given the increased desirability and benefits of using coal, is the extent to which emphasis should be given to accelerating the introduction and widespread application of coal gasification technology as opposed to using coal primarily to generate electricity. The resolution of this issue has significant implications for energy regulatory and developmental decisions especially those related to pricing of supplemental coal gas supplies.

This paper provides a comparative analysis of coal gasification and coal-fired electric generation of energy destined for the residential market on the basis of:

- Production and End-Use Efficiencies
- Environmental Degradation
- Plant Capital Requirements
- Production and Transportation Costs
- Production and End-Use Energy Costs

Executive Summary of Results of Analysis

In comparing coal consumption for electric generation and coal consumption for production of pipeline quality (high Btu) gas, the following results were obtained:

- On the basis of efficiency of the utilization of the energy content of the coal, gasification of coal is estimated to be considerably more efficient than coal electrification.
  - Using conventional technologies at the residential end-use, the overall system efficiency is 36% for coal gas and 25% for electricity.
  - Using advanced technologies at the end-use (heat pumps), the efficiency advantage of coal gas is substantially higher in almost all regions of the country with the greatest advantage for coal gasification in the most northern parts of the continental U.S. (62% for coal gas versus 35% for electricity).
- From an environmental standpoint, coal gasification plants would result in significantly less air pollution, would generate less solid wastes, and would use far less water than a coal-fired electric power plant producing the same amount of useful energy.
  - For comparable size plants, air emissions are between 9 and 12 times less for coal gasification, depending on the category.
  - With respect to water use, a coal gasification plant is estimated to consume 88% less water than a comparable coal-fired electric plant.

- With respect to the cost of the energy to the end-user, coal gasification has substantial advantage over coal electrification, even when advanced end-use technologies are employed.
  - For current technologies (i.e. using electric resistance heating and conventional gas furnaces), the average residential cost of energy used would be about $7/MMBtu for coal gasification vs. about $14/MMBtu for electricity from coal.
  - Using advanced space heating technologies (i.e. heat pumps), the cost of energy from gas produced from coal is between $4 and $5/MMBtu depending on the geographical area compared with $7 and $10/MMBtu for electricity for the same area.
- With respect to plant capital investment, for the same amount of delivered energy a coal gasification plant requires about one-third the capital investment of a coal-fired electric plant delivering the same amount of usable energy. When end-use efficiencies are considered, a coal gasification plant requires about one-half the capital investment of a coal electric plant.
  - A 250 billion Btu per day coal gasification plant would cost about $1.3 billion whereas an equivalent coal electric plant would cost about $2.7 billion.

Production and End-Use Efficiencies

Lurgi coal gasification technology is expected to have an overall thermal efficiency of production of 71%.[1] This conversion efficiency includes conversion by-products (liquid fuel and chemicals) that are marketable. For purposes of this analysis, coal gasification conversion efficiencies credit roughly half of the by-product as energy and half as non-energy, resulting in an overall plant efficiency of 65%. Capacity utilization is estimated at 90% for the gasification facility.

The coal-fired electric generating efficiency used in this analysis is based on western sub-bituminous coal with flue gas desulfurization (FGD). The thermal efficiency of production used is 32.8%[2] and the plant capacity utilization is estimated at 70%.

[1] C F Braun and Company Interim Report, Factored Estimates for Western Coal Commercial Concepts, October 1976.

[2] Electric Power Research Institute Final Report, Coal-Fired Power Plant Capital Cost Estimates, January 1977.

Residential end-use efficiency can vary widely depending on a number of factors, including the kind and age of the appliance, frequency of maintenance, etc. For purposes of this analysis, average rated efficiencies for the natural gas or electric home appliances have been used.

Table 1 shows average residential end-use efficiency for natural gas and electricity with conventional and advanced home appliances. For conventional appliances, the average residential end-use efficiency is based on the 1968 national residential consumption pattern for the four gas or electric appliances (space heating, water heating, cooking, clothes drying). For advanced appliances, conventional space heating has been replaced with thermally activated (gas-fired) heat pumps or electric heat pumps. Inclusion of both electric and gas heat pumps in this analysis is appropriate since electric heat pumps are available today and commercial availability of gas-fired heat pumps is expected in the same time frame (early 1980's) as the first commercial coal gasification facility.

Heat pump efficiencies vary due to climatic conditions. For this analysis, six cities have been chosen as representative of the range of U.S. climatic conditions. Since heat pumps include both heating and cooling cycles, cooling has been accounted for in the end-use seasonal performance factor (measure of efficiency).

Table 1

RESIDENTIAL END-USE EFFICIENCIES[1]

	Conventional 4 Appliance[2]		Advanced 4 Appliance Performance Factor[3]	
	Gas	Electricity	Gas	Electricity
Atlanta, GA	64	94	90	185
Concord, MA			109	130
Houston, TX			82	198
Philadelphia, PA			102	164
Seattle, WA			110	158
Tulsa, OK			99	178

[1] Based on 72% of energy consumed by space heating, 19% water heating, 7% cooking, and 2% drying. Because of the lack of data, residential energy consumption patterns for the six urban areas was not accounted for in this analysis; however, it is expected these differences would result in only small variation to the average residential end-use efficiency.

[2] Conventional gas appliance efficiencies: 66% space heating, 65% water heating, 40% cooking, and 65% clothes drying. Conventional electric appliance efficiencies: 98% space heating, 91% water heating, 75% cooking, and 65% clothes drying.

[3] Heat pump seasonal performance factor: Atlanta (gas 1.03, electric 2.20), Concord (1.29, 1.46), Houston (0.92, 2.38), Philadelphia (1.20, 1.92), Seattle (1.31, 1.84), and Tulsa (1.15, 2.12).

Combining conversion, transmission and distribution, and residential end-use efficiencies provides a measure of the total system efficiency of coal gasification and coal-fired electric generation. Table 2 shows total system efficiencies for both conventional and advanced (i.e. heat pumps) end-use appliances. Except in Houston when using advanced end-use technologies, total system efficiency for coal gasification is considerably higher than coal electricity.

Table 2

PERCENT OF COAL BTU'S
DELIVERED AS USEFUL RESIDENTIAL ENERGY

	Total System Efficiency (%)			
	Conventional[1]		Advanced	
	Gas	Electric	Gas	Electric
Atlanta, GA	36	25	51	40
Concord, MA			62	35
Houston, TX			46	53
Philadelphia, PA			58	44
Seattle, WA			62	43
Tulsa, OK			56	48

[1]Sample calculation using conventional appliances:

	Mining&Trans	x	Conversion	x	Trans&Dist	x	End-Use	=	Total System
Coal Gas	89.5%	x	65%	x	97%	x	64%	=	36%
Coal Electric	89.5%	x	32.8%	x	91.2%	x	94%	=	25%

Based on the above calculations assuming conventional appliances, nearly 30% less coal is required for a coal gasification facility supplying similar quantities of useful end-use residential energy than that required for a coal-electric facility.

Environment

From an environmental perspective -- including physical, chemical, biological, and socioeconomic impacts -- coal gasification would produce significantly less environmental effects than coal electrification at every major step in the production and transportation chain. Coal gasification versus coal burning, underground pipelines versus unit trains or overhead high voltage power lines, etc. (See Table 3). Indeed, coal gas plants would readily conform to the Clean Air Act, even with the proposed 1977 amendments on non-degradation.

- Air Quality. The President's Council on Environmental Quality recently found that commercial-scale gas plants will cause about one-tenth the air pollution of equivalent coal electric plants, even those that use the best pollution control technology available.[1]

- Non-degradation. Proposed 1977 Clean Air Act amendments concerning prevention of air pollution in areas that are presently clean would impose severe siting restrictions on coal-electric power plants. The restrictions on coal gasification plants, however, will be negligible. A recent FEA/EPA study[2] suggests that all the coal gasification plants that were proposed in 1976 for inclusion in the federal loan guarantee program would comply with, and even exceed, the most stringent version of the non-degradation amendments presently before the Congress.

  In fact, as shown in Table 4, numerous expansions of coal gas plants beyond the initial 250 MMcf/d level would theoretically be allowable at the proposed sites under the non-degradation rules, while not even a single coal-fired power plant of equivalent energy output could be built and operated at some of these same sites under the proposed law.

- Water Resources. Proposed coal gasification plants would consume 5 to 10 times less water than equivalent coal-fired or nuclear electricity generating plants (see Table 3), and would require only a small portion of available water supply in each region.

- Land Impacts. According to ERDA's draft programatic EIS,[3] the mining activities associated with a single 250 MMscf/d coal gasification plant could cumulatively affect 6,020 acres of land over a 20-year period in the Four Corners region, for example. In any single year, only a small portion of this acreage would be disturbed or out of production. In regions such as this, it is believed that the range and agricultural productivity of Western surface-mined lands can be largely restored, and often enhanced beyond previous levels. Proposed surface mining legislation currently before the Congress would impose little unanticipated new costs to most of the proposed near-term Lurgi coal gasification projects.

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[1] A Western Regional Development Study: Primary Impacts, prepared for CEQ under contract No. E04AC037, by Radian Corporation, August 1975.

[2] U.S. Environmental Protection Agency, Summary of EPA Analysis of the Impact of the Senate Significant Deterioration Proposal, April 1976.

[3] Synthetic Fuels Commercialization Program, Draft Environmental Statements, December 1975, Energy Research & Development Administration and Department of the Interior.

Table 3

SUMMARY COMPARISON OF ENVIRONMENTAL IMPACTS
OF TWO ENERGY-EQUIVALENT PROJECTS

	High-Btu Coal Gasification Plant (250 mmcfd)	Kaiparowits Power Plant (3000 Mwe with scrubbers)
Air Emissions (LB/HR)		
Particulates	180	1,070
SO_2	450	4,300
NO_x	1,780	20,830
CO	90	1,200
HC	30	360
Water Requirements (Acre-ft/yr)	6,300	54,300
Solid Wastes (Tons/day)	1,400	5,100

Sources: Radian Corporation, A Western Regional Energy Development Study: Primary Environmental Impacts, Volume II, prepared for the Council on Environmental Quality and the Federal Energy Administration under contract No. EQ4AC037, August 1975.

Final Environmental Impact Statement on the Proposed Kaiparowits Project, U.S. Department of the Interior, March 1976.

Notes: All figures rounded. Proposed coal electric power plant at Kaiparowits was to include wet cooling towers and underground mining, both of which tended to increase its projected water use.

Table 4

EFFECT OF NON-DEGRADATION RULES ON HIGH-BTU COAL GASIFICATION AND COAL-FIRED ELECTRIC GENERATING STATIONS[1]

Potential Sites	Nearest Protected Area (Class I)	Number of Plants	
		Coal Gas 250 MMcfd	Coal Electric 3000 Mwe
San Juan County, New Mexico	Canyon DeChelly National Monument (35 miles away) Mesa Verda National Park (50 miles)	8 plants	None
Mercer County, North Dakota	Lost Wood National Wilderness (90 miles) Theodore Roosevelt National Memorial Park (81 miles)	9 plants	None or One
Converse County,[2] Wyoming	None	8 plants	None or One

[1] Adapted from Reference 2, Page 7. Source for coal gas plants: Environmental Research and Technology, Inc., Impact Assessment of Significant Deterioration Amendments to the Clean Air Act on Siting of Synthetic Fuel Plants, April 1976.

All figures rounded. Results based on meteorological assumptions and 250 MMscf/d Lurgi coal gasification plants using best available control technology (BACT).

[2] Coal energy production at this site is limited by Class II SO_2 24-hour increments.

- Solid Wastes. Solid wastes from a coal gasification complex include spent ash remaining after coal gasification, sludges generating during the water treatment process, and spent limestone from the sulfur dioxide scrubbers installed on waste gas streams. The quantities of solid wastes are significantly less than those associated with a coal electric plant with the same energy output.

Capital Requirements

On the basis of equivalent quantities of end-use energy from conventional appliances (see Production and End-Use Efficiency Section), a unit-size coal gasification facility, 250 million cubic feet per day (MMcfd), produces the same amount of energy as a 3,000 megawatt (Mwe) coal-fired power generating station. When advanced appliances are used, the size of either facility, in terms of a fixed amount of usable energy consumed in the end use, would vary in each region since residential end-use efficiencies vary.

Based on recent capital cost estimates of $1.3 billion for a 250 MMcf/day western coal gasification facility and $895 per kilowatt of installed capacity for a western coal-fired electric facility with flue gas desulfurization, a coal gasification facility requires roughly half the capital investment of a coal electric facility delivering the same quantities of energy to the end-use ($1.3 billion versus $2.7 billion).[1] Table 5 shows unit investment on the basis of delivered and useful end-use energy. Even with the higher efficiencies available from advanced electric appliances, the investment savings from coal gasification in all cases is nearly 50%.

Table 5

UNIT CAPITAL REQUIREMENTS

($/Annual MMBtu)

	Delivered		Useful End-Use			
			Conventional		Advanced	
	Gas	Electric	Gas	Electric	Gas	Electric
Atlanta, GA					16.32	25.49
Concord, MA					13.48	36.28
Houston, TX					17.91	23.82
Philadelphia, PA	14.69	47.17	22.95	50.18	14.40	28.76
Seattle, WA					13.35	29.85
Tulsa, OK					14.84	26.50

[1] C F Braun and Company Interim Report, Factored Estimates for Western Coal Commercial Concepts, October 1976.

Electric Power Research Institute Final Report, Coal-Fired Power Plant Capital Cost Estimates, January 1977.

Table 6

DELIVERED RESIDENTIAL ENERGY PRICE CALCULATION
(1976 Dollars)

	Coal Gasification	Coal Electricity with Scrubbers
Capacity[1]	250 MMcfd	3,000 Mwe
Annual Generation[2]	91.3 billion cf	18,396 Gwh
Capital Cost	$1.3 billion	$2.7 billion
Annual Fixed Charge[3]	$213.1 million	$442.5 million
Capital Charge ($/MMBtu)[4]	2.34	7.05
Fuel Cost ($/MMBtu)[5]	0.72	1.31
Operating & Maintenance[6,7] ($/MMBtu)	0.96	0.59
Credit for By-Products[6] ($/MMBtu)	(0.72)	NA
Transmission & Distribution[6,7] ($/MMBtu)	1.15	4.82
Total ($/MMBtu)	4.45	13.80

[1] A 250 MMcfd coal gas plant delivers 155.2×10^9 Btu per day through conventional residential appliances. A 3,000 Mwe coal plant delivers 153.7×10^9 Btu per day through conventional appliances.

[2] For coal gas average daily send-out is 250 MMcfd and peak day is 275 MMcfd. For coal electric average daily send-out is 50.4 million Kwh.

[3] Calculated at 16.39% per year over facility life. Based on 75/25 debt to equity, 10.75% interest, 15% return on equity, 2% taxes (other than income), 50% income tax, and 35-year life.

[4] Annual fixed charge ÷ annual generation.

[5] Based on 7.50/ton sub-bituminous western coal.

[6] C F Braun and Company Interim Report, Factored Estimates for Western Coal Commercial Concepts, October 1976.

Gas transmission costs calculated on the basis of 300-mile transmission. Distribution costs are taken from data in 1975 Gas Facts. Residential distribution cost is calculated by subtracting the average price paid by utility companies from the average residential price charged by utility companies. An escalation factor of 5% was then used from mid-1975 to mid-1976.

[7] Electric transmission and distribution cost is the difference between average residential revenues per kilowatt hour and the average cost of production for investor-owned electric utilities. The average residential revenues per kilowatt hour are given in the 1975 Edison Electric Institute Statistical Yearbook. The average production cost is a computed figure obtained by adding average variable production costs as given in the above reference and estimated fixed capital charges. These fixed charges are calculated by allocating 45% of net total electric utility plant assests to the generation plant and multiplying it by the 1975 embedded capital cost of just over 12%. The fixed and variable costs are then combined and allocated over energy sales for investor-owned utilities in 1975. The differential resulting from the subtraction of production cost from average residential revenues per kilowatt-hour is then escalated at a 5% annual rate from mid-1975 to mid-1976.

Production and Transportation Costs

Table 6 shows production and transportation cost estimates for coal gasification and coal electricity. Production costs were calculated on an incremental basis, using standard regulated utility accounting procedures. Transmission costs assume use of existing lines and approximately 300-mile transmission from conversion facility to consuming market. Distribution costs are calculated on the basis of 1976 average residential distribution costs.

The costs of generation are particularly sensitive to two factors -- the capital cost of the facility and the price of coal. For this analysis the facilities were assumed to be located in the west, with operation beginning in 1982, and using Montana sub-bituminous low sulfur (Powder River) coal. Although national air quality standards could most likely be met without flue gas desulfurization equipment (scrubbers), more stringent State standards in many areas may necessitate their use. As a consequence, scrubbers and the resulting energy losses have been included in the calculations for the coal-fired electric generating facility.

The coal gasification advantages of greater conversion efficiency and lower capital cost per unit output cited earlier are clearly reflected in the delivered cost of coal gasification which is nearly one-third that of coal electricity ($4.45 versus $13.80/MMBtu).

Residential End-Use Energy Costs

Delivered energy costs do not, however, reflect the entire comparative cost, since residential end-use efficiencies are generally higher for electric appliances. By dividing the delivered energy cost by the average residential end-use efficiency, an average residential cost per useful Btu of energy is calculated (see Table 7).

Table 7

RESIDENTIAL END-USE ENERGY COSTS

	Cost $/MMBtu of Useful Energy Consumed			
	Conventional		Advanced	
City	Coal Gas	Coal Electric	Coal Gas	Coal Electric
Atlanta, GA	6.95	14.68	4.94	7.45
Concord, MA			4.54	10.61
Houston, TX			5.43	6.96
Philadelphia, PA			4.35	8.41
Seattle, WA			4.05	8.73
Tulsa, OK			4.49	7.75

Table 7 shows for the average residential user with conventional appliances (gas furnace or electric resistance space heating), that the average price per million Btu (MMBtu) of useful energy consumed by the four major home appliances (space heating, water heating, cooking, and clothes drying) is $6.95 for coal gas versus $14.68 for coal electricity. Even when advanced appliances are considered, the average residential consumer would still pay less (ranging from 24% to 63% less) for gas made from coal than for electricity from coal.

CHART 1

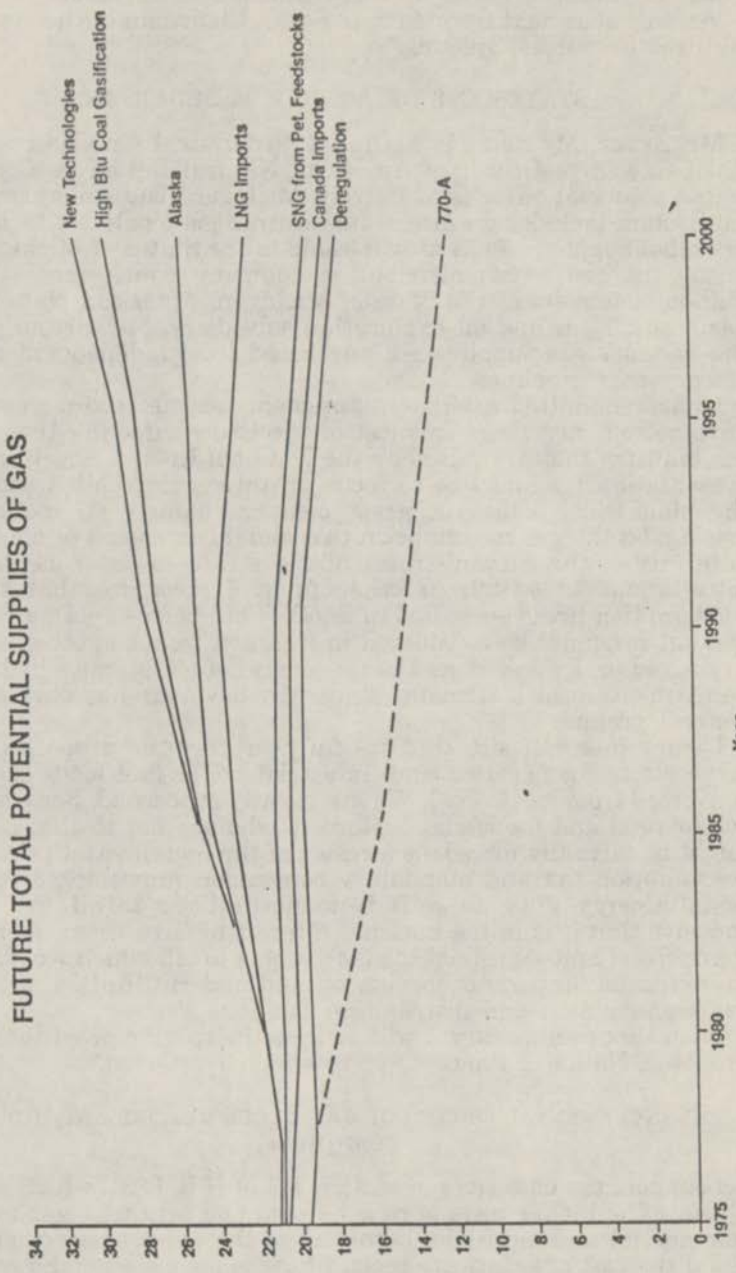
NATURAL GAS SUPPLY AND CONSUMPTION PROJECTIONS

QUADS--10^{15} BTU

SUPPLY	1976 ESTIMATE	1985 A.G.A.	1985 PRESIDENT'S PROGRAM	1990 A.G.A.	1990 PRESIDENT'S PROGRAM
LOWER 48	18.8	20.0	17.0	20.1	16.4
SNG FROM PETROLEUM FEEDSTOCKS	0.3	1.2	0.5	1.2	0.5
COAL GASIFICATION	-	0.4	-	1.6	-
ALASKAN GAS	-	1.2	0.1	1.2	1.2
LNG IMPORTS	0.01	2.0	0.6	3.0	0.6
CANADIAN IMPORTS	0.9	0.6	0.6	0.6	0.2
TOTAL	20.0	25.4	18.8	27.7	18.9
CONSUMPTION					
RESIDENTIAL & COMMERCIAL	7.8		8.2		12.2
INDUSTRIAL[1]	9.3		9.6		6.7
ELECTRIC GENERATION	2.9		1.0		-
TOTAL	20.0		18.8		18.9

[1] INCLUDES NATURAL GAS CONSUMED AND LOST IN TRANSPORTATION.

CHART 2


FUTURE TOTAL POTENTIAL SUPPLIES OF GAS
New Technologies
High Btu Coal Gasification
Alaska
LNG Imports
SNG from Pet. Feedstocks
Canada Imports
Deregulation
770-A
Trillions of Cubic Feet
Year
0
2
4
6
8
10
12
14
16
18
20
22
24
26
28
30
32
34
1975
1980
1985
1990
1995
2000

Mr. OTTINGER. Thank you very much, Mr. Seymour.

We will hear next from Arthur Seder, Chairman of the American Natural Resources Systems.

STATEMENT OF ARTHUR R. SEDER, JR.

Mr. SEDER. My name is Arthur R. Seder, Jr. I am Chairman and Chief Executive Officer of American Natural Resources Company, whose principal office is in Detroit, Michigan. The American Natural System includes an interstate natural gas pipeline which is the principal supplier of gas at wholesale to the States of Michigan and Wisconsin and a gas distribution company which serves over a million customers in the State of Michigan. American Natural also has a small gas and oil exploration subsidiary, but virtually all of the system's gas supplies are purchased from independent producers or other pipelines.

I have submitted a written statement for the record in which I have set out my views on most of the issues affecting the natural gas industry that are raised by the National Energy Act. In my oral presentation I would like to focus on three interrelated aspects of the plan which cause us great concern, namely (1) incremental pricing, (2) the gas consumption tax, and (3) extension of mandatory authority of the Administrator of the F.E.A. to order gas burning installations to switch to other fuels. I recognize that the gas consumption tax is embodied in another bill before another committee, but it cannot be considered in isolation from the other subjects I referred to. I won't repeat some general observations I had at this point in my oral statement, since Mr. Seymour has covered that general ground.

I want to emphasize that we fully support the proposition that large electric generation and industrial boiler fuel loads should be converted from gas to coal. We are greatly concerned, however, that commercial and industrial customers who are not in that category might be virtually forced, as a result of the incremental pricing, the consumption tax and mandatory conversion provisions of the National Energy Plan, to shift from natural gas to oil. We cannot conceive that it is in the national interest to force the conversion of commercial and industrial loads from gas to oil, which would result in increasing imports of foreign oil and underutilization of existing gas transmission and distribution facilities.

With that preliminary, I will address the specific provisions of the proposed National Energy Act to which I referred.

1. THE INCREMENTAL PRICING OF GAS TO COMMERCIAL AND INDUSTRIAL CUSTOMERS

I support the objectives of section 414 of H.R. 6831, which seeks to allocate the higher costs of new natural and synthetic gas to larger commercial and industrial cutomers to the point where their costs equal the cost of substitute fuels. I have some question, however, as to the desirability of attempting to bring about that result through a federally mandated gas pricing system, particularly since the State public utility commissions are moving in that direction in any event.

Nevertheless, while I would prefer to see the objectives of section 414 achieved through rate action at the local level, I believe that the proposal set forth in that section is a workable one if certain changes are made and certain principles are established.

The approach set out in section 414 is that the higher costs of new gas supplies will be allocated to commercial and industrial customers using over 50 Mcf on a peak day until such allocation "would result in rates of charges for such uses equal to an amount no greater than the reasonable price (as determined by the President) of substitute fuels." Thereafter, the remaining costs of the higher price gas would be allocated to high priority residential and small commercial users. The obvious intent of this language, with which we agree, is that lower priority users should not be charged rates higher than the reasonable cost of substitute fuels, as determined by the President.

The key, therefore, is the President's determination of the cost of substitute fuels—what "substitute fuels" are selected and how the determination is made of the "reasonable cost" of such fuels. In section 414(a) the matter is left entirely to the discretion of the President's designee, and it is here that we strongly urge the Congress to lay down some principles to serve as guides to the exercise of that discretion.

We certainly do not contend that the price of "substitute fuels" should be the cost of coal. But we are equally sure that it is not the intent of the National Energy Act to drive commercial and industrial users of gas to imported oil when gas is available.

It is essential, therefore, that the "reasonable price . . . of substitute fuels" be set at a level that does not necessarily result in the conversion of gas loads to oil. That means two things: (1) that the price of substitute fuels fixed by the Administrator be determined in the particular market where the fuel is to be used, and (2) that the price fixed by the Administrator relate to the cost of oil actually paid by large users, who are usually able to buy large quantities of oil at a discount from the retail price. In my longer written statement, which I have asked to be incorporated in the record, I have included some language which I would propose to carry out the purpose of my statement.

2. THE GAS CONSUMPTION TAX.

Section 1501 of the proposed National Energy Act would amend the Internal Revenue Code by adding provisions imposing excise taxes on electric utility and industrial users of oil and gas. While the provisions of the bill are extremely complex, the basic scheme is to impose a tax based on the difference between the average cost of gas paid by large industrial and commercial users and the price of No. 2 distillate fuel oil. The purpose of the tax, according to the National Energy Plan (p. 54), is virtually the same as the incremental pricing proposal, namely to encourage the conversion by industry and utilities from natural gas and oil to coal.

We strongly object to the imposition of the consumption tax. In the first place, incremental pricing will result in increasing gas costs significantly above the cost of coal and will, without regard to

the consumption tax, force the conversion to coal where that is technically and economically possible. While there will be periods when, in some market areas, incrementally priced natural gas would not be as high as No. 2 oil, incremental pricing will generally achieve the desired result without the severe problems associated with the consumption tax. Furthermore, where coal is a feasible alternative fuel, H.R. 6831 proposes mandatory authority to require conversions, as I will indicate in a moment.

In addition to being unnecessary and redundant, the gas user tax is poorly conceived and constructed. The following are among the problems it presents:

(1) While the ostensible purpose of the user tax is to encourage high volume industrial users to conserve and convert to coal and other fuels, the fact is that the tax is not related to the use of gas in particular large installations which might be converted to coal but to the user's nationwide consumption of gas and oil. For example, a company having stores or installations throughout the country, none of which were large users of gas or could be converted to coal, would nevertheless by subject to the tax.

(2) The method by which the tax is to be calculated is wholly illogical and impractical. The basic scheme is that the user compares his average cost of gas for the preceding calendar year, wherever that gas may have been used and without regard to source of supply, against a PAD District regional average price for No. 2 oil sold for all taxable use in the district in which such gas is used during the calendar year. But the average cost of gas would reflect differences in suppliers' rates, which vary widely throughout the country; differences in type of service (e.g. firm versus interruptible); differences in timing of supplier rate increases; and many other differences, all of which are subsumed in the average cost of gas. This means that when the national average cost of gas is compared with the cost of No. 2 oil in a particular PAD District, the resulting tax will not reflect the actual difference between gas and oil costs at the point of consumption.

Furthermore, the average cost of No. 2 oil sold in a PAD District, assuming such a figure could be determined, obviously would not represent the price paid by large users who are able to obtain quantity discounts. Thus, the tax would necessarily result in a switch from gas to oil by such users, which clearly is not the intent of the National Energy Plan. More fundamentally, I fail to see the logic of a scheme that imposes a tax on the difference between the cost of natural gas and oil if the object is to force conversion of large fuel burning installations to coal.

Studies made by the American Gas Association indicate that the direct cost of the gas consumption tax would rise from approximately $2.4 billion in 1979 to $8.9 billion in 1985, thus imposing a huge additional tax burden on industry and, ultimately, the public. Projections of the effect of the tax indicate that this tax alone would have an inflationary impact on the economy amounting to 0.2 percent in 1979 and rising to 0.4 percent in 1983.

(3) MANDATORY CONVERSIONS OF ELECTRIC GENERATING AND MAJOR INDUSTRIAL USES OF GAS

Section 601 of the National Energy Act amends The Energy Supply and Environmental Coordination Act of 1974 in a number of respects, including the addition of authority to require the mandatory conversion of electric power plants and major fuel burning installations from natural gas to other fuels.

While I do not oppose extension of Federal authority to prohibit the use of natural gas in electric power plants and major fuel burning installations which can feasibly use coal I am concerned about the breadth of the delegation of authority to the administrator with respect to new non-boiler installations and to existing major fuel burning installations which cannot feasibly use coal. In both instances the language of the bill appears to authorize the Administrator of F.E.A. to order the mandatory conversion of fuel burning installations that cannot use coal from natural gas to some other fuel. We feel that this is totally inconsistent with the overall objectives of the National Energy Plan to reduce imports of foreign oil.

CONCLUSION

I can and do support most of the objectives of the bill, but it is supremely important that each provision be fully understood and its implications assessed before it is enacted as part of the "package." I and my company stand ready to assist the committee in any way possible to reach a sound resolution of the issues before the Congress.

[Mr. Seder's prepared statement follows:]

STATEMENT OF
ARTHUR R. SEDER, JR.
CHAIRMAN AND CHIEF EXECUTIVE OFFICER
AMERICAN NATURAL RESOURCES COMPANY

Before the

SUBCOMMITTEE ON ENERGY AND POWER
OF THE
HOUSE COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE

May 18, 1977

My name is Arthur R. Seder, Jr. I am Chairman and Chief Executive Officer of American Natural Resources Company, whose principal office is in Detroit, Michigan. The American Natural System includes an interstate natural gas pipeline, Michigan Wisconsin Pipe Line Company, which is the principal supplier of gas at wholesale to the States of Michigan and Wisconsin, and a gas distribution company, Michigan Consolidated Gas Company, which serves over a million customers in the State of Michigan. American Natural also has a small gas and oil exploration subsidiary, but virtually all of the System's gas supplies are purchased from independent producers or other pipelines.

My written statement will cover the subjects of (1) the wellhead price of natural gas, (2) the incremental pricing of gas to industrial users, (3) the gas consumption tax, (4) forced conversions of industry from gas to oil, (5) proposed conservation measures, (6) utility rate design

proposals and (7) the extension of federal jurisdiction to coal gasification plants. I recognize that the gas consumption tax is outside the jurisdiction of this Committee, but it is integrally related to the incremental pricing proposal and cannot be considered in isolation from that proposal.

I should emphasize that I do not represent any industry group and speak only on behalf of my company.

General Perspective of the National Energy Plan Toward the Gas Industry

Before discussing specific proposals in the National Energy Plan, I would like to comment on the general perspective of the Plan toward the gas industry, which forms the basis for a number of the provisions of the Plan.

The general perspective of the Plan seems to be that the gas industry has no capacity to grow or even maintain its present level of service; that industrial uses of gas should be phased out; that development of a high-Btu coal gasification capability is not a high priority; and that because the ultimate reserves of natural gas are finite, efforts to stimulate exploration for additional supplies are unnecessary and unproductive.

We strongly disagree with these premises. We are convinced that, with proper incentives for exploratory drilling and for development of synthetic gas from coal, the gas industry can continue to meet the residential,

commercial and essential industrial requirements of its existing market areas well into the 21st Century. And we cannot emphasize too strongly that the nation must have a strong, vigorous industry if it is to maintain the kind of economic growth required to provide jobs and a decent standard of living for future generations.

In particular, the apparent premise of the National Energy Plan that most industrial loads should be converted from gas to another fuel is neither practical nor in the interest of residential users of gas. It is not practical because many industrial processes require a gaseous fuel, and in most cases small boilers cannot be converted to coal. Wholesale conversion of industrial loads from gas to another fuel clearly is not in the interest of residential consumers of gas because the loss of such loads, by reducing sales volumes, would force residential users to bear the entire cost of underutilized transmission and distribution systems, thereby significantly increasing residential rates.

I want to emphasize that we fully support the proposition that large electric generation and industrial boiler fuel loads should be converted from gas to coal. We are greatly concerned, however, that commercial and industrial customers who are not in that category might be virtually forced, as a result of the incremental pricing and user tax provisions of the National Energy Plan, to shift from gas to oil. We cannot conceive that it is in the national interest to force the conversion of commercial

and industrial loads from gas to oil, which would result in increasing imports of foreign oil and underutilization of existing gas transmission and distribution facilities.

I strongly urge, therefore, that the Congress make clear that it is not the intent of the National Energy Plan to bring about the conversion of commercial and industrial loads from gas to oil where coal is not a feasible alternative. I will later indicate specific statutory provisions that raise this problem. I also urge the Congress to find and declare that the maintenance of a strong, viable gas industry is in the national interest.

With that preliminary, I will address specific provisions of the proposed National Energy Act.

1. The Wellhead Price of Natural Gas

I support the proposition that full deregulation of natural gas would best serve the national interest. Because this proposition has been debated often and at great length, I will not repeat the arguments except to say that elimination of the interstate-intrastate dichotomy and the delays and uncertainties inherent in cost-based wellhead price regulation are absolutely essential from the standpoint of the interstate gas systems. The interstate systems cannot presently buy any significant quantities of onshore gas except on an emergency basis; that situation must be rectified. It is equally important that the producers be freed from the delays and uncertainties of a regulatory

system where the price is fixed retroactively after long periods of uncertainty and delay and even then is subject to judicial review and potential rollback of prices.

If, contrary to my recommendation, the ceiling price approach proposed in the National Energy Act is adopted, I believe that two important modifications should be made.

First, the definition of "new natural gas" contained in Section 402 (a)(5) is wholly inadequate and without basis from a geological standpoint. Many new reservoirs lie within 2.5 miles and at less than 1,000 feet in depth from existing production. Any such arbitrary and unscientific approach would mean that no new exploration for gas would take place within the proscribed areas. I recommend that the definition of "new natural gas" essentially as contained in S. 2310 in the last session of Congress be adopted.

Second, I strongly oppose the establishment of a ceiling price for new natural gas at the "Btu related price" as that term is defined in Section 402(a)(18). The "Btu related price" is defined as the average per barrel crude oil acquisition cost for United States refineries of all domestic crude oil, divided by a factor of 5.8. What this means is that the price of new natural gas would be based on the refiner's average cost of domestic crude oil, consisting of a mix of old oil, upper tier crude, new third tier oil proposed in the National Energy Act plus stripper and tertiary recovery oil.

The Administration estimates that the Btu related price of new natural gas would be $1.75 per Mcf early in 1978, which implies an average refiner's cost of domestic oil of $10.16 per barrel. I strongly urge the Congress, if it agrees that natural gas must be subject to price ceilings, to set the "Btu related price" at the equivalent of the new oil price, which is to rise to the 1977 world oil price plus inflation adjustments in three years. This would imply a wellhead price of new gas of about $2.15 early in 1978. My reasons are as follows:

(1) I do not believe that $1.75 per Mcf in 1978 adequately represents the cost of exploring for and producing new gas beginning next year. Even under the F.P.C. methodology, which produced a wellhead price of $1.42 per Mcf for gas discovered in the 1975-76 biennium, our studies indicate that the cost of gas discovered in the 1977-78 biennium would be about $2.20 per Mcf. This reflects the increasing costs of labor, material, etc. and also reflects a further decline in the reserves discovered per foot of well drilled. So $1.75 would represent a step backward even under the F.P.C. cost methodology.

But more important, the fact is that the drilling activity reflected in the F.P.C. cost analyses largely occurred in the older production areas at relatively shallow depths where drilling costs are less and risks are lower. As shown in an American Gas Association Analysis dated April 11, 1977 entitled "Drilling Activity and Potential Gas Resources," a

copy of which is attached as Appendix A, F.P.C. prices reflect very little drilling in higher cost exploration areas such as horizons below 15,000 feet, the deep offshore waters and the frontier regions where the great bulk of potential gas reserves are located. Indeed, the A.G.A analysis shows that about 90 percent of all gas well completions in 1975 occurred in regions and at depths where only 30 percent of the estimated potential gas resource base is located. Thus, the F.P.C. price methodology, which is based on an average of past drilling results, neither reflects the cost of exploration in the regions where most future gas potential exists nor provides the necessary incentive to encourage drilling in those areas.

(2) My second objection to the $1.75 wellhead price is that, because the rewards for discovering oil would continue to be significantly greater than for discovering gas, producers will again be encouraged to explore in areas of high oil potential rather than in gas-prone areas. This would perpetuate a gas-oil price relationship that has plagued the natural gas industry ever since its foundation, when natural gas was simply an unwanted by-product of the search for oil.

Our studies indicate that by 1980 the price of new domestic oil will have risen to about $17.25 per barrel, which equates to $2.97 per Mcf on a Btu equivalency basis. But under the Administration's proposal, the wellhead price of new natural gas in 1980, according to our analysis, would be only $2.30, or nearly 30 percent less. It is obvious, therefore, that the producer's interest lies in pointing

his exploration program toward oil rather than natural gas.

(3) My third comment is that the $1.75 price would result in a roll-back of wellhead prices at which significant quantities of gas have sold in the intrastate market during the past year. Exploration programs have been initiated and investment decisions made on the basis of price projections higher than the $1.75 per Mcf figure. It would be grossly unfair, in my opinion, to require a roll-back of these prices upon the expiration of contracts, as would be required under Section 406(c) of the proposed National Energy Act.

I have two additional comments concerning the proposed pricing of new natural gas.

First, I agree with and support the proposal that any ceiling price should apply to intrastate as well as interstate sales. While I would prefer that parity between interstate and intrastate purchasers should be achieved by deregulation, it is essential that the interstate systems have an equal opportunity with the intrastate systems to purchase onshore gas. Accordingly, if price ceilings are imposed, they must apply equally to all.

Second, we are unclear about the significance of the term "first sale" as it is used in Section 404 of the Bill covering wellhead pricing of "new natural gas." While we interpret the proposed legislation to mean that all "new natural gas" is increased in price whenever the President

calculates and publishes a new "Btu related price," the use of the term "first sale" might be construed to mean that the gas receives the "Btu related price" only at the time of first sale and thereafter that price is increased only by the inflation adjustment. The use of the term "first sale" is probably appropriate in Sections 405, 406 and 408, where specific wellhead prices are established plus the inflation factor. However, with respect to sales of "new natural gas" the "Btu related price" applies not only to the "first sale" but to all subsequent sales, and the inflation adjustment does not enter into the calculation. We therefore propose that the word "first" be eliminated from Section 404.

2. The Incremental Pricing of Gas to Commercial and Industrial Customers

I support the objectives of Section 414 of the Bill, which seeks to allocate the higher costs of new natural and synthetic gas to larger commercial and industrial customers to the point where their costs equal the cost of substitute fuels. I have some question, however, as to the desirability of attempting to bring about that result through a Federally-mandated gas pricing system, particularly since I believe that the State public utility commissions are moving in that direction in any event. For example, Michigan Consolidated Gas Company's last general rate increase in 1975 was

allocated 86 percent to commercial and industrial customers and only 14 percent to residential customers. And in its current rate increase application, Michigan Consolidated proposes that 75 percent of the increase be allocated to commerce and industry and only 25 percent to residential customers. In short, industrial users are already bearing the bulk of increased general costs, although it is true that increased purchased gas costs are spread equally among all classes of customers under our current Purchased Gas Adjustment Clause.

Nevertheless, while I would prefer to see the objectives of Section 414 achieved through rate action at the local level, I believe that the proposal set forth in that Section is a workable one if certain changes are made and certain principles are established. First and most important, I strongly urge that Congress define with more particularity what is intended by the phrase, "The reasonable price (as determined by the President) of substitute fuels" in Section 414 (a).

The approach set out in H.R.6831 is that the higher costs of new gas supplies will be allocated to commercial and industrial customers using over 50 Mcf on a peak day until such allocation

> "would result in rates or charges for such uses equal to an amount no greater than the reasonable price (as determined by the President) of substitute fuels."

Thereafter, the remaining costs of the higher price gas

would be allocated to high priority residential and small commercial users. The obvious intent of this language, with which we agree, is that lower priority users should not be charged rates higher than the reasonable cost of substitute fuels, as determined by the President.

The key, therefore, is the President's determination of the cost of substitute fuels -- what "substitute fuels" are selected and how the determination is made of the "reasonable cost" of such fuels. In Section 414 (a) the matter is left entirely to the discretion of the President's designee, and it is here that we strongly urge the Congress to lay down some principles to serve as guides to the exercise of that discretion.

We certainly do not contend that the price of "substitute fuels" should be the cost of coal. But we are equally sure that it is not the intent of the National Energy Act to drive commercial and industrial users of gas to imported oil when gas is available. To do so would defeat the intent of the President's program to reduce imports of oil from a potential level of 16 million barrels a day to less than 6 million barrels, or about one-eighth of total energy consumption. It would also be contrary to the projections in the National Energy Plan (page 95), which contemplate that total industrial use of natural gas is not

to be reduced under the Plan. It is essential, therefore, that the "reasonable price . . . of substitute fuels" be set at a level that does not necessarily result in the conversion of gas loads to oil. That means two things: (1) that the price of substitute fuels determined by the Administrator be determined in the particular market where the fuel is to be used, and (2) that the price fixed by the Administrator relate to the cost of oil actually paid by large users, who are usually able to buy large quantities of oil at a discount from the retail price.

Accordingly, we urge that the following language be added to Section 414 (a) after the words "of substitute fuels":

> "provided, however, that the President shall not establish a price for substitute fuels greater than the cost of petroleum sold to large volume purchasers in the area where the natural gas is being sold."

We suggest that Section 414 should be further modified in the following respects:

(1) Because in practice the allocation of purchased gas costs to a particular class of customers would be accomplished through the Purchased Gas Adjustment provisions of gas distribution company tariffs in the great majority of states where such provisions have been adopted, we suggest that a new subsection (d) be added to Section 414 reading as follows:

> "(d) The purchase gas adjustment provisions of gas distribution company tariffs shall be appropriately modified to carry out the intent of this section."

(2) The term "pipeline company" as defined in

paragraph (3) of Section 414 (b) does not appear to cover gas distribution companies, which are not ordinarily considered to be "in the business of transporting natural gas by pipeline". On the assumption that gas distribution companies are intended to be included, we suggest that the language be amended to read "who is engaged in the business of transporting or distributing natural gas by pipeline . . ."

(3) The definition of "high priority use" in Section 414 (b)(2)(B) refers to the use of natural gas in commercial establishments "in amounts of less than 50 Mcf on a peak day." Since gas use is not measured daily, we suggest that the definition should refer to the average daily use of Natural gas in the month of peak usage on the pipeline's system.

There are several other questions that should be resolved in this connection.

First, what happens when a customer's use declines from above 50 Mcf per day to below that volume or increases from below 50 Mcf per day to above that amount? When is the determination made -- annually after a peak month has been experienced or more often?

Second, the use of the term "commercial establishment" in paragraph (b)(2)(B) clearly would lead to unintended results. Read literally, that paragraph would suggest that non-commercial institutions such as schools and hospitals,

using less than 50 Mcf per day would be low priority users subject to incrementally priced rates -- just the opposite of the intended result. However, it seems unfair and inequitable to discriminate between small commercial and non-commercial consumers who use gas for essentially similar purposes and cannot, as a practical matter, convert to other fuels. I suggest, therefore, that paragraph (b)(2)(B) of Section 414 be changed to read:

> "(B) use of natural gas by other than an industrial user in amounts averaging less than 50 Mcf per day in the month of peak usage on the pipeline company's system.

Third, we assume that each high priority use refers to a separate location or a separately metered use, but the statutory language is unclear.

(4) We strongly object to the provisions of subsection (c) of Section 414, which imposes a fine of $10,000 for each sale in violation of the rules promulgated under this section. As is indicated in the preceding paragraphs, there are many unknowns and uncertainties in the application of this section and, no matter how detailed the regulations, there will be interpretive and operational problems that could well lead to inadvertent violations. It should also be remembered that the pipeline or distribution company will still be selling and charging for gas under the terms of tariff rate schedules subject to the jurisdiction of state or federal utility commissions. It is entirely possible, therefore, that a company would be fined $10,000 for making a sale required to be made under its tariff.

We respectfully urge, therefore, that the penalty prescribed in subsection (c) be eliminated. At the very least, we suggest that such a fine be imposed only for a willfull violation of the regulations.

3. The Gas Consumption Tax

Section 1501 of the proposed National Energy Act amends the Internal Revenue Code by adding provisions imposing taxes on electric utility and industrial users of oil and gas. A new Section 4992 of the Code would levy an excise tax on the taxable use of gas by electric utilities and by "a person in any trade or business" (Section 4992 (e)(1)). The "taxable use" is a device by which total consumption of natural gas and petroleum is based on a sliding scale under which, if total use is less than 500 billion Btu's (500,000 Mcf) annually, no "taxable use" occurs and no user tax is payable. With increasing use, the "taxable use" escalates up to the consumption of 1500 billion Btu's (1,500,000 Mcf) annually, at which point all consumption represents a "taxable use" and is subject to the gas consumption tax.

Two important points should be made regarding the "taxable use" aspect of the scheme. First, taxable use is based on consumption of both natural gas and petroleum. Second, taxable use is based on all natural gas and petroleum consumed by the user, including any 50 percent owned affiliate, anywhere in the United States. Thus, the tax does not purport to be based on specific gas usage at a particular location or upon the type of fuel burning installation or the

ability of the user to convert to coal. For example, a chain store company having a number of stores throughout the country, each burning a relatively small amount of gas and with no capability to convert to coal, would nevertheless be subject to the tax.

The taxing scheme provides that a user subject to the tax must calculate the average cost it paid for natural gas at all installations wherever located by dividing the aggregate amount paid for natural gas during the preceding calendar year by the number of Btu's consumed (subsection (c)). This is then compared with a "natural gas target price" which is the "Btu equivalency price" less specified cents-per-Mcf deductions in the early years of the tax and an inflation adjustment. The "Btu equivalency price," in turn, is defined as the average regional price according to PAD Districts of all No. 2 distillate oil sold for taxable use in the District in which the gas is used.

The intent of the gas user tax thus appears to be to impose a tax on the difference between the price paid by large commercial, industrial and electric utility users for gas and the cost of No. 2 fuel oil. According to the National Energy Plan (p. 54), the tax "would be levied on the use of oil and gas by industry and utilities in order to encourage conservation and conversion to coal and other fuels."

While we would not object to the imposition of

a tax on electric utility use of natural gas, we strongly object to taxing other commercial and industrial users. In the first place, the tax is wholly unnecessary and inappropriate to achieve the stated purpose. In the second place, the proposed legislation is hopelessly confused, impractical and counterproductive.

As noted in the earlier discussion of incremental pricing, Section 414 of the National Energy Act requires that the higher cost of new natural gas and supplemental supply projects be allocated to larger commercial and industrial users of gas up to the point where gas costs equal those of substitute fuels. Thus, incremental pricing will result in increasing gas costs significantly above the cost of coal and will, without regard to the user tax, force the conversion to coal where that is technically and economically possible. While there will be periods when, in some market areas, incrementally priced natural gas would not be as high as No. 2 oil, incremental pricing will generally achieve the desired result without the tremendous problems associated with the user tax.

Furthermore, Section 601 of the National Energy Act would amend The Energy Supply and Environmental Coordination Act of 1974 by providing that electric generating plants cannot use natural gas for new boilers and must phase out the use of gas in existing boilers (Sec. 105); by

providing that gas cannot be used in new major fuel burning boilers and that major new non-boiler uses may be prohibited from using gas (Sec. 106); and by providing that major existing fuel burning installations may be required to convert from gas to another fuel (Sec. 107). Thus, the proposed legislation includes ample authority to force conversions of large industrial and electric generating loads from gas to coal without imposing the user tax.

In addition to being unnecessary and redundant, the gas user tax is so poorly conceived and constructed as to defy logic or common sense. The following are among the problems it presents:

(1) As noted earlier, while the ostensible purpose of the user tax is to encourage high volume industrial users to conserve and convert to coal and other fuels, the fact is that the tax is not related to the use of gas in particular large installations which might be converted to coal but to the user's nationwide consumption of gas and oil. Thus, a company having stores or installations throughout the country, none of which were large users of gas or could be converted to coal as a practical matter, would nevertheless be subject to the tax. In short, the tax does not focus on the large industrial boiler loads where conversions might realistically be made but is a scatter-gun directed at larger companies regardless of the size or type of oil or gas burning equipment they employ.

(2) The method by which the tax is to be calculated is wholly illogical and impractical. As noted above,

the basic scheme is that the user compares his average cost of gas for the preceding calendar year, wherever that gas may have been used and without regard to source of supply (Sec. 4992(c)), against a PAD District regional average price for No. 2 oil sold for all taxable use in the District in which such gas is used during the calendar year. This latter determination is to be made by March 31, of the succeeding calendar year by the Administrator of the Federal Energy Administration (Sec. 4992(e)(3)). This raises the following problems:

(a) Since the cost of gas is the user's nationwide average cost, and the cost of No. 2 oil is a PAD District average in the District where the gas is used, the tax does not measure the difference between the cost of gas and the cost of the alternate fuel at the point of consumption. The average cost of gas would reflect differences in suppliers' rates, which vary widely throughout the country; differences in type of service (e.g. firm versus interruptible); differences in timing of supplier rate increases; and many other differences, all of which are subsumed in the average cost of gas. This means that when the national <u>average</u> cost of gas is compared with the cost of No. 2 oil in a particular PAD District, the resulting tax will not reflect the actual difference between gas and oil costs at the point of consumption.

(b) The Administrator of F.E.A. is supposed to determine the average price paid in each PAD District during the preceding calendar year for No. 2 oil sold for all tax-

able use. We know of no way this determination can be made, since the necessary information is not available. Perhaps more importantly, the average price paid for No. 2 oil in the District obviously would not represent the price paid by large users who are able to obtain quantity discounts. Thus, the tax would necessarily result in a switch from gas to oil by such users, which clearly is not the intent of the National Energy Plan.

(c) Since the tax is based on calculations of national average gas costs and average regional oil costs made after the calendar year in which the gas was used, it would be exceedingly difficult for an industrial user to estimate what his tax might be in a current or future period and to make his decision whether to switch from gas to oil on that basis. Because of this uncertainty, we are greatly concerned that the switch from gas to oil might be made simply so that the user would be able to calculate what his cost of energy would be, rather than having it fixed ex post facto through the gas consumption tax mechanism.

(3) We fail to see the logic of a scheme that imposes a tax on the difference in cost of natural gas and oil if the object is to force conversion of large fuel burning installations to coal. As indicated earlier, a combination of incremental pricing (Section 414) and mandatory conversion authority (Section 601) is certainly sufficient to bring about that result. What we are concerned about is the very real probability that a tax based on the difference between gas and oil prices, particularly in view of the

blunderbuss approach to that determination, would result in wholesale conversions from gas to oil. That certainly is not the purpose of the National Energy Plan, which is designed to reduce our dependence on imports of foreign oil, but the taxing scheme would almost certainly have that result.

Finally, studies made by the American Gas Association indicate that the direct cost of the gas consumption tax would rise from approximately $2.4 billion in 1979 to $8.9 billion in 1985, thus imposing a huge additional tax burden on industry and, ultimately, the public. Projections of the effect of the tax indicate that this tax alone would have an inflationary impact on the economy amounting to 0.2 percent in 1979 and rising to 0.4 percent in 1983.

In summary, the natural gas consumption tax is ill-conceived and poorly constructed; would undoubtedly result in significant conversions from natural gas to oil, thereby exacerbating our oil import problem; and would have a highly inflationary impact on the economy. We strongly urge the Congress to eliminate the Natural Gas Consumption Tax from the Bill. If any part is retained, it should be limited to a tax on the use of gas for electric power generation and should be based on the use of gas at particular large boiler installations.

(4) Mandatory Conversions of Electric Generating and Major Industrial Uses of Gas

Section 601 of the National Energy Act amends The Energy Supply and Environmental Coordination Act of 1974 in

a number of respects, including the addition of authority to require the mandatory conversion of electric power plants and major fuel burning installations from natural gas to other fuels.

In general, I have no objection to the prohibition of the use of natural gas or petroleum in new electric power plants (Section 104); the prohibitions against the use of natural gas in any existing electric power plant after January 1, 1990 or the conversion of such a plant from petroleum to natural gas (Section 105); or the prohibitions against the use of natural gas in new major fuel burning installation boilers (Section 106(a)(1)).

I am concerned about the breadth of the delegation of authority to the Administrator with respect to new non-boiler installations in Section 106(a)(2) and (3) and to existing major fuel burning installations in Section 107.

With respect to new non-boiler installations, we are apprehensive that an effort might be made under this authority to force the conversion of industrial process uses from natural gas to oil, which we again believe would be contrary to the basic purpose of the National Energy Plan. We do not object to granting the authority requested if the installation can use coal but do not feel that it is appropriate if the conversion would result in a switch from natural gas to another gaseous or liquid fuel. Accordingly, we suggest that Section 106(a)(2) and (3) be modified by adding the words

"which are capable of using coal" after the words "other than boilers".

With respect to existing major fuel burning installations (Section 107), we urge that the authority of the Administrator in subsection (a)(1) to prescribe categories of installations which are prohibited from using natural gas or petroleum should be limited to those installations "with the capability to use coal." We therefore recommend that the words "or other fuel" be deleted from that paragraph. The same comment applies to subsection (a)(2) relating to individual installations.

We also strongly urge that subsections (a)(4) and (a)(5) be deleted in their entirety. The intent of these subsections is apparently to authorize the Administrator to order the mandatory conversion of fuel burning installations that cannot use coal from natural gas to oil or another gaseous fuel. We feel that this is totally inconsistent with the overall objectives of the National Energy Plan to reduce imports of foreign oil. If enough gas is not available to supply higher priority users, existing curtailment plans would force the discontinuance of the use of natural gas in installations of this kind. We see no reason either in national policy or in practical necessity why the Administrator should be authorized to require the conversion of installations from gas to oil or another gaseous fuel.

5. Energy Conservation Programs

I strongly support the objectives of the conservation programs set out in Title I, Part A of the National Energy Act. American Natural's distribution subsidiary, Michigan Consolidated Gas Company, has been a leader in designing programs to encourage home insulation and installation of furnace retrofit devices.

We do feel, however, that a national utility conservation program should be voluntary rather than mandatory, with appropriate Federal encouragement and guidance. I endorse the statement of Maurice E. Halsey, Assistant Vice President of Northern Illinois Gas Company, who testified before this Committee on May 10, 1977 on behalf of the American Gas Association.

6. Gas Distribution Company Rate Design

Sections 541-548 of the proposed National Energy Act provide mechanisms under which State Public Utility Commissions would be directed to require elimination of declining block rates and other promotional rate schedules and would require the Administrator to develop regulations regarding summer-winter rate differentials, rates for interruptible service and master metering. When adopted, the regulations would be binding on State Public Utility Commissions, and compliance would be a prerequisite to future gas utility rate increases.

I strongly recommend that the Federal Government

should not take over the function of designing rates for local gas distribution companies. That function is, and should remain, the responsibility of state regulatory agencies.

The danger in blanket Federal directives is illustrated by the assumption that, in the natural gas industry, declining block rates are necessarily contrary to the public interest. But this ignores the fact that, as our System's studies have shown, poor families in the inner-city of Detroit use more gas than families in the suburbs because their homes are older and often larger, have less insulation and less efficient furnaces than surburban homes. Elimination of declining block rates therefore increases costs to this segment of the public and, while Michigan Consolidated has eliminated block rates at the direction of the Michigan Public Service Commission, we question whether that action was in the overall public interest.

The same comment applies to interruptible rates. Service to interruptible customers is a substitute for underground storage, since such customers can be shut off to meet peak day demands or the exigencies of a cold winter that must otherwise be met from storage. Any blanket Federal regulations regarding interruptible rates, therefore, might leave the local gas distribution company with no means of meeting winter load conditions at an acceptable cost.

There is no reason to assume that State Public Utility Commissions are less conscious of the need to conserve

gas than the Federal Government, and those Commissions are much better able to tailor rate schedules to the practical realities of gas utility operations. I strongly urge that that responsibility should remain with the state commissions.

7. Extension of Federal Jurisdiction To High-Btu Coal Gasification Plants

I support the provisions of Section 415 of the proposed National Energy Act, which would extend jurisdiction of the F.P.C. under the Natural Gas Act to pipeline quality synthetic gas manufactured for transportation in interstate commerce or sale in interstate commerce for resale. While this amendment will not eliminate the necessity for Government support for financing of the first one or two coal gasification plants, the fact that the F.P.C. has issued a certificate of public convenience and necessity covering construction of the plant would be a positive factor.

Conclusion

The proposed National Energy Act is tremendously complicated both in terms of the scope of its provisions and the potential effect on consumers, industries and, indeed, the future viability of various energy suppliers.

I can and do support most of the objectives of the Bill, but it is supremely important that each provision be fully understood and its implications assessed before it is enacted as part of the "package."

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I strongly urge, therefore, that this Committee consult in detail with those affected by each provision of the Bill and that the language and ramifications of each section be fully explored before action is taken. I and my company stand ready to assist the Committee in any way possible to reach a sound resolution of the issues before the Congress.

APPENDIX A

ENERGY ANALYSIS

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4/11/77

DRILLING ACTIVITY AND POTENTIAL GAS RESOURCES

A. Introduction

One of the major contentions of opponents of deregulation of the wellhead price of new natural gas is that the natural gas resource base will not support continued production at current levels even at significantly increased wellhead prices. This conclusion is largely based on the continued decline in reserves at a time when gas well completions are at an all-time high.

This paper provides an analysis which reconciles declining reserves and large potential resource estimates in light of gas well drilling activity.

B. Executive Summary of Results of Analysis

- While total gas well completions in the U.S. in 1975 were at an all-time high, over 80% of the gas wells completed were developmental as opposed to exploratory.
  - Further, exploratory well drilling has shown a consistent downward trend since the late 1950s (after federal wellhead price regulation was authorized) and has only in the past four years begun to show signs of some increase, although it is, at present, still only 60% of its peak level reached in 1956.
- Reserve additions have continued to decline largely because the predominance of drilling and well completions is in older, less risky, and less costly areas. These areas are generally onshore and at shallow to moderate well depths.
  - In 1975, more than 90% of all gas wells completed were onshore and at depths of less than 15,000 feet. Furthermore, the drilling cost associated

with these wells averaged only about $35/ft and the percentage of wells drilled that were successful was about 65%.

- By contrast, only 10% of gas well completions were generally in offshore or deep onshore areas (deeper than 15,000 feet) where drilling costs averaged well over $100/ft and the success percentage was about 50%.

- From the standpoint of the location of U.S. potential gas resources, which are estimated to be in the 600-900 Tcf range (in addition to proved reserves of 216 Tcf), the predominance of drilling activity and well completions has not been in areas containing this potential which is generally in deep onshore areas, in offshore areas, and in Alaska.

  - For example, about 90% of all gas wells completed in 1975 were in areas and at depths where only 30% of the estimated potential gas resource exists.

  - Even in the case of exploratory gas well activity, less than 4% of the gas well completions were in areas with over 50% of the estimated potential resource.

- Moreover, as further evidence that drilling activity is largely in historical production areas rather than in new frontier areas, almost 90% of all well completions in 1975 were in areas accounting for 50% of the current U.S. gas production.

- It is also clear that the predominance of drilling activity in older, less risky, and inexpensive areas is related closely to economic factors:

  - About 93% of all gas wells completed in 1975 were in generally shallow, onshore areas where the drilling costs were less than $50/ft.

  - However, from 1975 drilling and cost data, over 60% of the estimated potential gas resource is in areas that required more than $50/ft for a completed well.

- Finally, the fact that only 4% of the total wells completed in 1975 were in offshore areas and only an additional 3% were in deep onshore areas suggests that:

- the lack of economic incentive in the interstate market as a result of continued wellhead price regulation has been a deterrent to higher cost development in frontier areas.

- there is not sufficient availability of offshore federal lease tracts in view of the significant potential resources in these areas.

C. DRILLING HISTORY

Exploratory well drilling[1] has declined significantly since 1956 as shown in Chart 1. While the number of exploratory wells drilled has increased some since 1971, only a fraction of the decrease experienced since 1956 has been recovered. In contrast, developmental well completions peaked briefly in 1961 and then declined until the recent increase which started in 1972 and has since reached record levels.

Recent drilling for gas has been characterized by the following phenomena:

- Finding rates (natural gas volumes found per foot drilled) are generally declining.

- Drilling costs are steadily rising resulting in a decline in gas volumes found per dollar of exploration investment.

- Gas well drilling and well completions have increased dramatically starting in 1972.

- Productivity (Mcf/ft) has been steadily declining since 1967.

These drilling indicators have been interpreted by some as indicating the onset of resource depletion.

D. DATA SOURCES

Four primary sources of data were used in this study;

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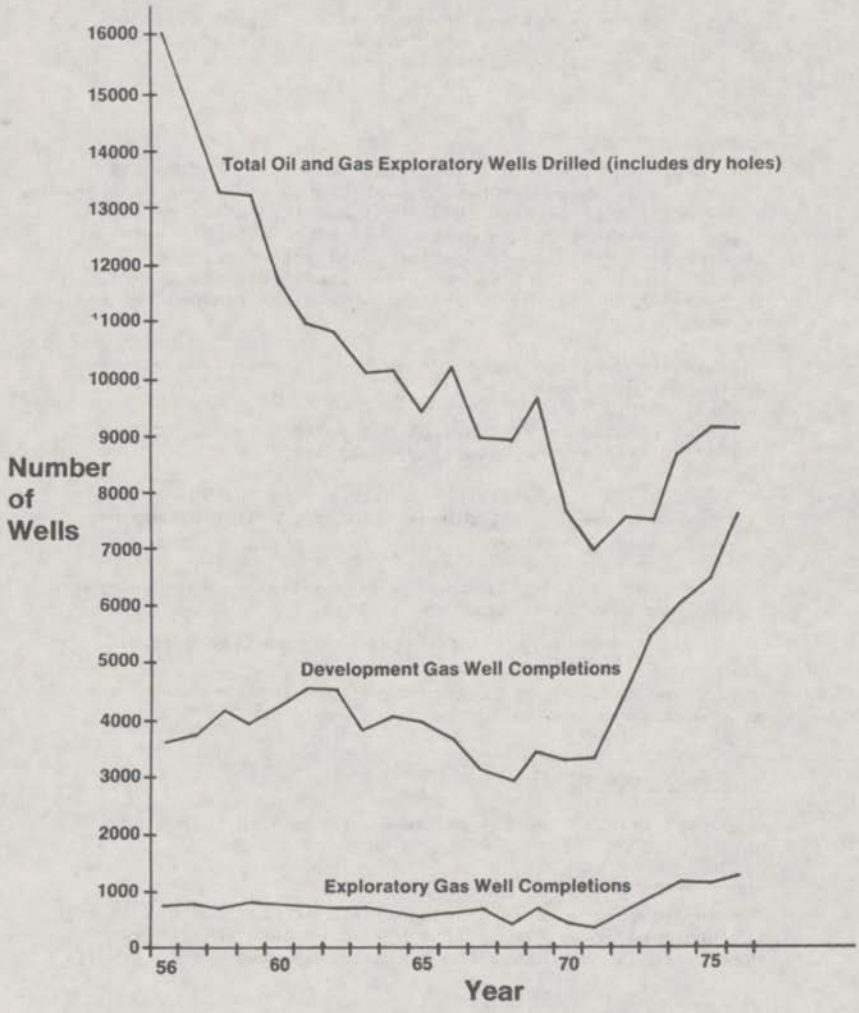
[1]An exploratory well is a well drilled (1) to find gas in an unproved area; (2) to find new reservoirs in a known field; on (3) to extend the limits of a known gas reservoir.

Chart 1
Development Gas Well Completions and Exploratory Well Drilling



the 1975 Joint Association Survey of the United States Oil and Gas Producing Industries; the Quarterly Review of Drilling Statistics for the United States, 1975; the Potential Supply of Natural Gas in the United States; and the Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada as of December 31, 1975. All of the various sources of data were used by restricting the analysis to 1975. Each of the reference documents contain 1975 statistics except for the Potential Supply of Natural Gas in the United States. It contains data as of December 31, 1972. Material from the Potential Gas Committee's 1976 estimates, which are as yet unpublished, was used to update this report.

Because the potential estimates of natural gas in the United States are reported in 12 geographic areas as shown in Figure 1, this analysis examines these 12 geographical areas and 27 drilling regions. The drilling regions subdivide the geographic areas into onshore, offshore as well as deep (greater than 15,000 feet) and shallow to moderate depths.

Gas well completions were available by depth of well only in the Joint Association Survey report so this information could be related to the potential for each drilling region. Unfortunately, developmental gas well completions and exploratory completions are not tabulated by depth. Similarly proved reserves and natural gas production data are not available by depth of well.

E. ANALYSIS OF POTENTIAL GAS ESTIMATES AND DRILLING

Table 1 displays for each of the drilling regions the well completions, reserve additions, production and potential gas resources. In order to compare the gas well completion data, the production estimates, and the potential gas estimates, the gas well completions in each drilling region are expressed as a percentage of total gas well completions in the United States in 1975. Likewise, the potential gas estimates (and production) by drilling region were tabulated as a percent of total U.S. potential (and production). Cost data were expressed in terms of the drilling costs actually experienced in the drilling region in 1975. Units of the cost data are dollars per foot drilled. No allowance was made for the fact that costs are averaged over different drilling depths. It was judged to be more important to reflect the actual drilling expenses for the regions considered.

Geographic Areas of Potential Gas Estimates.

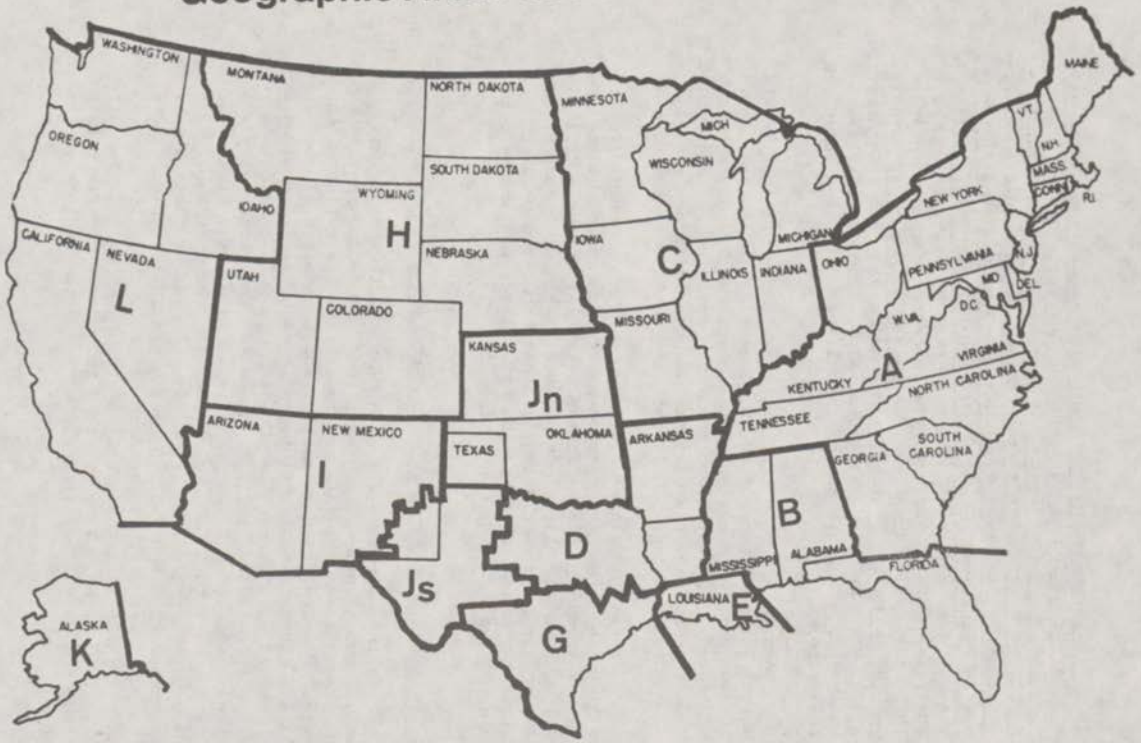


Figure 1

TABLE 1

PERCENT

AREA	Total Gas Well Comp.	Dev. Gas Well Comp.	Expl. Well Comp.	N.A. Additions To Proved Res.	Prod.	Total N.A. Proved Res.	Potential	Cost $/ft
A-Shallow	27.07	30.22	8.81	5.79	2.36	2.90	6.61	21.63
A-Deep	.01						.54	362.11
A-Offshore	0	0	0	0	0	0	3.90	---
B-Shallow	.40	.69	3.85	4.41	.50	1.13	1.95	44.36
B-Deep	.29						1.95	82.52
B-Offshore	0	0	0	0	0	0	2.60	---
C-Shallow	.75	.51	7.58	.95	.42	.31	.65	42.42
D-Shallow	11.14	11.92	13.26	5.39	5.31	5.29	5.20	31.38
D-Deep	.01						.65	77.25
E-Shallow	2.35	2.61	3.83	6.87	16.23	12.74	1.95	60.33
E-Deep	.39						2.06	120.87
E-Offshore	3.31	2.76	1.64	27.37	21.44	19.08	8.78	114.96/165.45
G-Shallow	14.84	9.86	14.83	9.73	13.49	15.74	4.12	43.98
G-Deep	.08						.98	105.11
G-Offshore	.24	.08	1.76	1.91	1.29	1.90	4.98	151.39
H-Shallow	8.87	9.02	17.93	6.71	2.55	3.80	6.18	35.49
H-Deep	.13						.76	228.09
I-Shallow	3.90	5.48	.59	3.50	3.20	4.91	.76	29.76
J_d-Shallow	17.16	18.40	14.75	15.74	19.90	19.67	6.18	36.26
J_d-Deep	.47						5.42	102.27
J_s-Shallow	7.33	7.99	8.32	7.99	11.38	7.44	3.03	36.53
J_s-Deep	.60						3.03	118.14
L-Shallow	.60	.45	2.21	2.31	1.04	1.43	2.49	35.25
L-Deep	.01						.76	131.66
L-Offshore	0	0	.07	0	0	0	1.08	---
M-Onshore	.04	.02	.23	1.32	.85	3.65	24.38	298.33
M-Offshore	0	0	.01	0	0	0	---	---

Table 2 displays the percent of gas well completions versus the percent of total gas potential ranked in order of the largest ratio of percent gas well completions to percent of potential. As can be seen from the table, the largest percentage of gas well completions is in shallow onshore regions rather than offshore or deep onshore.

Chart 2 is derived from a cumulative plot of the data in Table 2. It shows that more than three quarters of the gas well completions in the United States occurred in areas having only one quarter of the potential gas resource. It shows also that 90% of the drilling occurred in areas with less than one third of the estimated national gas potential. This indicates very little drilling in areas with large potential gas resources. If gas well drilling were motivated solely by the potential estimates, this plot would be a straight line at a 45 degree angle. The more this curve tends toward a right angle the more non-optimum the drilling program is from the viewpoint of exploitation of potential resources. This result indicates that there are factors other than potential resource estimates which strongly influence the region in which gas well drilling has occurred.

Chart 3 gives some insight into the cost factor.[2] The chart displays the percentage of gas well completions versus the cost of drilling in dollars per foot. This histogram shows the percentage of gas well completions in 1975 which occurred at various drilling costs. It is clear from this histogram that the national drilling effort is heavily biased towards drilling in less expensive areas for which the cost is between $20 and $50 per foot.

Chart 4 shows the significance of this bias.[2] It portrays the percentage of potential gas against drilling costs as a histogram. It can be seen, based on 1975 drilling data, that much of the potential gas in the United states occurs in regions where the drilling costs in 1975 exceeded $50 per foot. To illustrate this point more fully, only about 40% of the national potential occurs in areas for which the drilling costs are less than $100 per foot. Similarly, about 65% of the national potential occurs in regions where drilling costs are $160 per foot or less, and more than 90% of the national potential occurs in regions for which the drilling cost is less than $300 per foot.

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[2] Charts 3 and 4 exclude certain regions for which gas well drilling costs are not available. These regions are offshore Atlantic, offshore Florida and offshore California.

F. DRILLING AND CURRENT PRODUCTION

This analysis indicates that the gas well drilling activity is generally in areas which have been previously explored and are still being developed. Drilling costs in those regions are low. Federal regulators use these drilling costs to set new gas prices. In effect this forces much of the drilling to remain in these mature regions and discourages more expensive frontier development.

This trend is clearly apparent in Chart 5 which depicts cumulative percentages of gas well completions versus percentage of current gas production. These data show that in those regions already producing half of the natural gas over 87% of the new gas wells were completed in 1975. Thus, gas well drilling was largely not aimed at the high potential gas resources areas which have not already been extensively developed.

G. CONCLUSIONS

The results of this analysis indicate that the potential resource of natural gas has not been depleted and is not near depletion. It shows that new drilling regions have not been exploited and still have in place a large percentage of our national gas resource. It also indicates that drilling costs are certain to be higher in these frontier regions. Because federally regulated national gas rates are based on past drilling experience in generally less costly areas, the regulated price has limited higher cost drilling in more risky but potentially more productive areas.

The paradox of large amounts of drilling in the face of dwindling reserves because federal regulation of interstate wellhead gas prices has constrained drilling to regions which are inexpensive and have been extensively explored. Few "giant discoveries" can be expected in these areas and so the statistics have been mistakenly interpreted to indicate that resource depletion is near. Frontier areas, which are admittedly more expensive drilling regions, contain large volumes of gas which can be developed. Price incentives in the intrastate market have already demonstrated a dramatic turn-around in drilling in the mature, well-developed intrastate areas.

Chart 5

Percentage of Cumulative Gas Well Completions vs. National Production

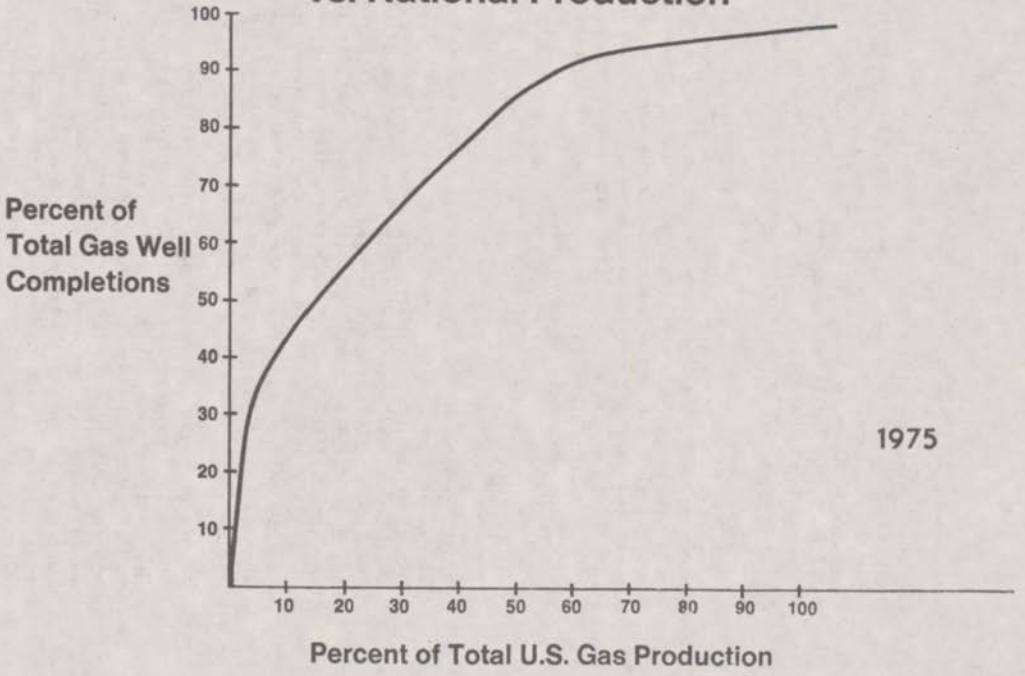


TABLE 2

DRILLING REGIONS RANKED BY RATIO OF PERCENT GAS WELL COMPLETIONS TO PERCENT POTENTIAL

	Percent			
AREA	Gas Well Comp.	Potential	Success Percentage[1]	Drilling Cost ($/ft)
I-Shallow[2]	3.90	.76	85	29.76
A-Shallow[2]	27.07	6.61	92	21.63
G-Shallow[2]	14.84	4.12	63	43.98
J_n-Shallow[2]	17.16	6.18	60	36.26
J_s-Shallow[2]	7.33	3.03	82	36.53
D-Shallow[2]	11.14	5.20	61	31.38
H-Shallow[2]	8.87	6.18	48	35.49
E-Shallow[2]	2.35	1.95	52	60.33
C-Shallow[2]	.75	.65	45	42.42
E-Offshore	3.31	8.78	62/55	114.96/165.45
L-Shallow[2]	.60	2.49	87	35.25
B-Shallow[2]	.40	1.95	28	44.36
J_r-Deep	.60	3.03	70	118.14
E-Deep	.39	2.06	46	120.87
H-Deep	.13	.76	62	228.09
B-Deep	.29	1.95	34	82.52
J_n-Deep	.47	5.42	60	102.27
G-Deep	.08	.98	43	105.11
G-Offshore	.24	4.98	15	151.39
A-Deep	.01	.54	100	362.11
D-Deep	.01	.65	33	77.25
L-Deep	.01	.76	40	131.66
K	.04	24.38	72	298.83
L-Offshore	0	1.08	93	---
B-Offshore	0	2.60	--	---
A-Offshore	0	3.90	--	---

1. Success Percentage is the total number of successful oil and gas wells divided by the number of wells drilled.

2 Shallow is used here to describe depths of less than 15,000 feet.

Chart 2

Gas Well Completions vs. Potential Gas Resource Base

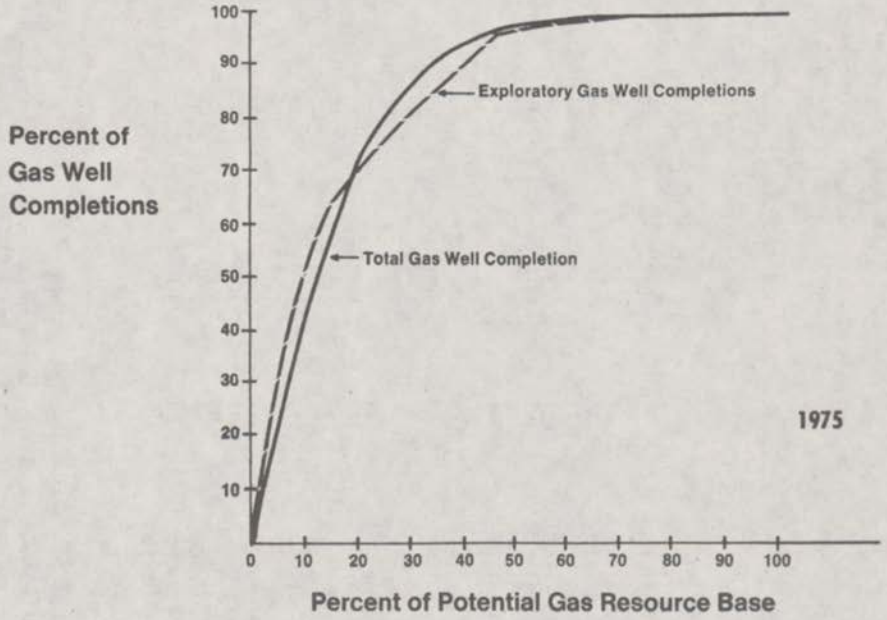


Chart 3

Total Gas Well Completions vs. Cost

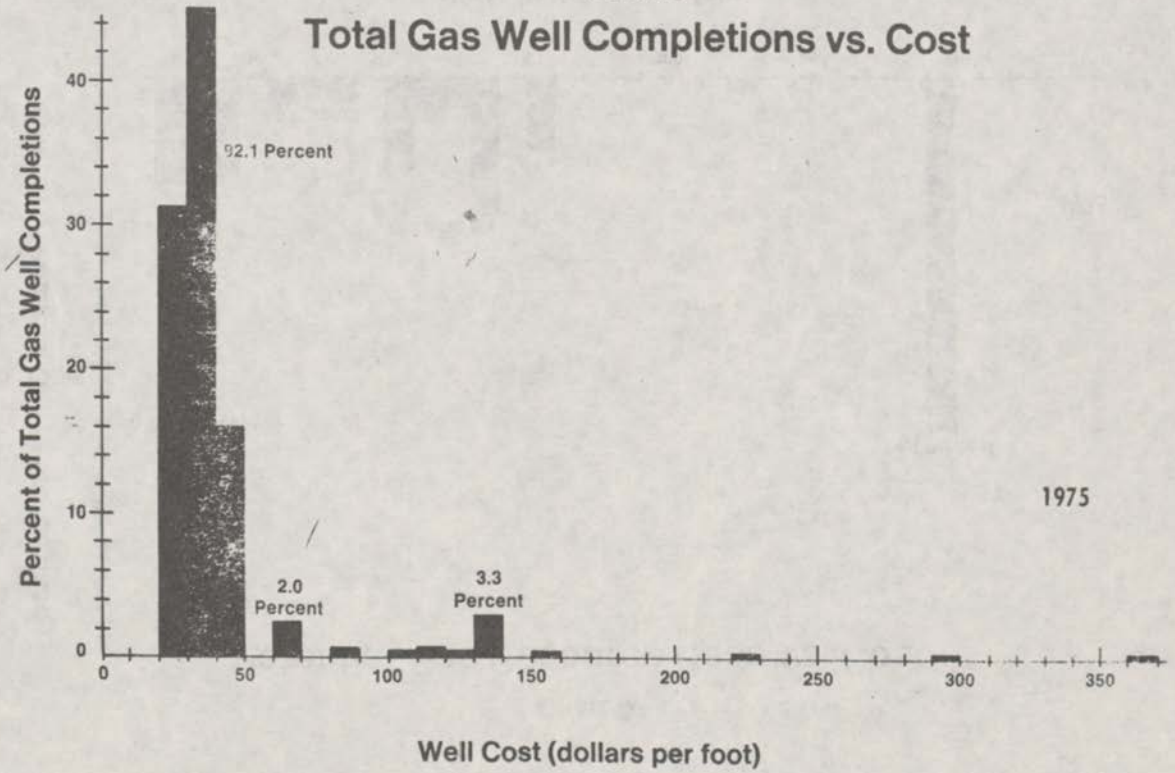
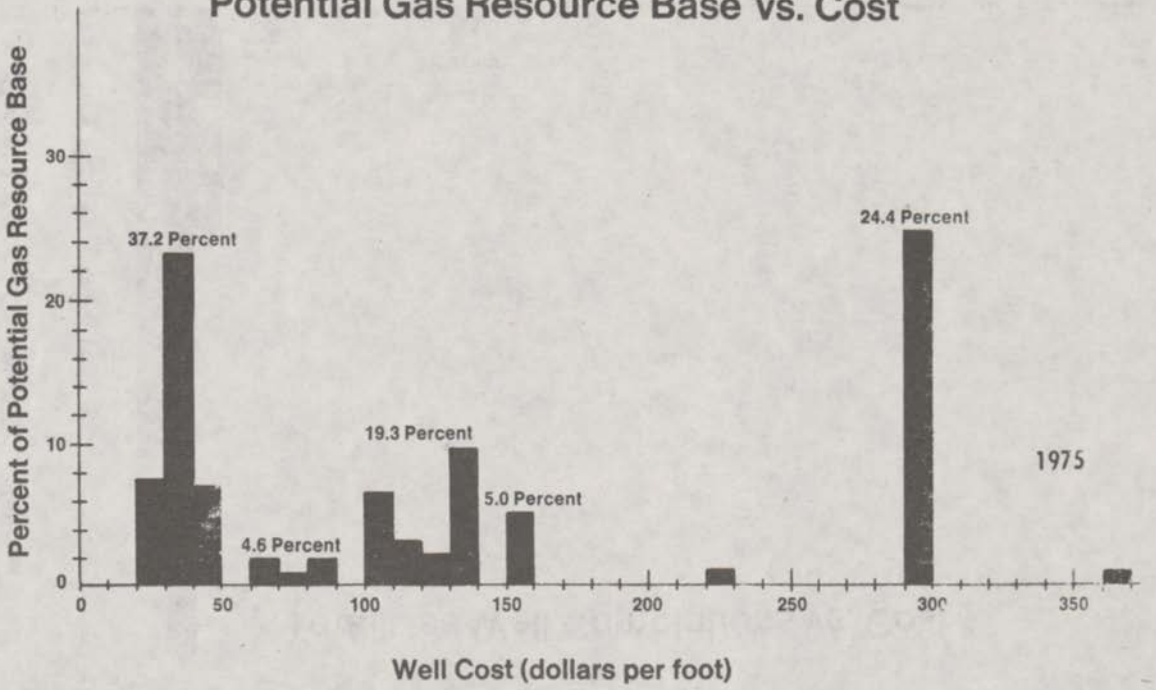


Chart 4

Potential Gas Resource Base vs. Cost



Mr. OTTINGER. Thank you for your very interesting and helpful testimony, Mr. Seder.

Our next witness is Alan Beringsmith, Pacific Gas and Electric Company.

STATEMENT OF ALAN W. BERINGSMITH

Mr. BERINGSMITH. Thank you, Mr. Chairman.

On behalf of Pacific Gas and Electric, I would like to thank you for the opportunity to share our views with the committee. I am an economist with Pacific Gas and Electric. One of my responsibilities includes rate design and analysis of the impact of various alternative rate forms. As a result, my comments are directed toward the issue of rate design. I will summarize my larger statement previously given to the committee.

The Pacific Gas and Electric Company is one of the largest gas distribution companies in the Nation, with some 2.6 million customers spread over more than 90,000 square miles of northern and central California. Given our relative size in the industry we are extremely sensitive to the potential impact proposals relating to the reform of natural gas utility rates may have on our customers.

PG and E and the California Public Utilities Commission are especially interested in rate reform and have been on the leading edge of such efforts with the introduction of multitiered conservation oriented rates, and in using interruptible rates for those customers with a backup energy source as a method to 'shave' system peaks.

In addition, we have aggressively promoted conservation through non-price mechanisms such as retrofit ceiling insulation in homes, solar demonstration projects, consumer education, offering of conservation devices, seminars for commercial and industrial users, energy audits of large users, direct targeted mailings to large users, and in setting an example by reducing our own internal company usage.

Currently we have an application before the California Public Utilities Commission which seeks to expand our conservation efforts to include provision for insulation financing, provision for assistance to insulation programs for low income families such as those operated by the Community Services Administration and seeks to expand experimentation and innovations in rate design.

The California Public Utilities Commission has further indicated its awareness of the critical supply situation for natural gas by attempting, through rate design, to encourage reductions in usage for outdoor decorative lighting, gas logs and swimming pool heating.

PG and E is concerned that parts D and E of the National Energy Act as they relate to the pricing of natural gas are premised on federally mandated standards for rate design. While PG and E is in general agreement as to the findings as stipulated in section 401, we have severe reservations as to the effectiveness of attempting to develop blanket criteria for rate design into which each gas utility should fit.

In California both the utilities and the California Public Utilities Commission have been studying and/or utilizing alternative gas

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rate designs such as inverted rates, incremental cost pricing, interruptible rates, and time differentiated rates. We are also researching customer impact resulting from rate redesign.

The one lesson we have learned from our experience and analyses is that in virtually every case the response and impact are unique and therefore attempts to delineate broad rules covering all possible occurrences are not likely to be successful. Therefore, we must question the fundamental premise that an attempt should be made to establish national standards for gas utility rate design.

We are also concerned that rate restructuring can result in severe financial problems for customers and gas utilities. For example, utility revenues could become volatile, and this may cause severe problems for utility financing, a critical concern given the need to obtain the financing necessary to make available to our customers alternative sources of supply such as LNG and SNG.

I have three areas relative to rate design which I wish to comment on. They include the incremental cost pricing provisions in section 414, rate flattening in section 543, and the time differentiated rate proposed in section 544.

In section 414, which as I said discusses incremental cost pricing to low priority users, we have reservations regarding the proposed incremental pricing of natural gas and particularly as such approaches impact on the level of economic activity and revenue stability of gas utilities, recognizing that in California we do have a limited coal option given existing air quality requirements.

The requirement in section 414, subsection (a), that 90 days after enactment of this legislation the cost of all gas above the current average cost to the pipeline be allocated to "low priority" users will cause problems in California. We are aware the legislation recognized a potential problem in this area by providing for some relief for "low priority" users where the existing price to these approximates price of substitute fuels.

However, we wish to reinforce the need for rate charged "low priority" users of natural gas not to be increased where they already approximate the cost of alternative fuels. This is because price increases may occasion a major shift by large users to those alternative fuels.

If these customers leave the system it will create serious revenue problems for gas utilities unable to sell or store available natural gas, especially during summer periods, and will also create major problems for firm service residential and commercial users who will find themselves facing substantially higher rates to cover system fixed costs previously paid for by the low priority interruptible service customers. These increases would be substantial on the PG and E system because a significant percentage of our sales to residential customes are at a rate below the commodity cost of gas.

Utilities facing loss of load will be unable to effect full cost recovery of their large capital investment and may be further disadvantaged by the provisions of their take or pay contracts. Therefore, systems such as PG and E which have already passed on the bulk of increases in the cost of natural gas to low priority users, may be unable to pass on further increases and as a result incur financial hardship.

We are also concerned that failure to pass higher prices on to the residential and commercial customers removes incentives they might have for the more efficient use of energy. We believe these two classes of customers have substantial ability to improve their efficiency of energy use.

As regards section 543, this section forbids gas distribution utilities from making sales at a rate that decreases with usage. Basic to rate design is the need to reflect equity in rates as measured by the cost of serving various customer classes. A portion of the distribution costs are incurred as a result of the utilities' so-called mandate or requirement to serve.

In practical rate design these costs are included in customer charges and their prohibition is of significant concern to us in that it fails to recognize the need for customer charges to recover a portion of the fixed costs of service.

Relative to section 544, PG and E is also concerned with the proposal for summer-winter rate differentials for natural gas rate design. Due to the nature of natural gas production, the resultant "take or pay" contracts, and the ability to store natural gas to meet peak demands, time differentiated rates do not make the same kind of sense for gas that they do for electricity.

In the case of PG and E, our winter peak demand for Priority One customers is about six times our summer peak demand and over a period of years the system has been designed to meet these characteristics. Therefore, seasonal differentials will simply charge higher rates for what have been designated high priority end uses and lower rates for end uses designated low priority. This is, of course, inconsistent with existing Federal Power Commission policy and we question whether it should be the intent of this legislation.

Proposals to expand the use of interruptible rates and eliminate master metering are supported by PG and E. The extent of our support is indicated by the fact we currently have 1,100 customers with stand-by alternative sources of energy on interruptible rates.

We also have studied master metering and conclude it provides a substantial disincentive to conservation. To an extent this is recognized in our "lifeline" rates which grant a smaller allowance to residents of master metered complexes.

It is also worth noting that natural gas pipeline and distribution industries have recently formed the Gas Research Institute which concentrates many of the individual research efforts of the industry and will have the responsibility for conducting aggressive research programs, including the areas of conservation and rate design. This application—Docket No. RM 77-14—is currently pending with the Federal Power Commission.

Finally, we wish to make clear, notwithstanding our prior comments that we applaud and are supportive of the attempt by Congress and the administration to develop the coherent and comprehensive national energy policy this country needs. It is PG and E's hope that our comments will be hepful in completing the difficult task of formulating this policy.

Thank you, Mr. Chairman.

[Mr. Beringsmith's prepared statement follows:]

PREPARED STATEMENT OF ALAN W. BERINGSMITH

I would first like to express Pacific Gas and Electric Company's appreciation for the Committee's invitation to address these hearings on the subject of gas rate design as proposed in the National Energy Act and specifically the provisions of Sections 414, 543, 644, and 648.

Introduction

Pacific Gas and Electric Company is one of the largest gas distribution companies in the nation with some 2.6 million customers spread over more than 90,000 square miles of northern and central California. In 1976 we distributed more than 605 million mcf of natural gas valued at nearly $1.1 billion. Given our relative size in the industry we are extremely sensitive to the potential impact proposals relating to the reform of natural gas utility rates may have on our customers in California.

PGandE and the California Public Utilities Commission are especially interested in rate reform and have been on the leading edge of such efforts with the introduction of multi-tiered conservation oriented rates, and in using interruptible rates for those customers with a backup energy source as a method to "shave" system peaks. In addition, we have aggressively promoted conservation through non-price mechanisms such as retrofit ceiling insulation in homes, solar demonstration projects, consumer education, offering of conservation devices, seminars for commercial and industrial users, energy audits of large users, direct targeted mailings to large users, and in setting an example by reducing our own internal company usage. Currently, we have an Application before the California Public Utilities Commission (Amended Application No. 56845), which seeks to expand our conservation efforts to include provision for insulation

financing, provision for assistance to insulation programs for low income families such as those operated by the Community Services Administration, and innovations in rate design. The California Public Utilities Commission has further indicated its awareness of the critical supply situation for natural gas by attempting, through rate design, to encourage reductions in usage for outdoor decorative lighting, gas logs, and swimming pool heating.

Overview

PGandE is concerned that Parts D and E of the National Energy Act as they relate to the pricing of natural gas are premised on federally mandated standards for rate design. While PGandE is in general agreement as to the findings as stipulated in Section 401, we have severe reservations as to the effectiveness of attempting to develop blanket criteria for rate design into which each utility should fit. In California both the utilities and the California Public Utilities Commission have been studying and/or utilizing alternative gas rate designs such as inverted rates, incremental cost pricing, interruptible rates, and time differentiated rates. We are also researching customer impact resulting from rate redesign. The one lesson we have learned from our experience and analyses is that in virtually every case the response and impact are unique and therefore attempts to delineate broad rules covering all possible occurrences are not likely to be successful. Therefore, we question the fundamental premise that an attempt should be made to establish national standards for gas utility rate design.

The need to adequately research impacts prior to implementing changes in rate design is clearly indicated by examining experience with electric rate reform. The issues have been discussed at length in numerous state "generic" hearings devoted solely to rate design issues.

While some agreement has emerged, the resulting rate restructuring is only now beginning to emerge in a slow measured way which generally includes the use of rate experiments as opposed to statewide mandated rate reforms. This approach is, of course, an explicit recognition of the problems involved in rapidly changing the rate structure. These problems can be particularly severe for industrial customers and could have debilitative effects on the economy if rate reform is not conducted in a measured way.

We are also concerned that rate restructuring can result in severe financial problems for gas utilities as well as their customers. For example, utility revenues could become volatile, and this, may cause severe problems for utility financing, a critical concern given the need to obtain the financing necessary to make available to our customers alternative sources of supply such as LNG and SNG.

Therefore, we conclude legislation which mandates specific requirements for utility rate design is neither justified nor desirable at this time if we are to continue to serve the best interests of our customers.

Section 414

We have reservations regarding the proposed incremental pricing of natural gas particularly as such approaches impact on the level of economic activity. The requirement in Section 414, subsection (a), that 90 days after enactment of this legislation, the cost of all gas above the current average cost to the pipeline be allocated to "low priority" users will cause problems in California. We are aware the legislation recognized a potential problem in this area by providing for some relief for "low priority" users where the existing price to these approximates price of substitute fuels. However, we wish to stress most emphatically that rates charged "low priority" users of natural gas should not be

increased where they already approximate the cost of alternative fuels. This is because price increases may occasion a major shift by large users to alternative fuels. This is even a greater problem since the legislation defines low priority to include feedstock, process, human needs, and plant protection uses. Since these low priority customers pay rates in excess of the average cost of natural gas, they are contributing an amount towards fixed costs. Thus, if they leave the system it will create serious revenue problems for gas utilities unable to sell available natural gas, especially during summer periods and will also create major problems for firm service residential and commercial users who will now find themselves facing substantially higher rates to cover system fixed costs previously paid for by "low priority" interruptible service customers. These increases would be substantial on the PGandE system because a significant percentage of our sales to residential customers are at a rate below the commodity cost of gas. Loss of industrial load may also occasion increases in prices from pipeline companies if their load factor deteriorates. It should be kept in mind that residential load factors are typically substantially below industrial load factors and this is extremely significant in determining unit cost given a large fixed capital investment in transmission and distributing facilities. The effects will, of course, vary from utility to utility, which is something any national energy policy must take into consideration. To do less will result in pricing rules which are discriminatory, especially as they impact on industry from region to region, and which are contrary to the public interest.

Utilities facing loss of load will be unable to effect full cost recovery of their large capital investment and may be further disadvantaged

by the provisions of their take or pay contracts. Therefore, systems such as PGandE which have already passed on the bulk of increases in the cost of natural gas to low priority users, may be unable to pass on further increases and as a result incur financial hardship. However, utilities must recover these costs if they are to remain financially viable. Therefore, we suggest that some portion of future cost increases must be passed on to all classes of customers and the decision as to the proper allocation to each class is best made by state or local regulators who are familiar with each individual situation.

We suggest that the first steps in any attempt to introduce incremental cost pricing in the manner prescribed in Section 414 recognize that a ceiling should be placed on the price to low priority users which is no higher than the "current Btu related price."

We are also concerned that failure to pass higher prices on the residential and commercial customers removes incentives they might have for the more efficient use of energy. We believe these two classes of customers have substantial ability to improve their efficiency of energy use. Therefore, we are concerned that depriving them of the price incentive to conserve will impact adversely on attempts to encourage conservation especially efforts related to emphasizing the need for insulation. It appears that "low priority" users have probably made the requisite investment to achieve conservation of the "easy to conserve" mcf, and subsequent conservation will be increasingly expensive.

Section 543

This section forbids gas distribution utilities from making sales at a rate that decreases with usage. Basic to rate design is the need to reflect equity in rates as measured by the cost of serving various customer classes. A portion of the distribution costs are incurred as a result of the utilities so called mandate or requirement to serve. In practical rate design these costs are included in customer charges and their prohibition is of significant concern to us in that it fails to recognize the need for customer charges to recover a portion of the fixed costs of service. A flat rate for all sales of natural gas would presumably have the fixed customer and distribution costs included in the commodity charges. This poses problems for a gas distribution utility in that it may be unable to recover its fixed costs given an unusually warm winter, a shift in usage among customers, or the movement of large customers to alternative fuels. We strongly believe this provision of the proposed legislation should be eliminated and state and local regulatory commissions given the freedom to design distribution level rates.

Section 544

PGandE is also concerned with the proposal for summer-winter rate differentials for natural gas rate design. Due to the nature of natural gas production, the resultant "take or pay" contracts, and the ability to store natural gas to meet peak demands, time differentiated rates do not make the same kind of sense for gas that they do for electricity. In the case of PGandE, our winter peak demand for Priority One customers is about six times our summer peak demand and over a period of years the system has been designed to meet these characteristics.

Because of the unique location of gas fields in the PGandE service area approximately 13% of the winter peak demand, accentuated by increased residential loads, is met through use of this source. Another 45% of system peak demand is met by underground storage. As a result of both the available local supplies and underground storage facilities, the PGandE system load factor on its pipeline suppliers is very high. The bulk of winter peak period usage is normally by residential and commercial customers while summer usage is by "low priority" customers. As a result, a seasonal differential will simply charge higher rates for what have been designated high priority end uses and lower rates for end uses designated low priority. This is, of course, inconsistant with existing Federal Power Commission policy and we question whether it should be the intent of this legislation.

As we perceive the rationale for time differentiated rates it is to more accurately reflect the costs of serving customers during peak periods with the expected result that the gap in usage between winter and summer would be somewhat reduced. We do not quarrel with the fact that peak usage might be reduced as a function of the elasticity of this use - particularly as insulation is substituted for energy - but we do have doubts that if the Seaboard method continues to be used for allocating fixed costs there will exist limited flexibility to increase winter rates.

While not as significant a factor on the PGandE system, given our storage capability, for many systems a seasonal rate differential may create volatility in utility revenue given unseasonably warm winters or cool summers. On the other hand we must also be cognizant of the situation in California and the Southwest where lower summer gas rates may result in increased use of natural gas to heat swimming pools, which we assume is not the intent of this legislation.

Proposals to expand the use of interruptible rates and eliminate master metering are supported by PGandE. The extent of our support is indicated by the fact we currently have 1100 customers with stand-by alternative sources of energy on interruptible rates. We have also studied master metering and conclude it provides a substantial disincentive to conservation. To an extent this is recognized in our "lifeline" rates which grant a smaller allowance to residents of master metered complexes. We are working closely with the California Public Utilities Commission to substantially reduce the usage of master metering, however, there are some installations where retrofit is technically infeasible.

A caution is in order under Subsection (b) of Section 544 in that the promulgation of pricing rules for all gas utilities requires substantial recognition of the differences between utility service areas. As I have attempted to illustrate one rule or set of rules will surely not suffice for the myriad situations faced by natural gas utilities in the U.S. Any pricing rules adopted under this legislation must set forth only very general principles and explicitly reserve for the state regulatory agencies the right to determine the final rate design.

Section 548

PGandE has serious concerns related to the provision in Subsection (2) (a) which provides that, without hearing, a state regulatory body will lose its authority over the regulation of natural gas pricing, if it has not implemented the policies and requirements determined as necessary under this act. While we are aware that a comprehensive national energy policy is needed and desirable, we believe it would be a grievous error

for the Federal Government to assume responsibility for regulation of natural gas distribution utilities. A fundamental purpose and value of state or local regulation is that it allows often major individual utility differences to be considered when making important policy decisions related to rate design. Federal policy, because of its need to be general, necessarily fails to recognize important individual utility characteristics. If state and local regulatory agencies are forced to adopt Federal standards in their rate design decisions and are no longer allowed to utilize their knowledge of specific utility situations, they are effectively placed in regulatory "straight jacket" and are likely to cease to be a factor in energy policy decisions.

It is also worth noting that natural gas pipeline and distribution industries have recently formed the Gas Research Institute which concentrates many of the individual research efforts of the industry and will have the responsibility for conducting aggressive research programs including the areas of conservation and rate design. This application (Docket No. RM 77-14), is currently pending with the Federal Power Commission.

Finally, we wish to make clear, notwithstanding our prior comments that we applaud and are supportive of the attempt by Congress and the Administration to develop the coherent and comprehensive national energy policy this country needs. It is PGandE's hope that our comments will be helpful in completing the difficult task of formulating this policy.

Thank you

Mr. OTTINGER. Thank you very much.

We will hear next from Mr. O. C. Davis, President of Peoples Gas Company, Chicago, Illinois.

STATEMENT OF O. C. DAVIS

Mr. DAVIS. Thank you, Mr. Chairman, members of the committee.

I am O. C. Davis, President of Peoples Gas Company of Chicago, Illinois. Ours is a holding company with an interstate pipeline subsidiary, Natural Gas Pipeline and two gas distribution utility subsidiaries, the Peoples Gas Light and Coke Company which operates in the city of Chicago, and the North Shore Gas Company which operates in the suburban area north of Chicago.

Overall, we serve a market of approximately 14 million people in Iowa, Illinois and Indiana and transport about 5 percent of the natural gas consumed in the country. Our system is the largest provider of energy for the State of Illinois.

I appreciate your invitation to testify before this subcommittee with respect to H.R. 6831. We commend President Carter and his energy advisers for putting together a comprehensive energy policy. However, we have suggestions to make with respect to several of its provisions.

First, let me comment on the provisions of title I—utility conservation programs. We have encouraged our customers to conserve and we estimate conservation has reduced demand in our markets during the winter months between 8 and 10 percent.

It is our judgment that the utilities can be most helpful by limiting their function to informing customers of available conservation measures and assisting in arranging financing. There are many small businessmen operating in our service territories who are qualified and anxious to undertake the installation of energy efficient equipment, insulation, caulking and other conservation modifications.

A utility should encourage investment for conservation and arrange financing either through financial institutions or, where this is not feasible, financing directly a customer's conservation investment.

Turning now to natural gas pricing, we have long advocated deregulation of the well-head price of new natural gas supplies. Deregulation will provide incentives for exploration for new supplies. Deregulated prices will move upward, and encourage greater conservation. Deregulation of new gas field prices will give the inter- and intrastate purchaser equal access to new supplies.

The definition of new gas proposed in section 402(a)(5)(B) is too rigid. It defines "new gas" by vertical and horizontal distances without regard to geological realities. The "new gas" classification should be given to gas which the seller can demonstrate is produced either on-shore or off-shore from a new well completed in a new producing reservoir, even though the new well is less than 2.5 miles from an old well or at a depth of less than 1,000 feet from the completion depth of any old well.

Development of coal gasification should be encouraged. Coal gasification is ready. The basic technology has been demonstrated

both in this country and abroad and the industry is prepared to go forward, if it can get support from the government in the form of loan guarantees.

High Btu coal gas has economic and environmental advantages as it uses existing gas transportation and distribution systems and the billions of dollars of customers' investments in gas appliances.

Liquid hydrocarbon based synthetic gas plants can provide a significant increment to the Nation's gas supplies and should be encouraged. Our customers are receiving up to 160 million cubic feet per day of synthetic gas produced in our SNG plant which uses naphtha as a feedstock. SNG plants are relatively inexpensive to construct, utilize well-known technology, and can be built in a rather short time.

Importation of LNG should be increased. H.R. 6831 contains no provision to assist in development of LNG projects. Gas supplies from large, known reserves are now available in many parts of the world where the local economy cannot absorb this energy. Although the liquefaction and ocean transport of these supplies tend to make imported LNG more expensive than domestic gas, imported LNG can be helpful in increasing the supply of energy.

With additional storage capability, LNG can be used primarily for high-priority loads. At least Congress should not discourage this energy source by insisting upon incrementally pricing LNG.

Legislatively imposed incremental pricing and mandatory allocation authority hinders the development of alternative gas supplies.

We again thank the subcommittee for inviting us to participate in these hearings. We shall be happy to assist in any way that you find helpful.

[Mr. Davis' prepared statement follows:]

TESTIMONY OF

O. C. DAVIS, PRESIDENT

PEOPLES GAS COMPANY
CHICAGO, ILLINOIS

Mr. Chairman and Members of the Committee:

My name is O. C. Davis and I am President of Peoples Gas Company of Chicago, Illinois. Our Company is a holding company which has an interstate pipeline subsidiary, Natural Gas Pipeline Company of America and two gas distribution utility subsidiaries, The Peoples Gas Light and Coke Company which operates in the City of Chicago, and North Shore Gas Company which operates in the suburban area north of Chicago. Our pipeline subsidiary delivers gas not only to our distribution companies, but to 47 other distribution operations, both municipals and shareholder-owned, primarily in the States of Iowa, Illinois and Indiana. We serve a market of approximately 14 million people and transport about 5% of the natural gas consumed in the country. Our system is the largest provider of energy for the State of Illinois.

I appreciate your invitation to testify before this Subcommittee with respect to H.R. 6831 as proposed by the Administration to establish a comprehensive national energy policy. We, in the Peoples Gas System, applaud the

expedition of President Carter and his energy advisors in putting together a comprehensive energy policy. We have several suggestions to make with respect to some of its provisions. While disagreeing with some details, we urge a national energy policy be adopted as soon as possible so that the general public and energy business have direction on national energy goals.

We also commend the Congressional leadership for its undertaking to give high priority to consideration of this essential legislation. We will be available to assist in any way we can to provide the Congress and the Administration the benefit of our experience and views.

Initially, I want to emphasize to this Committee that it is our firm belief that the gas industry and our System are important factors in supplying the energy needs of this nation and that we will be, in the future, playing a significant and decisive role. The gas industry has evolved and changed over the last century and a half; The Peoples Gas Light and Coke Company began operating in 1855, has experienced and adapted to many changes since its beginning. It is my conviction that the next century, although filled with many changes, will see the gas industry continuing to function as a vital participant in the energy picture.

Energy Conservation Plans

I would first like to comment briefly and generally upon the provisions of Sections 101 through 115 of Title I dealing with utility conservation programs. At present, we estimate conservation in our markets has reduced demand between 8-10%. This level of conservation has been achieved within the last year and results largely through the impact of higher prices.

It is our judgement that the utilities can be most helpful if their functions are limited to (1) informing customers of the conservation measures which are available and will be effective, and (2) assisting in arranging financing of those things which conserve energy. There are many small businessmen operating in our service territories who are qualified and anxious to undertake the installation of energy-efficient equipment together with insulation, caulking and other conservation modifications. We believe it would be better to help our customer and his contractor to the extent of encouraging investments for conservation and either arranging through financial institutions or, to the extent this is not feasible, financing directly a conservation investment.

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As we understand the proposed program, it contemplates that we not only advise the customer of measures that can be undertaken to conserve gas, but must give him a list of people who can do the work. We would screen the customer desiring the work for credit worthiness, arrange for financing either with third parties or through our resources, and collect periodic payments. This is a large undertaking and we believe that legislation in this area is not the best way to approach the problem.

My comments with respect to the utility program, (Sub-Part 1 of Part A of the bill) of course, apply equally to the proposals regarding energy conservation for schools and hospitals (contained in Part C of the bill).

Natural Gas - Policy and Implication (Part D)

We have long advocated amendments to the Natural Gas Act to deregulate the wellhead price of new natural gas supplies.

Deregulation of the field price of gas will have three beneficial results. First, it will provide incentives for the search for new supplies in areas largely unexplored due to greater depths and accessibility. Secondly, deregulated

prices will move upward and encourage greater conservation. Lastly, deregulation of new gas field prices will give the inter and intrastate purchaser equal access to new supplies - achieving parity. In the industrial market it may result in shifting to other fuels and it will certainly increase industry's conservation efforts. In the commercial and residential markets it will likewise stimulate careful usage of this premium fuel.

It is interesting to note the contrast in the Administration's proposals in respect to oil pricing on one hand and gas pricing on the other. The National Energy Plan proposes that newly discovered oil be allowed to rise in three years to the current 1977 world oil price, adjusted to keep pace with domestic price levels. By contrast the Administration's proposal on gas is tied to BTU equivalency price on the average domestic refineries acquisiton price of oil. At the very least new gas, the premium fuel, should have been given parity with new oil. To do otherwise would encourage exploration efforts directed away from gas and toward oil. Why encourage a further disparity in energy costs and the adoption of an extremely complex gas pricing scheme. We doubt that it was the Administration's intention

to restrict the development of additional gas supplies to deny present and future customers the benefits of gas, but its proposals will have that result, a result which is contrary to a very principle of the Administration's own National Energy Plan - namely, "that the United States must solve its energy problems in a manner that is equitable to all regions, sectors, and income groups," (p. 27, The National Energy Plan). Also, it undercuts the Administration's own parity statement that "[f] or both oil and gas, this [pricing] approach establishes an integrated pricing system that places the incentives on harder to find, new supplies,. . ." (p. 54, The National Energy Plan).

Further, the definition of new gas proposed in Section 402(a)(5)(B) is overly rigid. Presently, it defines "new gas" by vertical and horizontal distances without regard to geological realities. Rather, it should afford "new gas" classification to gas which the seller can demonstrate is produced from a new well completed in a new producing reservoir even though less than 2.5 miles from an old well, or at a depth of less than a thousand feet from the completion depth of any old well.

High-BTU Coal Gasification, Other Synthetic Gas and LNG

H.R. 6831 passes over the opportunity to encourage the development of coal gasification, gas from other feedstocks and LNG imports. High-BTU coal gasification is ready for development; the country possesses a plentiful supply of the feedstock - coal; the basic technology has been demonstrated both in this country and abroad and the industry is prepared to go forward provided the government will make available support in the form of loan guarantees - this recommendation with certain conditions attached was just recently supported by FEA. Converting coal to gas is the most economical, efficient and environmentally acceptable method of utilizing the vast coal reserves of this nation. I am attaching to this statement an exhibit, prepared by the American Gas Association, which compares the capital investment and plant outlet energy cost of a first generation coal gasification complex with an output of 250 Mmcf/d and a modern electric generation plant with an output of a comparable daily amount of energy.

We, of course, recognize that additional electrical energy is required by the nation. In some applications it is the only form that can be used. However, it cannot do the whole job and the nation can ill afford to deny itself

high-BTU coal gas which has economic and environmental advantages and utilizes the gas transportation and distribution system already in place, as well as the billions of dollars of customers' investments in gas furnaces, ranges, and other appliances.

As in the early days of nuclear energy development, coal gasification will need financial assistance, primarily in the form of loan supports. The financial community is reluctant to loan money to the gas companies as they are seen as inadequate guarantors of repayment of debt of the magnitude necessary to develop these complexes. A 250 million cubic ft/day plant will cost (in current dollars) about $1.3 billion. The industry needs to build and operate several of these plants to demonstrate commercial and financial feasibility. Congress can assist by making loan guarantees available. We don't think the government will ever have to make its guarantees good, but their existence will get the program off the ground.

Our distribution subsidiaries are receiving up to 150 million cubic feet per day of synthetic gas produced in a plant which costs slightly over $100 million. This plant uses naptha as a feedstock. There are currently 13 plants in

operation utilizing identical or similar technologies. We are pleased that the Administration has asked FEA to review its policies with respect to feedstock allocation. This option should be kept open. These plants are relatively inexpensive, utilize well-known technology, and can be constructed in rather short time. To the extent that liquid feedstocks can be committed either from domestic or foreign sources, such plants can add a significant increment to the energy inventory.

We are also pleased that the Administration is reviewing its predecessor's constraints on the importation of LNG. Gas supplies from large proven reserves are available in many parts of the world where the local economy cannot absorb this energy. Although the liquefaction and ocean transport of these supplies tend to be more expensive than domestic gas, even under deregulation, such gas can also be helpful in the supply of energy. When coupled with additional storage capability, LNG can be used primarily for high-priority loads. H.R. 6831 does not contain any provisions to assist in development of LNG projects; at least Congress should not discourage this energy source by insisting upon incrementally pricing LNG.

The Disincentive of Allocation on
Development of Alternative Sources

Legislatively-imposed incremental pricing and extension of mandatory allocation authority would constitute a major barrier to development of alternative gas supplies. The massive investments which non-traditional projects require should not be made more risky by the threat of losing the output to other consumers who are not supporting, through rates paid, for these investments. We urge that Congress not extend the Emergency Natural Gas Act of 1977. If a new short-term crisis recurs, the Congress (by its action in late January and early February, 1977) has shown that it can respond with dispatch. Allocation or the threat of allocation is a crutch that should be used sparingly, lest some become dependent and defer the necessary adjustments.

We again thank the Subcommittee for inviting us to participate in these hearings. As I stated earlier, we shall be happy to assist in any way that you find helpful.

HIGH BTU COAL GASIFICATION VERSUS COAL-FIRED ELECTRIC GENERATION FOR EQUIVALENT QUANTITIES OF END-USE USEFUL ENERGY

1976 Dollars*

	Coal Gas	Coal Electricity
Unit Plant[1]	250 MMcfd	3,000 Mwe w/scrubbers
Unit Plant Capital Requirement[2] (Billions 1976 Dollars)	$1.3	$2.7
Incremental Delivered Residential[3] Cost ($/MMBtu)	$4.45	$13.80
Total Cycle Efficiency[4] (Percent)		
Conventional Equipment	36	25
Advanced Equipment	56	48
End-Use Residential Energy Cost[5] ($/MMBtu)		
Conventional Equipment	$6.95	$14.68
Advanced Equipment	$4.49	$7.75
Key Environmental Residuals[6]		
Particulates lbs/hr	180	1,070
SO_2 lbs/hr	450	4,300
NO_x lbs/hr	1,780	20,830
Water Requirement[6] (Acre-ft/yr)	6,300	54,300
Annual Coal Requirements[7]		
Trillions of Btu's	140.4	201.4
Millions of Tons-Western Coal	8.0	11.5

* All prices are incremental unless otherwise stated.

Prepared by American Gas Association
May 16, 1977

Footnotes

[1]Based on average residential end-use efficiencies of 64% for natural gas and 94% for electricity, a unit-size coal gas facility delivers 155.2 billion Btu per day of useful energy and a 3,000 Mwe coal-fired electric facility will deliver 153.7 billion Btu per day of useful energy.

[2]Coal gasification facility uses single feed Lurgi technology, investment estimate from C F Braun and Company Interim Report, Factored Estimates for Western Coal Commercial Concepts, October 1976. Coal-fired electric facility is located in western U.S., using Powder River coal with flue gas desulfurization, investment estimate from Electric Power Research Institute Final Report, Coal-Fired Power Plant Capital Cost Estimates, January 1977.

[3]Cost of gas assumes:

	Delivered Total Cost ($/MMBtu)
90% capacity factor 35-year project life Straight line depreciation 48% federal income tax 75/25 debt equity ratio 15% return on equity .429 $/MMBtu coal	3.30
Transmission and residential distribution cost	1.15
Total	4.45

Transmission costs calculated on the basis of 300-mile transmission. Distribution costs are taken from data in 1975 Gas Facts. Residential distribution cost is calculated by subtracting the average price paid by utility companies from the average residential price charged by utility companies. An escalation factor of 5% was then used from mid-1975 to mid-1976.

Cost of electricity assumes:

	Delivered Total Cost ($/MMBtu)
70% capacity factor 35-year project life 50% federal income tax 75/25 debt equity ratio 15% return on equity .429 $/MMBtu coal	8.48
Transmission and distribution	4.87
Total	13.80

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Transmission and distribution cost is the difference between average residential revenues per kilowatt hour and the average cost of production for investor-owned electric utilities. The average residential revenues per kilowatt hour are given in the 1975 Edison Electric Institute Statistical Yearbook. The average production cost is a computed figure obtained by adding average variable production costs as given in the above reference and estimated fixed capital charges. These fixed charges are calculated by allocating 45% of net total electric utility plant assets to the generation plant and multiplying it by the 1975 embedded capital cost of just over 12%. The fixed and variable costs are then combined and allocated over energy sales for investor-owned utilities in 1975. The differential resulting from the subtraction of production cost from average residential revenues per kilowatt-hour is then escalated at a 5% annual rate from mid-1975 to mid-1976.

$^{\$}$Calculated by multiplying the following efficiencies for each stage of the process

	Coal Gasification	Coal Electricity
	(Percent)	
Coal Extraction & Handling	89.5	89.5
Conversion	65	32.8
Transmission	97	91.2
End-Use Efficiency		
Conventional	64	94
Advanced	103	178

Weighted average residential end-use efficiencies based on national consumption pattern for U.S. residential sector, Patterns of Energy Consumption, January 1972, Office of Science and Technology, Executive Office of the President.

		Equipment Efficiency			
		Conventional		Advanced	
	Weight	Gas	Electric	Gas	Electric
		(Percent)		(Percent)	
Space Heating	.72	66	98	115	212
Water Heating	.19	65	91	65	91
Cooking	.07	40	75	40	75
Clothes Drying	.02	65	65	65	65
Total	1.00	64	94	99	178

Note: For advanced equipment, thermally activated gas heat pumps (coefficient of performance 1.15) and electric ignition gas stove and electric heat pumps (coefficient of performance 2.12) where included.

[5]Calculated by dividing the delivered energy costs by the overall residential equipment efficiencies.

[6]For coal gas, Radian Corporation, A Western Regional Energy Development Study: Primary Environmental Impacts, Volume II, prepared for the Council on Environmental Quality and the Federal Energy Administration under contract No. EQ4AC037, August 1975.

For coal electricity, Final Environmental Impact Statement on the Proposed Kaiparowits Project, U.S. Department of the Interior, March 1976.

[7]Based on conversion efficiencies of 65% for coal gasification and 32.8% for coal-fired electric generation with 328 days of operation for the coal gas facility and 256 for the coal electric.

Mr. OTTINGER. Thank you very much, Mr. Davis.

Our last member of the panel is Mr. Charles F. Wheatley, Jr., general counsel of the American Public Gas Association, which is a

Mr. Wheatley, we welcome you here. There is a vote going on. I have arranged for Mr. Sharp to go over and vote, and come back, so we can proceed without interruption. But, you will see members coming and going. It is not attributable to your testimony. It is accommodating ourselves to the House.

STATEMENT OF CHARLES F. WHEATLEY, JR.

Mr. WHEATLEY. My name is Charles F. Wheatley, Jr., and I am general counsel of the American Public Gas Assciation, which is a group of over 200 publicly owned gas distribution systems located throughout the United States.

My testimony today relates to parts D and E of the National Energy Act as it affects publicly owned gas systems and the consumers served by them. My detailed statement contains a section-by-section analysis of these parts of the National Energy Act, with suggestions for improvement to make the legislation more responsive to the public interest.

At the outset, I will seek to briefly summarize certain major problem areas in the act which in our view ought to be amended by the Congress before this bill is enacted.

In general, the higher rates for natural gas which are proposed by the National Energy Act in our view will adversely and unnecessarily increase gas costs to the Nation's gas consumers and, at the same time, provide direct windfall profits to the natural gas producer companies consisting for the most part of the major oil companies.

Section 404, relating to the establishment of rates for new gas, would establish a completely new test based on equating the price of natural gas to domestic oil. The act contains no standard for pricing oil. Oil prices have been artificially increased due to the actions of the OPEC cartel.

This section of the new proposed act improperly abandons the long estlished judicially approved standard for just and reasonable rates contained in the Natural Gas Act of 1938. The new resulting rate of $1.75 per Mcf at the well head for new gas, which would

escalate upwards greatly, as oil prices escalated, exceeds the present $1.42 ceiling set by the present Federal Power Commission. That present ceiling of $1.42 is under review in the courts as lacking any substantial evidence to establish that it is based on actual costs of these companies plus even a very fair return allowance.

Sections 405 and 406 of the proposed bill similarly would permit substantial increases in the price of old gas over the present FPC set ceilings. To accomplish this, section 405 blatantly seeks to nullify the present appeal by consumer groups to the United States Court of Appeals from the FPC's Opinion No. 770 decision relating to old gas.

The section 406 provision, allowing the rate for old gas presently being sold at the various regulated prices to automatically jump to $1.45 simply upon renewal of a contract with no new costs incurred by the producers makes, we believe, a complete mockery out of any contention that the act seeks to maintain any meaningful relation on gas prices.

Now, this provision alone would cost consumers an additional $1.3 billion per year. That is a cumulative increase year in year out as these old contracts expire over the already high and unwarranted gas prices set by the FPC in Opinion No. 770.

Finally, we do have some suggestions relating to part E of the act which we suggest should be clarified to make it clear that publicly owned systems should not be subject to any more stringent requirements relating to the rate design provisions of the act to conserve gas than are privately owned systems.

We don't believe that that is the intent of the legislation. We feel it is ambiguous and should be clarified to remove any such construction.

I have submitted for the record some detailed section-by-section analysis of the various provisions of this bill. I simply request that they be incorporated in the record at this point.

Mr. OTTINGER. They will be incorporated.

[The attachment to Mr. Wheatley's statement follow:]

My detailed comments on the Act's provisions are as follows.

DETAILED ANALYSIS

Part D of the "National Energy Act", which is discussed below, relates to among other things the pricing of natural gas.

Section 401(a) sets forth certain findings and purposes of the new proposed legislation relating to natural gas. This section attempts to restate the history of natural gas in a way which does not accurately reflect the true events. For example, Section 401(a)(3) provides that "the Congress enacted the Natural Gas Act of 1938 to provide protection for consumers and to provide a regulatory structure through which interstate pipelines could be assured a fair return of return." First, it should be observed that the Natural Gas Act was not passed to "assure" pipelines a fair rate of return but to limit pipelines which because of their uncontrolled monopoly power, were able to charge exorbitant rates, to a fair rate of return. Secondly, the Natural Gas Act in 1938 expressly provided that it was to regulate "natural gas companies." In the first case to reach the Supreme Court on the proper interpretation of the Act, involving Hope Natural Gas Company, the Supreme Court held that the term "natural gas company" applied to the production operations of a company as well as its interstate transportation of gas functions. This holding that the Gas Act extended to producers, albeit at that time, they were interstate pipelines

engaged in production operations, was confirmed by several other Supreme Court decisions during the 1940's. It was clear from these cases, that Congress from the outset had intended for the Act to apply to wellhead operations. The only issue left open at that time was whether a company that was in the production operation of natural gas, but was not at the same time engaged in the interstate transportation of natural gas, would be subject to regulation. This issue was decided in 1954 by the United States Supreme Court in the first Phillips case which simply ruled that a so-called "independent" producer of natural gas was also a "natural gas company" within the meaning of the Natural Gas Act as enacted by Congress in 1938. Thus, the Phillips case in 1954 was not a radical departure from any prior interpretation of the Natural Gas Act by the Courts. As indicated, the Courts had held from the very beginning that the Act was intended to apply to the production of natural gas at the wellhead. In the early cases, the Supreme Court also made it quite clear that the Act was primarily designed to protect consumers against exploitation by natural gas companies.

Section 401(a)(4) states that "in 1954, the Supreme Court held that the Natural Gas Act applied to the wellhead sale of natural gas in interstate commerce, subjecting producers selling interstate gas, but not intrastate gas to a reasonable rate of return regulatory standard based on a determination of historic production costs." Here again, this section of the proposed bill is inaccurate. The 1954 decision by the Phillips case did not hold that producers selling interstate gas "but not intrastate gas" were subject to regulation under the Natural

Gas Act. In fact, the question as to whether the Natural Gas Act applies so as to prevent discrimination by natural gas companies operating in intrastate commerce against interstate users has never been definitively ruled upon by any court. At the present time, that issue is now before the United States Court of Appeals for the District of Columbia Circuit in an appeal from the Commission's Order No. 533. In that case, the Federal Power Commission ruled that it lacked jurisdiction over the intrastate market to prevent discriminatory activities by natural gas companies. That holding of the Commission, made in 1975, is now being challenged in an appeal taken by the American Public Gas Association and the Consumer Federation of America to the United States Court of Appeals. The issue before the Court is whether or not the Natural Gas Act prohibitions against "undue discrimination" apply to the intrastate activities of natural gas companies. The case is scheduled for oral argument before the Court on May 9, 1977.

Secondly, the Supreme Court in the 1954 Phillips case did not hold that producers subject to regulation at the wellhead under the 1938 Natural Gas Act were subject to a regulatory standard "based on a determination of historic production costs." In subsequent cases involving the setting of wellhead rates, the Supreme Court has held that the standard of "just and reasonable" rates set by Sections 4 and 5 of the Natural Gas Act is a

broad, flexible standard designed to provide the incentive needed to produce new supplies of natural gas, but no more than an adequate incentive for that purpose. The Supreme Court has recognized that "non-cost" items may be considered by the Federal Power Commission in setting wellhead rates. This standard of "just and reasonable" rates under the Natural Gas Act has been hammered out by a long-line of decisions by the United States Supreme Court. Clearly, any change to a new standard would likely invoke an entirely new process of litigation to determine the scope and meaning of the new standard.

Section 401(a)(5) states that "the differential between the price of natural gas and oil has widened with the continuation of cost-based regulation of natural gas,[and] the four fold rise in world oil prices in 1973 and 1974..." Oil prices have increased because of "artificial" situations caused primarily because of the OPEC cartel. The artificial increase in oil prices has no relationship to the price of natural gas produced from domestic fields, many of which are on offshore lands owned by the United States Government. In the meantime, the price of natural gas has not been held down during the past eight years. In fact, the Federal Power Commission, under the appointments of industry-oriented personnel, has granted one round of rate increases after another to set ever-escalating pleateaus of new high prices for natural gas. In 1971, the major oil company producers of natural gas entered into a stipulation in the Southern Louisiana Area Rate Case that a 26¢ per Mcf wellhead price for

new gas would provide them with all of the incentive required for them to produce natural gas from the major area through 1977. The industry-dominated Federal Power Commission subsequently has scuttled this industry-sponsored and Court-approved settlement agreement and has set rates which first escalated to 52¢ per Mcf and finally in Opinion No. 770 and 770-A to $1.42 at the wellhead, despite the industry's earlier representations that 26¢ provided them adequate incentive. Under these circumstances, it is patently erroneous to contend that the price of natural gas has been held down by the Federal Power Commission "with the continuation of cost-based regulation." We would also be remiss in not observing that an oil shortage, by which we mean that domestic consumption had exceeded domestic production, has developed in this country in recent years though oil prices were historically unregulated, so it is clearly wrong to attribute so-called gas shortage to cost-based regulation of production rates.

Section 401(a)(6) provides that "as a result, the incentives to find new natural gas have declined along with the proved reserves of natural gas." Here again, this is an erroneous statement of fact. There has been absolutely no showing that the incentives to find new natural gas have, in fact, declined. Nationwide figures indicate that in 1973 and 1974, as well as 1975, the footage of successful new gas wells drilled were the greatest in the nation's history. The curious thing about this successful drilling, however, is that the companies were reporting

very little new findings. The "proved reserves of natural gas" have been reported only by an industry-dominated committee of the American Gas Association. The AGA proved reserves estimates have been attacked by independent studies and analyses as inaccurate and dramatically understated. The validity of the AGA reserves estimates is now a central issue in the pending case before the United States Court of Appeals involving the Federal Power Commission's establishment of a $1.42 Mcf wellhead rate. Accordingly, it cannot now be said accurately that "the proven reserves of natural gas" have declined.

Section 401(a)(8) provides that "a new system of natural gas pricing is needed that recognizes the costs and risks associated with finding future supplies of natural gas as well as the commodity value of substitutable fuels." This statement erroneously ascribes to the view that somehow natural gas prices have been too low under the present regulatory scheme. As indicated previously, the industry-dominated Federal Power Commission has undertaken many techniques to seek to increase the price of natural gas above its costs, including a fair return, to the industry, including any appropriate "non-cost" items deemed allowable under the intepretations by the United States Supreme Court. For example, in Opinion No. 770-A, the Federal Power Commission added a component of 43.5¢ based on assumed Federal income tax costs that the producers would

would pay. This item is under challenge in the United States Court of Appeals, and APGA is there contending that the evidence indicates that the industry does not now pay Federal income taxes due to various tax gimmicks, and very likely, will continue in the future to avoid paying any Federal income taxes on their natural gas producing operations. Therefore, a substantial part of the present $1.42 rate is not cost-justified. It seems inconceivable that the Presiding could call for a "new system of natural gas pricing" that would ask for higher prices than that which the present industry-dominated Federal Power Commission has established, when the present $1.42 rate is clearly improper and excessive in many respects. The provision for a new system of gas pricing to recognize "the commodity value of substitutable fuels" merely repeats a contention that the major oil companies engaged in the natural gas business has been making for many years, in each instance up to this time unsuccessfully. The industry has objected to cost-based pricing or any other regulated method of subjecting it to receiving only a "reasonable return" on its investment. The technique which the industry has so strongly lobbied for over the years has been that gas should be priced at the "commodity value of substitutable fuels." In every case to reach the Courts, including the United States Supreme Court, this standard has been definitively rejected as not consistent

with the mandate of the Natural Gas Act of 1938 "to protect consumers against exploitation by natural gas companies." To now have this same standard embodied in the President's "National Energy Act" is shocking to consumers.

Section 401(b) provides that the purposes of this part are "(1) to bring the natural gas market back into better balance by reducing the demand for natural gas and increasing the supply through the establishment of an incentive based pricing approach for new natural gas...." The basic concept involved here is erroneous. The attempt at "reducing the demand for natural gas," by setting artifically high prices, which unduly burden consumers who are already overburdened by extremely high energy bills as a result of the just completed winter heating season is patently fallacious. Rather than trying to use drastic price increases to reduce the demand for natural gas which because of a number of factors including its clean burning characteristics, is relatively inelastic as to high priority users, demand should be reduced by a fair allocation plan which allocates the gas to the desirable uses. Any attempt to accomplish this through new high prices merely unnecessarily burdens the already overburdened consumer.

Section 402(a)(5) defines the term "new natural gas" as gas which is produced from a new lease on the Outer Continental Shelf or which is produced other than on the Outer Continental

Shelf from a new well, the completion location of which is 2.5 miles or more from an old well or (ii) "the completion location of which is at a depth of 1,000 feet or more in excess of the depth of the completion location of any old well ... provided that the completion location "... is not in the same producing zone as the completion location of any such old well." This definition seems to reject a definition of "new natural gas" recently adopted by the Federal Power Commission in Opinion No. 770-A. In that decision, the Commission refused to agree to an industry proposal that gas could receive the new gas price merely because there was a "recompletion of an old well to a new level of depth." The Commission's decision in Opinion No. 770-A would in effect be reversed by the language of this section.

Section 402(b) states that "[t]he President shall have the authority to define, by rule, the terms used in this [definitional] part in a manner consistent with the purposes of this part". Since "this part" contains, among other things, the definitions of "Btu related price," "inflation adjustment," "new natural gas," "old natural gas," etc. this delegation of virtually unbridled authority to the President (which in turn will undoubtedly be delegated to the Secretary of Energy) in effect gives the Secretary authority to re-write the Act and to set rates at any level applicable to whatever vintage of gas he chooses. Perhaps more than any

other section of the proposed legislation, this empitomizes the "politicizing" of the ratemaking process.

The bill in Section 403, Section 404, Section 405, Section 406, Section 408, and Section 410 authorizes the President to establish "by rule" certain prices for old and new gas, and to take certain other actions with respect thereto. These provisions are in conflict with the present provisions of the Natural Gas Act authorizing the setting of prices only by decision of an independent regulatory commission, i.e., the Federal Power Commission. The provisions also appear to conflict with the provisions of the proposed Energy Organization Act, S. 826, which would transfer the functions of the Federal Power Commission to a new Department of Energy and allocate those functions at the discretion of the Secretary of Energy between an independent Board of Hearings and Appeals and the Administrator of the Economic Regulatory Administration. Nothing in the proposed Organization Act bill, S. 826, vests any jurisdiction in the President to determine natural gas rates. To the extent that regulatory functions to adjudicate gas rates are vested in the Board of Hearings and Appeals under the proposed Organization Act, it would clearly be inconsistent to seek to vest such powers in the President, as proposed in the "National Energy Act." The setting of rates for natural

gas, new or old, should not be determined by Presidential (or any other) rulemaking. APGA strongly believes that natural gas wellhead rates, as well as all the other ratemaking functions of the FPC, should be undertaken by an independent board in an evidentiary-type ajudicatory proceeding with the full right of cross-examination. To the extent that such an independent adjudicatory board is established within the Department of Energy, it should have jurisdiction to establish natural gas rates only after full evidentiary hearings. Ratemaking is an essentially adjudicatory process, and for the Secretary of Energy, or his delegate, to determine rates without full evidentiary hearings and absent the "just and reasonable" standard set forth in the Natural Gas Act would improperly convert the ratemaking process from its present quasi-judicial nature to a political function. The net result would be the loss of confidence of the American consumer in the rate-setting process.

Another section of the Act contains a definition of the requirements of an evidentiary hearing which should be applied to the setting of natural gas rates. Section 502 (a)(14) defines an "evidentiary hearing" as one

> "...which includes notice to, and an opportunity for, participants to present direct and rebuttal evidence and to cross-examine witnesses and which results in a written decision based upon evidence appearing in a written record of the proceeding, and ... which is subject to judicial review."

No less of a standard should apply to the crucial matter, from the consumer viewpoint, of setting wellhead rates.

Section 404 relating to the establishment of a maximum lawful price for sales of new natural gas provides that the President shall, by rule, establish such price based on "a price equal to the current Btu related price." The current Btu related price is defined as the average per barrel crude oil acquisition costs for refineries in the United States for the most recent quarter divided by a factor of 5.8. Section 404 thus completely abandons the existing "just and reasonable" regulatory standard of the Natural Gas Act as interpreted by the courts and substitutes in its place a standard whereby natural gas will be priced by reference to oil prices. Nowhere in the "National Energy Act" are there any standards for the pricing of oil. Thus, Section 404 would subject American consumers to continual escalating prices on new domestic supplies of gas based upon an undefined ceiling, which in turn could depend in large part upon the actions of the OPEC cartel. This is unacceptable to American consumers.

In the fact sheet from the White House preceding the "National Energy Act", it was estimated that the initial price of new natural gas would be set at $1.75 per Mcf at the wellhead. Such a price is greatly in excess of the highest price which the Federal Power Commission has prescribed for new gas in Opinion 770 of $1.42. The Federal Power Commission's $1.42 price is now under review by the United States Court of Appeals for the District of Columbia Circuit. The APGA and other consumer groups have sought to demonstrate there that

many of the components of the $1.42 price are excessive. Thus, to increase the price for new gas to $1.75 as proposed in Section 404, and to thereafter have it pegged to the price of oil subject to increase through action by the OPEC cartel, is completely unjustified.

Section 405 applies to the setting of a maximum price for sales of old gas under existing contracts. It provides that the maximum ceiling should be either the contract price or the price that was determined just and reasonable by the Commission and was in effect on April 20, 1977 "(without regard to any appeal of such determination pending on April 20, 1977)". This provision directly seeks to nullify the pending appeal of the Opinion 770 case before the United States Court of Appeals by CFA and a large of group of consumer interests. The case has been thoroughly briefed by all parties and oral argument was held before the Court on March 23-24, 1977. In view of the fact that the Court of Appeals has not rendered a decision on the matter at this time, it would be improper for the Congress to establish a rate for old gas set by the Commission currently under appeal. Furthermore, such action by Congress would circumvent the authority, if not the dignity, of the Court. The bald attempt to cut off the appeal rights of the large group of consumers seeking redress from the Commission's Opinion No. 770-A, in addition to being an unjustified

slap in the face of the judiciary branch of government, is inimical to the interests of the American public.

Section 406 authorizes the establishment of a maximum price for producers of old natural gas under a new contract. Section 406(b) provides that in the case of old natural gas which is committed to interstate commerce on April 20, 1977, or which is produced from a new well or a new lease, the maximum price shall not exceed $1.45 per Mcf. This provision would apply when a contract relating to such old gas expires and is renewed by a new contract. This provision would permit producers an even higher price for old gas than that which the Commission allowed in its recent Opinion No. 770-A. Under the terms of that opinion, when old gas contract expire, producers are entitled to certain higher prices. For example, Opinion No. 770-A provides that old gas priced under area rate regulation at 26¢ per Mcf since it was discovered and drilled prior to 1973) would be entitled to a rate of 52¢ per Mcf simply upon the expiration of the contract and the entering of a new contract between buyer and seller. This provision in Opinion No. 770-A has been attacked on appeal by a large group of consumer interests as improper because it, in effect, would allow the doubling of the price for gas despite the fact that the original price was cost-based and no additional costs of any magnitude were incurred by the producer, other than the

price of the ink required to sign a new contract. The "National Energy Act" provision would allow that old gas to escalate not to just 52¢, but to go to $1.45 per Mcf. This is directly contrary to even the Commission's liberal ruling in Opinion No. 770-A. This is presently estimated to have an annual impact of $1.3 billion, 1/ which monies will represent clear, windfall profits to the producers because they have not been required to incur any new costs, but will receive the additional monies simply through the happenstance of the expiration of their existing contracts. Under the present Natural Gas Act, Section 7(b), no producer may abandon any sale to interstate commerce merely because his contract expired. Thus there is no reason why such gas should not continue to be sold to the interstate users at prices already determined to be just and reasonable for such flowing gas since such prices will return to the producers all of their costs of whatever nature, plus a fair rate of return, and avoid the windfalls resulting from per se excessive rates called for by Section 406(b).

Section 406(c) provides that in the case of old natural gas which has not been dedicated to interstate commerce, it shall be entitled to the price for new natural gas, i.e. the conservatively estimated $1.75 resulting from the application of the standard of the "current Btu equivalent price" for oil. By establishing a higher price for gas that has been withheld

1/ Source: FPC Data

or not previously dedicated to the interstate market (i.e., $1.75) as distinct from gas from old contracts that had been previously committed or dedicated to interstate commerce (i.e., $1.45), the bill not only insures windfall profits for the sellers of this old, low cost gas but in addition, discriminates in favor of those producers who have willfully declined to supply gas to the interstate market. The estimated annual impact of this provision is $1 billion. 1/

Sections 406(b) and (c) also would apply to shut-in gas which, if previously committed to interstate commerce, would get $1.45 under Section 406(b) and, if uncommitted as of April 20, 1977, would get the "Btu equivalent" price of $1.75 under Section 406(c). (A dollar impact of this provision is being worked up but is not presently available.)

Section 408 of the bill would authorize special pricing provisions "if the President determines that such special price is necessary to provide incentives for the production of [high cost] natural gas ...." Under the present decisions by the United States Supreme Court relating to the setting of wellhead prices, provision is made whereby producers can seek to establish a special exception from an applicable wellhead rate where costs justify such an exception. These provisions

1/ Source: Bureau of Mines Data.

of the existing law are completely adequate, APGA believes, without the need to establish new special legislation in this regard. A further problem with Section 408, is that it lists situations in which special high rates might be set to include "in depths of more than 500 feet of water" and "more than 15,000 feet below the surface of the earth." These are completely inadequate criteria for determining whether or not a special price should be required. The facts indicate that some of the most prolific producing wells have resulted from depths of more than 500 feet of water or at depths of more than 15,000 feet below the surface of the earth. While the costs of these wells may be more, the average cost per Mcf (i.e. the unit cost) of the gas produced from these wells may very well be substantially below that of a shallow well. The key issue is the determination of the cost per Mcf produced. Factors such as depth of more than 500 feet of water or more than 15,000 feet below the surface of the earth are but one part of the equation, specifically the numerator, necessary to the determination of that key matter. APGA believes that "special pricing provisions" should apply only when producers can establish that the costs per Mcf produced is such that the revenues under existing prices will be insufficient to cover all costs, including a fair rate of return.

Section 408(c) requires the Federal Power Commission to increase any prices previously set by it to the extent permitted by the terms in the contract, to "cause an inflation adjustment in such prices...." The amount of the adjustment is defined in Section 402(a)(20). It appears unnecessary for Congress to enact any mandatory increases by means of an automatic inflation factor, when such an increase would not have been permitted under prior rulings of the Commission and there is no evidence of any relationship between the inflation factor and the cost of producing the flowing gas in question.

Section 409(a) provides that the new high prices directed by the Act "shall be deemed just and reasonable" and may not be disallowed by the Commission under the terms of Section 4 and 5 of the Natural Gas Act. The problem is that Sections 4 and 5 of the Natural Gas Act provide for "full hearings" to establish proper "just and reasonable" natural gas rates and contemplate the production of full evidence by the producers as a condition precedent to their obtaining rate increases. All of those procedures designed to protect consumers would be swept aside by the new Act in its direction that the new national gas rates will be established not on the basis of any evidence of costs or fair rate of return or other factors traditionally considered appropriate by the United States Supreme Court for wellhead regulation, but by the establishment of an essentially "political" wellhead rate, without the need for any proof or

evidence by the industry to justify the new rate levels. Similarly, Section 409(b) provides that the Commission may not deny a certificate of convenience and necessity under Section 7 of the Natural Gas Act on the basis of price "if such price is not in excess of the maximum lawful price" to be established under the Act. This provision also would set aside the long line of decisions by the United States Supreme Court which require the FPC in granting a certificate to determine whether or not the price that would be charged under the certificate as an initial price is in line with the "just and reasonable" standards of Section 4 and 5 of the Natural Gas Act.

Section 410(a) provides that "[a]ny rule promulgated by the President ... shall be enforceable to the same extent and in the same manner as a regulation, or rule, promulgated under the Emergency Petroleum Allocation Act of 1973." It is not clear why the Act refers to the enforcement provisions of Emergency Petroleum Allocation Act rather than the Natural Gas Act. Furthermore, nothing in Section 410 or any other provision describes procedures relating to judicial review of any new rate set by the President (or his delegate). It would appear that even under the ratemaking provision of the Act as proposed, the judicial review provisions of Section 19 of the Natural Gas Act should apply to any rate-setting actions, and any attempt to cut off or terminate the right of judicial review of rate-setting decisions by the President or the Department of Energy

or the Federal Power Commission, as the case may be, would not be in the public interest. The need is to have rates which result from and hence reflect the integrity of the adjudicatory process and thereby gain the deserved confidence of the American people. Rates established by partisan political processes, such as by rule issued by the President (or his delegate) without evidentiary hearings and without any right of judicial review, will be immediately recognized by the American people as arbitrary and untrustworthy. The result would be a breakdown in confidence in the processes of government. Since setting of rates takes property, i.e., money, from the pockets of inflation-weary consumers and transfers that money to the pockets of the gas-company producers, it is imperative that due process be accorded the consumer in a full, fair adjudicatory proceeding. This is not provided in the "National Energy Act" for natural gas rates or in the earlier Energy Organization Act, S. 826. 1/

Section 412(a) provides that "[t]he Commission may grant abandonment under Section 7(b) of the Natural Gas Act at any time prior to the committing or dedication of natural gas for interstate commerce." This appears to amend the present standard of Section 7(b) of the Natural Gas Act, which is an important safeguard for consumers served by interstate pipelines. Under existing Section 7(b) of the Natural Gas Act, gas dedicated to interstate commerce may not be abandoned without a hearing

1/ As noted above, however, §502(a)(14) of the National Energy Act provides for evidentiary hearings for the less important rate design proceedings under Part E.

and a showing by the producer that such abandonment is in the public interest and will not injure the interstate users. It would appear that Section 412(a) would radically change that standard for no apparent reason and in the face of overwhelming evidence that Section 7(b) has served to protect consumers from the abuse of monopoly power by producers and pipelines.

Section 414 relating to the "incremental pricing of natural gas" provides that any portion of the average cost of natural gas delivered after the enactment of the Act which exceeds the average cost of natural gas to the pipeline company during the most recent 12 calendar months ending before enactment of the Act shall be allocated in the rates and charges to low priority uses, i.e. all uses other than residential and small commercial. This provision appears to be designed for the beneficial purpose of requiring that the incremental high cost of the new gas supplies would be allocated to low-priority users, and not be shouldered by the high-priority residential and small commercial customers. While such a provision is beneficial to consumers, clearly the implementation of such a provision in the pipeline rates to its many distributor-customers will be a very complex and difficult task to accomplish. One provision in Section 414(a) apparently could wipe out the benefits to residential and small commercial users. It states that the incremental pricing formula to low-priority users will

not apply "if such allocation would result in rates or charges for such uses equal to an amount no greater than the reasonable price (as determined by the President) of substitute fuels." Substitute fuels could constitute any exotic fuel that might be available, such as imported LNG. In any event, the exception appears to be a loophole which could negate the entire incremental pricing scheme to the detriment of the heavily burdened residential and small commercial customers.

The provisions of Section 415 authorizing regulation under the Natural Gas Act of synthetic gas appear beneficial and in the public interest.

Section 416 would amend the "Emergency Natural Gas Act of 1977". The first group of amendments would make the allocation authority of the President in Section 4 of the Emergency Act applicable to any pipeline, whether that pipeline was an interstate or intrastate pipeline. While this is a beneficial change, it is not substantially different from Section 4 of the present Emergency Act, which permitted the President to order during a national emergency any intrastate pipeline to transport interstate gas. Accordingly, this change appears merely procedural, rather than of any real substance. A major omission from the amendments, as well as from the original Emergency Act, was to give the President the power to make an

allocation of gas during a national emergency from any "producer" as distinct from a pipeline. If producers have available supplies of natural gas, there would appear to be no reason why the President should not allocate those supplies of natural gas during a national emergency to prevent closings of factories or the cure (or assist) other emergency situations. The omission of allocation authority over producers is a major loophole in the Emergency Act and in the amendments proposed in Section 416 of the "National Energy Act."

Section 416(5) would amend Section 4(a)(1) of the Emergency Act by striking out "April 30, 1977" and inserting in lieu thereof "April 30, 1979." There would appear to be no adverse effect by extending the President's authority to allocate natural gas during an emergency for an additional two-year period.

While the amendments in Section 416 to the Emergency Natural Gas Act of 1977 do not so state, it appears that there is no amendment proposed to Section 6 of the Emergency Act. That section permitted the President to authorize any interstate pipeline or distribution company to purchase gas at rates during the emergency in excess of the ceiling rates established under the Natural Gas Act. It thus appears that Section 6, which authorizes such emergency sales only until August 1, 1977 will expire by its own terms. This is beneficial. Any attempt to extend the emergency authorization of Section 6 of the Emergency

Natural Gas Act of 1977 would be contrary to the best interests of American consumers. Experience has shown that if there is establishment of a procedural loophole whereby producers may obtain a rate in excess of established national rates, this inevitably results in little gas being sold at the established rate. For example, the procedures used by the Federal Power Commission in authorizing limited term sales, optional pricing procedures, and emergency sales, all at prices in excess of the established "just and reasonable" wellhead rate, resulted in virtually all quantities of natural gas that were sold to interstate consumers in recent years being priced under those loopholes provisions. The same would be true for any new ceiling rates established under the National Energy Act if a loophole existed whereby producers could obtain more than the ceiling. Accordingly, it is imperative that Section 6 of the Emergency Natural Gas Act of 1977 not be extended, and hence, APGA supports the President's decision to terminate this loophole provision in the 1977 Emergency Natural Gas Act.

PART E, TITLE I

Part E of the National Energy Act deals with "public utility regulatory policies." This section designates certain rate design principles that shall govern retail rates by electric and gas utilities.

At the outset, it is interesting that the Act requires an "evidentiary hearing" to protect a utility when it is required to comply with the rate design policies of the Act. An evidentiary hearing is defined in Section 502(a)(14) as follows:

> The term "evidentiary hearing" means (A) in the case of a State agency, a proceeding (i) which includes notice to, and an opportunity for, participants to present direct and rebuttal evidence and to cross-examine witnesses and which results in written decision based upon evidence appearing in a written record of the proceeding, and (ii) which is subject to judicial review; and (B) in the case of a Federal agency, a proceeding conducted in accordance with Section 556 of Title 5 of the United States Code.

It is indeed curious that the National Energy Act recognizes the need for "evidentiary hearings" in the establishment of rate design criteria, when the Act in part D specifically does not provide for such evidentiary hearings on the important question of setting natural gas rates applicable to American consumers. The impact on American consumers from the setting of well-head gas rates will far exceed any impact from rate design policies. Yet the due process safeguards of an evidentiary hearing are to be provided only in the case of rate design proceedings, not for the multi-billion dollar proceedings involving the setting of wellhead rates. Clearly due process and fairness to the American consumer requires that "evidentiary hearings" be applied equally in both situations.

Subpart 4 of Part E relates to natural gas rate design policies. A "gas utility" covers any person, federal agency or state agency which sells natural gas as defined in Section 541(a)(2). This clearly covers publicly-owned agencies. Section 542 relating to coverage provides that the requirements of the subpart apply only to sales of natural gas by a gas utility where the sales exceed 10 billion cubic feet of natural gas after 1975. The coverage in Section 542 applies equally to private and public gas systems alike. However, in Section 547(a) relating to "nonregulated utilities" which expressly covers public and cooperative gas distribution systems, it provides that "each non-regulated utility shall comply with the national policies specified in Section 543(sic) in making sales of gas subject to this subpart." Section 543 sets forth the natural gas rate design and regulatory policies. The Act thus is ambiguous as to whether or not municipal and cooperative systems, even though exempt under the coverage section, are subjected to the natural gas rate design and regulatory policies of Section 543. If this is correct, which we do not believe should be the interpretation, then small municipal and cooperative systems would be subject to national rate design policy, even though small private investor-owned systems of a similar size would be excluded under the coverage section of 542. This would be clearly discriminatory. We suggest that the language be clarified to make it clear that the coverage Section 542 governs Section 547(a) relating to public agencies.

Mr. OTTINGER. We thank you and we find your suggestions valuable. I do think this section of the bill requires substantial reworking. You have been very helpful.

We will recess for the vote on the House floor or until Mr. Sharp gets back.

[Brief recess]

Mr. SHARP [presiding]. The subcommittee will come to order.

We appreciate your indulgence. We will have these votes periodically this afternoon.

The Chair will recognize Mr. Madigan for five minutes for questions.

Mr. MADIGAN. Mr. Seymour, what is the wellhead price of gas being drilled by Consolidated sold to East Ohio Gas Company?

Mr. SEYMOUR. The wellhead price in Ohio is $1.70.

Mr. MADIGAN. Would your company continue to drill in Appalachia with the $1.75 ceiling?

Mr. SEYMOUR. I would like to qualify my answer because I don't want to mislead you. You must understand that our motivation is primarily getting the gas. We hope to be able to do that profitably so we can continue to do it. We are somewhat different than an independent producer whose primary motive may be profits rather than getting the gas to service customers as is ours.

A great percentage of the gas that is produced in Ohio is produced by the independent producer. I think probably with a ceiling on the price—and I am not quarreling so much with the number as I am with the concept of putting a ceiling on the price—my concern would be that the independent producer would be discouraged.

Mr. MADIGAN. There is in this statement of yours the conclusion that there is new gas being produced but it is not being produced by pipeline companies. In fact, production by pipeline companies, people who produce it for profit, is declining although gas production is increasing.

Mr. SEYMOUR. The Ohio Company is an intrastate company not under Federal jurisdiction and consequently not under Federal price regulation as to the price of gas at the wellhead.

Your statement is correct. In West Virginia the pipeline company is a Federal Power Commission regulated company and as such is subject to Federal Power Commission price regulation.

Mr. MADIGAN. Do you have an opinion as to the amount of untapped gas reserves in Ohio, Pennsylvania, and the Appalachian States?

Mr. SEYMOUR. Well, the estimates at the present time are in the 16 to 20 trillion cubic foot area for the entire Appalachia area.

Mr. MADIGAN. Would you say that the $1.75 price ceiling hampers the production of that gas?

Mr. SEYMOUR. Yes, any price ceiling will hamper the continued production.

Mr. MADIGAN. Mr. Davis, would you explain to me the difference between low Btu coal gasification versus high Btu coal gasification?

Mr. DAVIS. The low Btu gasification, and I am not an expert in this field, is a product normally that ends up at around 360 to 400 Btu per thousand cubic feet. The methanation process that goes on gets it up to the 990 to 1,000 Btu which we call pipeline quality gas

which is more economic to transport. The lower Btu coal gasification would have an application at an installation where it is being used. If you had to transport at great distance, the price would get higher due to transporting a lower quality product.

Mr. MADIGAN. Is the system for doing either the same in the initial stages but the high Btu involves an additional process?

Mr. DAVIS. Yes, sir.

Mr. MADIGAN. Is there a substantial difference in the cost between the two?

Mr. DAVIS. I don't have cost figures on low Btu, but we are estimating high Btu on present-day costs as something in the $4.50 to $5 range.

Mr. MADIGAN. You indicated, and I think some of the other witnesses did, too, that this is an area that the Carter program seems to overlook entirely and is an area I believe you indicated of great promise as far as your industry is concerned.

Both you and another witness referred to the need for proper incentives coming, I assume, from the Federal Government. Could you list those for me?

Mr. DAVIS. We need first the loan guarantees that would enable us to finance such an operation. We need the pricing provisions that would permit us to recover costs in the operation. Those are the main ingredients.

Now, Mr. Madigan, the cost numbers on low Btu coal gasification I can provide for the record at a later date if you would like.

Mr. MADIGAN. I have no other questions, Mr. Chairman. I will yield the balance of my time to the gentleman from Michigan.

Mr. OTTINGER. I am afraid that you don't have any balance. I believe that Mr. Stockman at any rate is the next questioner. So you are recognized on your own time.

Mr. STOCKMAN. Mr. Seder, I think you raised some very helpful points in terms of the ceiling factor on incremental pricing. You have pointed out the substitute fuel, the price will vary and, two, that if things are not calibrated correctly, you may get the reverse effect potentially of encouraging or forcing people to switch from gas to imported distillate or petroleum-based fuel. I think we ought to bear down on that better to get more elaboration.

As I understand the administration's plan, if you take into effect the fully implemented crude oil implementation tax, that will take the refiner's cost up to a higher level. Assuming that OPEC maintains prices only to account for inflation in the world up to 1985, on top of that you have up to a $3 excise tax on industrial and utility use or consumption of oil or distillate products.

So in addition to that, you would have refining costs and transportation costs, et cetera.

What I come to is that in 1985 a current price equivalent of about $20 a barrel for consumption use. That is about the equivalent of $3.50 a thousand cubic feet for gas.

Do you think that given your structure of industrial utility load and the composition of that in terms of people who can switch and can't, et cetera, do you think the incremental pricing requirements would lead to a price that you would have to charge low priority users that would take it to that level of $3.50? I don't think there

would be any perverse conversion to oil unless it was below $3.50 or somewhere in that range.

Mr. SEDER. Mr. Stockman, we have attempted to make precisely that kind of analysis.

Mr. STOCKMAN. Maybe you have different numbers. I did this on the top of my head.

Mr. SEDER. I think there are some differences, but we have tried to take the Carter plan just as we understand it would work and what we come to is the proposition that in our particular service area we would bump up against the ceiling.

Mr. STOCKMAN. What would you see the ceiling to be?

Mr. SEDER. We have a high case and a mid case for the price of No. 2 oil. In 1985 our high case is $6.62 per Mcf. The mid-range case is $6.24. So in both of those, in the case of the mid-range increased price of oil, we would have a problem with incremental price reaching that level.

Mr. STOCKMAN. You have the oil price up to $6. There must be some assumptions in there about where OPEC is going to take the price.

Mr. SEDER. Yes, we have price assumptions.

Mr. STOCKMAN. What is your oil equivalent when you take in refining costs and transportation costs?

Mr. SEDER. Our assumptions are that in 1985 the cost of No. 2 fuel oil will be $6.24.

Mr. STOCKMAN. In Mcf equivalent?

Mr. SEDER. Yes, that is right.

Mr. STOCKMAN. I am wondering how you got that. It seems awfuly high. Maybe you can submit that for the record.

Mr. SEDER. Yes. We will have assumptions on which our system bases its planning projections as to what the OPEC increase will be. They are in the neighborhood of 10 percent increases per year. We build on top of that the various taxes, equalization taxes, et cetera.

Mr. STOCKMAN. You are still assuming that even with that very high price that the incremental pricing requirements will force you to load so much cost on whatever residual utility and industrial customers you have at that point in time, 1985, that some of them would reach the point where they might have the incentive to switch to oil?

Mr. SEDER. Yes. We get to that point by virtue of the fact that in addition to new domestic natural gas, we are assuming that we would add coal gasification gas, Arctic gas and other supplemental supplies at considerably higher than the new gas price for domestic gas.

So we roll all of those into our prices in order to get what we would regard as the incremental price. Once we apply that against the oil price ceiling, why, we do have a problem.

Mr. STOCKMAN. The other point you mentioned, I think, is also important and that is that there cannot be any single substitutable fuel in fact because it is going to depend on the end use for the product involved. If it is for boiler or processed steam, you can easily use coal and if you take all the add-ons for pollution control and storage, you are going to have a price that is at a fairly medium range. If it is for heat treatment, you have to have flame control

temperature and so forth and you are going to have to use the vertical cooled gas which will be at a higher price than in the first case and when you go to feed stocks, you have a very high price.

Would you recommend the bill be changed or there be some elaboration on that definition so we can take into account the three very different categories of end use?

Mr. SEDER. I am not sure the legislation should be as specific as that, but in my prepared statement I suggested some additional language. I suggested basically that Congress should provide that the President should price the substitutable fuels at a price that would not require in effect the conversion to oil.

What that means is that whoever sets that price must look at the realities of the marketplace, the fact that the purchaser, large industries, can buy oil at discount prices. As you say, there are different end uses for it. We just feel that account must be taken of the fact that the purpose of the act is not to force the conversion from gas to oil and that that could be the result of the setting of the price at simply an average oil price.

In other words, one of the large industrial users doesn't buy oil at the average price. It buys it at substantially less that than.

Mr. STOCKMAN. Thank you.

Mr. OTTINGER. The time of the gentleman has expired.

One of the things that has troubled me about the whole conservation effort is that it seems that there is no real incentive in the present rate structure for gas companies to conserve. Gas companies are in the business of selling gas. The way the rate structure is put together to the extent that consumers actually go ahead and insulate and use less gas, they are going to be penalized for it. We had that experience with electricity in New York, where Consolidated Edison Company went on a big Save-A-Watt campaign. People conserved as asked, and they then had a special surcharge added on to their bills in order to permit Con Ed to cover the loss of sales.

I wonder if any of you had any ideas as to how rate structures might be altered so that it would be an advantage to gas companies to encourage conservation? Any of you might address that who would like.

Mr. BERINGSMITH. Yes, I have several thoughts, Mr. Chairman, in that area.

In California what we have done is moved toward rate flattening which has eliminated a great deal of the problem that you indicated that customers of Con Edison had in their Save-A-Watt campaign.

We still have the need to recover the fixed costs of service. They are very important. So some kind of provision has to be made for that.

For example, there might very well be a customer charge that recovers those costs up front and then a flat energy charge. Speaking as an economist, that would be the most economic way perhaps to do it.

In California we have Life Line in effect, of course, which is basically an inverted rate form. I am not recommending it because it has extreme administrative difficulties and a lot of inequities I think are associated with it.

But we also are exploring the issue of multi-tiered rates which would in essence have some sort of penalty for large users and they would be inverted.

However, before we move to that, we are concerned about what customer impacts might be. A number of studies, including one we conducted in our service areas, indicated that there were no correlation between low users and low income. We credited that to poor housing quality and more home oriented life style.

I think they would be penalized. I think there is a need to research those kind of changes in the rate structures before they are implemented and particularly before they are implemented nationally.

Mr. OTTINGER. If you can give us any help in that area, we would appreciate it. We are in a time bind again so I will have to recess for a short period of time.

Mr. DAVIS. There is another point and that is that we don't have the marketing problem as in the instances you described. When we have conservation we have a waiting list of customers to use that gas.

Mr. OTTINGER. That is another thing that gives me some trouble, that is, that the companies are continuing to hook up new customers at the same time that there is a real shortage. I would like to explore when we have the time to do it how we handle that problem.

Now I will have to recess until Mr. Sharp can return again.

[Brief recess.]

Mr. SHARP [presiding]. The subcommittee will come to order.

We will recognize counsel, Mr. Demarest, for questions.

Mr. DEMAREST. Thank you, Mr. Chairman.

Mr. Seymour, you have given us attachments to your testimony. I am not going to quarrel with the policy that they support, nor with the absolute value of the number. I am just trying to put them in perspective.

In 1975 we received testimony from the AGA regarding natural gas production under two scenarios. One was continued regulation and the other was deregulation. Yesterday we received advance copies of your testimony with the attachments that showed production forecasts under FPC Order 770-A and under deregulation.

Today we received your formal testimony. The testimony we received yesterday showed 19.1 Tcf of production in 1990. The testimony today shows 20.1 Tcf in 1990 under the same deregulation scenario. That is an additional 1 Tcf. There are similar disparities in the figures for 1985 and 1980 of approximately a half Tcf.

Where does the additional one half Tcf come from, and where does the additional 1 Tcf come from in 1990?

Mr. SEYMOUR. Are you referring to attachment 2 of the testimony?

Mr. DEMAREST. Attachment 4.

Mr. SEYMOUR. Which figure is that?

Mr. DEMAREST. 1990, total U.S. supply under deregulation.

Mr. SEYMOUR. 20.1.

Mr. DEMAREST. That differs from the testimony the subcommittee received yesterday. It shows 19.1.

Mr. SEYMOUR. I think we have submitted corrected attachments. You probably are working with an uncorrected one. 20.1 is the correct figure.

Mr. DEMAREST. What was the basis for the change? Was another computer run made overnight?

Mr. SEYMOUR. I think it was just an error if I am not mistaken. The 19.1 was just an error. It was not picked up until last night.

Mr. DEMAREST. And there were similar errors then throughout this whole table?

Mr. SEYMOUR. That could be.

Mr. DEMAREST. It is not a clerical error?

Mr. SEYMOUR. It is not a case of putting new data into the model.

Mr. DEMAREST. It is the case of picking up the wrong output.

Mr. SEYMOUR. Evidently. I am sorry I cannot answer your question.

Mr. DEMAREST. Could you provide for the record an explanation of where these numbers come from and why the numbers included in your revised testimony differ from those contained in your advance testimony and allegedly represent a more accurate appraisal.

Mr. SEYMOUR. We will do that.

Mr. DEMAREST. The reason for my inquiry is that your 1975 testimony before this subcomittee showed that under continued regulation natural gas production during 1976 would equal 17.2 Tcf and 18.0 Tcf under deregulation. Yet your testimony today shows that estimated production in 1976 under continued regulation in fact exceeded your deregulation scenario. Actual production was estimated to be 18.8 Tcf.

Could you have someone explain or reconcile those numbers for the record?

Mr. SEYMOUR. Yes, I will be happy to do that.

Mr. DEMAREST. Thank you very much.

[The following letter was received for the record:]

AGA American Gas Association

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William T. McCormick, Jr.
Vice President
Planning and Analysis

May 26, 1977

The Honorable John D. Dingell
Chairman, Energy and Power Subcommittee
Committee on Interstate and Foreign Commerce
U.S. House of Representatives
2221 Rayburn House Office Building
Washington, DC 20515

Dear Mr. Chairman:

This letter provides clarification for the Record in connection with Attachment 4 to testimony delivered to the Committee by Mr. Robert Seymour, Chairman of the American Gas Association, on May 18, 1977. This letter also explains differences in gas supply forecasts made by A.G.A. in 1975 as compared to current estimates.

Clarification of Attachment 4

During the question and answer period, Mr. Seymour was asked by Staff Counsel Mr. Demarest why Attachment 4 was exchanged the day before Mr. Seymour's appearance before the Committee with a new version, which was subsequently entered into the Record. I would like to take this opportunity to clarify the differences between the two versions of the attachment and to explain why A.G.A. chose to provide the Committee with the latter version.

The attachment in question summarizes the results of an analysis which compares the gas supply impact of President Carter's proposed $1.75/Mcf new gas ceiling price proposal with continued regulation under FPC Opinion 770A and with deregulation of new gas prices. The major conclusions from the analysis, which are summarized in Attachment 4, are:

1. That the President's proposed new gas price would actually be a disincentive to production in the next few years, compared with continued FPC regulation, but beyond the mid-1980s, the President's proposal would result in some additional production. The principal reason for this result is that new gas ceiling price represents a rollback of prices for many contracts in the intrastate market

which already exceed $1.75/Mcf. Therefore, the proposed new gas ceiling price would constitute a reduced incentive for development of onshore gas, most of which has been directed to the unregulated intrastate market.

2. Compared with deregulation of new natural gas, the President's ceiling price proposal would do little to increase gas production. Under deregulation, an additional 1.8 Tcf of gas could be produced by 1980, an additional 3.7 Tcf by 1985, and an additional 4.9 Tcf by 1990.

These analysis results reflected in both the preliminary and the final version of Attachment 4 that was submitted to the Committee, (even though there are small differences of a few tenths of a Tcf between the numbers), are equally valid. While the absolute value of the numbers in the preliminary version of Attachment 4 are generally uniformly lower (again by a few tenths of a Tcf) than the numbers in the final version of Attachment 4 submitted to the Subcommittee, the differences in projected gas production between the ceiling price case and deregulation are virtually identical in the two versions. The reasons for this are twofold:

1. The potential gas resource base assumed in the calculations displayed in the preliminary version of Attachment 4 is based on the newest figures released a few weeks ago by the Potential Gas Agency at the Denver Research Institute. These potential resource estimates represent a downward revision from the previously published resource base, i.e. 1146 Tcf versus 983 Tcf.

2. The results in the preliminary attachment also reflect the more pessimistic reserves picture, dominated by negative onshore revisions (-1.2 Tcf) and lower than expected new reserve additions, just published by the Committee on Natural Gas Reserves.

The calculations summarized in the preliminary version of Attachment 4 represent the first time that A.G.A. has attempted to factor into our calculations and projections these two latest reserve and resource re-estimates. Because of time limitations in preparing for testimony before your Committee, we felt that it would be imprudent to rely on these calculations when we had not yet had an adequate opportunity

to ensure their validity. For this reason, we chose to provide the Committee with estimates and calculations based on well established resource and reserves data bases. The attachment to Mr. Seymour's testimony delivered in advance of his appearance was included by error. It was never intended before or during his testimony that the Committee receive this preliminary information.

Finally, while there are small differences in the numbers reflected in the preliminary and final versions of Attachment 4, I again emphasize the major conclusions from the analysis are equally valid, regardless of which resource base or reserves estimates are used--namely, that there are significant and near-equal differences between deregulation, the Carter proposal, and FPC 770A.

Gas Production Estimates

I also understand that during the hearing, Mr. Demarest requested an explanation of the differences between A.G.A.'s 1975 and current estimates of gas production under a policy of new gas deregulation.

Our 1975 calculations presented to your Committee in January of 1976 were presented in terms of "net marketed production," whereas the figures presented to the Committee in Mr. Seymour's testimony this week were "net production." Net production exceeds net marketed production by approximately 2.0 Tcf, which is gas used in the field (either during production or gas liquids processing) in transmission, and which is otherwise lost.

Enclosure 1 compares the figures presented in Mr. Seymour's testimony (Attachment 4) with those contained in testimony delivered in January 1976 by Mr. Leonard W. Fish, Senior Vice President of A.G.A. For the deregulation case, the difference in A.G.A.'s gas supply projections presented to the Committee a year and a half ago and those estimated today are 0.6 Tcf in 1980 (20.2 minus 19.6) and 0.5 Tcf in 1985 (20.5 minus 20.0). These small differences generally result from the fact that deregulation has "slipped" over the past two years and thus our near-term estimates of resulting production are slightly lower. With respect to the continued regulation case, the reason the A.G.A. estimates presented in January 1976 are lower than our current

estimates is that "current regulation" in Mr. Fish's testimony last year referred to prices under FPC Opinion 699H, whereas today "current regulation" refers to the higher prices allowed under FPC Opinion 770A.

I appreciate the opportunity to clarify these matters for the Committee and I would request that this letter be made a part of the Record of the Committee's deliberations on these matters.

If you or any of your staff or other Committee members would like to discuss these matters in greater detail, I would be happy to meet with you at your convenience or alternatively appear before the Subcommittee.

Sincerely,

William T. McCormick, Jr.

WTM/nlc

Encs.

cc: R. E. Seymour
G. H. Lawrence
L. W. Fish

Attachment 4
(Version submitted to Subcommittee)

IMPACT OF CARTER PROPOSAL ON LOWER 48 STATE NATURAL GAS PRODUCTION

	Annual Production (Tcf)			
	1978	1980	1985	1990
Offshore				
FPC 770A	4.1	4.4	5.0	5.2
Carter Proposal	4.1	4.4	5.4	5.8
Deregulation	4.1	4.6	5.7	6.0
Onshore				
FPC 770A	14.8	13.7	11.1	9.4
Carter Proposal	14.6	13.4	10.9	9.4
Deregulation	15.3	15.0	14.3	14.0
Total U.S. Supply				
FPC 770A	18.8	18.1	16.1	14.6
Carter Proposal	18.7	17.8	16.3	15.2
Deregulation	19.4	19.6	20.0	20.1

Attachment 4
(Preliminary Version)

IMPACT OF CARTER PROPOSAL ON LOWER 48 STATE NATURAL GAS PRODUCTION

	Annual Production (Tcf)			
	1978	1980	1985	1990
Offshore				
FPC 770A	4.1	4.4	4.8	4.9
Carter Proposal	4.1	4.4	5.3	5.5
Deregulation	4.1	4.6	5.5	5.6
Onshore				
FPC 770A	14.6	13.5	10.8	8.8
Carter Proposal	14.4	13.2	10.5	8.7
Deregulation	14.8	14.5	13.9	13.4
Total U.S. Supply				
FPC 770A	18.7	17.9	15.6	13.7
Carter Proposal	18.5	17.6	15.8	14.2
Deregulation	18.9	19.1	19.5	19.1

Enclosure 1

COMPARISON OF A.G.A. GAS PRODUCTION ESTIMATES 1975-1977

	1976	1978	1980	1985
Figures Presented in January 1976				
Continued Regulation (699H)				
Net Marketed Production	17.2	--	15.5	12.5
Net Production	19.2	--	17.5	14.5
Deregulation*				
Net Marketed Production	18.0	--	18.2	18.5
Net Production	20.0	--	20.2	20.5
Figures Presented in May 1977 (Net Production)				
Continued Regulation (770A)	--	18.8	18.1	16.1
Deregulation*	--	19.4	19.6	20.0

*$2.00/Mcf new gas price case - 1975 dollars.

Mr. DEMAREST. One of the questions that the committee will have before it will be related problem of incremental pricing and natural gas utility rate reform. It seems that the natural gas utility reforms proposed in the President's legislation are essentially a borrowing from the electric utility rate reform proposals, striking out electric wherever it appears and putting in natural gas.

First, does that approach make any sense and, secondly, are the concepts of incremental pricing and the regulatory reform proposals suggested in part E inconsistent with one another? Would each member of the panel please respond?

Mr. BERINGSMITH. I will take the first stab at answering that question.

I do have a problem when we try to take the kinds of rate reform that are being introduced into electric rate design and apply them to natural gas. They are two obviously different situations. You don't have the same kind of time differentiated cost of production associated with natural gas production that you do with electricity.

I think that because of that difference it is perfectly all right to consider and probably to implement, and we have in California, the time differentiated electric rates. But you don't have the same kind of justification for gas rates.

On the gas side a number of things have been done, of course, to achieve peak shaving, et cetera, such as storage. We have substantial storage, and the use of interruptible rates. But I have reservations with the attempt to use marginal or incremental pricing similar to what you use on the electric side for the gas utilities.

Mr. SEDER. I think I can give you a specific example of the problem.

The program provides among other things that block pricing will be eliminated. We ran a study in the City of Detroit by various zones of the city on customers' usage for residential and space heating of gas and found out that in the poorest districts of the inner city the gas consumption per residence was considerably higher. I think that was suggested earlier.

The reason is that they are old houses, poorly insulated. They don't have storm windows. There are children going in and out the door and things of that kind. So if you eliminate block billing, you really penalize the people who can afford increases the least.

So I am suggesting that any blanket, federally mandated proposal for utility ratemaking is a mistake. I think the State utility commissions have been in this business for many, many years. I think that they have the same motivations of conservation and saving of energy as the Federal Government does. I think they are a lot closer to the consumer and better able to tailor specific ratemaking to the exigencies of the situation.

Mr. SHARP. The Chair will recognize the gentleman from Ohio, Mr. Brown, for five minutes.

Mr. BROWN. Mr. Seder, could you give us some idea of what your gas acquisition costs were during the last heating season, or the quarter, either way?

Mr. SEDER. Yes, Mr. Brown. Our pipeline system, its average purchase price of gas was 85 cents per thousand cubic feet. That is from its various sources of supply.

Mr. BROWN. What is the range in that?

Mr. SEDER. Well, I can give you the figures. For the quarter, the cost of gas purchased from independent producers was 62 cents. From domestic pipeline suppliers it was $1.09. Our Canadian gas supplies were $2.11 and our emergency purchases of intrastate gas were $2.04. That mix resulted in the 85 cents average. We set objectives for purchased gas costs which we tried to achieve. In this instance, our objective was to achieve an average of 79¢, which we were unable to do, but we certainly attempt to buy gas at the lowest cost.

Mr. BROWN. Do you buy your gas where you find it or do you shop around or do you have any constraints on you in terms of the price you are able and willing to pay for gas?

Mr. SEDER. Well, as a practical matter, our ability to buy gas is constrained by the availability of the supply and by economic factors. We have been virtually unable to buy gas onshore for five or six years except emergency purchases. We have obtained most of our long-term supplies in the last five years from offshore sources.

Mr. BROWN. What does that mean, offshore sources?

Mr. SEDER. The Gulf of Mexico. We are buying the Canadian gas under long-term contracts.

Mr. BROWN. What percentage of your consumption is Canadian gas?

Mr. SEDER. Sixteen percent.

Mr. BROWN. Is it going up?

Mr. SEDER. No. It has stayed there. The Canadians are not exporting any additional supplies.

Mr. BROWN. But they are meeting their contracts?

Mr. SEDER. Yes, sir, they are.

Mr. BROWN. Do they intend to continue to do that?

Mr. SEDER. I think it depends on whether the Arctic gas project is approved or not. If it is, I think we have a good chance of maintaining existing exports from Canada. If that McKenzie Delta reserve is not made available, I am sure in the early eighties the export from Canada will be eliminated or reduced.

Mr. BROWN. Do you have any estimate of what that will cost when it comes in?

Mr. SEDER. The Arctic gas?

Mr. BROWN. Yes.

Mr. SEDER. It is about $1.60 transportation costs in 1975 dollars and it will probably be $1 more than that by the time the pipeline is completed. You have to add the wellhead price onto that.

Mr. BROWN. What does that come to.

Mr. SEDER. $2.70 cents plus the wellhead prices at the time. You are up to $3.50 or $4.50 price range in 1982 or 1984.

Mr. BROWN. I have heard testimony about the monopoly situation which all you gas distributors enjoy. It doesn't make any difference what you charge for gas, does it?

Mr. SEDER. It certainly does. We get the best price we possibly can.

Mr. BROWN. Why bother?

Mr. SEDER. There are a lot of reasons. We operate a distribution system as well as a pipeline system. We are having a very, very

hard time obtaining the rate increases that we are technically entitled to and we are having even a harder time collecting the bills once we get the increases, so we have to keep those costs down.

Mr. BROWN. But you don't have any competition?

Mr. SEDER. Yes, oil and coal.

Mr. BROWN. Is somebody really going to convert from gas heating to oil heating?

Mr. SEDER. I am talking about industrial loads particularly in that regard.

Mr. BROWN. What is your synthetic fuel price in Michigan?

Mr. SEDER. We have no synthetic fuel on our system yet.

Mr. BROWN. Is there a synthetic fuel possibility there?

Mr. DAVIS. The SNG price in Chicago is $3.75.

Mr. BROWN. Is that a constraint on gas prices at all?

Mr. DAVIS. It is a rolled-in price.

Mr. BROWN. It is coming into the natural gas distribution system?

Mr. DAVIS. Yes, sir. It has not been a constraint to this date, but we are getting closer. Fuel oil is our competition for industrial use.

Mr. SEDER. We are already losing markets to coal. As I have suggested earlier, with the increasing prices of gas and the fact that the State commissions are putting most of that increase on industrial loads, we foresee the period when we will be bumping up against fuel oil as a competitive factor.

Mr. BROWN. Do you have any opportunity for gasified coal?

Mr. SEDER. Yes, sir.

Mr. BROWN. Are you using it at all?

Mr. SEDER. We and the Peoples system are trying our best to mount a project to provide coal gasification into our system.

Mr. BROWN. And the cost of that?

Mr. SEDER. $3.50 per Mcf in 1976 dollars.

Mr. BROWN. But is that $3.25 or #3.50, then, providing a real restraint on the price of natural gas that might be appropriated in Michigan? Are you going to be able to produce enough gasified coal or enough synthetic product to restrain your purchase of natural gas?

Mr. SEDER. No, we need all the natural gas we can possibly get plus the synthetic gas.

Mr. BROWN. The question is whether there would be a price constraint.

Mr. SEDER. Well, I think, Congressman, as you get out into the early eighties, when you roll in the supplemental higher costs and higher cost natural gas, we are going to be in a situation where competition with oil is going to be a real factor in our marketing.

So the answer is yes, there are and will be price constraints on what we can pay.

Mr. SHARP. The time of the gentleman has expired.

The gentleman from Texas is recognized for five minutes, Mr. Krueger.

Mr. KRUEGER. Thank you, Mr. Chairman,

I would first like to ask Mr. Seymour, one of the things that we have had suggested to us during the course of these hearings is that the capital costs of constructing synthetic gas facilities should be put into the rate base. I know that there are—we have already heard a variety of opinions on this.

The arguments for, I suppose, would be that without it such synthetic gas facilities might not be done. The argument against that I have heard is that if we put in those very high capital construction costs into the rate base, we then are asking consumers to have guaranteed for them supplies of synthetic gas, but supplies that we would expect to come on at the neighborhood of $4 or so per Mcf and it would seem to be to the financial advantage of the pipelines to have that in the rate base because their returns would be increased since their return is a percentage of their investment.

On the other hand, that synthetic gas might very well be more expensive than any natural gas that we can find in the ground itself.

I am wondering what your response would be to that and whether you feel that I have, at any rate, posed the alternative positions fairly and what your attitude is overall.

Mr. SEYMOUR. If I understand your question, Mr. Krueger, I am not sure that the option has been fairly stated. It is not a matter of comparing or competing with the traditional or conventional supplies of natural gas when we talk about developing a new synthetic gas plant from coal. What we are trying to do is to furnish sufficient energy to meet the total energy requirements of the Nation, and that competition may not be from the natural gas, it may be from coal-generated electricity or some other fuel.

I will not propose to tell you that we will now or even in the future develop a coal gasification program that would compete on a dollar basis with our conventional, domestic natural gas supplies.

I hope that has been responsive to your question.

Mr. KRUEGER. Well, it has. I guess what troubles me is that here we have natural gas being delivered in the interstate market at an average of 60 cents per million Btu, and we are talking about synthetic gas at $4 per million Btu. It is a factor of 7-to-1. Those of us—you and I would probably agree that by removing the price controls on the wellhead we could probably bring on additional natural gas supplies and bring on those additional natural gas supplies at prices substantially below $4 per million Btu.

It is that area that is somewhat difficult for some of us.

Mr. SEYMOUR. Of course, you cannot either develop or buy any gas today for 60 cents. That is an average price.

Mr. KRUEGER. That is an average price, but if we look at the current intrastate prices in Texas, which are about $2, perhaps slightly less, that is still a very long way from $4 to $6. It is therefore, I think, cause for some concern to talk about very heavy investment, bringing on rather small supplies at high cost, before we know what price the market would set for deregulated natural gas.

Mr. SEYMOUR. Well, that is why I tried to pose the other option.

For example, in those areas where there is no natural gas available for new services, the option may be for electricity.

Mr. KRUEGER. Electricity generally runs what, about $8 per million Btu?

Mr. SEYMOUR. Closer to $10.

Mr. KRUEGER. $10 per million Btu?

Mr. SEYMOUR. And for heating purposes it may be as much as four times as much as natural gas. I think those are, in my opinion, the proper options to compare with, not to compare with our domestic natural gas because we just do not have enough of it to meet all of our potential energy requirements.

Mr. KRUEGER. Would you then be inclined to suppose, as a final question, that it might be better to put our money into research for in situ coal gasification, for example, in order to get the major energy results from that point rather than to put it into SNG facilities, which would put that SNG into the regular pipelines?

Mr. SEYMOUR. I am sorry to take up your extra time, but I am not sure I understood the question.

Mr. KRUEGER. Perhaps I am misunderstanding.

Mr. SHARP. Your time has expired.

I will recognize Mr. Gammage for five minutes.

Mr. GAMMAGE. Mr. Chairman, I yield my time to my colleague from Texas, Mr. Kreuger.

Mr. KREUGER. Thank you.

Mr. Seymour, it is my understanding that through in situ coal gasification, what we can do is to get the major source at initial use of the power at that point and then have it transmitted, for example, through electricity, rather than simply putting the gas that results from in situ coal gasification into the pipelines.

I am wondering whether that might not prove to be a more viable option than the SNG facilities, with the gas at $4.

Mr. SEYMOUR. No, we do not think so.

It can be demonstrated both from the standpoint of economics, from the standpoint of efficiency of conversion of raw energy, from the standpoint of the environmental impact, from the use of water and from air pollution, that the coal gasification would be the best route to go. This is not to say that we propose to discontinue the generation of electricity from coal, I do not propose that at all, but I think that in picking up our additional energy requirements that it is a better investment to put your chips on the coal gasification than it is additional electric generation from coal.

Mr. KRUEGER. If we did not have the blended pricing system that we have, the rolled-in system at which we hit averages of 60 cents because prices range from 5 cents to $1.42 or whatever, do you think there would be much of a market just for synthetic gas at $4?

Mr. SEYMOUR. Well, it would be difficult to sell gas, getting back to the incremental price issue again. It would be difficult to sell it on an incremental price basis. It would be difficult to justify financing for such a project because of the difficulty in the market area.

Mr. KRUEGER. I wonder whether I might hear from any of the other members of this panel on this question just of synthetic gas and any comments you might wish to make in whatever time I have remaining.

Mr. SEDER. Mr. Krueger, there are two points I would like to make.

In the first place, the $4 to $6 price you are talking about is for coal gasification plant going onstream in 1982, so I do not think that comparison is between $2 for natural gas and $4 to $6 for synthetic

gas but rather, between whatever the price of natural gas is in 1982 and the $4 to $6 price of gas made from coal.

In the second place, coal gasification gas has a unique property about it, that once that gas plant is built, because so much of the cost of the product represents simply the capital cost of the plant, our studies indicate that that cost may well be constant or even declining for the 25- to 30-year life of the plant. So that by the nineties, late eighties and certainly by the year 2000, that gasification gas will be the cheapest fuel around, much cheaper than natural gas, much cheaper than oil or anything else. So that you have a problem of the initial price of the tax produced from coal, I grant you that.

That is one reason incremental pricing makes it very difficult to build and finance such a plant, but once it is in being, which can be done by rolling in, that can become a very efficient, cheap source of gas and one that the domestic customers are going to need before we are through.

Mr. KRUEGER. What you are saying is that although the cost is really quite immense for the initial capital investment on construction, that you think that the coal itself will have so small an increase in cost and that the basic operation of the plant will be so economical that, within a decade or thereabouts, SNG might very well become a relatively low-priced fuel at $4 or $5.

Mr. SEDER. Exactly, Mr. Krueger; that the increases in the price of coal and the increases in maintenance costs would be offset in whole or in very large part by the decline in rate base resulting from depreciation.

Mr. KRUEGER. I see. Perhaps I could hear, before my time runs out, from some of the other members of the panel.

Mr. BERINGSMITH. I agree with Mr. Seder.

You asked one other question, whether or not there would be a market for that gas.

Mr. Seder indicated in real terms, because the capital investment is so large in the SNG facility and the variable cost for the coal input is very small by comparison, that you are going to have perhaps a declining real price.

Now what is going to be the determinant of whether or not there is a market for that is obviously what is the cost of alternative fuels. Clearly I think the numbers that we have heard and that I am familiar with for the SNG facilities on line in the mid-80s are going to be very competitive with the cost of the alternative fuel, i.e., oil. So I think there will be a market.

Mr. SHARP. The time of the gentleman has expired.

Mr. KRUEGER. I wonder if I could get the comments just from the other two members of the panel for the record, and I would not ask any further time.

Mr. SHARP. We will do that.

If you will do that quickly, we will have to recess for the vote and come back for Mr. Moore's line of questioning.

Mr. DAVIS. Mr. Seder and Mr. Seymour covered the subject very well. I think maybe a small amount of emphasis on one thing, that is the reserve itself.

In the synthetic plants, particularly coal gasification, you can identify 30 years of reserve for a plant like this. It is a very important base of supply for a major system; it provides flexibility in developing the more uncertain reserves that must be found from natural resources.

Mr. KRUEGER. Mr. Wheatley.

Mr. WHEATLEY. I am inclined to think there should be a very close analysis of these very expensive coal gasification projects, if in fact the same supplies can be obtained from our natural gas supplies. I think this is the basis for maintaining cost base regulation, to determine what it does cost to produce our natural gas supplies. But since the present average cost is only 60 cents for the interstate natural gas supplies, it would not seem to be reasonable to go to some incremental supply of $4, if we can maintain natural gas supplies and on a cost-plus fair return basis which would be cheaper to the American consumer in the long run. So I think it is a very serious problem.

Mr. KRUEGER. Thank you, Mr. Chairman.

Mr. SHARP. Thank you.

Gentlemen, after consultation up here, we have decided we will forgo further questions. If you do not mind, we will ask for additional information from you in writing.

We appreciate your appearance and your testimony.

We will recess and probably take the next panel at about 5 before 4 p.m., we hope.

[Brief recess.]

Mr. KRUEGER [presiding]. The subcommittee will come to order.

At this time we have before us with pleasure the Public Utility Commission Panel, with Mr. Robert Batinovich, President of the California Public Utilities Commission, and Mr. C. Luther Heckman, Chairman of the Ohio Public Utilities Commission.

Gentlemen, if each of you would identify yourself for the record to the transcriber, we would appreciate your doing that. Following that, we would ask you for your testimony, which you can offer either by reading the full testimony or else, if you prefer, by summarizing it, and then we will pose questions to you and you can summarize it orally.

Without objection, your complete statement will be included in the record.

STATEMENTS OF ROBERT BATINOVICH, PRESIDENT, CALIFORNIA PUBLIC UTILITIES COMMISSION, AND C. LUTHER HECKMAN, CHAIRMAN, OHIO PUBLIC UTILITIES COMMISSION, REPRESENTING THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

Mr. BATINOVICH. I am Robert Batinovich of the California Public Utilities Commission.

Mr. HECKMAN. I am Luther Heckman, Chairman of the Ohio Public Utilities Commission.

Mr. KRUEGER. Mr. Batinovich, would you care to begin?

STATEMENT OF ROBERT BATINOVICH

Mr. BATINOVICH. Thank you.

The California Public Utlities Commission (CPUC) supports the goal of the National Energy Act to create a national energy plan.

The CPUC continues to advocate parity between interstate and intrastate gas prices. The prices for "new" and "old" natural gas should not be established at levels which will give producers excess profits without any significant increases in gas supplies. That is our major concern.

California intrastate gas has gone up fivefold in the last five years and we have had a decrease in reserves of 2.6 percent. This has occurred without regulation.

The CPUC also supports the efforts to restructure rates. In this respect we feel we have been in the forefront of innovative methods to restructure rates so as to enhance conservation. Northern California has not had any declining blocks for over a year. We have lifeline rates, multi-tier inverted rate structures for residential customers, and discourage master-metering for gas and electricity.

We believe in higher prices for the interruptible customers. We think it is a value of service rather than cost of service. Within our State when we talk about incremental pricing, I would point out that Los Angeles can certainly pay a lot more for natural gas than Northern California just primarily because of the air pollution problems.

The oil equivalent price may be $16 for .025 percent sulfur oil, which is what the air pollution restrictions require for electric generation in Los Angeles. Obviously, natural gas then has a Btu equivalent value of a much higher price, compared to when we use .5 percent sulfur oil.

I would also say converting off of gas to .025 sulfur means that low sulfur oil is also scarce and more expensive. In the way that our rate design will reflect that expense you might say we have a form of incremental pricing.

We think the Federal Government should give the State regulatory commissions a reasonable period of time to establish rate reform for their respective jurisdictions.

California would be unduly burdened by the presently structured burner tip tax set forth in the National Energy Act.

In discussions with the administration it seems there is a possibility California might get somewhat of an extension because of transportation problems for coal and some additional technology. However, we would wholeheartedly concur that we should consider switching.

I guess the major concern I would like to talk about for just a brief second is, I was surprised to read in the paper when I arrived last night that some Members of Congress say there does not appear to be a sense of urgency in the matter of an energy plan.

I would propose and suggest that consumers, environmentalists, labor, community producers, shareholders, producers, utilities, even regulators have been working in a vacuum for a very long time. Those people feel there is an urgency. If there is no urgency but

only an urgent need for a plan—if you want to be so optimistic as to assume there is not a need—then we need a plan.

I would urge on bahalf of California that you accept, reject, modify or amend, but enact an energy policy now because everyone is left at a time when they really do not know in which dirction they should be going or should they even be moving at all. I think once that cloud has been moved and a plan enacted, it will not be perfect, but we support the goals in the plan as outlined by the administration before you today.

Thank you.

[Mr. Batinovich's prepared statement follows:]

TESTIMONY OF ROBERT BATINOVICH, PRESIDENT,
CALIFORNIA PUBLIC UTILITIES COMMISSION

BEFORE THE SUBCOMMITTEE ON ENERGY AND POWER,
SUBCOMMITTEE ON INTERSTATE AND FOREIGN
COMMERCE, U.S. HOUSE OF REPRESENTATIVES

May 18, 1977

My name is Robert Batinovich, and I am President of the California Public Utilities Commission. I would like to thank you for inviting me here today to comment upon the President's proposed National Energy Act.

At the outset, I wish to express my overall support for the goal of the "National Energy Act," namely, its attempt to create a national energy policy. My comments are intended to be constructive attempts to point out certain problem areas in the bill relating to natural gas pricing and rate structures. In response to the request of staff counsel, I will direct my comments to Parts D and E of Title I, regarding natural gas pricing and gas rate structures, and to Part E of Title II, the so-called "burner tip tax", as it relates to the first two proposals.

I would like to begin with the natural gas pricing proposal. The California Public Utilities Commission is on record advocating that parity should be achieved between interstate and intrastate gas prices, and that the extension of federal regulation to intrastate gas prices is preferable to complete natural gas price deregulation. It is not clear, however, that the language in this

legislation is designed to bring about such parity. In particular, Sections 408(d) and 412(a) are unclear in this respect.

The Commission is concerned about the increase in gas prices to equivalence with the price of oil. A key factor here is the groundrules that the President will set for future price increases, and this is left open-ended. There is considerable likelihood of excess profits for producers without significant increases in supply. Major price increases for old gas under new contracts can lead to prices that far exceed costs. Furthermore, some pipeline companies are now producing gas that was developed using funds advanced by ratepayers in exchange for deliveries priced at the cost of service. Price increases proposed here could result in customers paying at least twice for the same gas.

In addition, it is not at all obvious that price increases will lead to substantial increases in supply from at least the traditional producing regions supplying California. Gas prices have quadrupled in California in the last four years with no increase in supply. The total new gas in the Permian Basin has been declining annually, despite the presence and the willingness of the intrastate market to pay a very high price for any available gas. The large number of inter- and intrastate pipeline companies currently involved in the Hugoton-Anadarko basin lead us to believe that there will be plenty of takers for whatever new gas is discovered there.

I have been specifically asked to address the issue of incremental pricing as raised in Part D of Title I. This proposal would raise rates to "low priority" customers, until the price they pay for gas equals "the reasonable price of substitute fuels", as determined by the President.

We in California have several concerns here.

First, we feel that the definition of high priority users is too limited. It does not include feedstock users, hospitals, schools, or process industries with special needs. Thus, the definition presented here is much more restrictive than the presently effective definition, under which significant investments in gas-using equipment have been made.

Second, let me state that in California we have already revised our rate structures so that low priority users pay flat commodity rates that are higher than our lifeline residential rate (I will discuss these rate structure reforms in greater detail later). The average price paid in northern California for non-lifeline use is presently $2.14/MMBtu. As rate increases continue to be approved over time, we expect that rates will rapidly approach the price of oil for high volume users and could possibly reach such a price before the provisions of this Act are implemented.

Third, an explicit definition of "substitute fuels" is needed. If the substitute fuel is coal, at $1-2/MMBtu, then northern California rates, at $2.14/MMBtu for non-lifeline use, already exceed that price. If oil is the substitute fuel for California,

because of air quality constraints, then commercial and industrial rates in California will be higher than for large customers in other states, destroying the President's stated intent of not creating rate differentials that place states at a relative economic disadvantage.

Fourth, it is clear that the intent here is to induce low priority users to switch to alternate fuels, as well as to protect high priority users from the full brunt of the price increases called for elsewhere in Part D. The California Public Utilities Commission does not believe that requiring all low priority use, as defined in the Act, to convert to alternate fuels is in the highest public interest for the following reasons:

1) Supplies from traditional sources and supplemental gas supplies will allow some low priority demand to be met for many years;

2) Further underutilization of the gas distribution system will result in greatly increased costs for high priority customers;

3) Low priority users provide a "cushion" for high priority users in the case of temporary emergency curtailments;

4) In areas such as California, the combination of air quality constraints, lack of oil or coal distribution systems, and lack of room or ability to build storage facilities for alternate fuels in downtown areas make conversion particularly difficult. Furthermore, where air quality concerns leave low sulfur oil as the only viable

alternative to gas, low priority users would be forced to convert to a fuel whose supply is no more certain than gas.

With respect to emergency gas deliveries, also discussed in this section of the bill, the Commission believes that the provisions for allocating gas under emergency conditions should include a strong presumption of repayment in kind, or, as a last resort, repayment at the highest incremental replacement cost to the supplying utility.

Let me now turn to the issue of gas rate structure as dealt with in Part E of Title I. The California Public Utilities Commission has been engaged in conservation-oriented rate-making for several years and is supportive of the Administration's interest in this very important area. Finding that supply circumstances no longer warranted a declining commodity charge based on consumption, the Commission determined several years ago that the highest rates should be paid by the lowest priority users. The Commission, in the interest of protecting the residential user and encouraging conservation, also implemented lifeline rates to cover the minimum needs of the average residential customer. These rates vary seasonally to reflect heating requirements. As a result of these policies, recent rate increases have led to the flattening of commercial and industrial rates at prices higher than the lifeline rate and inverted rates for residential customers. The Commission

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is now working on the implementation of a multi-tier inverted rate structure for residential customers. The Commission has also been working on tariff provisions to discourage mastermetering for gas and electricity, and to encourage individual metering to enhance conservation.

Although the Commission is sympathetic with the intent of Part E, we have considerable concern over the provisions for implementation of these rate reforms. We feel that the states are best able to, and should be permitted to, continue to formulate and implement ratemaking policies that take into account local conditions and problems. We are concerned about the fact that the mechanism proposed here would:

1) Grant the Administrator of FEA broad powers to determine rate structures without any mechanism for consideration of regional or State differences,

2) Allow the Administrator to determine the acceptability of a state's implementation efforts with no formal mechanism for states to participate in the development of the guidelines or to object to or appeal an Administrator's decision.

3) Bypass, in certain instances, the authority of state regulatory agencies by requiring reporting and implementation directly from the utilities as well as the state agencies.

4) Provide for the absolute preemption of state rate-making authority should the Administrator not find that state or utility implementation efforts are acceptable.

All of the above provisions obviate the authority of state regulatory authorities to engage in their traditional job of ratemaking, with no real provision for procedures that allow for due process to the parties involved.

I would add a note here that if the Administrator assumes ratemaking authority for a substantial number of utilities, thereby preventing him from acting in a timely fashion to resolve the complex issues relating to ratemaking, and if as a result, utility rate increases, subject to refund, are permitted pending resolution, we may have another FPC-type situation where consumers' rates go up dramatically, but utilities still cannot raise capital because their increases may some day have to be refunded.

Lastly, I would like to make a few comments on the burner-tip tax, because it relates directly to the parts of the President's proposal that are being discussed here today.

The purpose of this tax is to shift large gas and oil users to coal. Unfortunately, with current pollution control technology one cannot burn coal in most of California--our air quality is deteriorating from burning oil. Furthermore, where it may be possible to burn coal there is no infrastructure to supply it. Thus California will have to pay more and more to keep its industry and business going.

For example, glass products, fruit and vegetable drying, pharmaceutical grade chemicals, and certain processes in the heavy metals industry do not have a non-petroleum fuel option and would be heavily taxed under the provisions of Sec. 4991(b).

We have schools and hospitals in California that use over the minimum for this tax. I think we can conclude that if the President really intends to maintain air quality standards (and we agree that he should) while implementing his energy program, states like California will suffer real economic hardship in the coming years, unless the proposals are appropriately modified.

I thank you for giving me an opportunity to present the views of the California Public Utilities Commission with respect to Parts D and E of Title I and Part E of Title II of the "National Energy Act".

Mr. KRUEGER. Thank you very much.

STATEMENT OF C. LUTHER HECKMAN

Mr. HECKMAN. Mr. Chairman, I have some written testimony; of course I would like it all submitted as a part of the record. I will summarize it.

From my perspective the most important part of the bill before us is in its title, where it says clearly we need a national energy policy. I think that is a recognition that State regulators have had and continue to have and I would indicate that my testimony is being made here today at the invitation of NARUC. While most of my statement is purely a reflection of the Ohio experience and not the result of a NARUC consensus position, some of my remarks I believe should be construed as reflecting the general States' attitudes concerning Federal regulation.

Ohio, to summarize my testimony, has had some severe natural gas curtailment. We are a large user of natural gas, 1.2 trillion cubic feet a year. We are well aware of what it means to have a shortfall of natural gas and have consequently been most interested in anything respecting natural gas that has been done at the Federal level.

The Ohio Commission has generally felt the brunt of the considerable energy shortage that we have had in Ohio with respect to natural gas. Accordingly, we have come up with several programs to try to stimulate production of natural gas in our own State.

One of those programs is a program that we like to call a self-help program which is designed so that curtailed customers can go out,

find independent drillers to drill gas in Ohio, move that gas to the customer; the customer actually owns the gas. Then we found that if he has been curtailed that we can get capital formation that way and we can get some of our marginal gas that is there in Ohio drilled where the gas companies really have not been going after it.

Parenthetically, I might add that the greatest road block that we have found to our self-help system has been generally the threat of Federal governmental interference.

In examining the whole question of where would it go, we believe that the present bill before you picks the wrong direction, particularly with respect to the pricing of natural gas. We do not think that the proposed wellhead ceiling price of roughly $1.75 provides enough incentive to get gas drilled. We think Congress can go in two directions to eliminate the price disparity.

One they could take is to deregulate, unregulate interstate production of natural gas, and the other is regulate intrastate gas. We believe this bill selects the wrong direction.

We also in Ohio believe that one of the worst features of the bill would be establishment of a new Federal bureaucracy that would be of rather complex nature; that that Federal bureaucracy, pursuant to the passage of the bill before you, would have to come up with an equivalent, in our minds, of an Internal Revenue Code set to energy. State regulators would be forced to follow the Federal mandates in that system. Frankly, we doubt very much that that system could be made simple or easy enough for us to understand and follow.

We do like to point out also that Federal regulation in the natural gas business, as far as we are concerned in Ohio, has been the cause of loss of jobs, shut-down of schools, and serious concerns about Ohioans freezing.

At the same time, where State regulation has had predominant sway in the electric system, in Ohio the electric capacity is there and we believe it will continue to be there with State regulation as opposed to more Federal. If Congress is determined to go ahead with this bill, we do point out in the testimony that there are various sections that would certainly have to be reworked and you can find that beginning at page 5 of my testimony and I will not go into them. But certainly one point that should be made is the definitional section, and so forth.

We think that the new natural gas definition needs work, we think price definition needs work, that the selected price level does not make as much sense as other selected price levels might.

We also would like to indicate that it is of considerable interest to us that one interesting feature of part D is the fact that the bill would propose to continue the Emergency Energy Act.

In Ohio from our examination of the Emergency Act we found there was a considerable use made of the portion of the act that allowed unregulated interstate gas to get to market on a market sort of basis, that there was little use of the allocation provisions of the act. We found that of considerable interest. When this bill suggests that we continue the Emergency Energy Act, we think it is somewhat incredible that in a time of extreme crisis we turn to the free market system essentially to bail ourselves out of the natural

gas shortfall if for a long-term Federal policy we are proposing more Federal regulation as the answer.

We do not suggest that is the right way to go and think that is the wrong way to go; just several remarks on part E, I would feel remiss if I were here and had not mentioned them.

Essentially the various pricing mechanisms that are suggested in section E do not particularly trouble State regulators, and indeed they should not since most of the various pricing mechanisms in section D originated as ideas with State regulators and are being tried in various States.

Mr. Batinovich's State, California, is one such State that has tried many of the gimmicks or devices, depending upon your point of view, and all regulators are looking with interest to the empiric results there so that we can determine whether or not it is best for us to go ahead. Ohio is certainly one of those States that has looked at various devices to guarantee the cheapest source of electric energy.

We would point out also, and do in our statement, that there are certain inconsistencies that exist in section E. Just pointing out one, the section E says that there cannot be any declining block rates. Yet it also says, somewhere in there, that we shall have cost of service as the basic principle by which rates are set.

If you find yourself in the anomalous situation of having only cost of service met by declining block rates, something has to give in that act and those two provisions should not be read, I think to be mutually exclusive, as they are. You have to provide us, I believe, more flexibility in our rate schedule-setting ability. The States are more than willing to take up the cudgels of rate reform and have been doing so. I believe we would continue to do so without a Federal mandate.

The only part of part E that really bothers the State regulators as a whole is I think the Federal mandate with regard to fixing prices.

Thank you.

[Mr. Heckman's prepared statement follows:]

UNITED STATES HOUSE OF REPRESENTATIVES
COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE
SUBCOMMITTEE ON ENERGY AND POWER

STATEMENT OF
C. LUTHER HECKMAN, CHAIRMAN
OHIO PUBLIC UTILITIES COMMISSION

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ON

H.R. 6831, A BILL PROPOSING THE NATIONAL ENERGY ACT--NATURAL GAS

MAY 18, 1977

Chairman Dingell and Members of the Committee:

My name is Luther Heckman and I am Chairman of the Public Utilities Commission of Ohio. I have been asked to present testimony by the National Association of Regulatory Utility Commissioners (NARUC) on Part D of H.R. 6831, a bill to establish a comprehensive national energy policy.

From my perspective, the single most important feature of this bill is found in its title. It is clear that the formation of a national energy policy has been and is desirable. While I have been chairman of the commission, I have noticed that both the former Administration and prior Congresses have been moving in the direction of establishing a national policy in the energy area. I am pleased that the present Administration and Congress are continuing that endeavor. I and my fellow members of NARUC are very appreciative of this opportunity to testify today.

Let me indicate by way of background that most remarks are of necessity more a reflection of the Ohio experience rather than the result of a NARUC consensus position. NARUC as a voluntary organization has not established firm policy guidelines in the natural gas area for its membership. Nevertheless, certain of my remarks should be construed as reflecting the general State's attitude concerning Federal regulation.

To begin let me indicate briefly the Ohio experience in natural gas over the last several years. Ohio has experienced considerable natural gas curtailment. We are one of the largest States in terms

of use of natural gas in the country. Over 1.2 trillion cubic feet represent average use in a year. The State has approximately 30 retail distribution companies that are primarily fed by two large pipeline systems--the Consolidated and Columbia Gas Systems. Curtailment on those two pipeline systems has not been identical, so consequently curtailment experience by the various retail companies has been uneven throughout the State. To take one system as an example, the Columbia Gas System up until 1975 had an average curtailment of around 25 percent on a pro rata basis. Due to a change in the Columbia System curtailment strategy (approved by the Federal Power Commission) pro rata curtailment ended on the Columbia Gas System and a modified end-use curtailment was adopted. 1976 and 1977, last winter, saw curtailment range from 100 percent in end-use category 3 to an average of 45 percent in end-use category 2.

Translating those numbers to Ohio results in substantial curtailment for industrial and commercial users of natural gas in a typical winter. In this last winter season, there were periods when almost 100 percent curtailment for commercial and industrial customers existed with a threat of curtailment for priority 1 customers. In short, the natural gas supply situation in Ohio was at best a crisis and at worst a potential catastrophe.

The Ohio Commission has felt the brunt of these gas shortages and responded in various ways. One of our early solutions for relieving curtailment of this magnitude revolved around a continuing faith in the free enterprise system being allowed to function. Accordingly, Ohio took the lead in developing a "self-help program."

Self-help was designed so that curtailed customers could find independent drillers in Ohio to drill gas for their own use. The gas distribution companies cooperated by providing transportation for that gas and the result was that over 100 self-help contracts were instituted over the last 3 years. Parenthetically, we have found the greatest roadblock to our self-help system has been Federal governmental interference.

When examining all of the above it is no wonder that we believe the need for national energy policy should be of paramount concern to Congress. Several points should be addressed in assembling the proper elements of a sane national energy policy. I shall limit my remarks to addressing sections D and E of the proposed bill.

Before getting into specifics, a few general comments are in order. We have noticed with considerable interest the near passage of price deregulation for new natural gas in last year's Congress. It is our judgement that section D represents a near 180 degree turn from that position. As opposed to deregulation, this bill proposes more regulation and unfortunately, from a State perspective, that regulation is Federal in character.

The history of Federal regulation in the natural gas area can give no State regulator any confidence that a future system of more Federal regulation makes any sense. The present price system in inter- and intrastate gas is the best example of what leads to increased natural gas production and what doesn't. When Ohio was critically short of natural gas last winter we did not turn to interstate pipelines for our emergency needs. The reason is no gas was there. In fact the Federally-regulated interstate system was

bereft of gas supplies and caused our problems in the first place. Ohio turned to intrastate unregulated production and did find some help.

The pricing policies set forth in the proposed bill will simply not provide adequate financial incentive for increased natural gas development. We believe that there will not be a significant increase in interstate production. We further believe that the proposed bill will result in a decrease in intrastate production. Some of Ohio's gas--and we are a producing State--will not be developed without the proper financial incentives. This will have a direct effect upon our self-help program. The proposed wellhead price ceiling in the bill of roughly $1.75 falls far short of the economic incentive required here.

Congress can go in two directions to eliminate the price disparity between inter- and intrastate gas. Congress can go along with the present bill and extend Federal price congrols to intrastate gas production or can do what it nearly did last year and remove Federal price controls on interstate production. The better view from our perspective is that Federal meddling and more Federal regulation won't do the job. A national Federal energy policy is not the equivalent of a new and expanded Federal bureaucracy. The thrust of the proposed bill is in the wrong direction.

One of the worst features of the new bureaucracy would be a complex administrative system that boggles the mind. According to the bill, as a State regulator I would be charged with implementing the Federal directives. I am convinced that the new rules and

regulations that the administrator would adopt would be the nightmarish equivalent of an Internal Revenue Code set to energy. Regardless of State regulators' response to such a code, the bill also provides for a continuing check upon State regulators and their enforcement of the code, the penalty being in the Administrator's discretion a total takeover by the Federal bureaucracy.

Such an administrative system is unthinkable. If one would compare the Federally predominated interstate natural gas system to the State regulated electric system an obvious conclusion is seen. While natural gas is in a mess in terms of supply, electricity at least in Ohio, is still in abundant supply. Federal regulation has caused loss of jobs, shutdown of schools, and serious concern about Ohioans freezing. I might point out however that there was no freezing in the dark and our electric systems are functioning. A future of more Federal regulation for natural gas is the wrong direction to go.

If Congress is determined to head in this direction some amendment work should be done to Part D of the bill. The natural gas price definition found in section 402 includes the "average per barrel crude oil acquisition cost...of all crude oil produced within the United States". Clearly this definition is inadequate if new supplies are to be developed. I would suggest instead a definition which is oil-based but at least should be set by reference to the price for new supplies of crude oil rather than to <u>all</u> sources of crude oil. It would also make considerable sense to me to provide some increment above the average price of new oil to reflect the

superior quality of natural gas as a fuel source. The new natural gas definition itself could be somewhat more broadly defined. There should be an exemption for intrastate gas produced by or for curtailed customers. Section 408 should be looked at with the thought in mind that the President make an annual determination of the price outlined in section 404.

Section 414 should be reworked and perhaps done away with in its entirety. Suffice it to say that no other other source of energy today is sold only at incremental prices. End-use pricing from a Federal standpoint should be deleted as there is no Federal experience in this area. In short, individual State commissions fully cognizant of the varying circumstances in their jurisdictions should be free to deal with appropriate individual customer rate structures. Section D has as its purpose increasing supply. On an historical basis increased supply and more Federal regulation don't go hand-in-hand and that is what Part D is all about.

One last point with regard to the natural gas area and that is the Emergency Natural Gas Act provisions. During the height of last winter's crisis that particular piece of legislation was passed with much fanfare. Ohioans had considerable hope that increased supplies of gas would be made available as a result of passage of that Act. So far as I know the allocation provisions of that Act were rarely if ever used. Instead, the features of that Act that allowed unregulated intrastate gas to get to market were used. It is rather incredible that in the time of extreme crisis we turn to the free market system to bail ourselves out of a natural gas shortfall, yet for a long-term Federal policy more Federal regulation

is the answer. We hope that Congress which has been involved in this area does not equate the need for a national energy policy to the expansion of the Federal bureaucracy but instead brings the experience of several years' study to bear on this proposed bill.

I would feel remiss if I did not take this opportunity to make some comments on Part E. When reading this section of the Act it appears that the Federal strategy planners found a problem in the natural gas area and came up with a "solution". My previous remarks indicated the efficacy of this solution. With no similar problem existing in the electric world more Federal regulation is apparently going to be the route to follow. My quarrel with most of the material found in Part E is the fact that it is Federally mandated.

Many electric pricing policies--peak load pricing, time-of-day metering, etc. have found favor with some State regulatory jurisdictions. Indeed they were originally formulated there. But, to lock into the statutes Federally mandated policies ignores a continuing state of change that regulators in the States have developed expertise to deal with. State regulatory flexibility and innovation are the only hope for the cheapest electric energy.

Part E is certainly inconsistent in some respects. It suggests that all electric and for that matter gas utility pricing is to be done on a cost of service basis. The proposed bill prohibits declining block rates. Mr. Chairman, wouldn't it be anomalous

if in your State or in mine, totally accurate cost of service price would require a declining block structure. This bill would preclude it.

Seasonal rates are mandated with two separate rate schedules presumably required. If seasonal peaks do not vary however, State regulators certainly know that one schedule would suffice. While most States are trying varying forms of new pricing policies and Ohio is among that group, sufficient empiric experience tells us that the country is not ready for Federal mandate in this area. Ohio as an coal-burning electric State doesn't have the same problems as oil or hydro States and shouldn't have the same Federally-mandated pricing structure.

One final word should be said about the provisions of the bill relating to "wheeling electricity". In theory, wheeling sounds like the absolute in practicality yet the actual result in wheeling between States can mean that Ohio consumers have paid the bill so that Indiana or Michigan consumers can have electricity.

The way such a potential exists is in the Federal mandate of wheeling as a concept. If the hard regulatory decisions have been made in one State jurisdiction and not in another, electric capacity may very well exist which the Federal government makes available. On a voluntary basis that situation can work to the advantage of consumers in a State that has paid the price. In a real world sense this concerns Ohioans for some of our neighboring States may not have paid for as much electric capacity as our consumers have. Properly done, voluntary electric wheeling is a useful tool

and should be encouraged but let's not mandate Federally electric allocation and call it whe ling.

I thank you very much for the opportunity to testify before this distinguished committee and would only once again restate that more Federal regulation will not solve our problems. Less Federal regulation could. We trust that Congress will encourage the continued development of conservation by Americans in the energy area. We hope that Congress will promote the fostering of an environment which will increase production of needed energy for the country. A new bureaucracy is not the answer, gentlemen.

Mr. KRUEGER. Thank you, Mr. Heckman and Mr. Batinovich. I am sorry at this time of day the time has slipped so, because it is nice to get such clear and concise testimony. We shall now proceed for questioning under the 5-minute rule. I would begin with, I believe the first person who came in was Mr. Brown and I will recognize Mr. Brown at this time for 5 minutes.

Mr. BROWN. Mr. Chairman, thank you very much.

Mr. Batinovich, I agree with you there is a fairly serious emergency at hand and that we have to take extreme action to deal with the problem. Is California prepared to do that with reference to the Long Beach off-loading of Alaskan oil?

Mr. BATINOVICH. I think that we are. I answered that, saying I think we are. I happen to be the assigned commissioner on that. So you are asking for my vote before I vote. But let's say it is on my desk.

Mr. BROWN. We have some concern about it in the Midwest because if we can get you to accept the oil through the Port of Long Beach from Alaska, then we can divert our Arabian oil from Midwest markets and bring it into midland Texas, I guess, through that pipeline across there and get it refined.

Mr. BATINOVICH. I would not want to sound like the senator who said he was the shiek from the North, but I guess the same analogy could be used with a port as when some of our States talk about their gas and oil.

We are very concerned in direct response on a different issue that was mentioned before about the finder's-keepers solution as far as natural gas is concerned. It seems to be the one common denominator among regulatory bodies. They feel they can do a job but they want to be protected and not have the so-called workingman who is paying the taxes end up helping the one that is on welfare who then ends up with a better energy package, let's say, than the one that does all the work.

We realize in California we will have to make some tremendous sacrifices, not the least of which is some added pollution and some risk——

Mr. BROWN. Not if I understand the deal made with the Standard Oil Company of Ohio. That was, they would eliminate one item of pollution for every item of pollution created by the off-loading of oil at the Port of Long Beach, and in that way I think they decided to go out and buy up all the little mom and pop dry-cleaning establishments in Southern California.

I am told the second offer is that the trade-off should be on a more than one-to-one basis and that those of us who buy oil and gasoline in Ohio would be paying for converting the Pacific Coast electric generating plants to less polluting sources.

I hope we do not wind up having to do that. One-to-one I do not mind, I guess. Maybe the dry-cleaning establishments are not needed anyway.

I am a little bit concerned about more than one-to-one. It seems to me that has all the charm of Mr. Rogers' amendment to the emergency gas.

Mr. BATINOVICH. No. If I could, Mr. Brown, I would only mention another point; there are only three cleaners.

Mr. BROWN. Left?

Mr. BATINOVICH. No, there are only three proposed, but I do not think that that would be the case. I do hope that they will be shortly before us with what those trade-offs are. Our commission will not make that decision; the ARB will.

Mr. BROWN. But I hope you make it generously less than we have to make it here, because several of us just don't believe in that.

Mr. BATINOVICH. I would heartily concur, and I don't think you will find when the time is ready to go that California would be "obstructionist" in that matter any more than it will be with LNG which we are not very happy with taking on our coastline.

Mr. BROWN. I am delighted to hear that and I will keep my fingers crossed.

Mr. Heckman, I don't want my time to go without welcoming you and your testimony and welcoming also the nature of the testimony. The concern that I have, we have had people today who are great breast beaters about this concern for the consumer, and have been in some instances, folks have testified that they have been architects of policy which have gotten us into the wonderful position we are in today, by keeping prices down on natural gas, and of course also on the price of domestic oil, so that we can now pay the Arabs for that oil, for oil to replace domestic oil, and I would just like to ask if you have done or if anybody in Ohio has done any quantification in terms of the impact, the economic impact, of the shortage that was experienced in Ohio and elsewhere in the country during the last year.

Are you aware of any figures on that subject?

Mr. HECKMAN. There has been some work done on that by the Economic Development Department in Ohio, and the figures are rather astronomical. At one point in the shortfall we had over 1.2 million people unemployed. We had almost two thirds of our schools closed and considerable amounts of damage done to property as a result of the lack of natural gas for industrial customers.

You see we experienced for a period of time in Ohio almost 100 percent curtailment for some industrial and commerce customers.

This resulted in just a great loss of business for Ohio, resulted in a great loss of wages for various people and so forth. The total is astronomical, and I can get it for you.

Mr. BROWN. I wonder if you would get it for us, and what I would like to have you do, if you could do it, is to relate that to what we might have paid for natural gas. There is another figure to throw in there, and that is what in effect, if you can do it, what was paid for synthetic gas with which many of the utilities were obliged to top off. In other words, I want to know that if all of that had been avoided, what the price for natural gas would have been relatively. You see that has some impact on whether deregulation makes any sense, or rather whether nonderegulation makes sense.

Before you bang the gavel, let me thank California for helping us with that problem. You sent us some natural gas.

Mr. HECKMAN. I was in touch with Mr. Batinovich and he did do some good work for us in California.

Mr. KRUEGER. The time of the gentleman has expired.

The Chair now recognizes the gentleman from Indiana, Mr. Sharp, for 5 minutes.

Mr. SHARP. If I understood the testimony Mr. Batinovich is telling us that in California you made a number of efforts in your rate structures to experiment to see if there is a possibility to bring about greater conservation of resources, and if I understand Mr. Heckman, I didn't understand that any real actions have been taken, but you are observing closely to see what comes out in California.

My question is if there is a presumption that rate structures can really bring about change, what will get those States who are not acting and who seem to show very little disposition to make any changes to act, if there is in fact an emergency situation in this country?

Mr. HECKMAN. I don't believe that my testimony should be characterized that we are not doing anything, for instance, in Ohio. We are experimenting with peak load pricing, with load management techniques, with just a variety of different things, in all of the electricity, telephone and gas utility areas as far as price is concerned. Other States are too. I believe California is somewhat farther down the road. I don't find any reluctance, when I go to national meetings of the various State commissions, to adopt any of the various techniques, provided that they are shown to be workable. That is why I say one thing that is very good about California having gone so far with so many of them, we all get to look at them, but I don't see any reluctance in Ohio, and not amongst most commissioners. I don't believe anything has to be done in terms of a mandate. We will do it if it works.

Mr. BATINOVICH. If I could, Mr. Sharp, our projections that we are holding to for the next 5 years show that we will be able to maintain a 2 percent growth in hookups, and still have only a 0.9 percent increase in demand on gas over the 5-year period by the implementation of all of these particular items that we have talked about.

I think when we talk about an inverted gas rate, which is the only place that we are talking about it, because there we are talking

volume, or capacity rather than talking about peak loads, what we are really talking about is pricing our fifth tier, our last step, at a cost much higher than any incremental source of gas that we know of at this time. That way we can keep what we call a lifeline, on which I heard some comments previously, at a frozen rate for 2.5 years, and estimate that we can probably hold it for another 2 or 2.5 years, which is a real reward for conservation.

It is true that lifeline doesn't always go along the lines of total conservation, and it doesn't alway reach all of the financially needy. However, the mass of the elderly people who are on fixed incomes live in smaller residences, and it certainly affects them right on the spot. We can say we haven't raised those rates.

What we are saying is that the fifth tier is the real price of the new gas, and the less you use, the cheaper it gets. Rather than saying it is a penalty, we say it is a reward. The reward is for keeping the usage down. We have offered this in California. We have kept the prices frozen.

Mr. HECKMAN. When I posed the almost identical sort of a question to my staff people who are directly concerned with testifying on the various rate reform devices in the cases, almost to a man, my staff people liked a lot of the devices that are there but they told me also, almost to a man, that if the Federal Government has an opportunity to mandate it, that they will mess it up.

Mr. BATINOVICH. I would have to concur, not so much on the basis of messing it up, but as I said within our own State as I mentioned earlier we have to have a different pricing policy because gas is worth more in Southern California than it is in Northern California. The other irony of it is that we pay more in Northern California for our supplies because most of it comes from Canada, whereas prices are lower in Southern California.

Mr. SHARP. So if I understand in the terms of a national energy plan you would simply remedy deregulation of natural gas.

Mr. BATINOVICH. I don't. California is adamant about deregulation of natural gas. I state that for the three commissioners. We have one vacancy. We have had testimony submitted by one of our other commissioners who has a different opinion. Our experience shows that in the 5 years that intrastate gas has gone up fivefold in California, that the supplies dwindled 2.6 percent. We do not believe that there is that much more gas, and we believe that the incremental cost of deregulation for new supplies could conceivably be as high as $60 a barrel of oil.

Mr. HECKMAN. I guess I have to state that certainly we would think in Ohio, at the Ohio Commission, that deregulation should be a part of a national energy policy, but that would be far from where I think the government ought to go. I wasn't supposed to testify on this I guess but I will be glad to talk on it. They think we need to do some things in the nuclear area, coal. There is room for coal research. There is certainly some room for some expansion of Federal bucks into ways to help finance utility costs. There are lots of different things that have to be done. I don't think, however, that more Federal regulation is the way to get those things done, and create a bureaucracy to establish a ceiling price for natural gas is not going to accomplish a thing in Ohio, except one thing, and that

will make our marginal gas that costs more to go down than it did, to $1.75, ungettable, and I don't believe we want that.

Mr. KRUEGER. The time of the gentleman from Indiana has expired.

There is a vote on the floor again. Perhaps while the members go to vote, if you will be willing, counsel for both majority and minority might share some time. We will try to be back in 15 minutes or so.

Mr. DEMAREST. I am sure I won't use 15 minutes.

Mr. Heckman, I would like to call your attention to and obtain your comment on, a couple of points.

You discussed the problem of declining block rates. The electric utility rate reform bill that has been introduced by Chairman Dingell prohibits declining block rates, unless—and I stress "unless" is the key point—such rates can be justified on a cost of service basis. I would assume that provision overcomes your first objection to a blanket prohibition on such rates.

Mr. HECKMAN. It wouldn't overcome my first objection to a blanket prohibition because my first objection would be the Fed should mandate it to begin with, but it overcomes my second objection, and that is there may actually be a situation that occurs at some point in time where cost of service properly reflected requires declining block rates as a pricing mechanism. I don't think that we are in a situation where declining block rates should ever be allowed to become promotional, and that really has been what most critics have complaints about but that doesn't mean you outlaw declining block rates if you believe in cost of service principle. I am aware of Chairman Dingell's bill, which is certainly better than the present bill before us, which says it is just out the window.

Mr. DEMAREST. So in that regard, except for a philosophical opposition to any Federal mandate of any particular regulatory approach, your opinion regarding the actual implementation of that regulatory approach would be obviated by a provision permitting declining block rates, if they are cost justified.

Mr. HECKMAN. I am convinced that cost justified rates make the most sense, and regardless of what the mechanism is that actually distributes those cost based rates, we should be allowed the freedom to put it into effect.

Mr. DEMAREST. You have addressed some wheeling concepts that are contained in the President's bill. The wheeling provisions as I understand them would apply only if service to a utility's customers would not be jeopardized. Therefore you don't have the so-called grasshopper and ant syndrome to which you have made reference.

Mr. HECKMAN. I think what we have got in the present bill is the camel sticking his nose in the tent. Once it gets in and a shortage occurs in some State that is sitting next to a State that has what someone might call an excess capacity or reserve capacity, that you would see very quickly the Federal mandate to wheel, and that frightens me because that says let's translate the payments made by Ohio's consumers to the benefit of other States' consumers where those payments might not have been made to provide the capacity.

I have no quarrel with wheeling at all as a concept in electric utility use. Indeed all of the electric utilities in the State of Ohio

practice wheeling by voluntary agreements amongst themselves that are supervised by our commission, and think that that is very wise, but I am concerned that the Feds get into a situation of mandating and allocating electric energy as opposed to wheeling as we have known it.

Mr. DEMAREST. Then your real opposition to wheeling is a perception that wheeling as contemplated in the legislation is only the first step, and that at some point down the road we are likely to see an extension of this Federal regulatory activity beyond the concepts set forth in this legislation.

Mr. HECKMAN. There is a natural inclination on the part of the State regulator who looks at allocation being talked about at various times for the last several years by various members of Congress and now by the administration to have that fear, I think, but yes, the answer is we are concerned that the other shoe could drop.

Mr. DEMAREST. Isn't the other side of that argument the same as was made in opposition to the Emergency Natural Gas Act. That we shouldn't permit the Federal Goverment to take gas from under a boiler in Texas and ship it to keep homes warm in Ohio, because there is some right to access to that fuel vested in consumers in Texas because they paid for the development of the resource, they paid high gas prices over a period of years, and now we are usurping that right? Do you have a problem with that concept in the natural gas area?

Mr. HECKMAN. In the Natural Gas Act, even as a shortfall user of natural gas, I have a problem with that concept, and frankly the allocation provisions of the Emergency Gas Act to my knowledge were rarely if ever used. Instead they focused on the ability of States such as California to voluntarily give up some gas that we in turn paid for at the market prices, and that is the way the system really worked to help us in the Emergency Gas Act. I don't believe there was much allocation.

Mr. DEMAREST. There were no allocations orders issued.

Mr. BATINOVICH. If I could, excuse me for interrupting, we loaned the gas rather than sold it, and then it was returned to us, most of which has been returned, and we would be more inclined in time of emergencies to loan gas and get paid back in kind, and if in fact any State had to be paid for its gas, we would suggest that that gas be paid for at whatever that State's incremental cost was.

Mr. DEMAREST. Is there any penalty associated with repayment in kind? Is it on a one-for-one repayment basis?

Mr. BATINOVICH. No, we are not looking for any penalty, no, just one for one. We would hope that that is only a rare occasion, I am sure, either way.

Mr. HECKMAN. I think almost all States that participated in the same sorts of endeavors as California went one for one. I don't believe there were penalties, or else they took direct payment if they had extra gas.

Mr. DEMAREST. Isn't one of the problems which we face here that if there is no Federal regulation, certain types of electric customers, users, may threaten withdrawal or actually go through with withdrawals from a State which attempts to implement innovative rate structures? Such users move to another area to obtain the advan-

tages of a promotional rate design. Thus, these threats are an impediment to the implementation of consumer oriented rate reform.

Mr. HECKMAN. California, as the largest State in the Union, I don't think would indicate that they are trying to pass innovative rate reform on the consumers so that they can drive various customers away from the State.

Mr. DEMAREST. I am sorry, I think my question was just the opposite.

Mr. HECKMAN. You think that there would be States who would pass——

Mr. DEMAREST. Let me rephrase the question. If a State implements or seeks to implement rate reform of the type we are discussing, isn't there the potential that some industrial consumers will threaten to leave the State? They will flee to another jurisdiction which does not have this form of rate design. They will flee to a jurisdiction with more attractive rates, rates that are promotional in nature. That threat then jeopardizes the ability of the local regulatory commission to implement effective rate reform. I see the commissioner from California nodding in the affirmative.

Mr. HECKMAN. I think Mr. Batinovich has stated that and he can speak to it, but from a State regulatory position I don't believe that any State regulator today is going to go out to pass promotional rates. I think that we have long since gotten past that theory in ratemaking, and that isn't a real concern of mine. I believe that other State jurisdictions view it the same way that Ohio does, and I think California, when they took the lead on some of these things, was certainly aware of the potential problem, and realized that you couldn't live with that kind of thing hanging over your head, federally mandated or not. The States are going to go ahead and do what is right.

Mr. BATINOVICH. I would also like to comment on that. I think that I agree with what you stated, because it is a concern of ours, and it hasn't been easy to talk about rate reform to business and industry, because they are threatening to leave at all times with the antibusiness climate in California as it has been described.

However, it seems to me that the Federal Government, in the new energy agency, would have more than enough leverage in many, many other areas, that it would not have to legislate, and on that point I would concur with my fellow commissioner that I don't think that you can legislate a rate reform.

I think what you can do is you can state that it is the policy and the intent of Congress and of the Energy Secretary, he certainly would have it within his powers in other areas, other things that States are going to require, to say that we don't think that you have done a job. We think you are failing here, and point out, so that a State has an opportunity to state, in one case or one area what their unique and special problems are.

We would still, as I say, think that the States should be given time, at least a couple of years as called for in the bill, and also we believe that leverage is not required to force States to do it because I think they can get the message with various other hammers that

this agency has, and you will either shape up or you won't get X, Y, or Z. I think that that is far more effective.

Mr. DEMAREST. Would it be fair to say that the question is not whether State will now pass promotional rate structures but whether such rate structures are now in existence to which industrial customers can go, so that the threat is a meaningful one? Second, I would like to know what percent of the U.S. population lives in California?

Mr. BATINOVICH. We have close to 22 million people.

Mr. DEMAREST. About 10 percent of the Nation's population?

Mr. BATINOVICH. About 10 percent of the population.

Mr. DEMAREST. Ten percent of the Nation.

Wouldn't it be fair to say that for industrial customers to leave California and write off that market as a base of operation is a lot more difficult than it is for an industrial customer in a much smaller State, one that doesn't have the economic leverage that California has by reason of its very broad economic base?

Mr. BATINOVICH. I would have to agree that it would be more difficult, just because of the dollars and cents that are involved and the market that is involved. However, there is still that threat, and I think that it is well founded in some areas because I would be remiss not to state that I think some industries have left our State based on the reforms that we have done.

Mr. DEMAREST. And the threat could be even greater for a smaller State.

Mr. BATINOVICH. Yes, I would concur that it would be, but I would also say that I think as a regulator, the ever driving force is to do your homework and get on about your business with the threat that Congress is going to take this responsibility away from you, and I think that if it is so stated as a policy matter, that you are going to take away those power unless the people shape up, so to speak, I think you will get tremendous response.

Mr. HECKMAN. Mandate if you will, just simply mandate cost of service as a pricing tool, and you don't have promotional rates left, if you agree that cost of service plus a profit given to the various companies isn't promotional. What is promotional I guess is what you had better define, but at least just put it in as a policy.

Mr. BATINOVICH. Maybe you had better write the bill.

Mr. Chairman, we have received a memo from Commissioner Symons of the California Public Utilities Commission, and request that it be placed in the record.

Mr. KRUEGER. Without objection it is so ordered.

[The document referred to had not been received at the time the record was closed.]

Mr. KRUEGER. Fifteen minutes of the counsel's time have expired.

The Chair now recognizes the gentleman from Louisiana.

Mr. Moore.

Mr. MOORE. Thank you, Mr. Chairman.

Mr. Heckman and Mr. Batinovich, I would like to ask each of you to answer questions separately on what is basically the same subject. We have had testimony from a number of people before the committee so far, including Governors, the Chairman of the FPC, and a number of producers and pipelines, all to the effect that

simply putting the price of natural gas at the same figure $1.75 as is done in this bill, price parity, price equity, what-have-you, will not in fact send a great deal more natural gas into the interstate pipelines due to the hesitancy of an intrastate producer or producers to deal with an interstate regulated market. He will still deal with his friends or with the intrastate market as long as there is a market there, and he gets at least the same price. He will forgo fooling with or coming under FPC regulations.

I would like to ask each of you to comment on this, whether you think there is validity to that comment or not.

Mr. HECKMAN. I don't know how much validity there is to it in some respects, but I do know this. Ohio producers have done everything they possibly could on the intrastate market to keep out from under the hands of the Federal bureacracy when it was the Federal Power Commission, and they had a fairly good idea of what they could expect in the way of regulation. I suspect that they will continue to do that in the future if they possibly can.

The whole question is in Ohio it seems to me though that is more important, at $1.75 or whatever that price gets to, will the gas be produced? Right now I very much doubt that it would be, and that our whole self-help program would be seriously jeopardized by the price level that is set there.

Mr. BATINOVICH. California producers have different problems. They don't have access to the interstate pipelines, and so their gas in effect goes to California utilities. However, as I stated before, we have had a decline even with an increase as far as reserves are concerned, and we still concur that both prices should be set the same on a parity.

Your question I think is probably that in some States and with some producers that that would happen, that they would feel more comfortable staying in the intrastate market. I don't think it is a flat statement either way. That would just be my own impression.

Mr. MOORE. As a follow-up question, it has occurred to many of us then that the only way we are going to, No. 1, in the words of Mr. Heckman, provide incentive to increase production, where it can be increased, and No. 2, get into the interstate market, would be to deregulate, a stairstep delay proposition, the interstate market, thereby giving price incentive, No. 1, and No. 2, removing the objections that a producer has to sell in the market. I would like to have your comment on that point.

Mr. BATINOVICH. My response to that, of course, you always get back to what is new gas? Based on what we have seen in the bill, it certainly allows for the highly technical, sophisticated areas of gas to have a price even higher. It is left in a sense open and up to the Secretary of Energy I guess or the Energy Board, so we think that that is covered. We have had a decrease with a fivefold rate increase in California, so we have no evidence. We were very concerned that the incremental amount of gas we have at a higher price in our estimation could conceivably be $60 equivalent in oil.

Mr. HECKMAN. I would say, Mr. Moore, the only problem that I have got with your question is that frankly I don't understand why we need the stairsteps.

Mr. MOORE. Why has California, as you say, had price increases, but has not had any response in terms of increased production? There has been no increase in production at all in California.

Mr. BATINOVICH. No, there has not.

Mr. MOORE. Why is that?

Mr. BATINOVICH. We don't think the gas is there. We haven't found that much new gas and we haven't drawn that much more out, and on the overall numbers we are down 2.6 percent in reserves during that 5-year period, and gas has gone up fivefold.

Mr. MOORE. Would you then become dependent as time goes on for more interstate gas, if the intrastate gas you say is depleted?

Mr. BATINOVICH. If it is there, yes, but you see we don't happen to believe that there is that much more gas in the interstate market or in the lower 48 States. Obviously if it is there, we would go after whatever our share was, or whatever we though our share could be, but California is not looking to tremendous increases in the interstate pipeline deliveries as a way of solving the natural gas shortage. We are looking towards LNG from south Alaska, from Indonesia, for gas from the North Slope in Alaska, for gas supplies out of Mexico, and gas supplies from Australia, gas supplies from Iran and the Soviet Union.

Mr. MOORE. That is increased dependence on foreign sources which we are all trying to get away from but I understand your position. If I could convince you that there were reserves, let's assume outside California, and that the question we just talked about a moment ago, that the only way we are going to get those reserves produced and get them into interstate commerce where you could get at them was through deregulation, would you then accept deregulation?

Mr. BATINOVICH. I would have to have it proven to me.

Mr. MOORE. I am just saying if we could prove that to you, that the reserves are there, and that the only way we are going to produce them is to give proper incentive and, No. 3, that as long as it is regulated it won't go in the interstate market, it will stay in the intrastate market, would you then support deregulation?

Mr. BATINOVICH. I would have to look at it all before I would say that. You are going to have to talk about what the amount of extra incremental gas is, because I would want to know what that is. If you are talking about raising supplies 10 percent I would say forget it.

Mr. MOORE. I'm talking about 1,000 trillion cubic feet, about 40 years' supply, increasing to 1985 to about anywhere from 4 to 10 trillion cubic feet by 1985, from figures we have gotten from other sources.

Mr. BATINOVICH. You mean on this 19 trillion that I heard earlier today that you would be adding between 4 and 10.

Mr. MOORE. Yes.

Mr. BATINOVICH. Or a factor of 20 to 50 percent more gas into the field.

Mr. MOORE. Yes.

Mr. BATINOVICH. I never heard of numbers or have seen them of that magnitude.

Mr. MOORE. The numbers are in the record. I am not arguing over the numbers. I am trying to get you in a hypothetical situation to answer the question. If it is proven to the satisfaction of the

Congress, United States, or to you that reserves are there, and that only an increase in pricing will get them, and that only deregulation will get them in the interstate commerce would you then support deregulation?

Mr. BATINOVICH. I can give you a hypothetical yes.

Mr. MOORE. That is all I was after.

Mr. BATINOVICH. A hypothetical.

Mr. MOORE. Thank you very much.

I thank both of you.

Mr. KRUEGER. The time of the gentleman from Louisiana has expired.

The Chair now recognizes himself for a brief period of time.

Mr. Heckman, last year this subcommittee received testimony from a gentleman from Ohio who said on January 23, 1976, and I quote: "Last fall we were warned, as a commission, of potentially thousands of layoffs in Ohio."

Would you have any comment on the wisdom of that prophet?

Mr. HECKMAN. I dare say that it wasn't myself.

Mr. KRUEGER. No, it was not you. I just wondered whether you cared to comment on it. I have a few more.

Mr. HECKMAN. Frankly the gas shortages that we had in Ohio in the mild winters that we had previous to this one were severe and significant shortages. The interstate market frankly had not done its job in supplying the gas that we had expected to get and expected to use in Ohio in the mild winters in the industrial and commercial sectors. We had in the winter of 1975-76 curtailments that ranged as high as 100 percent for some industrial customers to around 40 percent for a great many commercial customers of all types use, and I would have to say that I felt that there was a significant shortage in the two previous mild winters prior to this last one, where everybody else seemed to get the message.

Mr. KRUEGER. So obviously you didn't agree with that particular statement.

Mr. HECKMAN. I must admit though, Mr. Chairman, that there was some press in the State of Ohio that picked up statements like that and ran them in the spring.

Mr. KRUEGER. I will proceed to some of those points.

In the part of the same testimony this committee heard the following:

> Last month Columbia announced the intention to "roll in" the cost of these additional purchases through their purchase gas adjustment clause. That means the cost of these emergency purchases would be rolled in to the residential, commercial, and industrial customers even though only industrial and commercial customers would benefit in reduced curtailments.
>
> So it is with that background and with the pressure that is being placed on this Congress through media advertisements such I have mentioned, that I believe that the cost to Ohio's answer should deregulation occur, will go as high as $468.8 million, or 37 percent increase in our natural gas costs.
>
> This estimate is based on the recent release of the Library of Congress, Congressional Research Service study, which indicates the economic impact of Senate bill 2310 on pricing provisions.
>
> Now that report indicates a $20 billion cost. The GAO recently released a $13 billion cost. Other economists talk of a $10 billion cost. Whatever the actual cost, we know that Ohio consumers are concerned about the dramatic increase that will be experienced in their gas bills.

And then the summary is:

Recent emergency purchases of high-priced natural gas by Ohio gas utilities to relieve industrial and commercial curtailments in the State of Ohio are a preview of the impact and consumer response to permanent natural gas deregulation. It is estimated that Ohio gas consumers would pay up to $868 million more if deregulation legislation is enacted by the U.S. Congress. Because of the Ohio experience with mini-deregulation, the U.S. Congress should resist acting on deregulation until the facts of natural gas reserves are developed by sources independent from the gas industry.

I read that to you simply because I wish you to know that that was the statement, I take it, of your predecessor. It was the statement of a Mr. Sweet, who was at that time a member, a commissioner of the Public Utilities Commission of Ohio, and that statement was in fact widely picked up by the press, including the press in Washington. Mr. O'Toole of the Washington Post who I believe was here this afternoon picked it up and gave this as an example of Ohio's experience. I think it was not very well understood, and that Ohio really hadn't experienced any mini-regulation. It simply was allowed the opportunity through the FPC to make some emergency short-range purchases, which has very little to do with the concept of overall removal of Federal price regulation, but having welcomed Mr. Sweet a year ago, I wish now to welcome you, to welcome your testimony before this committee.

Mr. HECKMAN. Mr. Chairman, if I might respond, Commissioner Sweet is still a member of the commission.

Mr. KRUEGER. Oh, he is?

Mr. HECKMAN. I might point out that he is in the minority in terms of his viewpoint on this particular matter. The fact is that Ohio did allow emergency purchases to flow through to all customers at the commission level. The State legislature stepped in and overruled that determination and passed a thing called euphemistically House bill 1213 that has since been the subject of intense debate in light of last winter's severe shortfall. In fact, fewer emergency purchases were made as a result of the legislative action in part, so I think that while I can understand the testimony having been made, I would have to say that in most respects I would have to disagree. I don't believe that that is the way to go to try to get more gas. Frankly the present bill has within it the elements of moving on an Ohio bill 1213 upon the Federal scene imposed upon everybody with those various incremental price provisions in there.

Mr. KRUEGER. Thank you.

Now I would like to turn to some of the questions that both of you raised. I noticed that both of you were not particularly anxious to enlarge Federal regulation. I think that both of you said, although I realize that there is some difference on price regulation of gas, that as a general principle, accepting price regulation on gas, both of you would rather see less Federal regulation imposed on your State utility commissions; is that correct?

Mr. BATINOVICH. Less than what is called for, let's say, in the legislation before us.

Mr. KRUEGER. And you would——

Mr. HECKMAN. I would like to see less than theirs presently. I can think of some things in Federal regulation that I would like to see

removed. For instance, the semi-prohibition as it were using interstate pipelines to move intrastate produced gas within the State, things like that. I can envision a better system with less Federal regulation in gas and more State regulation, or State regulation of a different type or character, price-wise and that sort of thing.

Mr. BATINOVICH. I would also comment that I guess where we would look, and I think it goes to one of your other points you mentioned earlier, Mr. Chairman, with the other panel, that there are several things we would look forward to, rather than the ratemaking role, which I still think is regional even within a State, especially a State like ours. One is the finders-keepers legislation that would allow us to go ahead and give us an incentive to obtain new supplies, to be a self-help State. The finders-keepers rule is extremely important.

Two, in your syn gas program that you talked about as coal gasification, we have a project that we have asked the Federal Government several times for, and there is another bill on it, to guarantee the first syn gas plant. We are willing to take part of the risk but we don't want to take it all. It has been proposed to us on the basis that that technology would be used nationwide once in fact it is successful. We would encourage that the Congress give us the help in the way of that financial guarantee for the first plant, so that we could go on with the new technology.

I would concur with the gentleman earlier on the panel who comments about how 10 or 15 years from now syn gas in fact could be cheaper than any other gas. We think that coal gas could be also. We know it is a big, up-front cost but we would like to encourage the Congress to support legislation that would guarantee that first plant.

Also Mr. Brown talked about this Sohio project. One of our important concerns there is that we were talking about LNG traffic from Alaska and oil from Alaska, and we are extremely concerned about the Coast Guard regulations. I know that Mr. Tom Quinn of our Air Resources Board has been back several times talking both with the Congress and with Mr. O'Leary in the hopes of getting congressional legislation that would help us with both the pollution problem of emissions and cleaning out the tankers in the Los Angeles Harbor, and also in the traffic and the oversight, have some oversight by the States into monitoring the traffic. We expect to have 400 to 600 tankers a year going back and forth, and we would like to make certain that we are at least being careful with these so-called floating bombs that are on our coastline.

Mr. KRUEGER. I would like to return to further questioning later. I have taken more than 5 minutes for myself because Mr. Moore had more than 5. I think perhaps, since we have a bit more time, I recognize Mr. Brown.

Mr. BROWN. I would like to have minority staff ask some questions.

Mr. DAVIS. Thank you, Mr. Chairman.

Mr. Heckman, in your testimony you briefly alluded to the fact that the $1.75 price for new natural gas would seriously impinge upon Ohio's self-help program. I believe in response to Mr. Moore's question, you elaborated a little bit on that, but I wonder if you can

elaborate even further on how high the cost of gas is in Ohio, and what sort of a price is necessary to bring forward this self-help gas?

Mr. HECKMAN. The various deals range in price, I would say, from around $1.75 and maybe as low as $1.65 to probably around $2.25. The way the self-help deal is structured essentially is that the cost of the gas is directly almost associated with the cost of production in the field.

We have some marginal gas production that just simply won't get out of that ground at the $1.75 ceiling price. It should get out of the ground. It did keep some industries open this last winter who would otherwise have been closed down because they had lost their allocation from the various gas utilities.

Mr. BROWN. This is gas found in Ohio?

Mr. HECKMAN. Yes, gas found in Ohio that moves presently through intrastate distribution lines. Our program to really get off the ground further, and I would say it is a long way off the ground now, needs, (a) no price ceiling set on it, and (b) the use of interstate lines to bring some of this marginal gas to the customers where they are at.

For instance, East Ohio, which is a distribution company of consolidated gas systems, sits upon some gas that they can easily get to customers in their service territory, but without use of interstate lines Dayton Power, Light and Gas, and other companies in the western part of the State away from the gas deposits, have a very difficult time using the self-help technique. There are not enough exchange points on the intrastate distribution system, but, frankly, some gas just would not get out of the ground for less than maybe $2, $2.25, something like that, in terms of development now.

Mr. DAVIS. Last winter, we all know what sort of a shortage Ohio had, and for most of the winter demand exceeded supply in Ohio. If this gas, through the self-help program, was not available, I guess some sort of substitute would have to be used if the plants were to remain open.

Now, I understand that there is a plant in Green Springs, Ohio, that manufactures synthetic natural gas. Do you know how much that gas is in price and what other synthetic fuels are coming into Ohio?

Mr. HECKMAN. The synthetic price for the Green Springs gas is much higher, although the true effects of that price are not felt by the users of gas inasmuch as it is an average price gas rolled in with other sources of gas. So the two effects are not felt, but the synthetic price is roughly $1.50 to $2 higher than the other self-help deals.

Mr. DAVIS. It is almost twice as high as the natural gas produced under the self-help program?

Mr. HECKMAN. Yes, which is unregulated, and the interesting thing about it is, as you say, could they go to alternate fuels, and that is an interesting point because a great many of the industries who have put up the capital, gone and gotten this gas and participated in the self-help program, we have had almost 100 self-help deals, including some school systems, incidentally, but the interesting thing about it is a great many of the industries could not go to an alternate fuel; they need natural gas. The only possible thing

they could use would be propane or synthetic to make their product. In other words, it is a nonsubstitutable use.

Mr. DAVIS. What sort of price does propane or other alternative fuels have?

Mr. HECKMAN. Propane, under the auspices of the Federal Power Commission, is essentially a rolled-in peak-shaving supplement in Ohio priced like any other source of natural gas is, so it is rolled into the customer. Cost in terms of making it, we know what they are, and they are probably about 75 cents higher than the highest of our unregulated.

Mr. DAVIS. About $3 is what you are talking about?

Mr. HECKMAN. Probably, in that area.

Mr. BROWN. Will you yield on the pipeline question? The question on the pipeline situation is that Ohio has both interstate pipelines which go through Ohio, do not terminate there, and those which terminate there; isn't that correct?

Mr. HECKMAN. Yes, we have interstate pipelines that run through the State. We have a consolidated interstate pipe system that terminates in the State, so it means that there is different Federal Power Commission treatment of how you use the pipes.

Mr. BROWN. And the one which terminates in the State could be used for self-help gas, but the one which goes through the State could not be used; is that correct?

Mr. HECKMAN. Yes. And it should be.

Mr. BROWN. The ones that go through the State and don't terminate in the State ought to be allowed to be used in order to make the self-help program effective; that is your argument?

Mr. HECKMAN. More effective. It has been effective, but it could be more effective, and it doesn't need the exigencies of Federal regulation with application and certification and all the rest.

Mr. BROWN. In H.R. 1088, we take care of that problem, but that is self-serving and is beneath me.

Mr. MAGUIRE. But is nonetheless now on the record.

Mr. DAVIS. I just have one final concluding question, and it is not directly related to the natural gas part of the bill.

In, I believe, part A of President Carter's proposal, he proposes a public utility energy conservation program whereby each public utility would be required to inspect all houses within their service area and to offer to provide insulation, storm windows, other energy conservation devices and the person who took advantage of this plan could then be paid for the installation and purchase cost through the monthly billing charge.

Do either of you have any comment on this proposal? Do you think it is workable, first of all, and, second, do you have any estimate about how many people utilities within your State would have to employ to undertake a program of this magnitude?

Mr. HECKMAN. We have several utilities in the State now that are making a somewhat similar option available for their customers. I must say that the option has not been taken advantage of by large numbers of customers.

In part, I think that is because there has been a great deal of Federal talk that there will be such things as tax credits to do this sort of thing, and so forth, but in other part, it is frankly that there

just isn't enough conservation ethics built into Ohioans yet in understanding of the energy shortage and how much we are going to have to do to conserve our usage.

I think all commissions across the country have been promoting conservation, and I think that we have to keep doing that regardless of what the Federal mandate might be. I don't happen to like philosophically the Federal mandate, but I do think we are going to do that sort of thing in Ohio, anyway.

Mr. BROWN. I would like to ask you both, if staff will yield, do you think this is a desirable responsibility for a state-regulated utility to undertake, or is it more properly a function of the banking community or some other community?

I understand the utility's connection with the energy problem, but I have some concern about whether it is appropriate for the utility to undertake what is usually the function of a mortgage banker, that is, home improvements, and I really don't know what the ramifications are for state-regulated utilities.

Mr. HECKMAN. The question that could come up is simply that part of the thing that they are going to do, finance and inspect, and that sort of thing, if they do it, is it utility business within the meaning of the franchise that they have utility business to do in the State of Ohio? That is the legal question.

From the practical standpoint, the way it has been done in Ohio is that the banking community has been the actual loaner of the funds, and so forth, and the utility has drawn, where we have allowed it to happen, the banking communities and the homebuilders, and these sorts of individuals, so they are not actually doing the kind of activities you would normally think of that credit institutions or carpenters and such like that would be doing.

I think that is really a good question, philosophically, whether or not you go that route.

Mr. BATINOVICH. If I could, Mr. Brown, I will respond to that and minority counsel's question.

First of all, we have stated in California in several decisions that we believe it is the utility company's responsibility to see that homes are kept warm, not to sell gas. And we categorize insulation or making the best efforts with the least amount of gas, certainly part of that responsibility. We have never penalized. If anything, we have tried to offer encouragement and offered incentive rates of return for conservation, although there is discussion on our regulatory language which we hope to correct and are working diligently to correct.

We have stated many times that we think companies should be aggressive in this. I would point out that our companies are all involved in active programs of many different types. We estimated that we might convert 40,000 homes last year, insulate them, and we did over 200,000. We anticipate we will do a quarter million of homes a year without any problem. Yet I would tell you our program has been so successful in California that we have run out of supplies, such as boric acid, and I had a call one day from someone who opened a new insulating firm, demanding that I order U.S. Borax Corporation to ship them some boric acid, which I said we couldn't do.

Mr. BROWN. Needed for the roofing, insulation of the cellulose nature?

Mr. BATINOVICH. Right, so there are some limitations to the availability of supplies as you go through, and I also think that we should all be aware, when something is in short supply, the costs go up. So you are talking several things. California has the most mild climate probably of most of the States we are talking about, yet I think we have probably done the best job in conservation. We have the least cost-effectiveness of any State. We have our utility companies already doing these things. We think it is within their area, and within their responsibility to do that.

I think you will find that in the long run a thrust of this type makes sense whether or not once again it should be mandated by law or just an intent of policy. I think a lot of these things can be done where the energy secretary and energy board will have so many levers that I think they can just state a broad policy, what they expect, and kind of grade States as they go, and those that fall down should be rapped.

Mr. HECKMAN. There is one other little point I would like to make. We have offered utilities who wanted to get into this a lower rate for homeowners who would go into the business of insulating. The only question I have in looking at the Federal law that is being proposed here is whether or not that merit might be promotional and not justified, and I am not sure we are going to get into that.

Mr. BROWN. I wonder if you would elaborate on that in writing, and I would like, Mr. Chairman, to ask both of the gentlemen to comment, if they would in writing to us in somewhat more detail about the proposals in the electric utility area, pricing and the other things which you were not asked to address, I guess, when you were asked to come to the natural gas hearing, but if you would also comment on those items for us, it would be helpful certainly for the record on the electric utility area.

Mr. MAGUIRE [presiding]. Without objection, it is so ordered. The time of the gentleman has expired.

Mr. BATINOVICH. Before you concluded, I wanted to ask a question, if I could. I wonder if I could ask Mr. Moore a question?

Mr. MAGUIRE. As a matter of fact, I was going to recognize Mr. Moore for a few additional minutes.

Mr. MOORE. I have no additional questions, but I will be glad to answer your question.

Mr. BATINOVICH. You gave me a hypothetical scenario.

Mr. MOORE. It has been worrying you ever since.

Mr. BATINOVICH. Seeing it is hypothetical on deregulation, I wondered if you would agree on regulation on a hypothetical situation if, in fact, you didn't get 8 trillion new cubic feet of gas that you would refund or the producers who got the new higher rate would refund all that money? In other words, deregulate the price, then all amounts charged over $1.60, then would be, let's say, embargoed until such time as could prove we had increased our resources to this additional conceivably 10 trillion cubic feet, and if that, in fact, didn't happen those funds would be refunded.

Mr. MOORE. That is a concept I never thought about before.

Mr. MAGUIRE. If the gentleman might yield, perhaps if the funds can be refunded, the dryholes could be.

Mr. BATINOVICH. I am not saying each gas well should stand on its own, but maybe all the development cost could be cranked into it, certainly with some obligation not to go in the desert looking for gas unless it is there.

Mr. MOORE. The factors we are operating on are that the administration model or studies tell us if we will use the $1.75 figure, it will produce 1.1 trillion cubic feet more than we get if we continue the situation as it is now. There are additional models from FEA, FPC, and other agencies which show us it would be a great deal more if they deregulate. So what the price will be, we are working on now. It will be based on cost of production, and we know a great deal of that 1 trillion cubic feet is in deep sands, those below 15,000 feet and is going to cost more than some of the gas produced in the past.

Mr. BATINOVICH. Isn't that covered in the bill?

Mr. MOORE. No, it is not. They give us a $1.75 cap and tie it to domestic crude oil prices, and if they go up slowly, gas will, too, but it is not tied to new cost of new oil. It is tied to the average oil use in this country domestically. So we find any cap may be self-defeating for that gas that would cost more than the cap to produce. That is the problem.

Mr. BROWN. If you will yield, there is another problem, too, and that is this bill puts a geological limit of 2-1/2 miles in distance and I don't know whether either one of you want to testify to that, but I doubt that you want to testify in support of it, if you do want to testify on it.

Mr. MOORE. If I can reclaim what is left of my time, I would simply add on that point, the gentleman from Ohio is correct. I received notice this morning from the State Conservation Department of Louisiana, which contributes more gas in the interstate market than anybody else, and they claim 95 percent of all new gas wells in Louisiana would be considered old wells under this definition. And that means that you are wrecking the chance of any new discovery in the State of Louisiana with that definition.

Mr. MAGUIRE. At this time, the Chair would recognize himself for a very brief period of time, just to ask Mr. Batinovich about some of the problems with regard to air pollution in Los Angeles, in particular.

You mentioned earlier in your testimony there were problems in Southern California, particularly with regard to air pollution, as opposed to Northern California, and you therefore thought, if anything, Southern California, I assume, would meet the cleaner fuels, if that were possible. Is that correct?

Mr. BATINOVICH. Yes, I wouldn't want to state that we don't have any problems in Northern California. We certainly do.

Mr. MAGUIRE. I understand, and the record wouldn't suggest that. But Southern California is the worst problem.

We have heard instances of other cities that are caught in the situation in which if they try to convert coal-fired facilities for electricity, even using best available control technology, they will be, if the law is enforced, prevented from constructing such facilities because they are already in nonattainment areas.

Would you care to comment on some of the kind of air pollution problems that you will have in California if there is a substantial conversion away from natural gas, either for the production of electricity, or for other purposes, to other fuels?

Mr. BATINOVICH. I would say, of course, in the Los Angeles Basin, it would be impossible——

Mr. MAGUIRE. It would be impossible to convert from natural gas for the production of electricity?

Mr. BATINOVICH. I would say it would be, especially based on that technology that we have today even with the cost. And it is not so much a matter of cost. As we stated, we have been prepared to go to lower sulfur oil to clean up existing plants. However, we are not immune to the possibility of entertaining the fact that we might have new plants built in centralized locations where we might be able to adapt to coal.

One of our utilities has applied for 2 sites for coal/electric generation in Northern California. And I would think that we ought to go forward with that and certainly experiment and see what we can do.

Mr. MAGUIRE. One question I would like to pose there, because I am not as informed as I might be on that, perhaps, but it is my impression that the further electricity is transmitted, the more power is lost, and that basically when we use electricity, the very process of converting gas or oil to electricity, there is a very substantial Btu loss, in the first place. So if you would be required to move your electrical generating fcilities outside of Los Angeles because the Los Angeles area could not take the pollution if you convert from natural gas, once you moved those facilities, it would require you to consume a substantially increased number of Btu's in order to get the same amount of electricity. Is that correct?

Mr. BATINOVICH. Yes, it would require more coal, and if we were doing it with coal, we feel we have abundant supplies, and I wouldn't want to comment pro or con except to say it is conceivable the tradeoff might be worth it. We know the cost might be there. But Californians are willing to pay the cost for clean air. The cost difference is one, and the efficient use of energy obviously is the other, but the cost is not a problem. Californians are willing to pay the cost for the tradeoff of clean air.

On the other hand, whether or not the efficiency would be in the national interest by changing it, that would be difficult for me to comment on at this time. Obviously, if it were natural gas or oil, it wouldn't be. I think they are far too precious at this point.

Mr. MAGUIRE. When you say Californians would be prepared to pay the cost, you are talking the cost of constructing new facilities or the cost of producing electricity through coal, which might be higher just in terms of overall cost to get the same amount of electrical output, or both?

Mr. BATINOVICH. I think we would say both. The first thing would be the cost for the clean air, but the second item we would say would be that we phase in, we would like to close up every powerplant in the South Coast Basin and start over. We can't do that economically or physically, but our intentions, of course, are not to expand in that area and expand outside the area where we don't have the geographic formations that create those problems.

Mr. MAGUIRE. Mr. Heckman?

Mr. HECKMAN. Mr. Chairman, I just can't resist but say your questions prompt me to indicate that the only outfit I know that is doing significant research on line loss and how to reduce things by better convection methods and all kinds of things, wire things, and so forth, is the Electric Power Research Institute that is out in California, at Palo Alto, but the interesting thing is that is the kind of area where I think the Federal Government could go in and solve a very mundane problem by making some research money available and do some basic research on things like this and do a world of good.

I don't think you need to regulate, but I think you do need to think in terms of trying to help solve some very good basic research problems.

Mr. BROWN. Will you yield, Mr. Chairman?

Mr. SHARP. Will you yield?

Mr. MAGUIRE. I think Mr. Brown asked first.

Mr. BROWN. Only to make these comments: I made this point last night at the American Academy of Sciences meeting, and someone came up and challenged me, presumably a scientist, although God knows who goes to those meetings, on the idea that there wasn't really that much loss. Then he said, "Do you know how much that loss is?", and I said I was under the impression it could go as high as 20 percent. The average, I understand, is 10, but if the lines are long, it can go as low as 5 percent. He said, in the Washington area, because it is very compact, electric utility distribution systems, their line loss is only about 10 percent. But I assume out in the West and in districts such as the one I represent, which has some wide-open spaces in it, that the line loss could go as high as 20 percent, and I still think that is a significant factor.

Mr. HECKMAN. It is a little less than 10 in Ohio because we are fairly compact. But that is not the only type of thing. For instance, we could make more efficient boilers when we are burning coal, converting the fuel to electricity; we could find more efficient ways to do that. That is an appropriate thing the Federal Government should be looking into to provide basic research dollars for. There is only so much available.

Mr. BROWN. I would agree, and it isn't in this bill because none of it goes before the Science and Technology Committee. Nothing precludes them from originating this and adding it to our legislation or pushing it forward separately, but it is a commentary, I think, that it wasn't in the administration program.

Mr. MAGUIRE. I yield to the gentleman from Indiana.

Mr. SHARP. I am sorry I don't know all the facts of this, but there is, of course, already, and has been, ERDA budget money set aside for conservation projects. Whether it has been used on these specific cases, I don't know. I certainly think it should be, and I think it is the thrust in the energy plan, though it is not in this particular legislation, to try to step up that kind of research and development, and, of course, there already is some $13 million or so in the FEA budget to help stimulate demonstration projects.

Mr. HECKMAN. There is money in almost all of the budgets, but I am saying for some basic research techniques there isn't enough being spent, and the Federal Government certainly can take the leading role in that, and I think they should.

Mr. SHARP. I absolutely agree with you.

Mr. HECKMAN. There is a whole list of projects that I can tell you EPRI is funding. They have around a $135 million budget and could easily spend $500 million to $600 million very wisely and efficiently.

Mr. SHARP. I couldn't agree with you more. As I understand, part of the philosophy of the past administration of ERDA was to go for the big giant technological, exotic projects rather than taking fewer dollars and the greater immediate return on them for some other things.

The present administration has at least indicated philosophically they want to go in a different direction on that. I certainly support them.

Mr. MAGUIRE. I think there is one question more that Mr. Brown wants to ask, and that probably will conclude us.

Mr. BROWN. Mr. Batinovich, the comment you made about California's success in inducing individual homeowners to undertake insulation programs, I would like to know how you did that. It seems to me that California is not a State which would be inclined to rush to install insulation whereas I would think Ohioans and folks in Pittsburgh might, and we have had testimony today from Mr. Heckman and also from the Pittsburgh utility, that they have tried a promotional program with very poor results.

Can you explain to me what the unique qualities of your program were that got such a success in California?

Mr. BATINOVICH. I guess there are a lot of things that make some things successful. I guess I would have to tie it to one area, nd I am not known for praising people too often, but I would have to say the utility companies, themselves, deserve the most credit. I think we gave them the nudge on a financial basis, but I think they went out and did an excellent job of talking about the elimination of waste and the cost benefits of insulation, and having a series of programs, most of which I am sure you have heard about, similar type of programs, but I would have to say that our utility companies, with a strong nudge from the Commission indicating that we are going to reward or penalize your rate of return if we don't think you have done a decent job in conservation, because the job is to keep houses warm, not sell Btu's, and if you reduce your sales, we realize we have to increase the unit cost. Conservation does cost money per unit.

Your bill, if you don't conserve, might be four, and if you do it, might be two, but today it is only one, and that is just the facts of life. But I would have to say it was strong cooperation on the part of the utilities.

Mr. BROWN. Would you give us some specific materials or information on it? I don't ask you to elaborate further now, but I know the Pittsburgh utility people indicated they did a promotional effort with advertising in the local media and didn't have a response. I think the Ohio effort was at least a legitimate effort, and the response there has been somewhat limited apparently.

Mr. HECKMAN. I think we will get more response when it is finally resolved whether or not Congress is going to give tax incentives and this sort of thing. I think Ohioans needed the winter

we had to encourage them, and we have it started, but now the Congress is saying do this sort do that, and they are holding off a bit.

Mr. SHARP. If I could ask Mr. Batinovich to repeat what he said about the education process on the unit cost, because I have constituents who tell me, "If I conserve on my electric bill and gas bill, I pay more."

Mr. BATINOVICH. I would say it this way. I was rushing it. On the assumption that energy is the equivalent of one today, and I talked to consumer groups, and they ask me, "I keep conserving and the bill goes up," I say that they still have to have a total revenue requirement, the utility company does, and if we don't do anything, I say energy, if you can get it, it is going to cost you 8, and if we do everything right, whether it is regulation, deregulation, we get the maximum amount of gas, the best conservation, we do everything perfect, it is probably going to cost us 3-1/2, and you have to understand that that is where we are.

Mr. BROWN. In other words, it is the old argument, where we would be without this is, in a much worse position?

Mr. BATINOVICH. I might add we are doing now an intensive study to show what the effects of conservation over the last 2 years in California have been and trying to establish some kind of form of letting the public know, first of all, where they would have been, what the rates would have been had there not been lifelines, what the rates would be if they had not conserved.

We are trying to get this information, and obviously we have only been at the program a little over two years, and it takes that much time to get into. We are now preparing that data, because I think the public wants to know what did I accomplish by conservation, and all they know is their bill has gone up in California. That is all they do know for a fact.

Mr. MAGUIRE. Gentlemen, you have been patient. We thank both Mr. Heckman and Mr. Batinovitch, who has been so patient he has probably missed his plane back to California, but stay among the magnolias a bit longer. We are glad to have you.

Thank you very much.

[The following statements and letters were received for the record:]

American Iron and Steel Institute

May 25, 1977

AMERICAN IRON AND STEEL INSTITUTE'S COMMENTS
ON PROPOSED NATURAL GAS PROVISIONS
H.R. 6831 - THE NATIONAL ENERGY ACT

The American Iron and Steel Institute (AISI) is a trade association representing the American Steel Industry. Its domestic membership consists of 64 companies who produce 93.5% of the steel made in the United States.

The steel industry is unique among energy users in the United States because it is the only major industrial consumer that derives the majority of its energy from coal. It is one of the few industries that has consistently maximized the use of by-product gases. In 1976, blast furnace and coke gas used by the steel industry was the equivalent of 850 billion cubic feet of natural gas. These gases are derived from coal.

Energy Consumption in the Steel Industry
Year - 1976

Energy Form	Consumption	MMBtu Equivalent	% Total
Coal	78,698,842 tons	1,870,277,948	67.0
Natural Gas	520,859 million cu ft	537,005,910	19.3
Petroleum	39,896,508 barrels	250,829,354	9.0
Purchased Electricity	38,547 million kwh	131,523,486	4.7
		2,789,636,698	100.0

The data shows that the steel industry obtains more than two-thirds of its energy from coal. Nevertheless, our members and particularly the plants without by-product fuel, do depend on natural gas for certain process and finishing operations where

the use of alternate fuels is not technically or metallurgically feasible.

The steel industry commends the President for his decision to tell the American people the seriousness of the nation's energy situation. While we may not fully agree with every aspect of his proposals, we will do all we can to contribute to a change in this country's approach to energy consumption and the development of new energy resources. We urge that the principle of equity, included by the President as one of his ten energy goals, remain the fundamental guideline to all deliberations on the energy program.

This is the first opportunity our organization has had to review a comprehensive national energy program. We wish to comment on the natural gas provisions in a constructive manner to assist in developing the initial proposals into a workable system with minimum economic disruptions.

We recognize that the nation's economy has so many interrelated activities that even the most respected economists can honestly disagree on the expected results of some proposed government action. The following comments are based upon a working knowledge of our industry with which those drafting the Energy Plan may not be familiar.

The United States has developed into a strong nation by practicing the concepts of free enterprise. Why abandon a successful method when faced with solving a major national problem?

Free market pricing of any product results in each user making an economic judgement regarding its use. Experience has shown that as the price increases, additional supplies or viable alternates will be developed. The proposed program clearly

acknowledges that the price and supply problem of natural gas has been the outgrowth of over-regulation and misguided policies. As a solution, we are asked to believe that new price controls and more extensive federal regulation will solve the problem. We do not believe that this will accomplish the objectives. The incentive in this program to develop additional sources of natural gas is not adequate.

We would like to comment on five specific areas of the proposed legislation as it relates to natural gas.

NEW GAS DEFINITION

In our opinion, the definition of new gas proposed in H.R. 6831 will limit the potential for increased exploration and production. It seems unwise not to use every possible means to increase production, since the plan encourages production of SNG and imports of LNG, at much higher prices than permitted for natural gas.

The proposed definition as stated in H.R. 6831 Section 402 (5) has no known relationship to any exploration or development practice and is far more restrictive than the FPC position in Opinion 770-A or in any proposal considered seriously by Congress.

There are a number of areas in the United States which have over the years been extensively drilled, but still contain significant known gas reserves. As an example, the oil and gas producing areas in the State of Ohio have very specific producing zones and thousands of existing wells. It would be extremely difficult to drill any new well which would qualify as new gas under the proposed definition.

While S.256 has not become law, it does contain a workable definition of new gas in its proposed amendment to Section 4 (a) Section 2 of the Natural Gas Act. We recommend that this language be used in any legislation which defines new gas or oil.

NATURAL GAS RATE DESIGN AND REGULATORY POLICIES

Section 543 appears to propose a flat rate structure to all gas consumers. Such a proposal ignores any concept of cost of service principles. It must be remembered that the delivered cost of gas consists of two parts; first the acquisition cost of gas, and second, the cost of transportation and distribution at rates set by the FPC and various state regulatory agencies. Part one, the acquisition cost of gas, has always been paid in full by all customers. Part two, consisting of transportation and distribution charges, has been paid by the user at rates which may vary, but which are based upon sound cost of service principles. The historic system of utility rate-making using the cost of service has provided a means for each consumer to pay his fair share of the cost. An energy program based upon the principle of equity must provide pricing based upon cost of service.

Industry has over the years provided a service to the residential user by helping to pay pipeline amortization charges and other utility costs during periods when the residential demand was low. As industry converts to other fuels from natural gas, the cost of the transportation and distribution will shift increasingly to the residential user. Even given a fixed wellhead price of gas, the future increase to residential prices will be substantial since the transportation and distribution costs will be spread over a smaller number of cubic feet than in the past.

Sections 544 and 545 set up the Administrator as a Super Regulator with jurisdiction to control the policies and rate setting function of State public service commissions. For years, each state commission has balanced a number of regional factors in establishing rate design. Each state must protect the financial health of their utilities. We would be very concerned if federal pricing policies are mandated which would make utility revenue solely dependent upon the weather conditions affecting home heating. The danger is that utility revenue will become dependent on the residential load. In a mild winter, the revenue from this load may be insufficient to cover the utilities' fixed costs.

While conservation of natural gas is a desirable goal, it cannot be used as a reason to ignore the many years experience and practice in rate-making which has been developed by the professional staff of each regulatory commission.

We believe that utility regulation is best left with existing State Agencies within the current jurisdictional boundaries.

INCREASED PRICING LOAD UPON INDUSTRY

Section 414 places any new increase in the cost of gas upon "so called" low priority large commercial and industrial users. The reason put forward is that industry has more of an opportunity to convert to coal than residential users. Everyone must understand that industry does not pay for anything. The costs, by definition, eventually go right through to the purchaser of the final product. If not, that product will disappear from the market place.

It must also be remembered that costs placed upon industrial production are not passed through to the consumer on a dollar-for-dollar basis. For example, the increased cost of the product in inventories would incur increased personal property tax, and in most cases, the final sale will involve a sales tax on the higher product price.

If the first cost increases are placed on industry, the immediate effect will be to freeze the Purchased Gas Adjustment in residential rates. This will put gas heated homes in a subsidized category which discriminates against those whose homes are heated by oil, propane or electricity. In addition, this will create a false signal to home owners which will do nothing to encourage conservation at the residential level. While statistics may vary, the residential use of gas is approximately 40% of the national gas load, and will continue to increase as new homes are connected.

Another problem arises as industry converts from natural gas to alternate fuels. By law, a utility is able to recover its costs and earn a fair return. The acquisition cost of gas must be paid back to the utility as part of its delivered price. As industry converts from natural gas, the volume of industrial gas will drop. For the utility to recover its gas acquisition cost, the cost increases formerly included in industrial rates will then suddenly be thrust upon the residential rate. This will cause a much swifter rise in costs of home heating than the change in price of natural gas at that time.

While delay in the increase of residential rates may appear to be desirable in the short view, it will undoubtedly cause a consumer reaction at the time home heating rates rise rapidly

to absorb increases previously paid by industry.

We believe that discriminatory pricing against any class of user is self-defeating. It is preferable for everyone to pay the cost of energy directly rather than to have a higher residential subsidy buried in the cost of consumer products.

In the market place, the consumer has the final choice whether or not to buy higher priced products. Whether he does or does not buy, the product cost will be included in various cost of living indices. Many collective bargaining agreements now include COLA (Cost of Living Adjustment) provisions which will react to index increases granting automatic wage increases. Any increase in product cost mandated by governmental policy is clearly inflationary.

CONTROL OF INTRASTATE MARKET

The extension of federal jurisdiction from control of interstate commerce to control and pricing of all natural gas in the ground is a long step. Such a radical departure from the concept of private property rights needs to be fully explored before being incorporated in any legislation.

In the past four to five years, the only bright spot in gas development has been the intrastate supply of natural gas. With a free market establishing price, exploration and development have responded to meet the demand. Based upon supplies in regional areas, market prices have both risen and fallen within reasonable limits. It is inconsistent to admit the failure of price controls in the interstate market and then immediately attempt to impose similar controls on the intrastate market that has been functioning smoothly.

The proposed National Energy Plan states that natural gas is a national resource. Many would argue that this has never been established as a policy. Natural gas has always been considered the private property of the landowner. The concept of federal control over all pricing and utilization of natural gas in the U.S. is clearly breaking new ground.

USER TAXES ON ENERGY

The user tax concept assumes that it is technically and economically feasible for industry to convert from natural gas to coal. This is an over-simplification.

In developing curtailment plans to distribute natural gas supplies, the Federal Power Commission recognized that in industry, there were certain end uses where no substitute could be used. In the FPC 467-B Plan, these users were placed in Category 2.

The proposed plan makes no distinction in application of a user tax on industrial natural gas use between substitutable or convertable uses and Category 2 uses. Some examples in the steel industry would include heat treating of alloy plate, metallic and non-metallic coating operations, pilot lights for oil-fired furnaces, and flame stabilization for blast furnace gas fired boilers. The National Energy Act proposes the user tax as encouragement of conversion to coal, but in the case of Category 2 gas, this will not be an incentive, merely a simple tax increase. This tax load could conceivably be the last straw to some marginal operations, and cause shutdowns and loss of jobs.

In some industries, many plant locations have their processes and equipment tied to the economics of using natural gas obtained

under private, long-term contracts. In these cases, an increase in the cost of natural gas caused by a tax on the user, will cause severe economic problems. In effect, this is retroactive legislation wiping out many years of sound business decisions based upon long-term fuel commitments.

Industry's plans for energy conversions have been based on long-term contracts. Even if unlimited capital was available, the permits necessary for any major coal firing facility could not be obtained from EPA by 1979. Existing approval steps for an Environmental Impact Statement now take a minimum of 19 months.

Following permit approval, experience has shown that in heavy industry, at least another three years would be required for the facility to become operational. This period would include lead time before delivery of equipment, the construction phase, and operational start-up.

The earnings in the steel industry have been at an unhealthy low level for a number of years. Significant tax increases would have to be passed through in product cost, or would cause operations to shutdown, with a resulting loss of jobs.

This user tax is contrary to the stated objectives of not penalizing any individual or regional area. The tax will eliminate differences in gas transportation costs. The result may be a loss of the competitive position of various segments of industry who had the foresight to locate facilities in producing areas.

In summary, the user tax makes no distinction between necessary end uses and "so called" wasteful uses. The user tax will not operate to encourage increased exploration and development of new natural gas supplies.

Phoenix
Financial Corporation 1587 N.E. Expressway—Suite 130, Atlanta, Georgia 30329 (404) 321-4611

POSITION PAPER

NATIONAL ENERGY POLICY MUST RESOLVE THREAT OF IMMEDIATE NATURAL GAS SHORTAGE

One of the greatest challenges ever to test the American free market system lies in the creation of an effective national energy policy that offers: (1) incentives for increased exploration and production of natural gas to meet our immediate energy needs; (2) an extensive energy conservation program to prolong the supplies of our finite energy resources; and (3) a concerted effort by industry leadership to develop alternate, renewable sources of energy.

The most critical energy issue facing our nation today is that we must immediately increase proven domestic natural gas reserves. A thorough analysis of recent developments mandates that the most effective solution to this complex problem lies in the permanent deregulation of the price of natural gas.

To increase the domestic production of natural gas, invested capital must be guaranteed a reasonable return, an end that would be accomplished by letting the free market set its own price.

In the year prior to President Carter's energy statement on April 20th, Phoenix Financial Corporation, a nationwide financial planning organization, developed proven reserves of 3½ billion cubic feet of natural gas utilizing the limited tax incentive programs available in the law.

— more —

J. Chandler Peterson, president of the Atlanta-based firm and chairman of the International Association of Financial Planners' National Advisory Council, believes that if there were a more favorable investment climate, new natural gas exploration and production would show a marked increase.

"In an inflationary economy," Peterson explained, "private capital will not chase investments that are based on fixed prices, such as the President's proposed energy policy suggests. By deregulating natural gas and letting the free market set its own price, supply and demand would equate and private capital would again become interested in financing new exploration and production. If this were combined with a structured tax incentive program to plow the resulting profits back into even more exploration and development by the gas companies, the threat of windfall profits could be avoided, the nation would be awash with natural gas and savings could eventually be passed to the consumer in the form of lower prices and a guaranteed supply," says Peterson.

Last winter, shortages, curtailments and industrial cutbacks brought the energy crisis to the national scene. Yet even if the winter had not been so severe, the Federal Power Commission had predicted that curtailments for the 1976-77 heating season would cause gas supplies to fall 3.8 trillion cubic feet below contracted deliveries, a 26.7% increase in shortfall over the previous winter.

Additionally, a National Science Foundation Project at MIT indicates that at present prices, the gas supply situation will only worsen between now and 1980. While most plants have reopened, natural gas shortages will not end with the coming of spring. In fact, industrial curtailments of deliveries are expected to continue throughout the summer as gas companies attempt to rebuild reserves for the coming winter of 1977-1978.

- more -

Because natural gas supplies approximately one–third of total U.S. energy and 47% of our industrial energy, its importance to the American economy can hardly be overstated. Curtailment of this energy source last winter caused one million Americans to lose their jobs, with unemployment caused just by the gas shortage reaching two million in February 1977.

In response to the recent crisis, Congress passed the Emergency Natural Gas Act of 1977, allowing inter–state users facing curtailment to go to the Intra–state market for their supplies through government–controlled price limit exemption. Far from ending the disparity existing between inter–state and intra–state prices, this legislation offered only a temporary placebo to an emergency situation, providing neither a reliable market nor a consistent price for gas producers.

Offering a solution to the price disparity by setting a federally regulated fixed price level, the National Energy Policy as proposed by President Carter offers only false hope for solving the immediate problem, as there would be no new incentives for increasing gas exploration and production throughout most of the United States. Today, gas demand far outweighs supply, and projections for future use indicate steadily increased consumption. The Institute of Energy Analysis at Oak Ridge, Tennessee projects a 2.5% to 3% demand increase per year to the year 2000. However, even with less than a 2% increase, such as the President's plan calls for, current production levels of natural gas would fall far short of meeting the demand.

The most direct method of increasing domestic production of natural gas is by increasing the price. Not only would this help discourage unnecessary use, but it would also encourage expanded development of gas resources.

The April '77 issue of Oil and Gas Journal states that with increased prices, "not only are large gas finds likely in many scattered areas around the United States, but myriad deposits of small, low–volume deposits throughout the most heavily developed portions of U.S. oil and gas country could add up to very large new supplies if prices were high enough to warrant development."

A study by Breyer and MacAvoy, leading researchers on the energy shortage, indicates that "new reserve supplies might be three times greater" if there had been no gas regulation.

An example can be found in the Texas panhandle, where new wells increased 50% the year after deregulation for small producers in 1971. By comparison, between 1954––the year price regulation of natural gas began–– and 1974 the number of independent drillers decreased from 38,000 to 3,800. Today, three years later after limited deregulation of the inter–state price of natural gas, the number of independent drillers has increased to well over 10,000. Total deregulation should produce all the gas we can consume and more.

A basic fear underlying the Carter proposal is that the American economy could not handle the rapid increase in gas prices that would accompany deregulation. Comparing regulated to deregulated gas prices, the General Accounting Office of the U.S. Government feeds this fear with estimates that with deregulation, the cost of the United States natural gas bill would increase $13 billion by 1980.

However, these figures do not take into consideration the harm gas shortages do to both industry and the economy, or the economic and social costs of more expensive gas alternatives that must be used to augment these shortages. What most Americans are not aware of is that the replacement cost of the 15% natural gas shortage last winter equalled the entire cost of the available gas supply.

The GAO estimate also fails to consider the value of conservation to extend gas supplies and the resultant value of encouraging development of alternative energy sources.

In a revealing energy cost comparison, if deregulation of natural gas brought the price of 1,000 cubic feet up to a level between $2.50 and $3.00, it would be equivalent to paying approximately $3.00 per million B.T.U.'s. By comparison, Americans are presently paying $2.05 per million B.T.U.'s of natural gas, $3.00 per million B.T.U.'s of fuel oil, and $10.00 per million B.T.U.'s of electricity. So, even at the $3.00/mcf level, natural gas would still be a comparative bargain in terms of net B.T.U. equivalence.

Finally, in direct contrast with past estimates, recent evidence shows that with deregulation, 20,000 trillion cubic feet of natural gas reserves would become available, as opposed to 200 trillion cubic feet available at today's prices. This increase, in effect, would mean that at the present rate of consumption, our nation's gas reserves could last over 1,000 years.

Supplying the citizens of the richest country in the world with natural gas reserves capable of running their industrial plants and heating their homes without the threat of curtailment and cutback should be the first priority of a national energy policy and requires immediate action. The most realistic, democratic approach toward achieving this goal is through deregulation. When all consequences are taken into account, the benefits of placing our faith in the free market system will greatly outweigh the false security created by the restrictive arm of federal regulation.

* * *

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cable address: AMPAPINST New York

May 27, 1977

The Honorable John D. Dingell
Subcommittee on Energy and Power
Committee on Interstate and Foreign Commerce
United States House of Representatives
Washington, DC 20515

Dear Chairman Dingell:

Comments on H.R. 6831
Title I, Part D--Natural Gas

The American Paper Institute, the national trade association of the pulp, paper and paperboard industry, is pleased to be able to submit for the record the following comments and recommendations on Title I, Part D -- Natural Gas -- of H.R. 6831, the National Energy Act.

As one of the ten most energy consumptive manufacturing industries in the nation, we are vitally concerned with the development of a national energy plan that will encourage both conservation and the development of new energy supplies. A review of the natural gas provisions has revealed to us, however, that, because federal controls over natural gas pricing would be extended and expanded, neither one of these important goals will be met.

We believe the Administration identifies the cause of today's natural gas problem correctly when it states in Section 401 that historic cost-based price regulation of natural gas has resulted in declining incentives to find new natural gas while, at the same time, stimulating natural gas demand for purposes that - in many cases - are inconsistent with the fuel's unique qualities.

But the regulatory concepts the Administration proposes to replace cost-based pricing seem equally questionable and will create the same uncertainties and disincentives for conservation and exploration that have brought the nation to its present energy dilemma.

The American Paper Institute therefore recommends, as it has on two previous occasions before your Committee, that new interstate natural gas prices be freed from federal control.

Background and Industry Patterns of Energy Use and Conservation

The paper and allied products industry has approximately 6,000 facilities in virtually every state. It employs more than 680,000 people whose wages, salaries, and benefits exceeded $11 billion in 1976; and its net sales during that year totaled approximately $39 billion.

In 1976, the pulp, paper, and paperboard industry consumed 320.6 billion cubic feet of natural gas, down from 453.4 billion cubic feet in 1972. In terms of its contribution to total energy requirements, natural gas declined from 20 percent in 1972 to 15 percent in 1976. This loss of a significant energy supply source required rapid and expensive investments to substitute other energy sources. During this same period, the contribution of fuel oil rose from 23 to 24 percent, and purchased elctricity's share increased from 4 to 5 percent. Coal use declined from 10.5 to 9.5 percent of total energy consumed.

The most significant change, however, was in self-generated and waste fuels which increased their contribution to total energy consumed from 42 to 45 percent over the four-year period. This change represented an annual savings in 1976 of 8.4 million barrels of oil equivalent. Self-generated and waste fuels include bark, hogged wood (chipped residues from forest and manufacturing wastes) and spent pulping liquors from which chemicals as well as energy are recovered. Spent pulping liquors are largely lignin and, together with bark and hogged wood, are derived from trees, which themselves utilize solar energy.

The patterns of our industry's energy use have been clearly revealed by API's monthly Energy Monitoring System which was established in late 1974 in response to the Federal Energy Administration's voluntary energy-use reporting program. This monitoring system covers 85 percent of the industry's production.

In 1976, the industry reduced its use of fossil fuels and purchased energy per ton of product by more than 9 percent compared to 1972. However, there have been a number of significant operational changes affecting energy efficiency in the industry between 1972 and 1976. These operational changes included reduced capacity utilitization and increased environmental energy consumption. When appropriate adjustments for these factors are made, the industry's 1976 consumption of fossil-fuels and purchased energy per ton was 12.1 percent less than in 1972.

We have attached copies of API's Energy Fact Sheet and most recent Monthly Energy Report for your additional information.

The Administration's Proposed New Pricing Concept for Natural Gas

The Administration has proposed to replace the government's present historic cost-based pricing of natural gas offered for sale in the interstate market with a new system which recognizes "the costs and risks associated with finding future supplies of natural gas as well as the commodity value of substitutable fuels." It would extend this new pricing system to cover intrastate as well as interstate gas sales. The bill proposes to accomplish these goals by pricing new natural gas

at the BTU equivalent of the average per barrel crude oil acquisition cost for U.S. refineries.

In reviewing this proposal, we have seen no background data presented by the Administration which shows how it determined that $1.75 per MCF for new gas (the specifically suggested price in the President's Plan) meets the costs and risks associated with finding future supplies of gas. Rather, it appears to us that current natural gas prices in the uncontrolled intrastate markets (over $2.00 per MCF) give a better indication of the prices these costs and risks require, and we have seen the proof of it in the market-clearing effect in these intrastate markets.

In addition we must question whether crude oil - at whatever cost - represents a fuel substitute for natural gas. Certainly, not even refined petroleum products have the same premium qualities as natural gas.

In the section on "Findings and Purposes," the proposed bill also states that it intends to bring the natural gas market back into better balance by reducing the demand for natural gas and increasing the supply through the establishment of an incentive based pricing approach for new natural gas.

We must question, however, the proposed bill's effectiveness in dampening demand because the new price control system would not allow the BTU price for natural gas even to approach that for distillate fuel oil - which may be broadly substitutably for natural gas. Distillate fuel oil typically sells at prices a third higher than crude oil

Continuing, as the bill proposes, present low prices of natural gas to residential and commercial consumers would be a strong disincentive to conserve, especially when the proposed bill would allocate all new, higher-priced natural gas to industrial consumers.

If the Administration intends to eliminate industrial boiler fuel use of natural gas by these so-called incremental pricing measures, it should recognize that it already provides for this objective in its proposed amendment to the Energy Supply and Environmental Coordination Act by granting FEA the authority to prohibit boiler-fuel use of natural gas.

We firmly believe that the allocation of higher prices to industry alone will not achieve the Administration's stated objective of reducing demand for natural gas.

Furthermore, we see no evidence of "incentive based pricing to improve supply" in the proposals. Cost-based controls have already proved to be a disincentive to supply and controls based on such an arbitrary concept as the BTU equivalent cost of crude oil can be expected to induce a further disincentive in the future.

Decontrol of New Natural Gas Prices is the Best Answer to a Difficult Problem

It is clear to us that, in developing its natural gas proposals, the Administration has fallen into the trap of believing that, through another form of price control, it could avoid undue cost impacts on residential gas consumers, windfall profits for gas producers, and still solve the difficult problem of reducing natural gas demand while increasing new supplies.

As manufacturers of pulp, paper, and paperboard, and as businessmen, we have had direct experience with price controls and know how they can introduce uncertainties and severe distortions into the marketplace to the extent that both consumers and suppliers are ill-served.

After careful examination of the Adminstration's proposals for a new system of price controls, we can find no aspects which would give any prospects of avoiding the inherent problems of all price control systems, or which would in any way relieve the problems that, as the Administration itself recognizes, price controls have brought to the natural gas markets in the past. Under these circumstances, we recommend that the Committee consider and approve alternative legislation that would decontrol prices of new natural gas. We firmly believe that such decontrol is the best answer to a difficult problem.

Sincerely yours,

Ronald J. Slinn

Ronald J. Slinn
Vice President
Pulp, Fiber and Raw Materials

Attachment

RAW MATERIALS & ENERGY DIVISION
AMERICAN PAPER INSTITUTE
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March 1977

A FACT SHEET ON ENERGY IN THE U.S. PAPER INDUSTRY

A. The paper industry ranks among the top manufacturing consumers of energy.

1. The paper and allied products industry is the fifth largest consumer of purchased energy among manufacturing industries in the U.S. and the largest consumer of fuel oil.

B. Almost half of the paper industry's energy comes from non-fossil fuels.

2. Surveys conducted by the American Paper Institute show that the industry derives almost half of its total energy requirements from its own process wastes - spent pulping liquors, bark and hogged wood. In 1976, these non-fossil, renewable fuels provided 44.6% of the total BTU's consumed by the industry - an increase from 41.1% in 1972 and 42.6% in 1975.

   Self-generated hydro-electric power and other self-generated energy provided a further 0.8% in 1976 (0.8% in 1975, 0.6% in 1972).

3. The 54.6% of fossil fuels and purchased energy consumed by the industry in 1976, contrasted with 1975 and 1972, consisted of the following: -

	1976	1975	1972
Residual fuel oil	23.2%	22.9%	21.7%
Distillate fuel oil	0.8%	0.7%	1.0%
Coal	9.5%	9.1%	10.5%
Natural gas	15.1%	18.1%	20.3%
Purchased electricity	5.0%	4.8%	3.9%
Purchased steam	0.8%	0.8%	0.8%
Other purchased energy	0.2%	0.2%	0.1%
Total fossil fuels and purchased energy	54.6%	56.6%	58.3%

C. API initiated an industry wide conservation program in October 1973.

4. Early in 1973, API, in cooperation with the Technical Association of the Pulp and Paper Industry, set up an Energy Conservation Committee which, among other steps, initiated a conservation program based on a brochure "21 Ways to Save Energy" at API's Annual Presidents' Forum on October 19, 1973, - just two days after the Arab oil embargo was announced.

D. API has established communications with energy coordinators in member companies and organizes special energy conferences for them.

5. Through its Raw Materials and Energy Division, API has established the means for quick communication with energy coordinators within API member companies. In order to inform the appropriate officers in API member companies of the latest developments in energy regulations as well as energy conservation opportunities, the division maintains a periodic Raw Materials Newsletter.

6. API has convened four national energy conferences subsequent to October 1973, bringing together the energy coordinators of API member companies. These conferences have provided a forum for valuable exchanges on programs such as energy conservation initiated by member companies. They also serve to disseminate important information on energy legislation and regulations affecting the operations of pulp and paper plants.

E. The paper industry has supported proposals to expand the domestic supply of energy and to improve industrial energy efficiency.

7. API has lent support to legislation which would deregulate the well-head price of "new" natural gas as well as to proposals which would accelerate the leasing of offshore drilling sites.

API's Executive Committee has expressed the industry's preference for decontrol of domestic fuel oil markets, despite the fact that such a step would significantly increase its raw material costs. Changing regulations, especially on prices, add to the uncertainties with which industrial planners must contend. Decontrol would stimulate domestic oil production and encourage conservation.

API has testified on several occasions in support of government programs which would accelerate the development of new domestic energy sources and more energy-efficient industrial technologies.

F. The paper industry is committed to voluntary energy conservation programs.

8. On October 15, 1974 some 40 executives from 30 API member companies met with former Secretary of Commerce Dent and former Federal Energy Administrator Sawhill. At this meeting, the API group emphasized its commitment to voluntary energy conservation programs and, in response to Administrator Sawhill's request for a specific energy conservation goal, the API group suggested that the industry's reduction in purchased* energy per ton of output from 1972 to 1980 be set at 10%, provided environmental requirements do not interfere.

9. The Energy Policy and Conservation Act (December 1975) authorizes the Federal Energy Administration to set energy efficiency improvement targets for the ten most energy consumptive industries which include the pulp, paper, paperboard, building board and converting industry, (SIC 26).

API has advocated that the target for the SIC 26 industry be set in terms of fossil fuels and purchased energy rather than in terms of total energy. Such a target would be consistent with the national objective of reducing U.S. dependence on foreign sources of oil. It would also provide the industry with an incentive to expand further its substitution of non-fossil (but less efficient) waste fuels for oil and natural gas.

G. The industry's increased use of self-generated and waste fuels in 1976 has saved the equivalent of 8.4 million barrels of fuel oil.

10. The contribution of self-generated and waste fuels energy to the industry's total energy requirements increased from 41.7% in 1972 to 45.4% in 1976. The impact of this 3.7 percentage points increase, (after taking into account the lower efficiences of waste fuels relative to oil), was an annual saving of the equivalent of 8.4 million barrels of fuel oil at 1976 pulp, paper and paperboard production rates - a little more than one day's oil imports into the U.S.

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* The term "purchased energy" was intended to include all fossil fuels as well as purchased electricity and steam.

H. API has set up a MONTHLY energy reporting system to monitor the industry's conservation efforts.

11. During the October 1974 meetings with Administration representatives, API agreed to establish an industry-wide monthly reporting system to provide a means of monitoring the results of the industry's energy conservation efforts. This system was initiated in November 1974. Participation during 1975 and 1976 represented almost 80% of the industry's production of dried pulp, paper and paperboard and includes companies which are not members of the API.

The system is being expanded to cover converting operations in order to meet the criteria of adequacy under the provisions of the Energy Policy and Conservation Act which require reporting of improvements in industrial energy efficiency.

12. An advantage of the monthly basis in API's Energy Monitoring System was the early revelation of several important factors which affect energy efficiency in the pulp and paper industry. For example, over a range of capacity utilization rates from 70% to 90%, a 10 point reduction in capacity utilization results in a 5% increase in fossil fuels and purchased energy consumption per ton of product.

I. The pulp and paper industry has made significant progress in reducing its unit consumption of fossil fuels and purchased energy.

13. During 1975, lower capacity utilization rates resulting from the nation's economic recession inhibited the industry's ability to reduce its unit consumption of fossil fuels and purchased energy more than 4.1% when compared with 1972 consumption.

Improving economic conditions in 1976 permitted higher levels of energy efficiency which, when combined with specific conservation efforts, resulted in a 10.8% reduction in fossil fuels and purchased energy consumption per ton over the first seven months of 1976 compared with the same period in 1972.

Unusually cold weather over the concluding months of 1976 brought the industry's fossil fuels and purchased energy consumption per ton for the year as a whole to a level 9.7% below that for 1972.

Ronald J. Slinn
Group Vice President

Jeffrey M. Duke
Division Manager

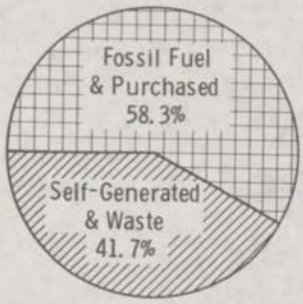
TABLE 1

SOURCES OF ENERGY CONSUMED
BY THE U.S. PULP, PAPER AND PAPERBOARD INDUSTRY

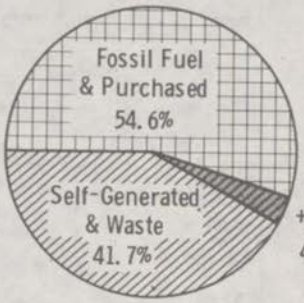
(Percentages)

SOURCES	1976 - (Preliminary)	1975	1972
Purchased Electricity	5.0	4.8	3.9
Purchased Steam	0.8	0.8	0.8
Coal	9.5	9.1	10.5
Residual Fuel Oil	23.2	22.9	21.7
Distillate Fuel Oil	0.8	0.7	1.0
Liquid Propane Gas	0.1	0.1	0.1
Natural Gas	15.1	18.1	20.3
Other Purchased Energy	0.1	0.1	-
Total Fossil Fuel and Purchased Energy	54.6	56.6	58.3
Hogged Fuel (50% Moisture Content)	3.7	3.0	1.9
Bark (50% Moisture Content)	4.4	4.3	4.9
Spent Liquor (Solids)	36.5	35.3	34.3
Self-Generated Hydro-Electric Power	0.5	0.5	0.4
Other Self-Generated Energy	0.3	0.3	0.2
Total Self-Generated & Waste Fuels	45.4	43.4	41.7
TOTAL ENERGY	100.0	100.0	100.0

Sources of Energy

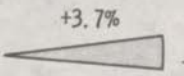


1972



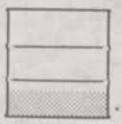
1976

Impact of Increased Use of Self-Generated & Waste Fuels*



equals

8.4 Million bbls. of Oil Equivalent Per Year



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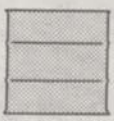

116% of one day's Oil Imports into U. S.

* Adjusted to take into account lower efficiencies of self-generated and waste fuels relative to oil.

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E 2

ISSUED: MAY 18, 1977

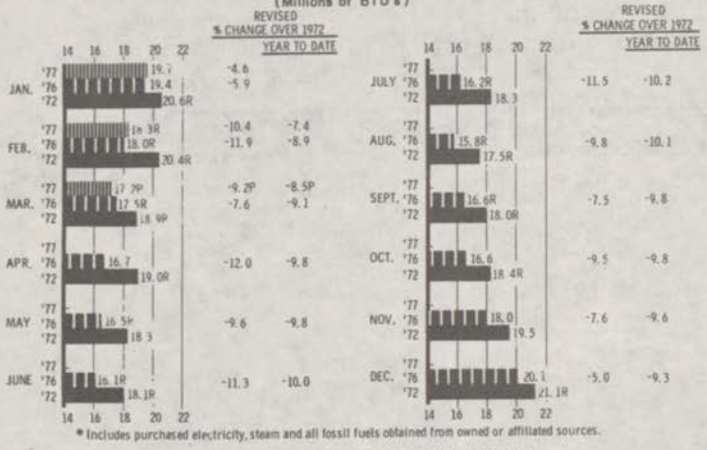
MONTHLY ENERGY REPORT

U.S. PULP, PAPER AND PAPERBOARD INDUSTRY

MARCH 1977

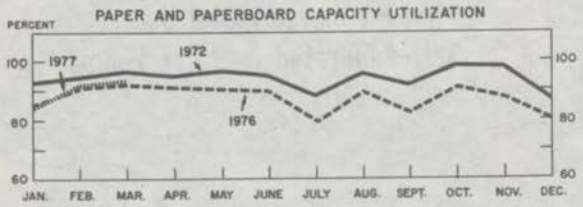
FOSSIL FUEL AND PURCHASED ENERGY* CONSUMPTION PER TON

(Millions of BTU's)

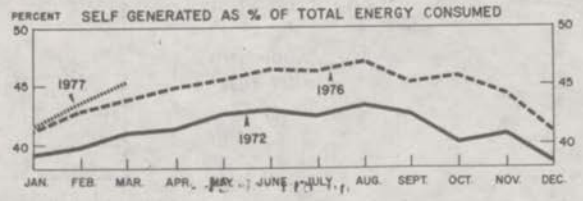


* Includes purchased electricity, steam and all fossil fuels obtained from owned or affiliated sources.

PAPER AND PAPERBOARD CAPACITY UTILIZATION



SELF GENERATED AS % OF TOTAL ENERGY CONSUMED



SAMPLE DATA USED FOR CALCULATION OF PERCENT CHANGES OVER 1972

		POSSIL FUEL AND PURCHASED ENERGY			TOTAL ENERGY		
		FEBRUARY	MARCH	YEAR-TO-DATE	FEBRUARY	MARCH	YEAR-TO-DATE
1977	ENERGY CONSUMPTION (Billion BTU's)	79,675.4R	77,750.4P	248,505.4P	142,317.3R	145,246.6P	442,438.5P
	TOTAL PRODUCTION (Thousand Tons)	4,352.9R	4,523.1P	13,505.5P	4,325.9R	4,523.1P	13,505.3P
	ENERGY USE / TON (Millions of BTU's)	18.3R	17.2P	18.4P	32.7R	31.7P	32.8P
	% OF INDUSTRY PRODUCTION COVERED	79.9R	73.9P	78.7P	79.9R	73.9P	78.7P
1976R	ENERGY CONSUMPTION (Billion BTU's)	84,161.9	87,422.6	264,596.9	148,358.6	157,044.8	465,192.1
	TOTAL PRODUCTION (Thousand Tons)	4,679.7	5,001.0	14,475.0	4,679.7	5,001.0	14,475.0
	ENERGY USE / TON (Millions of BTU's)	18.0	17.5	18.3	31.7	31.4	32.1
	% OF INDUSTRY PRODUCTION COVERED	86.3	82.6	84.9	86.3	32.6	84.9
1972R	ENERGY CONSUMPTION (Billion BTU's)	88,074.4	88,927.8	270,217.6	146,775.7	151,433.3	452,511.4
	TOTAL PRODUCTION (Thousand Tons)	4,313.2	4,599.6	13,433.3	4,313.2	4,599.6	13,433.3
	ENERGY USE / TON (Million of BTU's)	20.4	18.9	20.1	34.0	32.2	33.7
	% OF INDUSTRY PRODUCTION COVERED	81.0	78.4	81.1	81.0	78.4	81.1

PERCENT CHANGE IN ENERGY USE PER TON OVER 1972

	FOSSIL FUEL AND PURCHASED ENERGY		TOTAL ENERGY	
	1977	1976R	1977	1976R
NEW ENGLAND				
January	-12.7 R	-18.3	- 4.5 R	-11.6
February	- 9.9 R	-12.4	- 5.2 R	- 7.2
March	-10.7 P	- 9.7	-13.2 P	- 6.1
April		-14.8		- 7.8
May		-13.4		- 6.8
June		-11.6		- 6.6
July		- 6.5		- 1.4
August		- 5.4		+ 3.4
September		- 1.3		+ 0.8
October		- 9.3		+ 0.3
November		- 7.9		- 0.2
December		+ 0.6		+ 5.0
YEAR TO DATE	-10.8 P	-13.7	- 7.0 P	- 8.4
MID ATLANTIC				
January	- 8.6 R	- 8.4	- 4.9 R	- 0.6
February	-12.1 R	-14.0	- 4.2 R	- 6.5
March	-18.3 P	-13.1	-10.2 P	- 5.3
April		-13.4		- 5.5
May		-10.7		- 1.9
June		-10.4		- 2.6
July		-14.2		- 7.5
August		-11.6		- 3.2
September		-10.1		- 2.3
October		- 9.7		- 1.1
November		- 8.4		- 0.1
December		- 4.8		- 0.3
YEAR TO DATE	-13.2 P	-11.9	- 6.6 P	- 4.2
NORTH CENTRAL				
January	- 5.7 R	- 5.8	- 0.7 R	- 2.7
February	-10.4 R	-10.0	- 4.3 R	- 5.8
March	- 8.6 P	- 8.2	- 2.4 P	- 3.4
April		-10.0		- 5.0
May		- 6.5		- 1.8
June		-10.9		- 6.6
July		-10.1		- 5.9
August		- 8.4		- 3.5
September		- 8.6		- 5.0
October		- 9.3		- 4.7
November		- 7.9		- 3.7
December		+ 0.4		+ 4.7
YEAR TO DATE	- 8.0 P	- 8.0	- 2.6 P	- 4.1

	FOSSIL FUEL AND PURCHASED ENERGY		TOTAL ENERGY	
	1977	1976R	1977	1976R
SOUTH ATLANTIC				
January	+ 0.5 R	+ 0.7	+ 3.0 R	+ 2.6
February	-10.7 R	-14.2	- 1.2 R	- 4.9
March	-10.7 P	-10.2	+ 0.6 P	- 2.0
April		-13.1		- 4.9
May		- 9.9		- 2.5
June		-11.4		- 2.2
July		-14.3		- 4.0
August		-10.8		- 0.9
September		- 7.2		+ 0.7
October		-11.3		+ 2.0
November		- 9.2		0.0
December		- 7.7		+ 1.0
YEAR TO DATE	- 6.8 P	- 8.0	+ 0.8 P	- 1.5
SOUTH CENTRAL				
January	+ 0.3 R	- 4.6	- 0.6 R	- 2.5
February	- 7.9 R	-10.3	- 4.5 R	- 7.6
March	- 6.9 P	- 9.0	- 5.1 P	- 6.0
April		- 9.0		- 5.7
May		- 8.4		- 5.1
June		- 8.9		- 5.8
July		-10.4		- 5.2
August		- 8.1		- 4.7
September		- 6.9		- 4.0
October		- 6.5		- 4.7
November		- 3.6		- 2.1
December		- 4.2		- 2.4
YEAR TO DATE	- 4.9 P	- 7.9	- 3.4 P	- 5.4
MOUNTAIN & PACIFIC				
January	-13.0 R	-12.9	- 2.9 R	- 5.0
February	-14.6 R	-14.1	- 4.6 R	- 8.0
March	-16.6 P	-11.1	- 6.4 P	- 5.1
April		-16.9		- 9.1
May		-14.2		- 7.5
June		-17.8		- 7.7
July		-14.2		- 7.4
August		-16.1		- 1.9
September		-11.2		- 2.9
October		-12.0		- 3.0
November		-12.5		- 2.1
December		-12.1		- 3.5
YEAR TO DATE	-14.6 P	-12.7	- 4.6 P	- 6.0

NEW ENGLAND: Me., N.H., Vt., Mass., R.I., Conn.
MIDDLE ATLANTIC: N.Y., N.J., Penna.
NORTH CENTRAL: Ohio, Ind., Ill., Mich., Wis., Minn., Iowa, Mo., N.D., Neb., Kan.

SOUTH ATLANTIC: Del., Md., Wash. D.C., Va., W.V., N.C., S.C., Ga., Fla.
SOUTH CENTRAL: Ky., Tenn., Ala., Miss., Ark., La., Okla., Tex.
MOUNTAIN & PACIFIC: Mont., Id., Wy., Col., N.M., Ariz., Utah, Nev., Wash., Ore., Cal., Hawaii, Alaska.

P - Preliminary R - Revised

The Fertilizer Institute
1015 18th Street, N.W.
Washington, D.C. 20036
(202) 466-2700 • Telex 89-2699

EDWIN M. WHEELER
President

File No.
May 26, 1977

The Honorable John D. Dingell
Chairman, Subcommittee on Energy
and Power
House Committee on Commerce
U. S. House of Representatives
2221 Rayburn House Office Building
Washington, D. C. 20510

Dear Mr. Chairman:

You will recall during the consideration of the question of natural gas supplies and pricing before the House of Representatives last year, the measure that ultimately was adopted by the House gave American agriculture across-the-board a very high priority on the use of natural gas as a fuel. (See Section 26, H.R. 9464 as passed to the House (copy attached)).

Because the current Natural Gas Act of 1938 contains no direction on appropriate allocation priorities, we urge you to include in natural gas legislation now before your Committee a priority system similar to that adopted by the House last year. By providing essential agricultural uses of natural gas priority, the well-defined Congressional policy of maximum food and fiber production will be furthered so that the American people may benefit from adequate food supplies at reasonable prices.

Should you desire additional information or testimony on this proposed amendment, we would be more than pleased to await the call of you or your staff.

Sincerely yours,

Edwin M. Wheeler

Edwin M. Wheeler

Enclosure

cc: The Honorable Bob Bergland
The Honorable John C. White
The Honorable Edward R. Madigan
The Honorable Thomas S. Foley
The Honorable Clarence J. Brown

EMW:sln

Mobil Oil Corporation

SUITE 1030
1100 CONNECTICUT AVENUE, N.W.
WASHINGTON, D.C. 20036

The Honorable John D. Dingell
Chairman, Subcommittee on Energy and Power
House Interstate and Foreign Commerce
Committee
2221 Rayburn House Office Building
Washington, DC 20515

Dear Mr. Chairman:

I am enclosing a letter from Mr. Rawleigh Warner, Jr., Chairman of the Board, Mobil Oil Corporation, to Dr. James Schlesinger dated May 27, 1977. Mr. Warner takes issue with Dr. Schlesinger's assertion that the $1.75 per mcf price "was a substantial price on which all producers conceded they could make good money." Mr. Warner points out that that simply is not true insofar as Mobil is concerned. He further explains the need for deregulation of new natural gas.

We would appreciate it if Mr. Warner's letter could be made a part of the record in hearings held on H.R. 6831.

Cordially yours,

N. Boyd Ecker

N. Boyd Ecker

NBE/bd

cc: Honorable Clarence J. Brown

Mobil Oil Corporation

150 EAST 42ND STREET
NEW YORK, NEW YORK 10017

RAWLEIGH WARNER, JR.
CHAIRMAN OF THE BOARD

May 27, 1977

The Honorable James R. Schlesinger
Assistant to the President
The White House
Washington, D. C. 20500

Dear Dr. Schlesinger:

In view of the importance of the Administration's natural gas proposals in the national energy program, we would like you to be aware of our views. At the outset, I want to take issue with your assertion that the proposed $1.75 per mcf price "was a substantial price on which all producers conceded they could make good money." This is simply not true insofar as Mobil is concerned.

The proposed ceiling of $1.75 per mcf is, as I am sure you are aware, significantly below the price of some intrastate gas currently. The Administration's proposal to equate this price for new natural gas with the average controlled price for domestic crude oil, old and new, seems a short-sighted continuation of the very policies of the past which led to an excessive use of this premium fuel. At least, were the gas ceiling price to be equated solely to the current definition of new oil - upper tier domestic crude - the btu equivalent price would now be approximately $2.00 per mcf, which might tend to restrain gas usage. Equating natural gas to the average domestic controlled crude price unfortunately offers no such economic disincentives. Hence, one is forced, as is very clear from the proposed program, to institute a wide range set of mandatory restrictions on the future use of gas in order to reserve future supplies to premium users.

The solution of a problem caused primarily by federal control is not to be found in additional federal controls. On the contrary, removal of federal controls on the wellhead price of new natural gas offers a most effective means of eliciting new natural gas supplies. This approach will not only provide incentive to producers to develop new natural gas reserves, but will induce conservation by natural gas consumers.

We believe the Administration's natural gas proposals would discourage high risk exploration and development in frontier and offshore producing areas where most potential supplies would be located. Certainly, the proposed definition of new gas, in our judgment, is arbitrary and unreasonable. There are industry estimates that 90% of all new gas discovered last year was taken from wells within a 2 1/2 mile range of existing fields. Your indicated willingness in

Mobil

testimony to accept an alternative definition is heartening and may alleviate our concern on this situation. However, the total package coupled with our past experience as to special exceptions to FPC ceiling prices convinces us that the program is a poor approach to encouraging the search for higher cost new gas supplies.

The nation's potential natural gas resource base is more substantial than the Administration's energy planners have estimated. This potential is illustrated by several estimates. The USGS estimates potential undiscovered supplies ranging from a low of 322 tcf to 655 tcf (USGS Circular Number 725). These estimates may be conservative, due to the fact that they assume the cost/price relationships as of 1974. A study by the Potential Gas Committee, sponsored by the Colorado School of Mines, using economic criteria which assume the existence of "adequate prices and reasonable government controls," estimates, as of May 2, 1977, that between 923 and 973 trillion cubic feet of probable, possible and speculative potential reserves exist.

It is our hope that, in light of the above, you will re-evaulate your stated position and lend your support to a free market in new natural gas.

Sincerely,

Rawleigh Warner, Jr.

Rawleigh Warner, Jr.

RW:tm

NATIONAL LP-GAS ASSOCIATION
1800 N. KENT STREET (NLPGA) ARLINGTON, VIRGINIA 22209
Phone: 703/525-5135

ARTHUR C. KREUTZER
EXECUTIVE VICE-PRESIDENT
& GENERAL COUNSEL

May 27, 1977

Honorable John D. Dingell
Chairman, Subcommittee on Energy
House of Representatives' Committee
On Interstate and Foreign Commerce
U.S. House of Representatives
Washington, DC 20515

Re: H.R. 6831
National Energy Act

Dear Mr. Chairman:

The Subcommittee on Energy of the House of Representatives' Committee on Interstate and Foreign Commerce has under consideration H.R. 6831, the National Energy Act providing the statutory basis for President Carter's National Energy Plan. The National LP-Gas Association submits the following comment for consideration by your Committee.

The National LP-Gas Association is a trade association having as members suppliers of LP-gas, predominately propane. It has over 5400 members, including 43 affiliated states. Propane is a fuel, or energy source, used in over 13 million installations throughout the United States. Its principal use is on the farm, or in rural communities.

Suppliers of LP-gas are concerned with two subjects, relating to the Energy Plan, that while not treated directly in the bill, are inferentially involved in its consideration and to these subjects we direct the following comment for your consideration.

1. Synthetic Natural Gas (SNG). H.R. 6831 only deals with FPC jurisdiction over the facility and specifically provides that the Act shall not apply to the feedstock employed in SNG manufacture. This we fully support in that adequate FEA regulation exists on SNG feedstock - more particularly on propane, the product of our concern. However, we do note in "The National Energy Plan" as presented by the President under the heading "Synthetic Natural Gas" statement indicating that FEA regulations will be revised to provide a priority for SNG feedstocks.

How Should We Then Live?

The Rise and Decline of Western Thought and Culture

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Written By and Featuring

DR. FRANCIS SCHAEFFER

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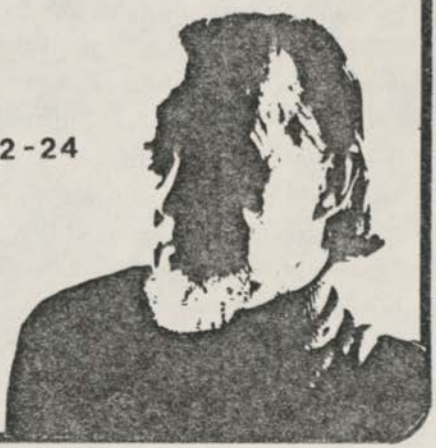

SEPT. 15 - 17 ; 22 - 24

About Francis Schaeffer

TIME Magazine called him a missionary to the intellectuals. Hundreds of college students, curiosity seekers, drifters, and spiritually hungry nomads of all nationalities and ages have sought him out in his home in the Swiss Alps. There he has developed a reputation for his ability to communicate ideas and principles to men and women from all walks of life. In the L'Abri communities and study centers in Europe, he and his staff have exposed these many individuals to Biblical Christianity, trying to meet every honest question with an honest answer.

From Harvard to the local church, in Europe, North America and the Far East, he has raised the spectre of the potentially destructive direction of our society. As a voice in the wilderness, for years he has preached that Biblical Christianity is not only true, but intellectually defensible and reasonable. He has warned that our commonly accepted human freedoms, often taken for granted in the West, are in great danger of disappearing. But, unlike most doomsayers, he offers positive alternatives for the future.

Francis Schaeffer has written a number of books including "The God Who Is There," "True Spirituality" and "Escape From Reason." These have been widely read and studied in over 15 different languages. The sales of his books have exceeded one million in the U.S. alone.

Dr. Schaeffer as

- *Why isn't it safe to walk*
- *Why is there more violen and an ever-increasing a the other?*
- *What's happening to our freedoms?*
- *Should we throw up our If not...*

How Shou We Then Liv

10 moving 30-minut

EPISODE I *The Roman A*

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EPISODE II *The Middle*

The simple devout church in was tragically corrupted by p materialism. Dr. Schaeffer tra from the ways of God to the

EPISODE III *The Renais*

Next he salutes the artistic a Renaissance man. Yet he wa in man alone and in the inev humanism.

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EPISODE IV *The Reformation*

Here he reviews the many contributions of the Reformation and its culture, declaring that a modern Reformation could rescue modern man from his dilemma.

EPISODE V *The Revolutionary Age*

Dr. Schaeffer shows historically how tyranny and terror is a result of building a culture on a non-reformation base.

EPISODE VI *The Scientific Age*

The fathers of modern science – Galileo, Bacon, Copernicus and others – built on a biblical understanding of the universe and of man. Apart from this, modern science can become the enemy of man.

EPISODE VII *The Age of Non-Reason*

In a review of modern philosophy and theology, Dr. Schaeffer illustrates man's attempted escape from reason into non-reason and his abandoning of the truth.

EPISODE VIII *The Age of Fragmentation*

Here he reviews the current fragmented state of art, music, poetry, and the motion picture as expressions of man's dilemma.

EPISODE IX *The Age of Personal Peace and Affluence*

A look at the youth of the 60's and their escape into drugs, occult, and the NEW LEFT. In the 70's the trend changes to apathy and they join their parents and accept the horrendous values of personal peace and affluency.

EPISODE X *Final Choices*

Finally, Dr. Schaeffer reviews the tragic history of the last two decades and concludes that man's only hope is a return to God's biblical absolutes – truth revealed in Christ through the Scriptures – if authoritarian society and arbitrary absolutes are to be replaced with truth once again.

HOW SHOULD WE THEN LIVE?

SEE THESE 10 EPISODES BEING SHOWN AT:

KSU UNION LITTLE THEATER

	EPISODE	TIME	DATE
I	*The Roman Age*	7:00 PM	9/15/78
II	*The Middle Ages*	7:45 PM	9/15/78
III	*The Renaissance*	7:00 PM	9/16/78
IV	*The Reformation*	7:45 PM	9/16/78
V	*The Revolutionary Age*	7:00 PM	9/17/78
VI	*The Scientific Age*	7:00 PM	9/22/78
VII	*The Age of Non-Reason*	7:45 PM	9/22/78
VIII	*The Age of Fragmentation*	7:00 PM	9/23/78
IX	*The Age of Personal Peace and Affluence*	7:45 PM	9/23/78
X	*Final Choices*	7:00 PM	9/24/78

In the fear that this approach may threaten propane supply for the historical user and may enter into your Committee's deliberations, we present the following for your consideration.

SNG manufacture from propane simply converts one form of energy into another with a significant efficiency loss ranging up to 10% and is contrary to the policy of conservation of natural resources, the major thrust of the National Energy Plan. Apart from the loss of energy in this transformation, the domestic supply of propane cannot support additional demand beyond the historical and traditional consumer. These consumers, largely rural and agricultural, do not have alternatives.

Domestic propane is obtained from gas processing plants and from refinery sources, with about 70% coming from the former and 30% from the latter. Propane production peaked in 1972 at 601 MB/D and has declined since that time to 521 MB/D in 1976, a decline rate of 3.5%. This decline is forecast to continue at a 4% decline rate. Refinery production has increased slightly and this increase is expected to continue. However, a net annual decline in availability of domestic propane of 2 1/2 to 3% is forecast. U.S. Bureau of Mines data further demonstrate this supply shrinkage. Numerous studies, including studies sponsored by SNG interests, contain similar data.

While propane continued to serve its historical customers in the drastic weather conditions of the 1976-77 winter, and was supplied to relieve critical natural gas shortfalls, this latter action was only possible with a big drawdown on accumulated record inventories of 95 M/B. At the end of March, 1977, 51 M/B were in inventory. It will not be possible to restore the opening inventories going into 1977-78.

Overseas production of propane does present a world wide surplus, and import will be necessary to satisfy projected demand. Its use has become necessary to counterbalance shrinking domestic production to some degree in historical markets. However, its higher cost should not be imposed on the historical residential and agricultural user, by removing domestic propane from this user's supply in providing domestic propane for SNG feedstock.

We express no objection to use of overseas import for SNG manufacture but caution it should be controlled by FEA, through a case by case evaluation to prevent undue demand and reliance on this import. It also requires control to prevent disruption of a sensitive distribution and transportation system serving the historical user.

The data on propane supply and demand that can be expected to further amplify the statements of this comment should appear in a study by the LP-Gas Advisory Committee to FEA on LP-gas supply/demand, and transportation, that is expected to be completed and released by the end of June.

All of this means that there is simply not enough domestic propane to provide feedstock for projected SNG plants. In 1973 FEA conducted hearings on use of propane as SNG feedstock in which the unavailability of propane and declining production were foreseen. These hearings resulted in the present FEA allocation regulations governing propane use for SNG feedstock. There has been no change justifying feedstock use of domestic propane.

2. It has been firmly established that the nation is experiencing a continuing and growing shortage of natural gas. Recognition of this is reflected throughout the "National Energy Plan", and in particular in the proposed Federal pricing policy which would discourage use of natural gas by utilities and industry.

In spite of the demonstrated critical scarcity of natural gas, the Farmers Home Administration is making Community Facility loans available for the purpose of extending natural gas use to consumers who presently are served by alternative energy sources. Not only is this a questionable interpretation of the "Rural Development Act", but more seriously it directly conflicts with the goals of the "National Energy Plan".

Applying the limited funds of the public treasury for the purpose of constructing distribution facilities, which will unnecessarily add to the number of consumers of natural gas, is a misuse of Federal monies. It is also an endorsement and support by a Federal agency of an undertaking which is unnecessary and one which adds to the depletion of fuel, of which there are diminishing reserves, in complete opposition to national policy and the public interest.

In order to avoid this type of circumvention of the purpose and intent of the "National Energy Plan", and to prevent the waste of tax revenues the following amendatory language to H.R. 6813 is respectfully suggested.

"Title I, Part D, Section 412 "Special Rules" is amended by adding a new paragraph (d). The President is authorized to prohibit the use of Federal funds, for the construction and/or extension of natural gas transmission facilities to consumers presently served by existing energy sources, when he considers such use contrary to the goals of the "National Energy Act".

We will appreciate Committee consideration of these comments and suggestions and ask that they be included in the record. We will be privileged to supply additional detail, if desired.

Respectfully,

A. C. Kreutzer

Arthur C. Kreutzer
Executive Vice-Pres.
and General Counsel
National LP-Gas Assn.

ACK:mm
cc: Members of Subcommittee
Frank Potter - Staff Director

Southwest Regional Energy Council

Suite 507
3300 West Mockingbird Lane
Dallas, Texas 75235
214—358-1254

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June 10, 1977

Honorable John D. Dingell
Chairman, Subcommittee on Energy and Power
Committee on Interstate and Foreign Commerce
House of Representatives
Washington, D.C. 20515

Dear Mr. Chairman:

The Southwest Regional Energy Council, an organization consisting of State Legislators from five Southwestern States--Arkansas, Louisiana, New Mexico, Oklahoma and Texas--has viewed the development and presentation of the National Energy Act (H.R. 6831) with great interest and some concern.

The Council's primary objective is to serve as a forum for discussing and debating energy issues and, during the nearly two-and-a-half years since its creation, it has unanimously adopted a number of resolutions which it feels can and should provide the framework for a workable energy policy. While in many instances the National Energy Act, as introduced, is compatible with the resolutions adopted by the Council, in some instances it is not.

A major conflict exists with respect to the pricing of natural gas, our cleanest and most precious fuel. The National Energy Act would continue and expand the federal controls which have resulted in lower prices, lower supplies and significant shortages in the interstate market. The Southwest Regional Energy Council favors the market mechanism which has resulted in higher prices, increased drilling activity and ample supplies in the intrastate markets. It has become increasingly obvious, as demonstrated this past winter, that there are costs associated with any price set at the well head for natural gas, either direct costs in terms of higher prices, or indirect costs in terms of unemployment and economic dislocation suffered as a result of shortage.

The National Energy Act would provide little in the way of additional incentives to bring on new supplies, but would attempt to ease the

strain on interstate systems by extending federal controls to intrastate markets in order to allow the rest of the country to have access to those supplies that currently exist there; thus allowing the interstate market to have its cake and eat the intrastate cake too. The rationale behind this extension of controls is that artificial differences between these two markets must be ended. The only thing artificial about natural gas pricing in this country today is the artificial price structure imposed on the interstate market by the Federal Government. An extension of that price structure to intrastate markets may result in additional availability of supply for interstate systems in the short term, but only at the expense of consumers in the intrastate markets who have already borne and are continuing to bear the cost of providing the incentives to make that supply available. At best such an act would be inequitable, and at worst it is confiscatory. In any case, in the long term this action will provide for nothing more than continued production declines, the perpetuation of the myth that the potential natural gas resource has been depleted, and increases in costs to consumers as conversion to other more expensive fuels is necessitated.

As Chairman of the Southwest Regional Energy Council, I hereby request that, if possible, this letter, and the attached Resolution, adopted unanimously by the Council, be made a part of your Subcommittee's permanent hearing record on this crucial subject.

Sincerely yours,

Joe C Hanna

Representative Joe C. Hanna
Chairman

JCH/mld
Enclosure

A RESOLUTION OF THE SOUTHWEST REGIONAL ENERGY COUNCIL CONCERNING NATURAL GAS DEREGULATION

WHEREAS, large shortages of natural gas now exist in the interstate market; and

WHEREAS, the primary reason for this shortage is the Federal Power Commission's regulation of well head prices for gas flowing into the interstate market; and

WHEREAS, the shortage will continue to grow if the price of natural gas is kept artificially below the price of alternate fuels and the free market price; and

WHEREAS, we recognize that the value of this resource will continue to increase as environmental quality becomes more difficult to maintain and that it is very important to find and produce new supplies to meet growing demands; and

WHEREAS, the continuation of federally imposed price controls at the well head for sales of natural gas in interstate commerce subverts the stated national purpose of conservation of energy and development of alternate fuel sources; now

THEREFORE, be it resolved the Southwest Regional Energy Council strongly advocates the passage of legislation which would remove well head price restrictions from natural gas. Provided that natural gas being sold and delivered under contracts, the terms of which have not expired as of the effective date of such legislation, shall remain in full force and effect. After the expiration of those contracts in effect as of the date of such legislation, further sales of those supplies formerly subject to such contracts should be free from all federally imposed well head price restrictions, so as to effect the orderly deregulation of natural gas well head prices.

SOUTHWEST REGIONAL ENERGY COUNCIL
Unanimously Adopted November 12, 1976

Stauffer Chemical Company
1725 K Street, N. West / Washington, D.C. 20006 / Telephone (202) 331-1627

May 27, 1977

Honorable John D. Dingell, Chairman
Subcommittee on Energy and Power
Committee on Interstate and Foreign Commerce
Room 3204 Annex No. 2
2nd and D Streets, S. W.
Washington, D. C. 20515

Dear Congressman:

Stauffer Chemical Company supports the national energy goals of reducing oil imports, increasing coal production and consumption, and conserving energy proposed in H.R. 6831, The National Energy Act. We believe in the free enterprise system, however, and are convinced that these goals can be best achieved at the lowest cost to consumers by deregulation and allowing oil and natural gas prices to reach equilibrium under free market conditions. Price deregulation would also correct a major flaw in H.R. 6831 by providing incentives which would increase reserves and production of oil and natural gas.

We would also like to offer for the record the following comments regarding the natural gas provisions of H.R. 6831, The National Energy Act.

1. Regulation of the price of new natural gas would be extended to intra-state sales for the first time. We see this as a step in the wrong direction, and one which will inhibit the development of new natural gas reserves and production.

2. The provisions of Part D, Section 414, Incremental Pricing of Natural Gas provide that industry not only pay the cost of new gas on the system up to the quantity of gas used by industry, but also require that industry pay for the cost (over the average system cost as of the time H.R. 6831 is enacted) of new gas used by residential and small commercial customers. This goes far beyond the questionable concept of incremental pricing and is clearly a subsidy paid to home owners to use natural gas. This will certainly not promote conservation. It would be far less disruptive to our economy and far more effective in conserving natural gas if true costs were passed on to all consumers at the point where they are incurred.

If we must accept price subsidies for non-industrial users, then a clearer definition of the term "substitute fuels" as used in Section 414(a) is needed. No provisions exist to pass on the costs of new gas to so-called "high priority" users until "low priority" users are paying up to a price of substitute fuels, which can be defined and set at the whim of the Administration. The term "substitute fuel" should be stricken and replaced by "Natural Gas Target Price as defined in Section 4992". Such a change would at least prevent industry paying in excess of the intent of H.R. 6831 while other consumers are paying prices which would be frozen at the 1977 pipeline system cost.

3. The definitions of "high priority use" and "low priority use" used in Section 414(b) would establish by law that heating a residential swimming pool is a higher priority use of natural gas than is the use of gas as a feedstock for fertilizer manufacture or as a non-substitutable process fuel in the processing of food grade products. If end use priorities must be established, we recommend using the priorities established by the Federal Power Commission Order 467B. These are not perfect, but have at least been tested and refined in practice.

4. The Natural Gas Consumption Tax as proposed in Section 4992 should not apply to feedstock uses or to non-substitutable process uses of natural gas, where no opportunity exists to convert to other fuels.

Thank you for the opportunity to comment on this Section of H.R. 6831.

Very truly yours,

STAUFFER CHEMICAL COMPANY

D. M. Greeno
Director
Energy Management

DMG:dw

[Whereupon, at 5:30 p.m., the subcommittee adjourned, to reconvene at 9:30 a.m., Thursday, May 19.]

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