POTENTIAL DISPLACEMENT OF OIL BY NUCLEAR ENERGY AND COAL IN ELECTRIC UTILITIES

HEARING

BEFORE THE

SUBCOMMITTEE ON
OVERSIGHT AND INVESTIGATIONS

OF THE

COMMITTEE ON
INTERSTATE AND FOREIGN COMMERCE
HOUSE OF REPRESENTATIVES

NINETY-SIXTH CONGRESS

SECOND SESSION

DECEMBER 9, 1980

Serial No. 96–230

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

U.S. GOVERNMENT PRINTING OFFICE
72–981 O WASHINGTON : 1981

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POTENTIAL DISPLACEMENT OF OIL BY NUCLEAR ENERGY AND COAL IN ELECTRIC UTILITIES

TUESDAY, DECEMBER 9, 1980

House of Representatives,
Subcommittee on Oversight and Investigations,
Committee on Interstate and Foreign Commerce,
Washington, D.C.

The subcommittee met, pursuant to notice, at 10 a.m., in room 2322, Rayburn House Office Building, Hon. Edward J. Markey, presiding (Hon. Bob Eckhardt, chairman).

Mr. Markey. Good morning.

This is a hearing of the Subcommittee on Oversight and Investigations of the Committee on Interstate and Foreign Commerce. The purpose of today's hearing is to lay out the facts as to how much oil is displaced by nuclear power and the potential for oil displacement by nuclear plants in the future.

I would like to welcome the panel. We have six distinguished guests: George Weil, Charles Komanoff, and Vince Taylor all will testify that the nuclear industry's claims of oil displacement by nuclear are exaggerated. John J. Taylor of Westinghouse and Carl Walske of the Atomic Industrial Forum will defend the industry's claims, and Richard Weiner of the Department of Energy has his analysis as well.

We all agree that our addiction for foreign oil, particularly Persian Gulf oil, poses a serious economic and national security threat to our country. We must reduce quickly our use of imported oil in order to lessen international tensions.

The question before us today is whether nuclear powerplants will free us in any significant way from our dependence on foreign oil.

It is important to stress at the outset that we are analyzing a specific issue within the nuclear power controversy. The questions of reactor safety, nuclear waste, economics of nuclear power, nuclear proliferation, electric reliability, and others are important questions but not within the scope of today's hearing.

The nuclear industry estimates that currently operating nuclear powerplants displace some 1.5 million barrels of oil daily, or 548 million barrels a year. Dr. Weil recently completed a study that disputes these figures. He has concluded that somewhere between 67 and 108 million barrels of oil per year are displaced by nuclear. Both cannot be correct.

Nuclear power has been promoted as the answer to our oil import problem. President Carter, in his January 1980 state of the Union message, said that:

> Once we have instituted the necessary reforms to assure (nuclear plant) safety, we must resume the licensing process promptly so that new plants which we need to reduce our dependence on foreign oil can be built and operated.

The nuclear-oil connection is a powerful promotional tool for the nuclear industry. I recently came upon an advertisement for nuclear power in New England Business, with a picture of the Ayatollah, and the large print says, "If he were our only source of oil, you'd probably be reading this ad in the dark."

Dr. Weil and others take issue with the premise behind this ad and President Carter's statement. The issue of foreign oil dependence is very important to the making of energy policy. If it is indeed true that nuclear replaces oil in significant amounts, Congress should know this. If the oil-nuclear connection is not as substantial as we have been led to believe, we should know that, too. Let us separate fact from fiction.

I look forward to listening to the experts in this field. I have one question that I hope each witness will answer.

How much difference will nuclear power make in reducing our dependence on imported oil by the year 1990?

I recognize for an opening statement, as well, the ranking minority member of this subcommittee, Mr. Lent.

Mr. LENT. Thank you very much, Mr. Chairman. I want to commend you for your leadership in bringing about this hearing this morning.

I would also like to welcome our distinguished panel, and thank each of you for your appearance today.

The advance testimony submitted by our participants reveals sharp differences in how our Nation should act to solve one of our gravest problems—extreme overdependence on foreign oil.

The colloquy soon to begin here should serve to focus attention on how best to proceed with the proper mix of fossil- and nuclear-fired plants to back out foreign oil as much and as quickly as possible.

Underlying this debate, of course, is the future of nuclear power in this country. Many Members of Congress are quite concerned that other nations, notably France, Germany, and Japan are forging forcefully ahead with nuclear plant construction. It is disturbing that we are falling behind in a technology once solely ours. I would hope that panel members would comment on this fact.

Closer to home, my State of New York has prohibited any new nuclear plants. The ban does not affect plants already under construction, such as the Shoreham facility being built by my district's utility, Long Island Lighting Co., Lilco.

The fact that Shoreham has yet to be licensed to operate is a constant frustration because Long Island is so heavily dependent on expensive foreign oil for power generation and space heating.

It is estimated that the Shoreham 820 megawatts plant slated for completion in 1982 will displace 8 million barrels of OPEC oil annually. I would hope that the panel, particularly Dr. Weil, would be able to discuss whether Shoreham is one of the nuclear plants that will back out a great deal of imported oil.

I thank you, Mr. Chairman. I have nothing further at this time.

Mr. MARKEY. Thank you.

Mr. Mottl?

Mr. Mottl. Mr. Chairman, I want to commend you also for having this important hearing. I think it will be very enlightening, and I am very interested in hearing the testimony this morning.

Mr. Markey. I think, as a format, without objection I would like to go through the panel and let each one of them make their statement and then at that point I think we might be in a position to have questions from the individual members.

Why don't we begin with Dr. Weil, and perhaps you could identify yourself for the record, your background, and then proceed.

TESTIMONY OF GEORGE L. WEIL, ENERGY CONSULTANT, WASHINGTON, D.C.; VINCE TAYLOR, UNION OF CONCERNED SCIENTISTS; CARL WALSKE, PRESIDENT, ATOMIC INDUSTRIAL FORUM; JOHN J. TAYLOR, VICE PRESIDENT AND GENERAL MANAGER, WATER REACTOR DIVISIONS, WESTINGHOUSE ELECTRIC CORP.; RICHARD WEINER, DIRECTOR, DIVISION OF POWER SUPPLY AND RELIABILITY, DEPARTMENT OF ENERGY; AND CHARLES KOMANOFF, KOMANOFF ENERGY ASSOCIATES

Mr. Weil. Thank you, Mr. Chairman.

Mr. Chairman, and members of the subcommittee, my name is George L. Weil. I am an independent consultant in energy with a background of many years association with the development and use of nuclear power. This background extends to the very beginnings of almost 40 years ago, the operation of the first nuclear reactor at Stagg Field in Chicago at the university, and later with the Atomic Energy Commission.

I appreciate the subcommittee's invitation to testify at these important hearings.

Over a year go I became interested in the subject of the subcommittee's first question—to what extent commercially licensed nuclear plants displaced or backed out oil during 1979.

Various numbers were publicized by the administration and the nuclear industry. Although the numbers differed substantially, one common denominator was the assumption that each nuclear plant displaced oil.

Since it appeared highly unlikely that a nuclear plant operating in the heart of coal country would be displacing oil, I undertook a detailed analysis, for the most part based on information directly obtained from the utilities, of the fossil fuels displaced during 1979 by commercially licensed nuclear plants.

The methodology and conclusions of this study were reported in "Nuclear Power's Role in the Oil Crisis," July 23, 1980. A copy of this report has been submitted to the subcommittee. [See p. 6.]

In summary, the analysis concluded that the administration overestimated the amount of displaced oil during 1979 by a factor of 10, and the nuclear industry by a factor of 6. Recently I have run across a Department of Energy estimate which agrees closely with that of the nuclear industry.

Referring now to the subcommittee's third topic of interest, future trends in utility fuel use, it may be pertinent to consider the Department of Energy's estimates of the potential increased consumption of oil, coal, and gas which would be required in 1985 to replace lost nuclear energy.

This lost energy would result if a moratorium were to be imposed on commercial licensing of nuclear plants now under construction. The Economic Regulatory Administration's staff issued a report titled "Staff Report Effects on Electric Power Supply of a Moratorium on Nuclear Plant Licensing," December 28, 1979, which examined this question.

Since, for another relatively brief study which was published in the Journal Science, August 1, 1980, I have accumulated information on nuclear plants under construction. Mr. Sims of the subcommittee staff requested that I undertake an analysis of estimates of increased fossil fuel consumption to be compared with those made by ERA staff.

However, in attempting to develop a comparison, I encountered difficulties. These difficulties arose because, by definition, my methodology assumes no shortage of excess fossil fuel capacity in 1985 to replace lost nuclear energy, whereas the ERA staff report concluded that there would be a 30-percent shortage.

This problem in responding to Mr. Sims' request was resolved when I discovered that a revised ERA analysis is contained in a later, official, DOE report. The methodology and conclusions of the report, titled "Electric Power Supply and Demand for the Contiguous United States," are presented in section VII.

Since this revised analysis encounters no shortage, it was then relatively straightforward to compare our estimates. This comparison is presented in my December 1 memorandum to Mr. Sims, "Effect on Fossil Fuel Consumption in 1985 Resulting From a Moratorium on Nuclear Plant Licensing." [See p. 42.]

To summarize the conclusions of my analysis, a direct comparison indicates that DOE's oil estimate is roughly three times greater than mine, DOE's coal estimate is roughly one-third mine, and our gas estimates are roughly equal. DOE's total increased consumption of fossil fuels in 1985 is 16 percent greater than my estimate.

I have referred to the above comparison as direct in the sense that it is based on DOE's estimates as published. Such estimates are sensitive to differences in assumed performance characteristics of both fossil and nuclear plants.

In particular, DOE's analysis assumes lower thermal efficiencies, as measured by heat rates, for oil- and gas-fired plants compared to that assumed for coal-fired plants.

Compared to my assumptions, which apply the same heat rates to all fossil fuel-fired plants, DOE's values serve to inflate the consumption of oil and gas by 20 percent relative to consumption of coal.

Glancing through DOE's voluminous report, I discovered in section X, "Coal Unit Delays," that DOE uses heat rates for oil- and gas-fired plants which agree closely with the heat rate used by DOE for coal-fired plants in section VII as well as with the single value I have used for all fossil-fueled plants.

Moreover, DOE identifies these heat rates as U.S. national averages for the years 1977, 1978, and 1979 as reported by utilities to the Federal Power Commission. Substituting section X heat rates, DOE's oil and gas estimates are reduced by 17 percent while DOE's coal estimate remains unchanged.

Moreover, our estimates of total increased fossil fuel consumption in 1985 now differ by only 4 percent, compared to 16 percent in the case of the direct comparison. Additional relatively minor adjustments, such as those for assumed nuclear plant capacity factors and the heat content of a barrel of oil, bring the totals into full agreement. This agreement provides confidence that all adjustments have been considered and properly applied.

In summary, a measure of the major difference between the Department of Energy's estimates and mine is revealed by examining the ratios of increased coal to oil consumption. The Department of Energy's ratio is .9 while the same ratio of my estimates is 3.6.

In this connection, it is of interest that the national average of coal to oil usage is about three. Whether the closer agreement of the national average with my analysis than with that of the Department of Energy is fortuitous or significant would require a much more detailed comparison of the two studies.

Thank you.

Mr. MARKEY. At this point we will hold the record open for your report and memorandum and response from the Department of Energy to those documents.

[Testimony resumes on p. 54.]

[The material referred to follows:]

July 23, 1980

NUCLEAR POWER'S ROLE IN THE OIL CRISIS

by

George L. Weil

Summary

The role of nuclear power in this country's energy policy is a subject of great debate. Probably the most important argument used in support of rapid expansion of nuclear plants is the claimed potential for reducing our oil consumption. For example, the Administration and the nuclear industry cite savings of 884 and 511 million barrels, respectively, during 1979. This analysis concludes that the most probable saving lies in the range of 88 $\pm$ 20 million barrels.

I). Introduction

In the wake of the Three Mile Island accident, the question of continued licensing and expansion of nuclear plants has become a matter of major national importance. The possibility of serious, if not catastrophic, accidents involving enormous health and financial risks to the public can no longer be dismissed as it has been in the past.

II). Background

Prior to the Three Mile Island accident, many of those supporting continued expansion of nuclear plants based their position largely on both economic grounds, claiming lower generating costs compared to those of coal-fired plants, and on savings in consumption of oil. However, the economic difference was, at best, small and under careful scrutiny highly questionable and misleading.[1]

Since Three Mile Island, implemented recommendations proposed by the Kemeny Commission[2] as well as those by the Nuclear Regulatory Commission Special Inquiry Group,[3] will certainly increase the cost of electricity generated by nuclear plants.

Recognizing the uncertainties in the economic comparisons and the emergence of oil shortages as of major public concern, those who favor continued licensing and expansion of nuclear plants are now focusing on the argument that these plants are needed to reduce our dependence upon oil, in particular imported oil.

To support this position, it is common to cite a one-to-one relationship between presently operating nuclear plants and savings in oil consumption. For example, it is reported that President Carter claims "... that each nuclear plant eliminates the need to import 13 million barrels of oil annually ... ."[4] Along the same line, the Atomic Industrial Forum (AIF) has testified before the Nuclear Regulatory Commission that "The nuclear reactors presently licensed to operate ... supply the nation with electricity that otherwise would require burning 1.5 million barrels of oil a day."[5] Similiarly, John T. Conway, president of American Nuclear Energy Council (ANEC) has stated, " ... the 70 operating nuclear plants represent the equivalent of 1.3 million barrels of oil a day,"[6] which agrees closely with Atomic Industrial Forum's figure.

Since 68 plants had commercial operating licenses during 1979, Mr. Carter's figure translates into an oil savings of 884 million barrels of oil for the year, "imported" or not. On the other hand, the nuclear industry's figure (average of Atomic Industrial Forum and American Nuclear Energy Council) translates into a savings of 511 million barrels of oil for the year.

The substantial difference between the two (figures), 373 million barrels of oil, can be reconciled on the basis of differing assumptions related to the design characteristics and performances of both nuclear and oil-fired plants. For example, Mr. Carter must assume that each nuclear plant has a net generating capacity of 1000 Mwe and operates at a plant capacity factor close to 90 percent.[7]

The facts are:

1) The average net generating capacity of the 68 plants during 1979 was 741 Mwe.

2) The average plant capacity factor of the 68 plants during 1979 was 57.2.

Making these adjustments, the Administration's figure is reduced by 50 percent, from 884 to 429 million barrels of oil.

The nuclear industry's figure of 511 million barrels of oil must assume an average plant capacity factor close to 70 percent during 1979. Again, adjusting for the actual 57.2 percent, the industry's total is reduced to 418 million barrels of oil, a difference now of only 11 million barrels of oil between Mr. Carter and the nuclear industry, compared to the original 373 million barrels of oil. This difference, less than 3 percent, is not significant, particularly in view of other assumptions which enter into such computations.[8]

The close agreement between the two "adjusted figures" is grossly misleading. Each significantly distorts the relationship between the operation of nuclear plants and oil saved. This relationship is important to those who plan our energy policies and to the public, which must judge these policies.

Implicit in the figures of Mr. Carter and the nuclear industry is the assumption that all nuclear plants displace oil. However, utilities operating nuclear plants in the heart of coal country are more likely to be displacing coal. In other locations, the fossil fuel alternatives may be broader, for example, not only oil but also coal and/or gas.[9]

III). Purpose

This study was undertaken to determine a more realistic estimate of how much oil was directly displaced by nuclear plants with commercial operating licenses during 1979. Since oil and coal are the primary fossil fuel alternatives to nuclear fuel, the amount of coal directly displaced is also determined.

IV). Procedure

A letter, dated August 23, 1979, was addressed to each utility licensed to operate one or more nuclear plants on its system. The following information was requested: 1) a list of all plants with their design electrical ratings; and 2) the primary fuel alternative(s) considered when the decision was made to construct a nuclear plant. Of the 40 utilities queried, 34 responded (85 percent). These utilities, operating 62 of the 68 commercially licensed nuclear plants in 1979, accounted for 93 percent of the total electrical energy generated by nuclear plants during the year.

Twenty-seven of the 34 utilities, operating 50 nuclear plants, responded explicitly to both questions (Class A). Based on this information, their plants were assigned to five "alternative fossil fuel" categories; oil, coal, oil/coal, oil/gas, and oil/coal/gas. Seven utilities, operating 12 nuclear plants, did not explicitly state primary fuel alternatives, but provided informative statistics covering all plants operating on their systems (Class B). Six utilities, operating 6 nuclear plants, did not respond (Class C).

Statistics illustrating the relative importance of the three classes in terms of contributions to the total electrical energy generated by nuclear plants during 1979, are summarized in Table 1. It will be noted (column 9) that Class A utilities accounted for close to 80 percent, and Classes A and B combined accounted for over 90 percent of the total energy generated.

TABLE 1

Summary of Responses from Utilities

Classifications[1]	Utilities		Nuclear Plants[2]		Design Electrical Rating[3]		Electrical Energy Generated[3]	
	No.	%	No.	%	(Mwe)	%	(Mwhe)	%
CLASS A	27	67.5	50	73.5	36,961	73.3	198,353,914	78.7
CLASS B	7	17.5	12	17.7	9,314	18.5	36,150,178	14.4
CLASS C	6	15.0	6	8.8	4,115	8.2	17,437,629	6.9
TOTAL	40	100	68	100	50,390	100	251,941,721	100

NOTES: (1) See Text.

(2) Excludes - Arkansas 2 in power ascension; and Indian Point 1, shutdown.

(3) Data from Operating Units Status Report January 1980, Nuclear Regulatory Commission.

The explicit assignments of 50 nuclear plants to alternative fuel categories by the utilities (Class A) are presented in Appendix A, Table A-1.

The assignments of 12 nuclear plants in Class B to alternative fuel categories, supported by information contained in utilities' responses, annual reports and other literature, including items in the press and nuclear industry newsletters, are presented in Appendix A, Table A-2.[10]

The assignments of 6 nuclear plants in Class C to alternative fuel categories, supported by both fuel statistics issued by the Department of Energy[11] and news items, are presented in Appendix A, Table A-3.[12]

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V). Computations and Results

Conversion of electrical energy generated by a nuclear plant to millions of barrels (Mbbl) of "oil equivalent" is computed from the following equation:

$$(1)\ \text{Oil Equivalent} = \frac{DER \times PF \times 8760 \times 3413}{34.6 \times 5.8 \times 10^6}\ \text{Mbbl}$$

Where:

DER = Design electrical rating (Kwe) of nuclear plant

PF = Average plant capacity factor (percent) during 1979

8760 = Number of hours per year

3413 = Btu's per Kwh(e)

34.6 = Average thermal efficiency (percent) of large, modern oil fired plants

5.8 x 106 = Btu content of a barrel of oil.[13]

The allocations to alternative fossil fuel categories corresponding to the three utility classes (Appendix A, Tables A-1 to A-3) are combined in Table 2. The Table also includes (column 7) the computed "oil equivalent" of each fuel option category.

TABLE 2

TABLE 2

Fossil Fuels Displaced by U.S. Nuclear Plants

Fossil Fuel[1] Alternatives	Nuclear Plants[2] No.	%	Design Electrical[3] Rating (Mwe)	%	Electrical Energy[3] Generated (Mwhe)	Oil Equivalent[4] (Mbbl)	%
OIL	10	14.7	6,933	13.8	39,329,995	66.9	15.6
COAL	43	63.2	33,655	66.8	164,981,715	[280.6]	65.5
X	15	22.1	9,802	19.4	47,630,011	[81.0]	18.9
TOTAL	68	100	50,390	100	251,941,721	[428.5]	100

NOTES: (1) X represents more than one fuel alternative, e.g. oil and gas.

(2) Excludes - Arkansas 2 in power ascension; and Indian Point 1, shutdown.

(3) Data from Operating Units Status Report January 1980, Nuclear Regulatory Commission.

(4) Brackets [ ] indicate that fossil fuel(s) displaced not exclusively oil.

Of the 68 commercially licensed nuclear plants during 1979, 10 plants "definitely" displaced 67 million barrels of oil (Appendix B, Analysis B-1). Forty-three plants "definitely" displaced coal, corresponding to an "oil equivalent" of 281 million barrels or 65 million short tons[14] (Appendix B, Analysis B-2). Fifteen plants displaced either oil, coal or gas corresponding to an "oil equivalent" of 81 million barrels (Appendix B, Analysis B-3).

In terms of percentages of the total 429 million barrels, oil accounted for 16 percent, coal for 65 percent and the multiple fuel alternatives for 19 percent.

VI). Discussion

The results in the previous section represent the "oil equivalent" of the fossil fuels, primarily oil and coal, displaced during 1979 by the 68 commercially licensed nuclear plants. These results may be considered a base. They refer to the displacement of fossil fuels when the utility decisions were made to construct the plants. The time period during which these decisions were made extended from 1955 to 1970.

Recalling that it may take 10-15 years to construct and obtain a commercial license for a nuclear plant, the energy supply situation, in particular that of oil, has changed drastically since decisions were made. Although the initial primary fuel alternatives, oil and coal, would not be affected, it may be argued today that some of the 15 nuclear plants in the multiple alternative fuel category (X), oil, coal, or gas, are today generating electrical energy which otherwise, if the nuclear plants had not been constructed, might be generated by oil-fired plants.[15]

Breakdowns of the assignments of the "X" category according to type of utility responses, i.e. Class A or B, are presented in Appendix C, Tables C-1 and C-2. (Note: There are no Class C assignments to the "X" category. Refer Appendix A, Table A-3). The distribution among the fossil fuel alternatives and statistics of the X Category plants are summarized in Table 3.

TABLE 3

TABLE 3

Summary - Multiple Fossil Fuel Alternatives (X) Displaced by U.S. Nuclear Plants

Fossil Fuel Alternatives	Utilities	Nuclear Plants[1]	Design Electrical[2] Rating	Electrical Energy[2] Generated	Oil[3] Equivalent	
	No.	No.	(Mwe)	(Mwhe)	(Mbbl)	%
OIL/COAL	5	10	7,485	34,704,962	[59.02]	72.9
OIL/GAS	2	2	983	5,711,999	[9.71]	12.0
OIL/COAL/GAS	2	3	1,334	7,213,050	[12.27]	15.1
TOTAL	9	15	9,802	47,630,011	[81.0]	100

NOTES: (1) Excludes - Arkansas 2 in power ascension; and Indian Point 1, shutdown.

(2) Data from Operating Units Status Report January 1980, Nuclear Regulatory Commission.

(3) Brackets [ ] indicate that fossil fuel(s) displaced not exclusively oil.

The 15 plants in the multiple fossil fuel alternatives, Category (X) accounted for about 19 percent of the total electrical energy generated by nuclear plants during 1979 (See Table 2). Since the question of their "what if" contribution to oil savings in 1979 is a hypothetical one, there is no clear-cut method to determine how the X Category should be allocated to the major primary fossil fuel alternatives, oil, and coal. In this situation, it appeared that a reasonable approach would be to apportion each multiple fuel alternative on an equal share basis. For example, 50 percent of oil/coal to oil and to coal, 50 percent of oil/gas to oil and 33 percent of oil/coal/gas to oil and 33 percent to coal. Adding the results obtained by this procedure to the base amount of oil displaced by nuclear plants, 67 million barrels, reveals an upper limit of 108 million barrels of oil saved, with a median, for the year 1979, of 88 million barrels.

The same procedure applied to coal reveals an upper limit of 314 million barrels of "oil equivalent," or 73 million short tons,[16] saved, with a median, for the year 1979, of 69 million short tons.

VII). Conclusions

1. Comparison of the median value of 88 million barrels of oil displaced by nuclear plants during 1979 with the figures of Mr. Carter and the nuclear industry show the following differences: Mr. Carter overstates the oil displaced by nuclear plants by a factor of about 10, and the nuclear industry overstates by a factor of about 6.

2. Ten plants in the Northeast account for all of the oil "definitely" displaced by nuclear plants during 1979, 67 million barrels. (See Appendix B, Analysis B-1). Even after apportionment of the multiple fuel alternatives category (X), these 10 plants account for almost 80 percent of the median value, 88 million barrels of oil.

3. Considering the results of this analysis in the context of current policy to substantially reduce this country's oil consumption, in particular our dependence upon imported oil, it appears that the operation of nuclear plants during 1979 provided only a modest contribution when compared with the estimates of Mr. Carter and the nuclear industry. Even the "upper limit" of the range of oil displaced, 108 million barrels of oil a year (300,000 bbl/day), represents less than 4 percent of our current annual petroleum imports, and less than 2 percent of our current

total annual consumption.[17]

4. To place into perspective the oil saved by nuclear plants during 1979, the median, 88 million barrels, could have been realized by a 3 percent reduction in gasoline (1.5%) consumption.[18]

5. There are other credits and/or debits in the relationship between the operation of nuclear plants and oil saved.[19] For example, this analysis has not considered oil that may be indirectly consumed when utilities, "wheel-in" energy from other utilities to off-set generating capacity lost by extended, unscheduled shutdowns of nuclear plants. The frequency of such occurrences is attested to by the low cumulative capacity factor of all licensed nuclear plants averaged over their years of commercial operation, 56.7, compared to an expected 70-80 percent for base-loaded plants. However, such "fine tuning" is unwarranted in view of the gross differences between Mr. Carter's and the nuclear industry's claims of 884 and 511 million barrels of oil, respectively, of oil saved in 1979 and the range of 67 to 108 million barrels resulting from this analysis.

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6. Lanouette, William J. "The Ayatollah Factor." National Journal, February 9, 1980.
7. Plant capacity factor is defined in this paper as the amount of electrical energy actually produced by a plant during any period, say the year 1979, divided by the amount that would have been produced if the plant had operated continuously at its Design Electrical Rating (Mwe net).

NOTES AND REFERENCES

8. For example, the thermal efficiency of the "displaced" oil-fired plants and the thermal heat content of a barrel of fuel oil.

9. A hydroelectric alternative is not considered as a economic substitute for nuclear plants. No utilities stated it as an alternative.

10. See page 24 for references.

11. U.S. Department of Energy, Electric Power Statistics December 1978. Washington, D.C.: Department of Energy, EIA-0034/12(78) June 8, 1979.

12. See page 24 for references.

13. Both the average thermal efficiency of oil-fired plants and the Btu content of a barrel of oil can vary in a range of $\pm$ 5%. The combination (they appear as a product in the divisor of the equation used in this analysis) conforms with conversion factors published by the Federal Energy Administration, Energy in Focus Basic Data. Washington, D.C.: Federal Energy Administration, May 1977.

14. Assumed conversion factor; 1 barrel of oil is equivalent to .23 short tons of coal. FEA, Energy In Focus Basic Data. Washington, D:C.: FEA, May 1977.

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15. Hydroelectric power not included as an alternative to nuclear plants.

16. See No. 14.

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APPENDIX A

TABLE A-1

CLASS A: Nuclear Plants Assigned by Utilities to Fuel Alternatives[1]

Fossil Fuel[2] Alternatives	Utilities No.	Nuclear Plants[3] No.	Design Electrical[4] Rating (Mwe)	Electrical Energy[4] Generated (Mwhe)	%
OIL	3	4	3,010	17,968,405	9.1
COAL	17	36	28,390	149,494,274	75.3
X	7	10	5,561	30,891,235	15.6
TOTAL	27	50	36,961	198,353,914	100

NOTES: (1) See Text.

(2) X represents more than one fuel alternative; e.g. oil and gas.

(3) Excludes - Arkansas 2 in power ascension; and Indian Point 1, shutdown.

(4) Data from Operating Units Status Report January 1980, Nuclear Regulatory Commission.

TABLE A-2

CLASS B: Nuclear Plants Assigned to Fuel Alternatives[1]

Fossil Fuel[2] Alternatives	Utilities No.	Nuclear Plants No.	Design Electrical[3] Rating (Mwe)	Electrical Energy[3] Generated (Mwhe)	%
OIL	4	5	3,348	17,245,251	47.7
COAL	1	2	1,725	2,166,151	6.0
X	2	5	4,241	16,738,776	46.3
TOTAL	7	12	9,314	36,150,178	100

NOTES: (1) See Text.

(2) X represents more than one fuel alternative, e.g. oil and gas.

(3) Data from Operating Units Status Report January 1980, Nuclear Regulatory Commission.

TABLE A-3

CLASS C: Nuclear Plants Assigned to Fuel Alternatives[1]

Fossil Fuel[2] Alternatives	Utilities No.	Nuclear Plants No.	Design Electrical[3] Rating (Mwe)	Electrical Energy[3] Generated (Mwhe)	%
OIL	1	1	575	4,116,339	23.6
COAL	5	5	3,540	13,321,290	76.4
X	0	0	0	0	0
TOTAL	6	6	4,115	17,437,629	100

NOTES: (1) See Text.

(2) X represents more than one fuel alternative, e.g. oil and gas.

(3) Data from Operating Units Status Report January 1980, Nuclear Regulatory Commission.

ANALYSIS B-1

APPENDIX B

COPY OF DATA FILE ANALY-O FILE NO. 1 (19/JUN/80)

SUMMARY (GLWEIL 18/JUN/80)

DISPLACED FUEL CATEGORY: ALL
FOR PERIOD JAN THRU DEC 1979
ANALYSIS FOR TERM: O

NMBR. OF PLANTS RETRIEVED: 10

PLANTS RETRIEVED							MWE	PF	MBBL
FITZPATRICK	PASNY	BWR /GE	NY	07/75	O	NPCC	821	41.2	5.04
HADDEM NECK	CYAP	PWR /W	CT	01/68	O	NPCC	575	81.7	7.00
INDIAN POINT 2	CONED	PWR /W	NY	08/73	O	NPCC	873	62.8	8.17
INDIAN POINT 3	PASNY	PWR /W	NY	08/76	O	NPCC	965	56.7	8.15
MAINE YANKEE	CMP	PWR /CE	ME	12/72	O	NPCC	825	62.8	7.72
MILLSTONE 1	NU	BWR /GE	CT	03/71	O	NPCC	660	73.0	7.18
MILLSTONE 2	NU	PWR /CE	CT	12/75	O	NPCC	870	58.6	7.42
PILGRIM 1	BE	BWR /GE	MA	12/72	O	NPCC	655	84.4	8.24
VERMONT YANKEE	CVPS	BWR /GE	VT	11/72	O	NPCC	514	76.6	5.87
YANKEE ROWE	YAE	PWR /W	MA	07/61	O	NPCC	175	80.4	2.10

TOTAL DESIGN ELECTRIC GENERATING CAPACITY (MWE):	6933
AVERAGE ELECT GEN CAPACITY PER PLANT (MWE):	693
TOTAL ELECTRICAL ENERGY GENERATED (MWHE):	39329995
TOTAL ELECTRICAL ENERGY GENERATED (QUADS):	.39
AVERAGE PLANT CAPACITY FACTOR (PERCENT):	67.8
OIL EQUIVALENT (MBBL):	66.9
AVERAGE OIL EQUIVALENT PER PLANT (MBBL/PLANT):	6.7

NOTES:

† E.G. 12/75 : MONTH AND YEAR OF COMMERCIAL OPERATION

†† 'O' OR 'C' : EITHER 'OIL' OR 'COAL' DISPLACED
'X' : DENOTES MORE THAN 1 FOSSIL FUEL OPTION

††† E.G.'NPCC' : ONE OF 'U.S. ELECTRIC RELIABILITY COUNCILS'

ANALYSIS B-2

COPY OF DATA FILE ANALY-C FILE NO. 2 (19/JUN/80)

SUMMARY (GLWEIL 18/JUN/80)

DISPLACED FUEL CATEGORY: ALL
FOR PERIOD JAN THRU DEC 1979
ANALYSIS FOR TERM: C

NMBR. OF PLANTS RETRIEVED: 43

PLANTS RETRIEVED							MWE	PF	MBBL
ARKANSAS 1	AP&L	PWR /B&W	AK	12/74	C	SWPP	850	44.6	5.65
BEAVER VALLEY 1	DL	PWR /W	PA	05/76	C	ECAR	852	23.8	3.02
BROWNS FERRY 1	TVA	BWR /GE	AL	08/74	C	SERC	1065	80.3	12.75
BROWNS FERRY 2	TVA	BWR /GE	AL	03/75	C	SERC	1065	79.8	12.66
BROWNS FERRY 3	TVA	BWR /GE	AL	03/77	C	SERC	1065	58.8	9.32
BRUNSWICK 1	CP&L	BWR /GE	NC	03/77	C	SERC	821	44.1	5.39
BRUNSWICK 2	CP&L	BWR /GE	NC	11/75	C	SERC	821	50.8	6.21
COOK 1	AEP	PWR /W	MI	08/75	C	ECAR	1054	61.3	9.63
COOK 2	AEP	PWR /W	MI	07/78	C	ECAR	1100	61.8	10.12
COOPER STATION	NPPD	BWR /GE	NE	02/74	C	MARCA	778	73.3	8.49
CRYSTAL RIVER 3	FP	PWR /B&W	FL	03/77	C	SERC	825	52.1	6.40
DAVIS-BESSE 1	TOLED	PWR /B&W	OH	07/78	C	ECAR	906	39.4	5.32
DRESDEN 1	COMED	BWR /GE	IL	07/60	C	MAIN	200	.0	-.02
DRESDEN 2	COMED	BWR /GE	IL	07/70	C	MAIN	794	71.0	8.40
DRESDEN 3	COMED	BWR /GE	IL	11/71	C	MAIN	794	50.0	5.91
DUANE ARNOLD	IE	BWR /GE	IA	02/75	C	MARCA	538	61.5	4.93
FARLEY 1	AP	PWR /W	AL	12/77	C	SERC	829	24.0	2.97
FORT ST. VRAIN	PSCC	HTGR/GA	CO	07/79	C	WSCC	330	8.5	.21
GINNA	RG&E	PWR /W	NY	07/70	C	NPCC	470	71.9	5.03
HATCH 1	GP	BWR /GE	GA	12/75	C	SERC	786	48.5	5.68
HATCH 2	GP	BWR /GE	GA	09/79	C	SERC	784	79.1	2.99
KEWAUNEE	WPS	PWR /W	WI	06/74	C	MAIN	535	73.4	5.85
LACROSSE	DP	BWR /A-C	WI	11/69	C	MARCA	50	45.9	.34
MONTICELLO	NSP	BWR /GE	MN	06/71	C	MARCA	545	92.2	7.48
OCONEE 1	DUKE	PWR /B&W	SC	07/73	C	SERC	887	64.4	8.50
OCONEE 2	DUKE	PWR /B&W	SC	09/74	C	SERC	887	76.8	10.15
OCONEE 3	DUKE	PWR /B&W	SC	12/74	C	SERC	887	41.9	5.54
OYSTER CREEK	JCP&L	BWR /GE	NJ	12/69	C	MAAC	650	80.1	7.76
PEACH BOTTOM 2	PSE&G	BWR /GE	PA	07/74	C	MAAC	1065	91.9	14.58
PEACH BOTTOM 3	PSE&G	BWR /GE	PA	12/74	C	MAAC	1065	65.4	10.38
POINT BEACH 1	WE	PWR /W	WI	12/70	C	MAIN	497	70.2	5.20
POINT BEACH 2	WE	PWR /W	WI	10/72	C	MAIN	497	85.2	6.31
PRAIRIE ISLAND 1	NSP	PWR /W	MN	12/73	C	MARCA	530	62.7	4.95
PRAIRIE ISLAND 2	NSP	PWR /W	MN	12/74	C	MARCA	530	90.3	7.13
QUAD CITIES 1	COMED	BWR /GE	IL	02/73	C	MAIN	789	69.2	8.13
QUAD CITIES 2	COMED	BWR /GE	IL	03/73	C	MAIN	789	57.6	6.77
ROBINSON 2	CP&L	PWR /W	SC	03/71	C	SERC	700	65.3	6.81
SALEM 1	PSE&G	PWR /W	NJ	06/77	C	MAAC	1090	21.4	3.47
TROJAN	PGE	PWR /W	OR	05/76	C	WSCC	1130	53.2	8.96
3 MILE ISLAND 1	METED	PWR /B&W	PA	09/74	C	MAAC	819	11.8	1.44
3 MILE ISLAND 2	METED	PWR /B&W	PA	12/78	C	MAAC	906	16.6	2.24
ZION 1	COMED	PWR /W	IL	12/73	C	MAIN	1040	60.8	9.42
ZION 2	COMED	PWR /W	IL	09/74	C	MAIN	1040	52.2	8.10

TOTAL DESIGN ELECTRIC GENERATING CAPACITY (MWE):	33655
AVERAGE ELECT GEN CAPACITY PER PLANT (MWE):	783
TOTAL ELECTRICAL ENERGY GENERATED (MWHE):	164981715
TOTAL ELECTRICAL ENERGY GENERATED (QUADS):	1.63
AVERAGE PLANT CAPACITY FACTOR (PERCENT):	56.6
[OIL EQUIVALENT] (MBBL):	280.6
AVERAGE [OIL EQUIVALENT] PER PLANT (MBBL/PLANT):	6.5

NOTES:

Weil

T E.G. 12/75 : MONTH AND YEAR OF COMMERCIAL OPERATION

TT 'O' OR 'C' : EITHER 'OIL' OR 'COAL' DISPLACED
'X' : DENOTES MORE THAN 1 FOSSIL FUEL OPTION

TTT E.G.'NPCC' : ONE OF 'U.S. ELECTRIC RELIABILITY COUNCILS'

ANALYSIS B-3

COPY OF DATA FILE ANALY-X FILE NO. 3 (19/JUN/80)

SUMMARY (GLWEIL 18/JUN/80)

DISPLACED FUEL CATEGORY: ALL
FOR PERIOD JAN THRU DEC 1979
ANALYSIS FOR TERM: X

NMBR. OF PLANTS RETRIEVED: 15

PLANTS RETRIEVED							MWE	PF	MBBL
BIG ROCK POINT 1	CP	BWR /GE	MI	03/63	X	ECAR	72	18.0	.19
CALVERT CLIFFS 1	BG&E	PWR /CE	MD	05/75	X	MAAC	845	56.7	7.13
CALVERT CLIFFS 2	BG&E	PWR /CE	MD	04/77	X	MAAC	845	74.2	9.34
FORT CALHOUN	OPPD	PWR /CE	NE	06/74	X	MARCA	457	91.6	6.23
HUMBOLDT BAY	PG&E	BWR /GE	CA	09/63	X	WSCC	65	.0	.00
NINE MILE POINT 1	NM	BWR /GE	NY	12/69	X	NPCC	620	55.3	5.11
NORTH ANNA 1	VEPCO	PWR /W	VA	06/78	X	SERC	907	52.7	7.12
PALISADES	CP	PWR /CE	MI	12/71	X	ECAR	805	48.7	5.84
RANCHO SECO	SMUD	PWR /B&W	CA	04/75	X	WSCC	918	71.0	9.71
SAN ONOFRE 1	SCE	PWR /W	CA	01/68	X	WSCC	436	87.9	5.71
ST. LUCIE 1	FPL	PWR /CE	FL	12/76	X	SERC	802	69.5	8.31
SURRY 1	VEPCO	PWR /W	VA	12/72	X	SERC	822	31.3	3.84
SURRY 2	VEPCO	PWR /W	VA	05/73	X	SERC	822	8.5	1.04
TURKEY POINT 3	FPL	PWR /W	FL	12/72	X	SERC	693	47.4	4.89
TURKEY POINT 4	FPL	PWR /W	FL	09/73	X	SERC	693	63.3	6.54

TOTAL DESIGN ELECTRIC GENERATING CAPACITY (MWE):	9802
AVERAGE ELECT GEN CAPACITY PER PLANT (MWE):	653
TOTAL ELECTRICAL ENERGY GENERATED (MWHE):	47630011
TOTAL ELECTRICAL ENERGY GENERATED (QUADS):	.47
AVERAGE PLANT CAPACITY FACTOR (PERCENT):	51.7
[OIL EQUIVALENT] (MBBL):	81.0
AVERAGE [OIL EQUIVALENT] PER PLANT (MBBL/PLANT):	5.4

NOTES:

† E.G. 12/75 : MONTH AND YEAR OF COMMERCIAL OPERATION

†† 'O' OR 'C' : EITHER 'OIL' OR 'COAL' DISPLACED
'X' : DENOTES MORE THAN 1 FOSSIL FUEL OPTION

††† E.G.'NPCC' : ONE OF 'U.S. ELECTRIC RELIABILITY COUNCILS'

APPENDIX C

TABLE C-1

CLASS A: Fossil Fuel Alternatives of X Assigned by Utilities[1]

Fossil Fuel Alternatives of X	Utilities	Nuclear Plants[2]	Design Electrical[3] Rating	Electrical Energy[3] Generated	Oil[4] Equivalent	
	No.	No.	(Mwe)	(Mwhe)	(Mbbl)	%
OIL/COAL	3	5	3,244	17,966,186	[30.5]	58.1
OIL/GAS	2	2	983	5,711,999	[9.7]	18.5
OIL/COAL/GAS	2	3	1,334	7,213,050	[12.3]	23.4
TOTAL	7	10	5,561	30,891,235	[52.5]	100

NOTES: (1) See Text.

(2) Excludes - Arkansas 2 in power ascension; and Indian Point 1, shutdown.

(3) Data from Operating Units Status Report January 1980, Nuclear Regulatory Commission.

(4) Brackets [ ] indicate that fossil fuel(s) displaced not exclusively oil.

TABLE C-2

CLASS B: Fossil Fuel Alternatives of X[1]

Fossil Fuel Alternatives	Utilities No.	Nuclear Plants[2] No.	Design Electrical[3] Rating (Mwe)	Electrical Energy[3] Generated (Mwhe)	Oil[4] Equivalent (Mbbl)	%
OIL/COAL	2	5	4,241	16,738,776	[28.5]	100
OIL/GAS	0	0	0	0	0	
OIL/COAL/GAS	0	0	0	0	0	
TOTAL	2	5	4,241	16,738,776	[28.5]	100

NOTES: (1) See Text.

(2) Excludes - Arkansas 2 in power ascension; and Indian Point 1, shutdown.

(3) Data from Operating Units Status Report January 1980, Nuclear Regulatory Commission.

(4) Brackets [ ] indicate that fossil fuel(s) displaced not exclusively oil.

Abbreviations	Utilities
AP	Alabama Power Company
AEP	American Electric Power Service Corporation
AP&L	Arkansas Power & Light Company
BG&E	Baltimore Gas and Electric Company
BE	Boston Edison Company
CP&L	Carolina Power & Light Company
CMP	Central Maine Power Company
CVPS	Central Vermont Public Service Corporation
COMED	Commonwealth Edison
CONED	Con Edison
CYAP	Connecticut Yankee Atomic Power Company
CP	Consumers Power Company
DP	Dairyland Power Cooperative
DUKE	Duke Power Company
DL	Duquesne Light
FP	Florida Power Corporation
FPL	Florida Power & Light
GP	Georgia Power Company
IE	Iowa Electric Light and Power Company
JCP&L	Jersey Central Power and Light Company
METED	Metropolitan Edison Company
NPPD	Nebraska Public Power District
NM	Niagara Mohawk Power Corporation
NSP	Northern States Power Company
NU	Northeast Utilities

Abbreviations	Utilities
OPPD	Omaha Public Power District
PG&E	Pacific Gas and Electric Company
PGE	Portland General Electric Company
PASNY	Power Authority of the State of New York
PSCC	Public Service Company of Colorado
PSE&G	Public Service Electric and Gas Company
RG&E	Rochester Gas and Electric Corporation
SMUD	Sacramento Municipal Utility District
SCE	Southern California Edison Company
TVA	Tennessee Valley Authority
TOLED	Toledo Edison Company
VEPCO	Virginia Electric and Power Company
WE	Wisconsin Electric Power Company
WPS	Wisconsin Public Service Corporation
YAE	Yankee Atomic Electric Company

TYPES OF REACTORS

Abbreviations	Reactors
BWR	Boiling Water Reactor
HTGR	High Temperature Gas-Cooled Reactor
PWR	Pressurized Water Reactor

NUCLEAR STEAM SUPPLY SYSTEM

Abbreviations	Vendor
A-C	Allis-Chalmers
B&W	Babcock & Wilcox
CE	Combustion Engineering
GA	General Atomic Company
GE	General Electric
W	Westinghouse

U.S. ELECTRIC RELIABILITY COUNCILS

Abbreviations	Councils
ECAR	East Central Area Reliability Coordination Agreement
MAIN	Mid-America Interpool Network
MAAC	Mid-Atlantic Area Council
MARCA	Mid-Continent Area Reliability Coordination Agreement
NPCC	Northeast Power Coordinating Council
SWPP	Southwest Power Pool
WSCC	Western Systems Coordinating Council

GEORGE L. WEIL
1730 M STREET, NORTHWEST
WASHINGTON, D.C. 20036

TELEPHONE
(202) 659-1266

December 1, 1980

Mr. Stephen F. Sims
U.S. House of Representatives
3558 House Office Building
Annex No. 2
Washington, D.C. 20515

Dear Mr. Sims:

The attached is in response to your request to review the Economic Regulatory Administration's (ERA) staff report titled, "Effects on Electric Power Supply Of A Moratorium On Nuclear Plant Licensing" (12/28/79), and to examine the report's conclusions in the context of my studies as reported by W. Lanouette (National Journal 8/23/80).

As you know, on October 15th I met with Messrs. Mark Gielecki and Tony Como of the Department of Energy at their request. The purpose of the meeting was to discuss the methodology and conclusions of my analyses. At the conclusion of our meeting, Mr. Gielecki handed me a copy of "Electric Power and Supply and Demand for the Contiguous United States 1980-1989" (DOE/RG-0036 Rev. 1 July 1980).

Since comparison of the ERA staff estimates with those of my analyses was already underway, and further, since the title of the DOE report did not suggest that it included an analysis of the effects of a nuclear licensing moratorium, I placed it aside. It was only later that I discovered that DOE does include such an analysis, Section VII, "Nuclear Capacity," which appears to be a final version of the ERA staff report.

Since I noted significant differences between the ERA staff estimates and those of DOE, I decided it would be more responsive to your request to compare my estimates with those of the final DOE report, rather than with those of the ERA staff.

Digesting and analysing all of this material has incurred substantially more time than I had originally envisaged.

Copies of my analyses which have provided the estimates for comparison with those of the Department of Energy are attached.

Sincerely,

George L. Weil
Consultant

Attachments (2)

MEMORANDUM

TO: Stephen F. Sims, Special Assistant, Subcommittee On Oversight and Investigations

FROM: George L. Weil GLW

DATE: December 1, 1980

SUBJECT: Effect on fossil fuel consumption in 1985 resulting from a moratorium on nuclear plant licensing

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Referring to the above subject, this is in response to your request to compare the Department of Energy's estimates with those of my analyses.*

At the outset, it is important to recognize a basic difference in the objectives of my analyses, GLW A and GLW B, and those of DOE. Both GLW A and GLW B focus on fossil fuels displaced by nuclear plants, whereas DOE focuses on fossil fuels to replace "unprovided" nuclear energy.

The importance of this distinction is revealed when one examines the nature of the information upon which the analyses are based.

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* "Electric Power Supply and Demand for the Contiguous United States 1980-1989" (DOE/RG-0036 Rev. 1 July 1980) Section VII. This report is abbreviated DOE. "Nuclear Power's Role in the Oil Crisis," by G.L. Weil (July 23, 1980), is abbreviated GLW A. "Nuclear Power Prediction," by G.L. Weil, Science (August 1, 1980) is abbreviated GLW B.

In GLW A, the nuclear plants produced electric energy during 1979. Operational statistics were obtained from the Nuclear Regulatory Commission, "Operating Units Status Report," January 1980, covering the full year 1979. Identification of fossil fuels displaced was largely determined by explicit statements from utilities. Thus, the relationship between the operation of nuclear plants during 1979 and the fossil fuels displaced was, for the most part, factual.

Uncertainties deriving from those nuclear plants which originally displaced more than one fossil fuel, were resolved by simple arithmetic apportioning of the total to the three fuels -- oil, coal and gas.

My second analysis (GLW B) addressed a specific question, namely, how much oil and coal would be displaced by 91 nuclear plants under construction if the licensing period could be halved. This very brief study was based on information compiled for GLW A. In this regard it is partially factual. Again, the focus is on displaced fossil fuels.

In contrast with the objectives of GLW A and GLW B, DOE examines the hypothetical inverse situation, namely, to what extent consumption of fossil fuels would be increased to replace "lost" nuclear energy if a moratorium were to be imposed on commercial licensing of nuclear plants now under construction.

Compared with the DOE methodology, GLW methodology is unsophisticated. Beyond that, it should be recalled that since GLW's methodology focuses on those fossil fuels displaced by the nuclear plants operated by specific utilities, it follows that in the inverse situation (replacement), the methodology assumes that those utilities would rely upon the same fossil fuel(s) to replace "lost" energy from nuclear plants on its system affected by a moratorium.

In other words, GLW estimates of increased fossil fuel consumption are on a "parochial" rather than, as in DOE, on a "regional" replacement basis. Moreover, GLW assumes a sufficient excess of fossil fuel-fired plant capacity available to each utility, either from its own plants or, through wheeling from other utility systems, to completely replace "lost" nuclear energy on its system in 1985, the year of interest.

TABLE I

Additional Fossil Fuel Consumption to Replace "Lost" Nuclear Energy

Estimates for the Year 1985

FUELS	DOE	GLW
	Equivalent Barrels of Oil per Day	
OIL	697,400	244,000
COAL	605,200	866,700
GAS	155,400	148,300
TOTAL	1,458,000	1,259,000

NOTES: DOE column is from "Electric Power Supply and Demand for the Contiguous United States 1980-1989" (DOE/RG-0036 Rev. 1 July 1980, pp. VII.22-24). DOE estimates: average capacity factor 61.6%; heat rates oil and gas 12,000, and coal 10,000. GLW estimates: average capacity factor 57.2%; heat rate oil, gas and coal 10,000.

DISCUSSION OF DOE AND GLW ESTIMATES IN TABLE I

1. Difference in DOE and GLW Totals

The total "lost" nuclear energy which must be replaced by fossil fuels in 1985 differs between DOE and GLW by a significant 200,000 bbl (oil equivalent) per day, a difference of 16%. A major portion of this difference is accounted for by the difference in the heat rates which DOE assumes, on the one hand 12,000 for oil and gas-fired plants, and, on the other hand, 10,000 for coal-fired plants. GLW assumes a single heat rate of 10,000 for all fossil fuel-fired plants. The heat rate adjustment is related only to DOE oil and gas estimates.

The higher the heat rate, for a fossil fuel-fired plant, the more that fuel must be consumed to replace a given amount of "lost" nuclear energy. Thus, the DOE heat rate assumptions serve to inflate the consumption of oil and gas compared to that of coal.

Applying the heat rate adjustment to the DOE estimates reduces the 200,000 difference in totals to about 54,000 bbl/day and these totals now differ by only 4% compared to the original 16%.

NOTE: There is no evidence to support the relatively high assumed capacity factors assumed by DOE for nuclear plants in 1985.

The remaining small difference in the totals can be attributed to differing assumptions regarding the average capacity factor, DOE 61.6% and GLW 57.2%, of the nuclear plants scheduled for operation in 1985.

2. Comparison of Estimated Increased Oil, Coal and Gas Consumption

The unadjusted DOE estimates for each fossil fuel compared to those of GLW show the following:

OIL:	DOE is almost three times greater than GLW
COAL:	DOE is almost one-third less than GLW
GAS:	DOE is roughly the same as GLW

The difference between the coal and gas assumed heat rates in DOE Section VII is confusing since, in a later part of DOE, Section X, "Coal Unit Delays," DOE states that 1.7 U.S. average barrels of oil are burned per megawatt hour generated, and identifies this as an "average U.S. value" reported to the FPC by electric utilities for the years 1977, 1978 and 1979. (Page X.3) Moreover, in the same Section X, a relationship for gas-fired plants, is similarly identified.

These relationships used by DOE in Section X can be directly converted into heat rates of 10,000 and 10,750 for U.S. oil and gas-fired plants, respectively. The mean of these values is within 5% of that assumed in GLW.

The DOE oil and gas estimates in TABLE I have been adjusted by a factor of 0.83 to conform with the national average heat rates for oil and gas-fired plants used in DOE Section X. Column 3 in TABLE II presents the adjusted DOE estimates for comparison with the original DOE and GLW estimates, columns 1 and 2.

TABLE II

Comparison of GLW Estimates With DOE Estimates

With and Without Heat Rate Adjustments to DOE

FUELS	DOE	GLW	DOE (Adjusted)
	Heat Rates: Coal 10,000 Oil/Gas 12,000	Heat Rates: Coal 10,000 Oil/Gas 10,000	Heat Rates: Coal 10,000 Oil/Gas 10,000
	Equivalent Barrels of Oil per Day		
OIL	697,400	244,000	578,800
COAL	605,200	866,700	605,200
GAS	155,400	148,300	128,900
TOTAL	1,458,000	1,259,000	1,312,900

Although, it has not been closely examined, it is possible that the equation (DOE, page VII.15) used to determine the percentage of the "lost" nuclear energy in each region to be supplied by each fossil fuel, also contributes to the oil/coal difference.

This equation differs from that used in the earlier Economic Regulatory Administration's staff report* (p. 55) which was supplanted by DOE's Section VII. In that report, the staff analysis, contrary to that of DOE, concluded that there would be a substantial shortage, 30%, of fossil fuel-fired plant capacity to compensate for the total "lost" nuclear energy in 1985.

Finally, it may be of interest to observe in TABLE I that the ratio of additional coal to oil consumption is 0.9 for DOE estimates and 3.6 for GLW estimates. The national average of coal to oil usage by utilities is in the ratio of about three. Whether the closer agreement of the GLW ratio and the national average is fortuitous or significant, cannot be resolved in this analysis.

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* "Staff Report Effects On Electric Power of a Moratorium on Nuclear Plant Licensing," Economic Regulatory Administration, Office of Utility Systems, Division of Power Supply and Reliability, December 28, 1979.

Letters

News and Comment in Retrospect

An important point that should be added to John Walsh's excellent centennial article "*Science* in transition, 1946 to 1962" (4 July, p. 52) is that the key figure in the genesis and development of *Science*'s News and Comment section was Joseph Turner, then associate editor of the journal.

Turner not only hired the first staff writer, Margolis, and the second, myself, but formulated the concept of News and Comment as a place for journalism *and* analysis. The concept is a familiar one in professional journals today, but it surely wasn't then.

To the implementation of this design, Turner also brought the best editorial instincts that I've encountered in 25 years of newspaper, magazine, and book writing. He could quickly and clearly point out what was right and wrong with an article, and any piece he touched was invariably the better for it.

I don't have the slightest doubt that, without Turner, News and Comment would have either not developed at all or followed the well-worn ruts of newsweekly reportage and never achieved the distinction with which it is so widely credited.

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Conflict Management

Perhaps modesty prevented Kenneth E. Boulding from discussing his own role in creating reason to hope that *Science* will have a 200th anniversary issue. His editorial on the 100th anniversary (4 July, p. 19) points to the creation of a commission on proposals for a National Academy of Peace and Conflict Resolution by Congress and of the commission's active "seminars" around the nation.

Of course, this didn't just happen. If the impulse was there in Congress, it still needed to work with substance, and it needed to know that the public cares. Boulding and a good many other social scientists have provided theory and procedure which convince congressional committees that new forms of conflict management are possible.

Even this is not enough. Boulding and other scientists have also joined with nonscientists in a campaign to demonstrate constituent concern; his letter in the Washington *Post* of 13 June 1977 suggesting that such an institution "would move the whole future in the direction of greater capacity to cope with organized conflict . . ." is a persuasive example. Every scientist should both examine this vital issue and join in supporting the effort that Boulding has helped move ahead.

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Nuclear Power Prediction

A recent article by Eliot Marshall, "Planning for an oil cutoff" (News and Comment, 11 July, p. 246), refers to a statement by J. J. Taylor of Westinghouse to the effect that nuclear plants could be constructed in half the time it takes today. Taylor argues that with government support "nuclear power could provide the equivalent of an extra 700,000 barrels of oil a day within 6 months, 1.6 million barrels in $2^1/_2$ years, and 3.8 million barrels in 5 years."

Marshall pointedly comments, "The catch in this scenario . . . is that it assumes an extraordinary degree of governmental and financial support. That support is not available today."

Beyond the "catch" disclosed by Marshall, there are two additional catches inherent in Taylor's statement. First, referring to the 91 nuclear plants under construction, a simple analysis of Taylor's numbers shows that he is assuming these plants would generate electricity at a capacity factor close to 100 percent. During 1979, the average capacity factor for commercially licensed nuclear plants was only 57 percent. Using this value decreases his upper estimate of 3.8 million barrels of oil by 40 percent.

Second, even if the 91 nuclear plants now under construction could be completed in half the time it takes today, all of these plants would not displace oil. Fossil fuel consumption statistics (*1*) of the utilities constructing these plants indicate that 61 plants would displace coal; 24 plants would displace either oil, coal, or gas; and only six plants would displace oil. These six plants would displace approximately 160,000 barrels of oil a day compared to Taylor's 3.8 million barrels.

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References

1. *U.S. Central Station Nuclear Electric Generating Units: Significant Milestones* [DOE/NE-0030/1(80), Department of Energy, Washington, D.C., 1980]; *Electric Power Statistics, December 1978* [EIA-0034/12(78), Department of Energy, Washington, D.C., 1979].

Galileo's Observations

In reply to the letter from Ewan A. Whitaker (2 May, p. 446), some of Galileo's observations were excellent; others, including some of his observations of the moon, were much less so. Not all of the latter can be improved by consulting the original drawings (which I mention), for some are described in the *text* of the *Sidereus Nuncius* and are criticized by Kepler, on the basis of his own observations. (There is no need, incidentally, to argue that the *Sidereus Nuncius* was written in Latin; everybody knows that, and I never said otherwise.) I admit that recent research, Whitaker's included, has changed our views concerning part of Galileo's observational (experimental) work; but the change is not always for the better, and there remains ample material to support my general description of his procedure.

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Erratum: In the article "Resources, population, environment: An oversupply of false bad news" by Julian L. Simon (27 June, p. 1431), an error was introduced in production. On page 1435, column 1, paragraph 4, under the heading *Fact*, the second sentence should have read, "And the increase [in land used for urban areas plus roadways] over the half century starting in 1920 was only 0.00025 of total land annually," not "0.00025 percent" as printed.

Erratum: In the report "Associative behavioral modification in *Hermissenda*: Cellular correlates" by T. J. Crow and D. L. Alkon (18 July, p. 412), the last sentence on page 412, column 2, paragraph 1, should read, "We have now found that modification of the photopositive response in *Hermissenda* is correlated with cellular changes in the type B photoreceptors."

August 1, 1980

91 Plants Used In The Letter To Science 9/27/80 SW

#	Fuel Displaced		Plant Name	State	Com-op	% Completed 4/80	
1	C	ECAR	Bailly	Indiana	06/87	.5	
2	O/G	WSCC	Diablo Canyon 1	California	00/80	99.2	
3	O	NPCC	Shoreham	New York	05/81	80.	
4	C	MAAC	Salem 2	New Jersey	4Q/80	99.9	loading
5	C	MAAC	Limerick 1	Penn.	04/83	60.	
6	C	MAAC	Limerick 2	Penn.	04/85	35.	
+7	C	SERC	Sequoyah 1	Tennessee	06/80	100.	+operating
8	C	SERC	Sequoyah 2	Tennessee	06/81	89.	
9	O/C/G	ECAR	Midland 1	Michigan	00/85	60.	
10	O/C/G	ECAR	Midland 2	Michigan	01/85	64.	
11	C	MAAC	Susquehanna 1	Penn.	01/82	77	
12	C	MAAC	Susquehanna 2	Penn.	01/83	48.	
13	O/G	WSCC	Diablo Canyon 2	California	00/81	97.9	
14	C	ECAR	Enrico Fermi	Michigan	03/82	79.5	
15	C	MAAC	Hope Creek 1	New Jersey	05/85	23.	
16	C	MAAC	Hope Creek 2	New Jersey	05/87	w/unit 1	
17	C	ECAR	Wm. H. Zimmer 1	Ohio	01/81	95.6	
18	C	SERC	Wm. B. McGuire 1	N. Carolina	08/80	98.	
19	C	SERC	Wm. B. McGuire 2	N. Carolina	04/82	73.	
20	C	MAAC	Forked River	New Jersey	12/83	5.6	suspended
21	O/C	SERC	North Anna 2	Virginia	08/80	99.	loading
22	O/C	WSCC	San Onofre 2	California	10/81	89.	
23	O/C	WSCC	San Onofre 3	California	01/83	60.	
+24	C	SWPP	Arkansas 2	Arkansas	04/80	100.	+operating
25	C	MAIN	Lasalle 1	Illinois	12/80	97.	
26	C	MAIN	Lasalle 2	Illinois	12/81	76	
27	C	SERC	Bellefonte 1	Alabama	09/83	71.	
28	C	SERC	Bellefonte 2	Alabama	06/84	47.	
29	C	SERC	Watts Bar 1	Tennessee	09/81	84.	
30	O/G	SWPP	Waterford 3	Louisiana	02/82	74.4	
31	C	SERC	Joseph P. Farley	Alabama	09/80	89.8	
32	C	SERC	Virgil C. Summer	S. Carolina	12/80	94.8	
33	C	WSCC	WPPSS 2	Washington	09/81	83.3	
34	C	SERC	Shearon Harris 1	N. Carolina	03/84	29.4	
35	C	SERC	Shearon Harris 2	N. Carolina	03/86	3.7	
36	C	SERC	Shearon Harris 3	N. Carolina	03/90	1.0	
37	C	SERC	Shearon Harris 4	N. Carolina	03/80	1.0	
38	C	MAIN	Byron 1	Illinois	10/82	67.	
39	C	MAIN	Byron 2	Illinois	10/83	54.	
40	C	SERC	Watts Bar 2	Tennessee	06/82	72.	
41	O/C	SERC	North Anna 3	Virginia	study underway to determine		
42	O/C	SERC	North Anna 4	Virginia	economics		7.0, 3.7
43	C	SERC	Alvin Vogtle 1	Georgia	11/84	5.0	
44	C	SERC	Alvin Vogtle 2	Georgia	11/87	3.0	
45	C	MAAC	Beaver Valley	Penn.	05/86	35.2	
46	O/C	NPCC	Nine Mile Pt. 2	New York	10/86	37.	
47	O	SWPP	Grand Gulf 1	Mississippi	04/82	83.	
48	O	SWPP	Grand Gulf 2	Mississippi	04/85	23.	
49	C	ECAR	Perry 1	Ohio	05/83	50.7	
50	C	ECAR	Perry 2	Ohio	05/85	39.2	
51	O	NPCC	Seabrook 1	New Hamp.	04/83	36.7	
52	O	NPCC	Seabrook 2	New Hamp.	02/85	7.2	
53	O/G	SWPP	River Bend 1	Louisiana	04/84	11.9	
54	C	SERC	Catawba 1	S. Carolina	07/83	64.	
55	C	SERC	Catawba 2	S. Carolina	01/85	12.	
56	C	MAIN	Braidwood 1	Illinois	10/83	55.	
57	C	MAIN	Braidwood 2	Illinois	10/84	43.	
58	C/G	ERCOT	Comanche 1	Texas	00/81	80.	
59	C/G	ERCOT	Comanche 2	Texas	00/83	45.	
60	O/C	SERC	St. Lucie 2	Florida	05/83	34.	
61	C	WSCC	WPPSS 1	Washington	12/83	38.6	
62	C	SERC	Hartsville A1	Tennessee	07/86	26.	
63	C	SERC	Hartsville A2	Tennessee	07/87	14.	
64	C	SERC	Hartsville B1	Tennessee	06/89	17.	
65	C	SERC	Hartsville B2	Tennessee	06/90	7.	
66	C	MAIN	Clinton 1	Illinois	12/82	66.	
67	C	MAIN	Clinton 2	Illionis	06/88	3.	
68	O	NPCC	Millstone 3	Connecticut	05/86	33.5	
69	C	SERC	Cherokee 1	S. Carolina	01/87	15.	
70	C	SERC	Cherokee 2	S. Carolina	01/89	1.0	
71	C	SERC	Cherokee 3	S. Carolina	01/91	1.0	
72	C/G	ERCOT	South Texas 1	Texas	02/84	55.8	
73	C/G	ERCOT	South Texas 2	Texas	02/86	19.2	
74	C	WSCC	WPPSS 3	Washington	12/84	21.5	
75	O/G	SWPP	River Bend 2	Louisiana		5.0	
76	O/C/G	WSCC	Palo Verde 1	Arizona	05/83	62.3	
77	O/C/G	WSCC	Palo Verde 2	Arizona	05/84	31.6	
78	O/C/G	WSCC	Palo Verde 3	Arizona	06/86	7.6	
*79	G	SWPP	Black Fox 1	Oklahoma	07/85	2.0	*work
*80	G	SWPP	Black Fox 2	Oklahoma	07/88	.5	authorized
81	C	MAIN	Callaway 1	Missouri	10/82	64.	
82	C/G	SWPP	Wolf Creek	Kansas	04/83	54.3	
83	C	MAIN	Callaway 2	Missouri	04/87	.7	
84	C	WSCC	WPSS 4	Washington	06/85	15.4	
85	C	WSCC	WPSS 5	Washington	06/86	9.6	
86	C	ECAR	Marble Hill 1	Indiana	10/82	27.	
87	C	ECAR	Marble Hill 2	Indiana	01/84	11.2	
88	C	SERC	Yellow Creek 1	Mississippi	11/85	11.	
89	C	SERC	Yellow Creek 2	Mississippi	04/88	3.	
90	C	SERC	Phipps Bend 1	Tennessee	03/87	12.	
91	C	SERC	Phipps Bend 2	Tennessee	08/89	3.	

Two Plants that have construction permits but no work has been done.

O	NPCC	Jamesport 1	New York	06/89	0.
O	NPCC	Jamesport 2	New York	06/91	0

News and Comment

Planning for an Oil Cutoff

Academics and industrialists meeting at Stanford find the United States unready to confront energy threats

If the nation is ready to go to war for Persian Gulf oil, as the President has said it is, shouldn't it be prepared to do something more constructive to reduce the importance of this source of energy and lessen the risk of bloodshed?

A group of about 60 academic and industrial energy specialists met at Stanford University last month to consider this question and suggest how the government might act quickly to buy some protective insurance against disaster.

The meeting was sponsored jointly by Stanford, the Hoover Institution on War, Revolution, and Peaçe—a conservative think tank with influence in the Ronald Reagan camp—and by the Scientists and Engineers for Secure Energy (SE_2)—an academic group organized in 1976 to defend the cause of nuclear power. The SE_2 sponsors, reluctant to place too heavy an emphasis on the nuclear option, made it clear nonetheless that they are more interested in producing energy (particularly electricity) than in devising conservation plans. As one speaker summarized the dominant outlook, "Conservation may be absolutely necessary as a tactic, but it is potentially disastrous as a strategy."

The conference examined some weaknesses in current emergency planning and endorsed a handful of proposals for quickly increasing energy supplies. In essence, the wish list asked for a relaxation of environmental laws, faster decontrol of oil and gas prices, and accelerated building of coal and nuclear electric plants.

The first objective should be to fill the strategic petroleum reserve, the group decided. The reserve was meant to hold at least 1 billion barrels of oil, but now holds only 92 million. For more than a year, from the winter of 1978 to the summer of 1980, the government refrained from adding to this stockpile. The moratorium was begun during the Iranian oil production cutback in an attempt to avoid bidding up prices in a short market.

Participants in the Stanford meeting were shocked by reports that before ending the moratorium, the Department of Energy (DOE) this year asked Saudi Arabia whether it had any objection to DOE's resuming the fill. When the Saudi king objected, the DOE hesitated. This deferential nod apparently bought no favors from OPEC, as the recent price increases demonstrated. The Administration has decided now to resume filling the reserve, at a rate of 100,000 barrels a day. At this pace, the maximum planned capacity of 1 billion barrels will be achieved in 26 years.

The Stanford conferees agreed that this is a poor safety net, and they proposed instead that the reserve be filled at a rate of between 300,000 and 1 million barrels a day. If the faster rate were adopted, the United States would have enough oil on hand in 2 years to make up for a total loss of imports lasting 3 months. All these figures assume that the government would honor its pledge to the International Energy Agency, which, in a total Mideast oil cutoff, would require the United States to share most of its remaining imports with the allies, reducing oil shipments to this country by 6.3 million barrels a day.

Despite its symbolic importance, the reserve now has little practical value except as a means of buying some time, extending the 90-day shipping lag that already exists between the source of oil and consumers in the United States. During the grace period between a cutoff and its impact, emergency programs would be rushed into force. What should they be?

The Stanford group considered, but stopped short of recommending anything that involved a warlike mobilization of the economy to produce additional energy supplies. Centralized coordination of the energy industry, necessarily involving the federal government as an overseer, seemed anathema to most of those present. They were eager to find free market (nongovernmental) solutions to the oil dependence problem.

The federal government is not well prepared itself, a point that became clear during the conference. One law, passed in 1975, allows the President to institute an oil allocation and gasoline rationing program during an emergency. It has some important weaknesses. Another law, passed in 1979, will require each state to come up with an energy emergency plan or else accept a plan designed by federal bureaucrats. This effort is still unfinished; regulations are being drafted now. Finally, on 30 June the President signed a bill creating a federal synthetic fuels corporation and a bank to finance energy-related renovations made by homeowners. The corporation has been given \$20 billion to spend in launching a synthetic liquid fuel industry in the United States, and a promise that it will get an additional \$68 billion later. The objective is to encourage the production of 500,000 barrels of synthetic fuel a day by 1987 and 2 million barrels a day by 1992. This would provide a little protection against a cutoff by the end of the decade. The bank has been authorized to give \$3 billion in subsidies over the next 4 years to homeowners who install solar energy devices or make other energy-saving investments. Another \$1.2 billion has been set aside to subsidize investments in biomass and grain-based fuels.

What would the government be prepared to do if the oil were cut off tomorrow? Barton House, the DOE official in charge of contingency planning, told the conference that he was authorized in May to bring together a "core group" of planners, numbering about 25, to think about five to ten "significant shortage scenarios." His first oil loss scenario (1.6 million barrels a day) will be about one-fourth as severe as the one being considered at Stanford. House's task, as he described it, will be to create a matrix management chart to coordinate the emergency functions of federal agencies, local governments, and industry. The first draft of this document may be ready in the fall.

If events in the Middle East move faster than the U.S. bureaucracy, which is not inconceivable, an oil supply crisis might force the government to work with the only tools it has now: gasoline rationing, and anything else that could be improvised quickly.

Alvin Alm, a former assistant secretary of DOE for policy in the Carter administration, now at Harvard's Kennedy School of Government, said flatly that the government is not ready to cope with the kind of shortage being discussed, and that the rationing program now on the

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books would lead to chaos. If imports were reduced by 6 to 7 million barrels a day, Alm calculated that the government would have to cut back gasoline sales at least by 37 percent, but, more likely, by 50 percent if school buses and other essential vehicles were kept running on normal schedules. Alm said that the effect would be to render the nation "virtually immobile" and plunge the economy into a slide worse than the Great Depression of the 1930's.

The DOE rationing plan now on the table, Alm thinks, is "simply unworkable" (i) because it would distribute supplies according to records of car registrations, and (ii) because it would create a new paper currency (coupons) two and one half times more voluminous than the dollar currency now in circulation. Based on his research on car registration systems, he concluded that even in ideal conditions, only 80 percent of the coupons would get to the correct owners. The plan would encourage people to buy and register junk cars, for the gasoline coupons would have a cash value. Finally, Alm said, the government simply does not have the technical ability to supervise a new currency larger than the one now managed by the Federal Reserve Board. Alm predicted that any federal attempt at rationing, no matter how well intentioned, would increase confusion and heighten public cynicism.

Alm proposed an alternative: he would lift government price controls on oil and let the market allocate gasoline. His plan, which would be difficult to put into effect unless adopted before the shortage hit, would impose a tax of up to 90 percent on any windfall increase in the price of petroleum caused by supply cutoff. The money collected this way would be returned to households by the Internal Revenue Service, making the system just as equitable in economic terms as coupon rationing. The tax and rebate system would be phased out gradually as the economy recovered from the shock of a cutoff. The advantages of this approach are its flexibility, its relative incorruptibility, and its equity. The tax, Alm said, would make people adjust quickly to the oil shortage, but not add to their burden by forcing them to live with a new rationing bureaucracy. Its economic virtue is that it would gather up most of the cash windfall that would normally go to the oil companies and OPEC and redistribute it to American consumers.

Although many at the conference liked the concept, they did not endorse it. One participant, former Treasury Secretary George Shultz, now vice chairman of Bechtel Inc., spoke strongly against the idea, saying the country would be ill served by a second windfall tax on oil. Oddly, an Exxon official then spoke in defense of the tax. But in the end, the conference came up only with the vague recommendation that "a plan for emergency energy curtailment measures . . . should be prepared."

After cutting back gasoline use, there are few steps the government could take that would relieve the shortage quickly. There is some potential for fuel switching—ordering industry to use coal, electricity, natural gas, or other substitutes for oil. But even the electric utilities, which seem to have the greatest flexibility, claim there are physical constraints on the extent of switching that could be done in the first year or two. According to Michehl Gent, executive director of the National Electric Reliability Council, the utilities burn about 1.7 million barrels of petroleum a day. Current plans call for the utilities to scale this appetite down to 1.5 million barrels a day by 1989. It will take a prodigious effort just to meet that target, Gent said. He thought it unlikely that oil consumption could be trimmed in a crisis by more than 150,000 barrels a day.

Several industry analysts presented decidedly optimistic scenarios for increasing energy output. A vice president of Bechtel estimated that coal production could be speeded up, if the government and the environmentalists were cooperative. Within 6 months, he said, coal could be made to substitute for 300,000 barrels of oil a day; within 5 years, for 1.3 million barrels a day. Gent said these calculations represented wishful thinking.

Benjamin Schlesinger, a policy analyst for the American Gas Association, made an equally hopeful estimate. By 1985, he said, the United States could obtain new natural gas supplies equivalent to about 2.3 million barrels of oil a day. (If no crash program is started immediately, however, gas supplies will decline.) To accomplish this feat, the gas industry will have to increase underground storage capacity by 24 percent, complete the new Alaska gas pipeline and ship gas through it, increase imports from Mexico and Canada, produce gas from domestic landfill sites, and synthesize gas from coal.

Charles Zraket of the MITRE corporation estimated that with adequate government subsidies, renewable energy sources (wood, alcohol, methanol, wind, hydropower, geothermal heat, and solar energy) could make a big contribution. Within 2 years, under the best circumstances, Zraket guessed these could produce the equivalent of 600,000 barrels of oil a day; within 5 years, 3 million barrels a day. BBL

One of the easily accessible, untapped sources of energy is nuclear power. Scores of plants have been started already and are partially built. J. J. Taylor of Westinghouse said that it would be possible, if desired, to reduce the lead time for building a nuclear plant from the present 11 years to about $5^1/_2$ years, "even without wartime priorities." If the government endorsed such a program, Taylor said, nuclear power could provide the equivalent of an extra 700,000 barrels of oil a day within 6 months, 1.6 million barrels in $2^1/_2$ years, and 3.8 million barrels in 5 years.

"The financial condition of the electric power industry is the worst it has ever been," said Gordon Corey, of Chicago's Commonwealth Edison.

The catch in this scenario, as in the others, is that it assumes an extraordinary degree of governmental and financial support. That support is not available today. The point was driven home by Gordon Corey, vice chairman of Commonwealth Edison, the Chicago utility which was one of the earliest users of nuclear power. "The financial condition of the electric power industry is the worst it has ever been," he told the conference. "We can't proceed with the nuclear program or any of the things we're talking about," Corey said, unless something is done to make the utility business more profitable. He saw no encouraging signs.

Thus, while it may be technically possible to turn on the energy taps in the United States, the impetus to do so is not present. That could change if there were a major oil cutoff. But, as one conference goer asked, will there be any private energy industry if such a calamity strikes?

—ELIOT MARSHALL

DOE'S RESPONSE TO DR. WEIL'S REPORT AND MEMORANDUM
AS REQUESTED BY CONGRESSMAN MARKEY ON PAGE 12
OF THE HEARING TRANSCRIPT

On December 18, 1980 DOE obtained a copy of Dr. Weil's memorandum to Mr. Stephen F. Sims presenting the results of his analyses of the potential savings in oil that could be obtained by installing future nuclear generating units. Dr. Weil's supporting report was not available at this time. Consequently, the DOE response will be limited to the information contained in Dr. Weil's memorandum.

The conclusion reached by Dr. Weil's analysis is that the differences in his results and the DOE results are almost completely reconciled by changing the assumptions of heat rates, heat content of coal and oil, and nuclear unit capacity factors. Allowing for differences in these parameters, according to Dr. Weil, total fossil fuel consumption in both his and DOE's analyses are brought to a very small difference: less than 4%. This conclusion is misleading.

Dr. Weil's analysis of the ability of future nuclear units to displace oil is based upon his earlier study of the fossil fuel displacement of <u>existing</u> nuclear units during 1979. In that study he concluded that most existing nuclear units are displacing coal, since the utilities operating these units considered coal as an alternative fuel when the new unit was planned. The fallacy of this methodology, is that, for example, if a New England utility had considered building a coal-fired unit instead of the nuclear unit, Dr. Weil's analysis would have shown that nuclear unit displacing coal in New England. This is an unlikely situation since coal-fired generation accounted for only 4% of New England's energy requirements in 1979.

The DOE analysis has attempted to account for the potential displacement of fossil fuels based on present operating conditions within and between electric systems. The equation Dr. Weil refers to (Page 7 of his memorandum) is based on the theory that the greater the amount of generating capacity of a particular fuel type in a region, the greater the potential for that fuel type to "pick-up" additional energy (if nuclear units were not available). However, this potential for additional energy "pick-up" must be limited by the maximum capacity factor at which that particular type of generation could be expected to operate.

Dr. Weil notes a difference between the December 28, 1979 "Staff Report Effects on Electric Power Supply of a Moratorium on Nuclear Plant Licensing" (December report) and the July 1980 publication, "Electric Power Supply and Demand for the Contiguous United States 1980-1989" (July Report). In the December report Dr. Weil correctly notes that the fossil-fueled generation is not able to compensate for 30% of the "lost" nuclear energy in 1985. However, he fails to note that the July report also accounted for this energy shortage. The July report shows a much lower value of energy shortage because of new, lower load growth rates and the consideration of the slippage of several nulcear units beyond the study period.

Dr. Weil also notes a difference in assumed heat rates for fossil-fueled units between the coal delay study in section X of the July report and the nuclear impact study in section VII of the same report. Each of these sections was developed separately and for different reasons. Choosing specific parameters from each study and performing analyses with these values is essentially taking portions of these studies out of context and contributes towards Dr. Weil's misleading conclusions.

In summary, DOE finds that the conclusions of its testimony are accurate. Many existing and planned nuclear units have and are capable of displacing the utility consumption of fuel oil. In regions such as New England, California and Florida this displacement is almost on a one-for-one basis. New nuclear and coal fueled generation are both necessary options for the electric utilities to pursue to provide for an adequate and reliable supply of electricity and reduce the anticipated consumption of fuel oil and natural gas by these utilities.

DOE will be pleased to provide review comments on Dr. Weil's supporting report when it becomes available.

Mr. MARKEY. Dr. Taylor?

TESTIMONY OF VINCE TAYLOR

Mr. VINCE TAYLOR. I am Vince Taylor. I have a doctorate in economics from Massachusetts Institute of Technology and a bachelor's in physics from Caltech. I worked for the Rand Corp. for approximately 9 years, in the 1960's, and since 1974 I have been working on the economics of energy, with emphasis on the economics of nuclear power, the potentials for the conservation of energy, and problems raised by our dependence on imported oil.

In my remarks today I would like to emphasize the major conclusions that are documented in my prepared testimony. I have entitled that testimony "Electric Utilities: The Transition From Oil" to emphasize the fact that the transition from oil is already well under way.

In 1978 approximately 10 percent of all the oil in this country was being consumed in electric utilities. In 1979, in response to the very major price rises in oil, utilities began to take a number of measures to decrease their use of oil, and I think the experience since that time is an important confirmation for those who would rely upon the efficacy of the market to bring about the changes in our energy consumption that are badly needed.

Just since 1978, our consumption of oil in electric utilities has declined by over 30 percent, and this in spite of a decline in the generation of nuclear power during the same period of time and an increase in our consumption of electricity of several percent. This trend, which I have laid out in a figure in my prepared testimony on page 11, can be seen to be continuing at an undiminished rate. It is not something that took place once and for all. It is a process that is taking place over time, and a continuation of the trends which are shown in that chart will bring the consumption of oil by electric utilities in this country to below 5 percent of our total oil consumption by 1982.

We have achieved a decline in oil consumption of 600,000 barrels of oil per day just since 1978.

I think it is important to understand this is a very major decrease relative to the potentials for nuclear power.

I have calculated the number of nuclear plants that are due to be completed, planned to be completed, by 1985, in regions that are now heavily oil-consuming. If all of those plants are actually completed by 1985, they would displace an amount of oil equal to 300,000 barrels of oil a day. That is only one-half as much as the amount of oil that has already been saved by the actions of utilities.

Utilities at the present time are planning expansions in their transmission networks to allow them to import more hydropower from Canada. In the Northeast, which is a heavy oil-using region, and in New York, including New York State, they are planning to expand their transmission capacity over the next several years between eastern parts of New Jersey and Pennsylvania and the western regions that are heavily coal-fired, and that have a large amount of excess capacity for generation. Plants are being converted from oil to coal voluntarily without the need for Government compulsion, and more of these will take place.

It is also probably the case that nuclear plant construction will be accelerated in oil-using areas to the extent possible because the economics have become compelling to move away from oil. At the prices that exist at the current time, a utility will save over $100 million a year by converting 1,000 megawatts of generating capacity from oil to coal, even assuming that they must pay $50 a ton for delivered coal, far above the national average.

So the conclusion that I reach from this is that whether or not nuclear power goes forward, the utilities will move away from oil in the use of generating electricity at a rapid rate, continuing trends that are already underway, and that by the late 1980's, whether or not more nuclear plants are actually constructed, even if, for example, safety reasons were to dictate that they not go forward, we would be down to oil consumption levels of only a few percent of our total oil consumption in this country by 1990. And recognizing that this is residual oil, which cannot be burned in homes or automobiles, and that it is a fraction of the crude which will remain in relatively plentiful supply, I think we can conclude that oil consumption by utilities is not a major part of our oil problems, and that nuclear power is not an essential ingredient to reducing our consumption of oil in the utility sector.

I want to make one other point, and that has to do with the implications of increased use of coal in the electric-utility sector. I believe that the major barrier to the transition to coal which will take place is the perception that coal is a dirty fuel; if we move to more coal we are inevitably sacrificing our environment. This is not the case. The technology that has now been mandated for new coal plants—in terms of air pollution levels for the acid that creates acid rain and for the particulates that create smoke and soot—it is so efficient and so effective that if that was applied to all of our existing coal-fired plants today, and we replaced all of the nuclear power that is generated in this country with coal and we replaced all of the oil that is used for the generation of electricity and all of natural gas, we could still reduce the pollution level to one-half the present level for acids and to one-tenth of the present level for the particulates or smoke. So the problem is not technology for clean coal, it is only a matter of political will.

Thank you.

Mr. MARKEY. Thank you.

[Testimony resumes on p. 70.]

[Mr. Vince Taylor's prepared statement follows:]

STATEMENT OF VINCE TAYLOR, UNION OF CONCERNED SCIENTISTS

Electric Utilities: the Transition from Oil.

My name is Vince Taylor. I am an economist specializing in energy and am currently employed by the Union of Concerned Scientists. I have a bachelors in physics from the California Institute of Technology and a doctorate in economics from the Massachusetts Institute of Technology. I worked for 9 years in the Economics Department of the Rand Corporation, Santa Monica, California, applying methods of quantitative analysis to a wide variety of problems. For the last 7 years, I have worked for a number of governmental agencies and private organizations with particular emphasis on nuclear power, the potentials for improving energy productivity, and the problems created by oil dependency. I have attached to this testimony a summary of my professional experience and a list of my energy-related publications.

A Part of the Oil Problem that Is Being Solved

Consumption of oil by electric utilities is one part of the oil problem that is being solved--far faster than is commonly recognized, without the help of special government subsidies, and in spite of a decline in nuclear generation. Electric utilities will consume less than 7 percent of all oil used in the United States in 1980, down from 10 percent in 1978, and this share can be expected to decline to less than 5 percent by 1982. By the end of the decade, utilities will consume only a few percent of total oil consumption. Recognizing that utilities burn residual oil, which is not useable in homes or vehicles and which can be expected to remain in relatively plentiful supply, it can be concluded that utility consumption of oil is not a critical part of the oil crisis.

Trends in Utility Consumption of Oil

Figure 1 shows the monthly consumption of oil by electric utilities from the beginning of 1977 through August 1980.

The substantial, continuing downward trend that began in earnest in 1979, when oil prices jumped sharply upward, is apparent. The share of total electricity being generated by oil declined by 19 percent between 1978 and 1979, and for the first 8 months of 1980, the year to year decline was 23 percent (Table 1). The downward trend, thus, shows no signs of slackening . Utility consumption of oil in 1980 will be about 1.15 million barrels of oil per day (MBD), or slightly under 7 percent of total U.S. consumption of about 16.8 MBD.

If total electricity consumption grows by 2 percent per year, somewhat faster than recent electrical growth and economic prospects suggests is likely in the near term, a continuation of the current declining trend will cause utility consumption of oil to fall to about .8 MBD by 1982, or less than 5 percent of prospective total U.S. oil consumption.

The Importance of Coal

Increased use of coal has been the dominant factor in reducing utility use of oil. Table 2, which compares the sources of electrical generation in the period of April-August 1980 with the corresponding period in 1978*, shows that the increase in coal-fired generation more than offset the reduction in oil-fired generation. Gas-fired generation also increased, but to a much smaller extent, while nuclear generation declined moderately.

The Nuclear-Oil Equality Proven False

The experience of these last few years should put to rest once and for all the widespread misperception that any reduction in nuclear power means an equivalent increase in oil

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*The first three months are omitted in this comparison because a coal strike caused abnormal utility patterns of fuel consumption in January-March 1978.

consumption. If the nuclear-oil equality were correct, the 1978 to 1980 decline in nuclear generation during the April-August period would have resulted in an 8 percent increase in oil consumption by electric utilities. Instead, actual oil consumption declined by 25 percent.

Market Incentives versus Government Compulsion

The decline in utility oil consumption provides powerful support for those who favor relying on market forces rather than government compulsion to achieve oil conservation. Efforts of the Department of Energy to force utilities to convert from oil to coal are presently mired in acrimonious controversy; if eventually implemented, the forced conversion program might eventually reduce oil consumption by about 400,000 barrels per day--actual reductions will almost certainly be less. Further, it seems likely that a large portion of the savings eventually achieved will represent conversions that would have occurred without compulsion. Meanwhile, without compulsion or subsidy, the electric utility sector has reduced oil consumption in the last two years by 600,000 barrels per day--50 percent more than the goal of the Administration program.

Dollars: The Driving Force

The rapid move of utilities away from oil is being driven by the powerful engine of dollars and cents. Even though most oil is consumed in areas where coal is relatively expensive, the price of oil has risen to the point where it costs twice as much as coal per unit of electricity generated, and the savings from switching from oil to coal are very large. For purposes of illustration, consider 1000 megawatts of capacity operating at 60 percent of capacity in a location where residual oil sells at $25 per barrel and coal at $50 per ton (prices that were at the high end of the actual range of prices paid by utilities in oil-consuming areas in July, 1980).

Switching from oil to coal would produce annual savings in fuel costs of $110 million.

Steps Being Taken to Reduce Oil Use

The high cost of oil provides a powerful incentive to utilize coal wherever possible. Long-distance transmission of coal power, so-called "coal-by-wire," has become relatively cheap, and transmission lines between coal-using areas with excess capacity and oil-consuming regions are being used to capacity. Utilities are considering plans to expand transmission lines to permit still greater importation of coal and hydro power into oil-using regions, and expedited implementation of these plans should be expected. Many existing plants will be converted from oil to coal, and efforts will be made to accelerate completion of nuclear plants under construction in oil-using areas. All of this is a natural consequence of savings from substituting coal for oil that will exceed $500 million per 1000 megawatts of capacity in 5 years.

Meeting stringent environmental standards is not an important deterrent to converting existing plants from oil to coal. At the cost differentail between coal and oil existing in 1980, conversion to coal would save a utility enough in three years to pay for retrofitting a plant with a technically advanced pollution control system, including a sulfur-dioxide "scrubber."*

A wide range of efforts to increase use of coal are now clearly economical, but construction of new coal or nuclear

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* A scrubber on a new plant is estimated to cost $135 per kilowatt. Allowing a cost penalty of one-half to account for the greater difficulty of retrofitting a scrubber, its cost would be about $200 per kilowatt. The total cost of retrofitting improved air pollution controls, including installation of an electrostatic precipitator, would be about $340 per kilowatt. Estimates of the cost of air pollution controls are from C. Komanoff, "Pollution Control Improvements in Coal-Fired Electric Generating Plants," Journal of the Air Pollution Control Association, September 1980.

plants to replace existing oil-fired plants is still marginal.* An expectation that oil prices will continue to increase more rapidly than coal prices would, however, tip the balance in favor of new construction of coal plants rather than continued use of oil.

The Contribution of Nuclear Expansion to Reducing Oil Consumption

Only nuclear plants being added in areas where oil is a major utility fuel will reduce oil consumption. Table 3 shows that nuclear plants scheduled for completion by 1985 in oil-using areas would provide electrical generation equivalent to about 0.3 MBD of oil. This amount of oil is equal to 1.8 percent of prospective 1980 consumption and 5 percent of imports. If for some reason the nuclear plants were not completed, efforts would be accelerated to find other substitutes and, thus, the loss in oil replacement would be less than 0.3 MBD.

Additional nuclear plants are scheduled for completion after 1985, but the further in the future they are completed, the more likely they are to represent a substitute for coal rather than oil.

A widely shared assumption is that continued expansion of nuclear power is very important for solving the energy problems of the United States. The above analysis show that in spite of its prevalence, this assumption is incorrect. If for safety or other reasons, nuclear plants under construction were not brought into operation, there would be a modest loss of a potential substitute for utility consumption of oil, a loss equivalent of 0.3 MBD of oil or less over the next 5 years. With or without additions to nuclear capacity, utility consumption

*The cost of oil alone is now about 4 cents per kilowatt hour, and this is slightly less than the expected total cost (in 1980 dollars) of electricity from coal-fired plants beginning construction in 1982 and coming into operation in 1988; electricity from new nuclear plants would be still more expensive: see the testimony of Charles Komanoff at this Hearing.

of oil will continue its downward trend, reaching relatively minor levels (a few percent of total oil consumption) by the end of the decade.

The Effects on Oil Consumption of a Nuclear Shutdown

If it were determined that risks from continued operation of existing nuclear plants were unacceptable, even a complete nuclear shutdown could be accommodated without major effects on oil consumption and imports. Table 4 shows that existing nuclear plants in major oil-using areas provide generation equivalent to 0.5 MBD of oil. If these plants were closed, not all replacement fuel would be oil, and strong efforts could be expected to shift from oil to coal over time.

An increase of 0.5 MBD in oil consumption would not be trivial, but neither would it be unmanageable unless it came at a time when oil supplies were severely disrupted. One-half million barrels of oil per day amounts to 3 percent of prospective 1980 oil consumption and about 8 percent of imports. An increase of this magnitude would still leave utility consumption of oil slightly below its 1978 level, and oil imports would remain 15 percent below their 1978 level.

After absorbing the increase that would be caused by a nuclear shutdown, oil consumption by utilities would resume its downward trend. The major consequence, thus, would be a temporary delay in the transition of electric utilities away from oil.

Excess Coal Capacity Available

In 1979, coal-fired plants operated at 48.5 percent of capacity.* Increasing their utilization rate to 60 percent,

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*Based on capacity data contained in Inventory of Nuclear Power Plants--December 1979, Dept. of Energy, DOE/EIA-0095(79), modified for the East North Central Region by data obtained from FERC Form 4. The Inventory contains serious errors, See "Note on DOE Data Deficiencies" at the end of this testimony.

well below the 65 percent generally considered attainable, would suffice to replace all electricity generated by nuclear plants in 1979. As noted above not all nuclear capacity is located in areas with excess coal capacity, but in those areas where coal predominates as a utility fuel, sufficient excess coal capacity appears to exist to replace almost all nuclear electricity generated there (about 60 percent of the U.S. total).

Coal Supplies Adequate

Producing sufficient coal to support the transition of utilities away from oil, and if necessary, away from nuclear power, should not be a serious problem. The recently completed President's Commission on Coal estimated that excess coal production capacity equalled 200 million tons in 1979. Replacement of all projected 1980 oil and nuclear generation by coal would require 240 million tons, only slightly more than estimated 1979 excess capacity.

Air Pollution From Coal

In the short run, coal provides the major alternative to nuclear power as a substitute for oil in electrical generation. To many, the spectre of increased pollution from coal-fired plants is as unappealing as the uncertain dangers of nuclear power. Nuclear proponents sometimes play on this concern by suggesting that foregoing nuclear power will inevitably lead to much greater air pollution in the years ahead.

What needs to be recognized is that no increase in pollution <u>need</u> occur, even if all existing nuclear, oil, and gas generating plants were to be replaced eventually by coal--implying a 72 percent increase in coal-fired generation. The reason for this is that the large pollution burden from fossil plants is an artifact of past policies, which paid little attention to air quality. Most existing plants are many times dirtier than need be. Pollution from the utility sector could be reduced markedly by installing modern pollution control equipment on existing plants.

If all existing oil, gas, and nuclear plants were converted to coal and if at the same time all existing plants were required to meet the 1979 pollution standards for new plants set by the Environmental Protection Agency (EPA), emissions of sulfur and nitrogen oxides (suspected to be the primary cause of acid rain) would decline to about one-half of current levels and emissions of smoke ("particulates") to one-tenth.*

At present, most existing plants are not required to meet the pollution standards for new plants, nor is the federal government moving toward this goal. Instead, in its anxiety over oil dependence, the Carter Administration during 1980 was moving to relax standards on plants that convert from oil to coal--a move that has been endorsed and encouraged by affected utilities and coal interests. If continued, this policy will represent another example of a technically and economically unnecessary sacrifice of the environment for the sake of short-sighted profit. Greater reliance on coal, thus, may well lead to a greater pollution burden--but it need not.

Conclusion

Several conclusions emerge from the evidence reviewed here.

- Most importantly, market forces are causing utilities to rapidly reduce consumption of oil. The high cost of oil provides a powerful incentive to decrease its use. Neither federal subsidies nor compulsion appear necessary to insure continuation of the downward trend in oil use.
- Coal will constitute the major replacement for oil.

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* Calculation by the author. Current emissions of pollutants are assumed to be approximately equal to those reported for 1975 in Staff Findings, The President's Commission on Coal, March 1980, Table 1, p. 27. Generation of electricity by type of fuel is from the Monthly Energy Review, op. cit.

The major obstacle to substitution of coal for oil is the public perception that coal is a dirty fuel. The EPA standards for new coal-fired plants are sufficiently stringent to make them generally cleaner than oil-fired plants they would replace. Many existing coal plants, however, do produce large quantities of air pollutants. The technical potential exists to reduce greatly this pollution burden, an action that would facilitate the transition of utilities from oil by reducing public opposition to greater use of coal.

- Expansion of nuclear power cannot be justified as an essential substitute for oil. Whether or not more nuclear plants are built, utility use of oil will decline to only a few percent of U.S. oil consumption by 1990.

Conversely, there is a danger in accelerating nuclear expansion before there is high confidence that nuclear plants can be operated safely. The United States is not now critically dependent on nuclear power, but if nuclear capacity triples by 1990, as nuclear advocates desire, this will no longer be the case. A nuclear accident leading to a shutdown of nuclear plants would then be a major national disaster, causing severe disruptions in electrical supplies and possibly creating unmanageable demands for more oil. In these circumstances, the wise course is to delay any major expansion of nuclear capacity until present uncertainties about safety can be resolved.

Note on DOE Data Deficiencies

In doing the research on which this testimony is based, I became aware of two major sources of error in energy data published by the Department of Energy. Given the importance of these data for national policy decisions, the Committee may wish to attempt to have them corrected.

The first error is in the Monthly Energy Review, the most widely used federal source of energy data. In the section entitled "Consumption" of energy, they present data on oil consumption by end-use sector that is very inaccurate. For example, this section provides data that shows utility consumption of oil to have declined by 19 percent since 1978, rather than the 35 percent shown by data reported by utilities (and, ironically enough, presented in another section of the _Monthly Energy Review_). This is, perhaps, the largest quantitative error in the "Consumption" section, but errors pervade the entire section due to the methodology employed there.

A second major error is in _Inventory of Powerplants in the United States_, another publication of the Department of Energy. It is the only federal source of electric generating capacity categorized by type of fuel, yet the data reported there bear little relation to actuality. For example, the _Inventory_ reports that coal-fired capacity in the East North Central region totaled 47,500 megawatts in 1979, but data in FERC Form 4 (from which the Inventory is supposedly compiled) show that 76,400 megawatts of capacity in this region actually burned coal in this year--an error of 60 percent.

Providing policy makers with accurate and meaningful analyses when DOE source data contain errors of the magnitudes of those summarized above is nearly impossible. I hope the Committee will give this matter its attention.

Figure 1

UTILITY CONSUMPTION OF OIL

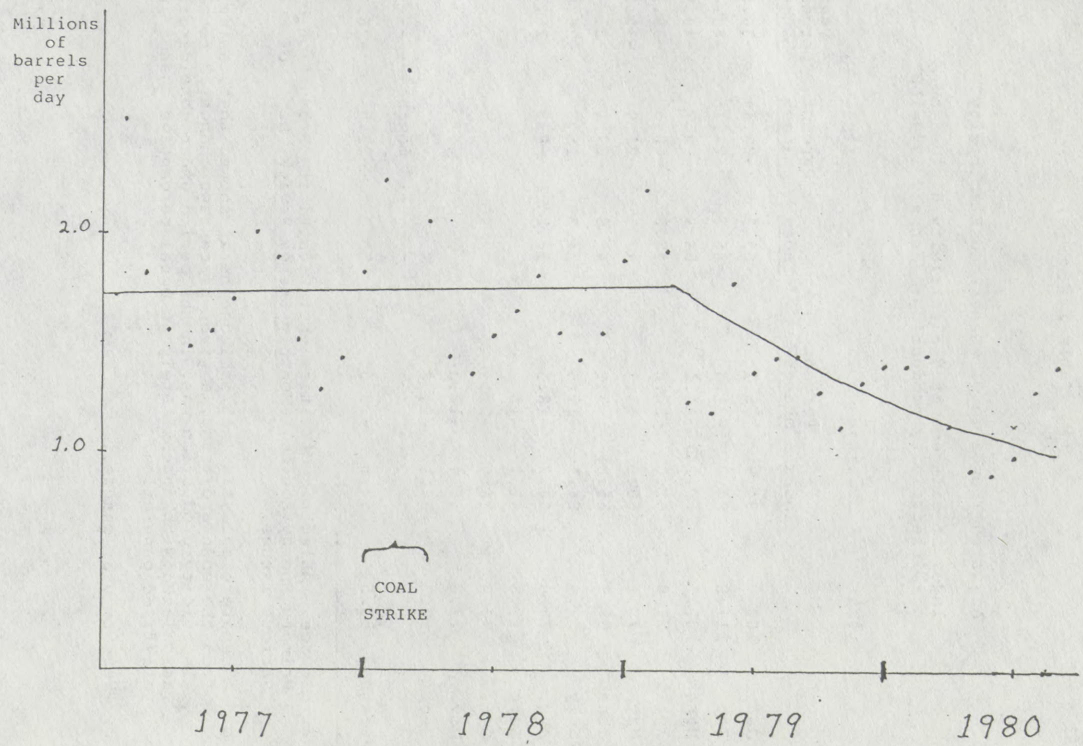

Table 1

Adjusted Trends in Oil-Generated Electricity[a]

Index of oil-generated electricity divided by total electricity production: January 1979=100[b]

	1978	1979		1980		
		Index	Percent change[b]	Index	Percent change[c]	2 year percent change
Jan.	100	94.9	-5.1	63.2	-33.4	-36.8
Feb.	111.0	87.2	-21.4	66.2	-24.1	-40.4
March	107.5	60.1	-44.1	54.9	-8.7	-48.9
April	78.8	61.0	-22.6	48.0	-20.5	-39.1
May	70.1	60.8	-13.3	47.5	-21.9	-32.2
June	69.9	65.8	-5.9	48.0	-27.1	-31.4
July	72.4	64.1	-11.5	54.3	-15.3	-25.0
Aug.	78.8	64.2	-18.5	58.2	-9.3	-26.1
Sept.	72.3	62.7	-13.3			
Oct.	73.8	56.9	-22.9			
Nov.	77.6	66.4	-10.3			
Dec.	89.3	67.3	-24.6			
				8 months		
Averages	83.5	67.6	-19.0	55.0	-23.5	-36.0

a. Source: "Electric Utilities--Net Electricity Production by Primary Energy Source," Monthly Energy Review, Dept. of Energy, various issues.

b. A separate analysis (not included here) showed that, aside from the downward trend, a given percentage change in total electricity production was, in the period under consideration, associated with approximately an equal percentage change in oil-fired generation.

c. Year to year change.

Table 2

Sources of Electrical Generation:
April-August 1978 and 1980[a]
(billions of kilowatt hours)

	1978	1980	Difference
Coal	413.83	477.60	+63.77
Gas	143.86	158.57	+14.71
Oil	132.48	98.82	-33.66
Nuclear	110.79	100.85	-9.94
Total Above Fuels	810.96	835.84	+34.88
Total All Sources	932.37	965.21	+32.84

a. Source: "Electric Utilities--Net Electricity Production by Primary Energy Source," Monthly Energy Review, Department of Energy, July and October 1980.

Table 3

Nuclear Additions in Oil-Using States or Regions
Scheduled for Completion by 1985 and Oil Equivalents[a]

	Nuclear Capacity (Megawatts)	Oil Equivalent[b] (MBD)
New England	1,150	.027
Middle Atlantic	5,606	.130
Virginia	980	.028
Florida	850	.020
California	4,650	.108
Total	13,236	.308

a. Source: Inventory of Powerplants in the United States, December 1979, Dept. of Energy, DOE/EIA-0095 (79); modified by later information.

b. At 58 percent of capacity (based on nameplate capacity), 10,500 BTU/KWH, and 6.287 million BTU/barrel.

Table 4

Nuclear Generation in Oil-Using States or Regions and Oil Equivalents: 1979[a]

	Generation (billions of KWH)	Oil Equivalent[b] (MBD)
New England	26.72	0.12
Middle Atlantic	43.91	.20
Virginia	7.06	.03
Florida	15.39	.07
California	8.76	.04
Total	101.84	.47[c]

a. Source: "Power Production, Fuel Consumption, and Installed Capacity Data for 1979 (Final)," Energy Data Report, Dept. of Energy, DOE/EIA-0049 (79), Table 1.

b. Calculated at 10,500 BTU/KWH and 6.287 million BTU/barrel.

c. Total does not add due to rounding.

Mr. MARKEY. Dr. Walske?

TESTIMONY OF CARL WALSKE

Mr. WALSKE. Mr. Chairman, I am Carl Walske, president of the Atomic Industrial Forum, Inc. The forum is an international association of over 600 domestic and overseas member organizations interested in the civil application of nuclear energy. These organizations include electric utilities, manufacturers, architect-engineers, consulting firms, mining, and milling companies, nuclear fuel service companies, financial institutions, labor organizations, universities, legal firms, and others.

I appreciate this opportunity to discuss with you the long-term potential of electricity for reducing our dependence on imported oil and for augmenting our overall energy supplies. What I shall argue is that through increased use of coal- and nuclear-fueled electricity we can do much to ease our energy problems, but that our utilities are not now able to launch the additional plants that are needed. For the electric utilities to order and build large amounts of new generating capacity, they must have:

One: Greater financial strength,

Two: A more predictable regulatory climate, and

Three: The understanding of the public and national leadership.

One of the difficulties about discussing future electrical capacity is that it now takes over 10 years from the point of decision until a new nuclear plant can be placed in operation. For a coal-fired unit it is just a bit under 10 years. Thus, changes in our electrical supply system must be decided by estimating conditions a decade in the future. In today's energy situation that is certainly difficult. But I shall nevertheless try in a moment.

First, let me say that our electrical supplies for the eighties, essentially determined at this time, will not be too bad in the absence of prolonged oil cutoffs. Presently our national electrical capacity is about 600 gigawatts—that is, 600,000 megawatts. Of that, perhaps 10 percent is excess to our current needs. In the field today, under construction, we have about another 200 gigawatts—roughly half coal-fired and half nuclear. By and large this is the capacity addition for the eighties, so that by 1990 our capacity will total roughly 800 gigawatts. That is not a bad program for the next decade, approximately a one-third expansion. Recall that until 1970 electrical consumption was doubling every decade. The difference for the eighties reflects anticipated conservation and improved efficiency.

Electrical generation for 1990 and beyond is still a large question mark. As I explained, orders today will come into service in 1990, 10 years later.

At this time there are few orders being placed. In 1979 approximately 6 gigawatts of coal capacity were ordered, but nuclear cancellations that year exceeded the coal order figure. In 1980 so far, about 2.5 gigawatts of coal capacity have been ordered, but the cancellation of nine nuclear plants subtracted 10 gigawatts from future plans. These figures can be compared with a total ordering rate of 40 gigawatts per year which I believe the Nation needs. Let me explain.

Our overall energy requirement is to make supply equal demand, including all sources of energy. Many organizations have made estimates of our demand level in the year 2000. Not surprisingly, there is disagreement. However, industry and Government projections tend to agree that more energy will be needed, even with major improvements in the conservation and fuel-efficiency areas. One basic reason is that our labor force will be some 30 percent greater. Another is that our people are still motivated to increase their well-being, which means an increase in GNP per worker and hence an increase in energy used per worker.

I realize that there are those who believe that through large changes in our life style the United States can manage in the year 2000 with even less energy than it uses today. Since there seems to be no compelling economic reason or even resource limit to mandate this, I believe changes will be moderate, based on free choices by our people. Therefore I tend to disbelieve estimates based on extreme and unnecessary changes in life style.

Returning then to industry and Government estimates, I would like to submit for the record a recent paper by Dr. Chauncey Starr, vice chairman of the Electric Power Research Institute. This paper, dated November 17, 1980, and entitled "Electricity's Role in the Economy" [see p. 74], was presented at AIF's recent annual conference. Reporting work at EPRI, it makes a number of key points:

First: The percentage of total energy used in the United States for the generation of electricity has been rising, from about 15 percent during World War II until today it is over 31 percent. EPRI projects that the electricity fraction will increase to a level of 45 to 55 percent in the year 2000.

Second: Technology-implemented electricity conservation may fall in the range 17 to 34 percent—compared to 28 to 46 percent conservation for total energy.

Third: Increasing environmental standards could cause as much as a 10-percent increase in total energy requirements, making the effective conservation potential for total energy approximately 20 to 40 percent.

Fourth: Our growing labor force alone would require an average growth in GNP of 1 percent per year for the rest of the century. To satisfy minimum social expectations, another 1.5 percent per year growth is needed, for a minimum total of 2.5 percent. In fact, the historical growth from 1950 to 1970 was 3.6 percent. The seventies, as is well known, were disappointing to the average citizen.

The Starr paper goes on to estimate that 160 to 355 gigawatts of nuclear capacity in addition to that now in the pipeline will be needed by 2000 in its minimum-expectation case. The range comes from electricity conservation varying between 34 percent and 17 percent.

The EPRI estimates are consistent with my own minimum estimate that by 2000 at least a third more total energy will be needed after conservation and improved efficiency in fuel use. To meet this increase we must look beyond the three-fourths of our present energy supply which is provided by domestic oil, imported oil, and domestic natural gas—about one-fourth from each. These are not likely to increase. In fact, imported oil should be decreased. In the fourth quarter of our energy supply we find principally coal—17 percent, nuclear—4 percent, and hydroelectric power—4 percent. Only the coal and nuclear can be substantially increased. Of course, other solar and renewables may contribute 5 percent or so of our total needs in the year 2000.

Since a main use for the increased coal would be electrical generation and the only use for the nuclear is electrical generation, it follows that more electricity is needed. Another 400 gigawatts of coal and nuclear in the nineties added to the 800 gigawatts we plan to have by 1990, appears necessary. That would produce the one-third increase in total energy supplies over what we have today. Prudently, this addition should be about half coal and half nuclear, in general agreement with EPRI's 160 to 355 gigawatts of additional nuclear.

Additional coal and nuclear capacity, 400 gigawatts, between 1990 and 2000 would imply a current ordering rate of about 40 gigawatts per year. As I said earlier, our current ordering rate for coal and nuclear is, in fact, negative—more cancellations than new orders.

Utilities are ordering few new plants because of the obstacles they face with new construction: Difficulty in financing, regulatory uncertainty, and lack of public and political support. Consequently, they also are not promoting electrification to nearly the extent they did in years past. In fact, in some jurisdictions advertising to promote electricity is prevented by utility commissions. This must be reversed to provide information on the economic opportunities for substituting coal- and nuclear-fired electricity for oil and natural gas.

There are many such opportunities for economic substitution. The electric heat pump is today our least costly means of home heating and cooling, where both are needed. Electrified mass transit should be increased to save fuel use by automobiles. The electric car will apparently be launched in the mideighties. And there are substitution opportunities in industrial uses.

It appears to me that this particular energy problem—ordering some 400 more gigawatts of electrical capacity for the nineties and educating people on new economic uses for electricity—is the least understood of our consequential energy problem areas.

In order for utilities to institute a major expansion program for the eighties, the obstacles they face must be removed.

Most importantly utilities must be strengthened financially. On the average they are earning about two-thirds the profits that would be necessary for them to finance major building programs. The State utility commissions which set electric rates would have to allow a special, one-time increase of some 10 to 15 percent in rates to set this right. After that, increases for higher fuel, construction, and operating costs would have to be provided as they occurred.

Of course, electric rates in the United States have at least doubled since 1973 as a result of increases in fuel, construction, and operating costs. But not all of such increased utility costs have been passed through by the rate regulators to the customers. It is the last bit which has been withheld, thus weakening almost all of our electric utilities to the point where further growth is almost impossible to finance. When new, large, expensive coal and nuclear plants are completed—and thus ready for amortization through increased electric charges—the ratemakers balk at allowing full cost recovery. Hence profits suffer, stock and bond prices fall, and utilities find it increasingly difficult to borrow money for more expansion. This is a shortsighted way to save the customer's money. In the long run he will lose more if our economy lacks the energy supplies it needs for growth.

The regulatory climate for both coal and nuclear generating plants has been a changing and increasingly stringent one for a number of years. Some of the changes are desirable, but many have frankly been of greater cost than the value of their benefits. Often changes have been made without regard to cost. The result of this is that a new construction project becomes unpredictable as to cost and schedule. With utilities already financially weak, the regulatory burden becomes impossible to bear. We must make fewer changes once a plant has been started. Only changes essential to public health and safety should be allowed. This can return us to reasonable predictability and stability.

Finally, all this must eventually be understood by our public and our political leaders. It must be incorporated into a consensus energy policy. It seems not too much to ask, considering the brighter future it will provide for all Americans.

Thank you.

Mr. MARKEY. Thank you, Mr. Walske.

[Testimony resumes on p. 94.]

[The attachment to Mr. Walske's prepared statement follows:]

EPRI

ELECTRICITY'S ROLE IN THE ECONOMY

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WASHINGTON, D. C.
NOVEMBER 17, 1980

ELECTRIC POWER RESEARCH INSTITUTE

ELECTRICITY'S ROLE IN THE ECONOMY

Those of us concerned with the future of energy supply carry heavy responsibilities. Failure to act so as to assure energy adequacy could lead to intolerable societal tensions at home and a substantial weakening of U.S. power in the world. We are already paying both domestically and internationally for our past energy failures. What to do about lessening our present vulnerability to fuel supply and price actions originating in the Middle East is outside the scope of my talk today, but obviously no national energy problem is of greater urgency.

My message in this discussion is that electric power can serve America as a critical tool for accomplishing its long-term energy targets. Electricity is a uniquely flexible means for converting a variety of primary sources into productive power. This flexibility is the key to the transition from imported oil to our domestically plentiful resources of solid fuel -- coal and uranium. It can also be employed to make the end-use of energy more efficient, thus promoting conservation and increasing worker productivity, as it has done in the past.

There is an essential link between economic and social well-being and energy consumption. The historic relationship between these elements is changing as a result of price and other factors, but each additional unit of economic activity, each additional worker, each increment of population will still require additional energy. Consequently, increases in population and economic activity will determine future energy and electricity requirements.

The important fact that we must keep in mind throughout this discussion is that the United States labor force is still expanding rapidly. By the year 2000, jobs will need to be provided for a number of workers about 30 percent greater than the present labor force. As we know with reasonable certainty the makeup of the adult population in the year 2000, we can calculate that the labor force will contain some 132 million workers at that time, corresponding to an average annual growth rate of 1.2 percent. At the same time, we expect that the gradual trend toward less hours worked per employee will continue at a 0.2 percent per year average rate of decrease.

In the usual approach to estimating future GNP, expected labor force growth is multiplied by an assumed increase in productivity per worker. The product of the two is GNP. With no change in productivity, GNP would grow 1 percent per year on average for the rest of the century, due solely to the increase in total labor hours. But under these circumstances, there would be no growth whatsoever in average living standards. In this "zero sum" situation, no group could gain without imposing losses on some other group. Thus, <u>productivity growth is essential to increase the average real income of workers</u>.

Although productivity is a critical variable, there is no certainty as to its future level, unlike the estimated future labor force, which we can approximate more closely. Estimates of the average annual increase in productivity* over the remainder of the century used in current projections range from 0 percent per year to 2.3 percent per year (the historical value from 1947 - 1973). This range corresponds to a GNP growth range of 1 - 3.3 percent per year. For comparison, from 1947 to 1966, productivity increased at 3.0 percent per year. However, since 1973, it has increased at only 0.3 percent per year, and this has become a matter of grave national concern.

Still another approach to estimating future growth is not to select a productivity figure arbitrarily, but instead to ask the question: What levels of economic growth will be required, if only to meet the minimum social expectations of a growing labor force?

We have developed such a "minimum expectation GNP" concept at EPRI. This involves the calculation of the aggregate GNP growth necessary to support the income expectations of an older, more experienced, and better educated labor force. In the computations, real income expectations for the year 2000 are held fixed relative to 1979 levels for a given age and educational attainment. Thus, for example, a 40-year-old college graduate

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*Productivity defined as GNP/civilian employee-hour, an aggregate measure of the whole economy.

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in the year 2000 would achieve no greater real income than his 1979 counterpart. However, the difference is that in 2000, there will be many more of these workers than there were in 1979. Therefore, while relative income expectations are held constant, the absolute requirement, aggregated over the entire economy, increased due mainly to the increase in the age and experience of workers and their educational attainment.

To satisfy such a minimum level of income expectation, we have calculated that the GNP must grow at an average rate of 2.5 percent per year. We call this a minimum expectation, because historically we have done much better than this. Real income has been rising, as a result of productivity growth, and expectations have always been running ahead of current and past achievements. Indeed, we calculate that during 1950 - 1970, a minimum income expectation approach would have required a GNP growth of only 1.5 percent per year, while GNP in fact grew at 3.6 percent per year, thus greatly increasing the average standard of living.

Given our assumptions about the size of the labor force and hours worked, productivity estimates translate directly into GNP estimates, as shown in Figure 1. Our minimum expectations rate is shown with other national estimates. Clearly, choosing a GNP growth target for future planning is a social and political decision. In this study we have looked at the range of 1 - 3.3 percent per year.

Just how much energy do we estimate will be required to sustain healthy levels of economic growth? We know that the growths of both U.S. energy consumption and GNP have been closely related during much of the post-World War II period. Only in the last few years have we witnessed what may be a significant deviation from what had been the established energy-GNP trend.

Such deviations are most likely lifestyle and technology adjustments to higher energy prices and insecure supply situations, and are usually termed "conservation." Believing that such conditions are now an integral part of our energy future, we can incorporate conservation assumptions with GNP estimates, in order to project a range of future energy consumption.

For this purpose, we assume a technology-implemented conservation potential for total primary energy consumption of between 28 and 46 percent* of that level, which would be expected from a simple extrapolation of the historical energy-GNP trend. However, we also assume that the increasing environmental standards for energy use could cause as much as a 10 percent increase in total energy requirements, making the effective conservation potential approximately 20 - 40 percent. As shown in Figure 2, these assumptions lead to the trapezoidal area of possible energy demand outcomes for the year 2000.

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*Craig Smith, Efficient Electricity Use, Pergamon Press, New York, 1978.

What do these energy projections imply for electricity need? During the past decades, the percentage of total energy consumption in the United States used as an input to electricity generation has been increasing. Since World War II, this percentage has risen from about 15 percent to over 31 percent today. We expect that the electricity fraction will continue to increase and reach a level of 45 to 55 percent in the year 2000, as shown in Figure 3.

Fifty percent has been the expected value for the year 2000 for some time, corresponding to our projection of the historical trend. However, relative energy price changes, which might favor electricity consumption versus other fuels, as well as differences in conservation of electricity and non-electric energy, may cause the year 2000 percentage to be greater than the 50 percent figure. As total primary energy conservation increases, so does our projected electricity fraction. This is because conservation will be more easily implemented in the non-electric applications, such as transportation and heating fuels. We assume a technology-implemented electricity conservation potential of 17 to 34 percent*.

Figure 4 shows the range of primary energy input to electricity generation and the electricity output that we expect with various levels of economic growth and conservation.

Given these estimates of electricity need, we next look

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*Ibid.

at the energy resources expected to supply the primary input for the generation of electricity.

Coal is now heralded as the fuel of the future, as it was a century ago. We have studied in some detail the nation's capability to produce coal. It is our belief that the maximum coal production the nation can expect in the year 2000 is 1.9 billion tons, or 40 quads. This is nearly 2.5 times 1979 production. This figure takes into account the future evolution of the coal market, as well as lead times for mine developments.

Non-electric uses of coal in the year 2000, according to the Energy Information Administration, will total 16.8 quads. We believe that for political reasons, these uses will have priority over electric utilities for coal supply. Thus, about 60 percent of coal production will be available to electric utilities, as shown in Figure 5.

The resources required to develop and support a 1.9 billion-ton per year coal industry are substantial, as shown in Figure 6. In effect, all of the mines now in operation and most of the transportation equipment must be replaced, in addition to providing for an increase of 1.5 times current levels of output. Also, a large portion of the current labor force will have retired, and new workers must be recruited for replacement, as well as expansion.

Because of the above ramifications, the private coal industry has historically invested in new production facilities at a rate consistent with its perception of the likely growth in long-term demand. For this reason, the 1.9 billion-ton (40-quad) estimated maximum production is associated with the maximum GNP growth rate (3.3 percent). A lesser GNP growth rate would undoubtedly result in a lower coal production. Our judgmental relationship is illustrated in Figure 7, which also shows past production levels. The 1980 production level is already the result of a recent national policy emphasizing the potential for coal and encouraging the expansion of coal production.

Figure 8 illustrates our estimates of the range of fuel requirements and sources for power generation, for the two extremes of GNP growth (1 percent per year and 3.3 percent per year average growth rates) along with the corresponding electricity generation levels expected from the historical trend. Each electricity requirement is then reduced by 17 percent and by 34 percent to reflect the electricity conservation range mentioned earlier.

Our estimates of energy supply for power generation from non-nuclear sources are reasonably optimistic and consistent with other professional estimates. This leaves from 9 to 37 quads to be supplied by nuclear, if our estimated power requirements are to be met. This is equivalent to 147 to 604 GWe of nuclear plants at 70 percent capacity factor.

Assuming present schedules for nuclear plants already well into construction are maintained, we anticipate that about 100 GWe of nuclear capacity will be available in 1985. An additional 20 GWe of currently planned capacity should be operable by 1990. In the two low-GNP growth cases, we have reduced our coal production estimate in accord with Figure 7. It is evident that the lack of planned nuclear plants beyond 1990 creates a serious deficiency, except for the lowest-GNP growth rate (1 percent) and maximum conservation (34 percent).

Of special interest is the electricity supply for the "minimum expectation" GNP growth rate (2.5 percent). This is illustrated in Figure 9. The electricity requirement ranges from 4,600 to 5,800 terawatt-hours (2 - 2.5 times present production). In this case coal production is almost at its maximum, and the resulting nuclear plant deficiency ranges from 160 to 355 GWe. We believe that this case represents the lowest GNP growth rate that might maintain social stability, and certainly should be the minimum considered for long-range national planning.

It is evident that any reasonable economic growth projection based on our national welfare is likely to result in electricity needs greater than our presently planned capacity additions could produce. Two-thirds of our electricity is used by the business community, and, as a result, the consequences to the national economy of a real shortage could be very severe. More subtle, but equally important, would be the depressing effect on manufacturing productivity of a gradual accommodation to a growing electricity shortage. Electricity has had a key role in improving manufacturing efficiency. A shortage would seriously hamper our industrial potential to compete with foreign goods in both our domestic and international markets, and would result in a prolonged period of economic stagnation.

Recognizing the very long times required to correct a deficiency in generating capacity, the prudent national course is to plan for a surplus. Economic studies have repeatedly shown the insurance value of such investments in excess capacity. It is important that the discouraging events of the 1970's not be allowed to limit our hopes for future economic growth or to create a philosophy of scarcity. A future of reduced expectations will become a self-fulfilling prophecy, if we allow it to be the basis for our planning.

# # # # # #

GNP & PRODUCTIVITY RELATIONSHIP
(1979-2000)

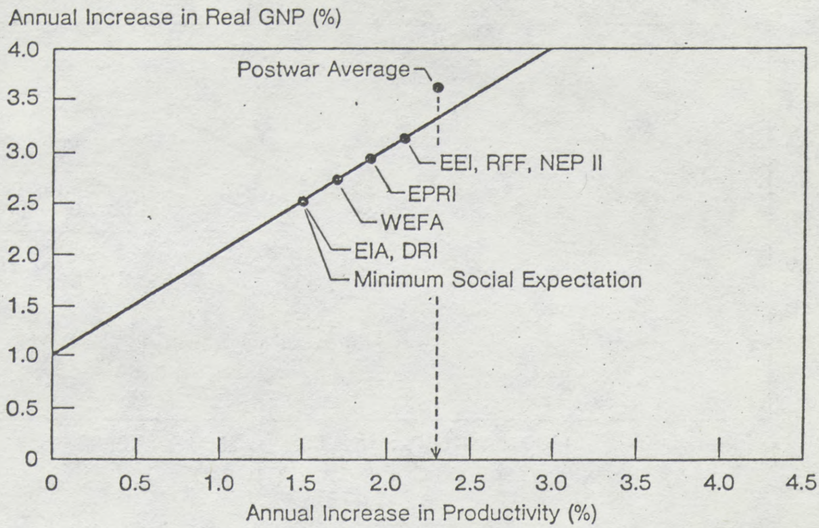

Fig. 1

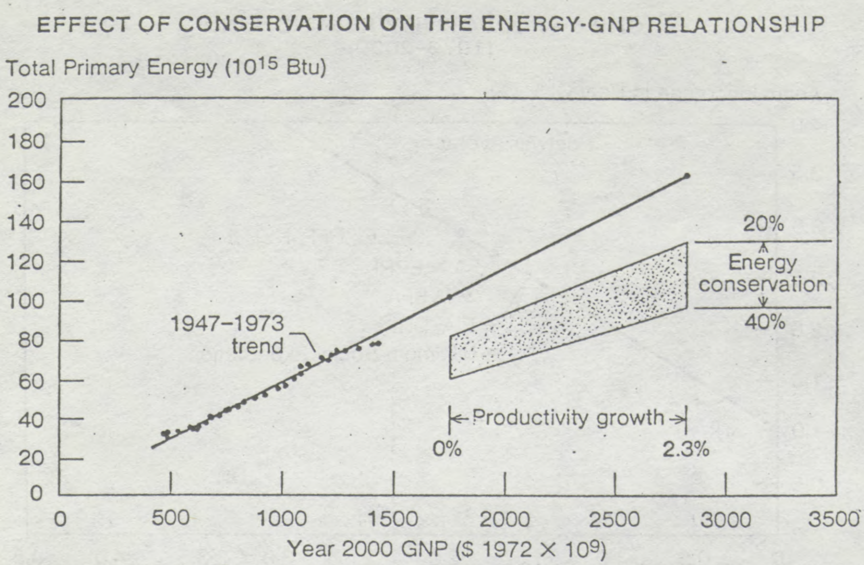
EFFECT OF CONSERVATION ON THE ENERGY-GNP RELATIONSHIP
Total Primary Energy (10^15 Btu)
200
180
160
140
120
100
80
60
40
20
0
1947–1973
trend
20%
Energy
conservation
40%
Productivity growth
0%
2.3%
0
500
1000
1500
2000
2500
3000
3500
Year 2000 GNP ($ 1972 × 10^9)

Fig. 2

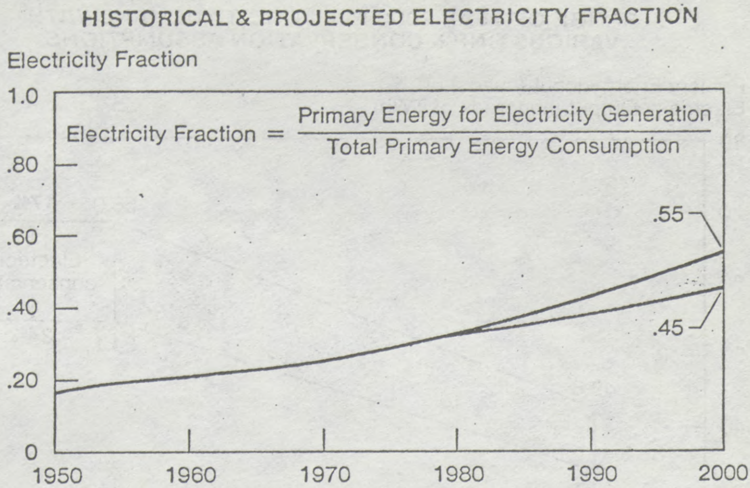
HISTORICAL & PROJECTED ELECTRICITY FRACTION
Electricity Fraction
1.0
.80
.60
.40
.20
0
Electricity Fraction = Primary Energy for Electricity Generation / Total Primary Energy Consumption
.55
.45
1950
1960
1970
1980
1990
2000

Fig. 3

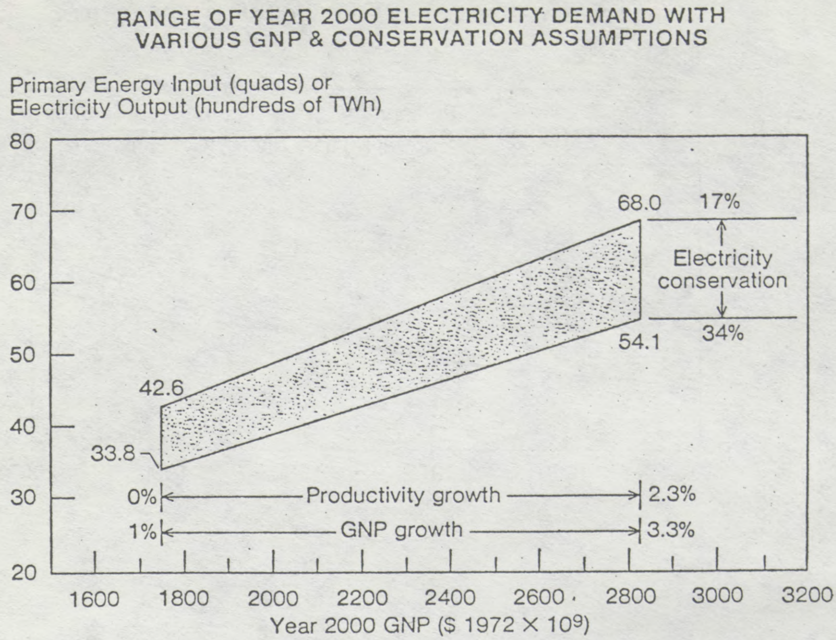
RANGE OF YEAR 2000 ELECTRICITY DEMAND WITH
VARIOUS GNP & CONSERVATION ASSUMPTIONS
Primary Energy Input (quads) or
Electricity Output (hundreds of TWh)
80
70
60
50
40
30
20
68.0
17%
Electricity
conservation
54.1
34%
42.6
33.8
0%
Productivity growth
2.3%
1%
GNP growth
3.3%
1600
1800
2000
2200
2400
2600
2800
3000
3200
Year 2000 GNP ($ 1972 × 10⁹)

Fig. 4

COAL
Year 2000

		Quads
Production Estimate		
• EPRI		40
• EIA	38	
Nonutility demand (EIA)		
• Direct use		
Industrial coal	8.2	
Metallurgical coal	2.1	
Residential coal	0.2	
• Synthetics	2.6	
• Net exports (coal and coke)	3.7	17
Available to electric utilities (EPRI)		23

Fig. 5

RESOURCE REQUIREMENTS FOR COAL PRODUCTION & TRANSPORTATION

Nominal Facility	*Estimated 1980*	*Total in 2000*	*Total Additions* 1980–2000*
Underground mines (capacity 2 million tons per mine per year)**	173	427	450
Surface mines (capacity 4 to 6 million tons per mine per year)	105	229	235
Unit trains (capacity 10,500 tons per train)	268	948	984
Conventional trains (capacity 7225 tons per train)	2,856	4,282	3,327
Coal trucks (capacity 25 tons per truck)	9,060	16,615	39,596
Coal barges (capacity 21,000 tons per barge)	68	106	76
Coal slurry pipeline (25 million tons per line per year)	1	27	26
Land area (acres)	144,565	158,034	—
Water (acre feet per year)	103,370	323,900	—

*Additions include replacements for retired capacity as well as increases in total capacity.

**There are presently approximately 5000 underground coal mines in the USA. These have been lumped together in mines producing 2 million tons each per year for comparison purposes.

Fig. 6

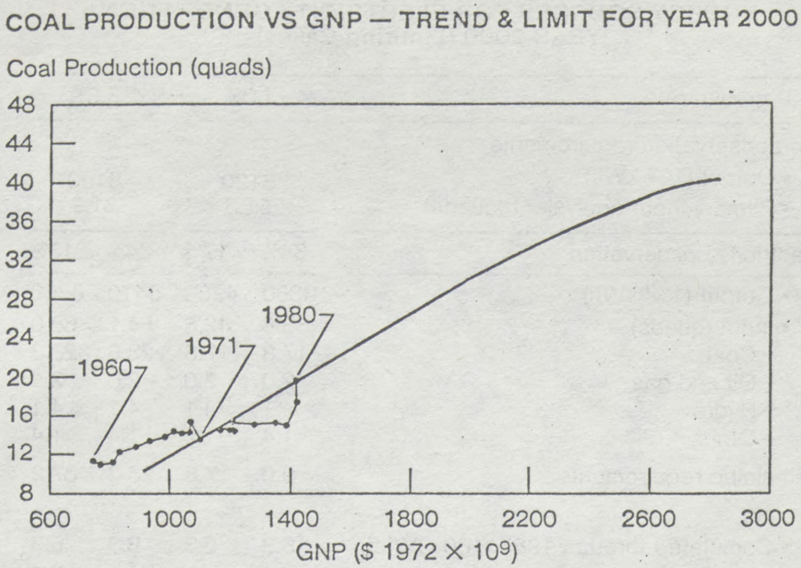
COAL PRODUCTION VS GNP — TREND & LIMIT FOR YEAR 2000
Coal Production (quads)
48
44
40
36
32
28
24
20
16
12
8
1960
1971
1980
600
1000
1400
1800
2200
2600
3000
GNP ($ 1972 X 10^9)

Fig. 7

ENERGY SOURCES FOR ELECTRICITY GENERATION
YEAR 2000 (Limiting Cases)

GNP growth rate	1.0%		3.3%	
Pre-conservation requirements				
• Output (10^9 kWh)	5130		8190	
• Primary input equivalent (quads)	51.3		81.9	
Electricity conservation	34%	17%	34%	17%
• Output (10^9 kWh)	3380	4260	5410	6800
• Input (quads)	33.8	42.6	54.1	68.0
– Coal	17.3	17.3	23.3	23.3
– Oil and gas	2.0	2.0	2.0	2.0
– Hydro	4.1	4.1	4.1	4.1
– Other	1.4	1.4	1.4	1.4
Remaining requirement	9.0	17.8	23.3	37.2
Nuclear				
• Completed through 1985 (100 GW[e])	6.3	6.3	6.3	6.3
• Additional through 1990 (20 GW[e])	1.2	1.2	1.2	1.2
Deficiency (quads)	1.5	10.3	15.8	29.7
• Equivalent generation capacity (GW[e])	(25)	(170)	(260)	(485)

Fig. 8

ENERGY SOURCES FOR ELECTRICITY GENERATION YEAR 2000 (Minimum Expectation Case)

GNP growth rate	2.5%	
Pre-conservation requirements		
• Output (10^9 kWh)	7000	
• Primary input equivalent (quads)	70.0	
Electricity conservation	34%	17%
• Output (10^9 kWh)	4620	5810
• Input (quads)	46.2	58.1
– Coal	21.4	21.4
– Oil and gas	2.0	2.0
– Hydro	4.1	4.1
– Other	1.4	1.4
Remaining requirement	17.3	29.2
Nuclear		
• Completed through 1985 (100 GW[e])	6.3	6.3
• Additional through 1990 (20 GW[e])	1.2	1.2
Deficiency (quads)	9.8	21.7
• Equivalent generation capacity (GW[e])	(160)	(355)

Fig. 9

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Mr. MARKEY. Mr. Taylor, could you identify yourself.

TESTIMONY OF JOHN J. TAYLOR

Mr. JOHN TAYLOR. Thank you, Mr. Chairman, for the opportunity to be here this morning to discuss this important issue. My name is John Taylor. I am vice president of the water reactor divisions of Westinghouse Electric. I have been engaged in nuclear-power development since 1947 in a variety of ways, most particularly in the development of the pressurized water reactor for the propulsion of nuclear ships and the generation of central station electricity.

We at Westinghouse commend the subcommittee in this effort to draw attention to, and enhance understanding of, one of the truly compelling issues of our time: Our country's dangerous dependence on foreign oil.

I strongly believe that the overriding, immediate objective of our national energy policy should be to reduce this oil dependence. This objective has both economic and strategic aspects.

The economic needs are to achieve more stable energy prices and supplies at affordable costs to our society, and to reduce our balance-of-payments deficit.

Our strategic need is equally important. Our vulnerability to a shutoff of foreign oil is of vital concern, particularly in light of recent events in the Middle East.

Increased use of both nuclear- and coal-fired electricity can bring us a giant step toward our objective of reduced dependence on foreign oil. And substituting electricity for oil consumption in our economy addresses both the economic and strategic needs of that objective.

For these reasons, we strongly endorse the conclusion of the recent National Academy of Sciences report that every reasonable effort must be made to substitute coal and nuclear power for oil.

To illustrate the point: A recent Canadian study concluded that Canada can reduce her oil imports—presently approaching 20 percent of consumption and rapidly rising—to zero within the next 10 to 15 years simply by reestablishing her traditional 7-percent-per-year growth rate in electric capacity. Substitution of electricity for oil, the study found, would be expected to follow by the normal incentives of marketplace economics.

I do not suggest that the Canadian study is directly applicable to the United States. But it does emphasize that the fuel mix for the entire economy is our ultimate concern, rather than merely the oil burned to produce a certain amount of electricity.

I will address the potential for electric substitution for oil, and the contribution that nuclear power can make toward generating that electricity focusing on the 1980's.

There are numerous opportunities for replacement with nuclear- or coal-generated electricity. Most of these opportunities will require conversion of equipment over a period of time, but all are feasible with technology that exists today. Many are economically attractive now, and others will become competitive with rising oil prices. And all are heavily dependent upon the extent to which political and regulatory policies encourage the substitution of electricity for oil.

The industrial sector is both the largest and fastest growing user of electric power—and a major consumer of oil and natural gas as well. Its diverse uses of fuel oil offer many opportunities for electric substitution. A recent report prepared for the Department of Energy concluded that existing technology would permit substitution of electricity for approximately 75 percent of the oil now being consumed by industrial processes, an amount equal to 2.7 million barrels per day of oil at present consumption.

If an assured supply of electricity were available, a reasonable expectation might be that market forces would cause a 10-percent penetration by electricity into this potential market during this decade, or a saving of 300,000 barrels of oil per day in 1990.

Space and hot water heating, in homes and stores, offers a large potential in this decade for oil conservation through electrification. In 1979, 3.4 million barrels of oil per day were consumed in the residential and commercial sector, the great majority of which was used for space and hot water heating. Electric energy in the form of resistance heating or heat pumps could replace this oil consumption.

If existing oil-fired space and water heating were replaced over a 10-year period—10 percent per year—and not used in new construction, the fuel oil savings in 1990 would be 3 million barrels per day. This replacement could come from various sources, including electricity, conservation, natural gas, solar, and wood or coal stoves. The fraction replaced by electricity would depend on economics and regulatory pricing policies, national policy, and outlook for long-term supply.

We consider replacement of either oil or gas for electric generation to be equally effective in reducing oil imports.

According to Department of Energy figures, the United States consumed 1.6 million barrels of oil per day to generate electricity in 1979. Much of this 1.6 million barrels of oil per day could be replaced by coal or nuclear generation.

Equally important is the 1.7 million barrels per day oil equivalent of natural gas consumed for electric generation. Much of this gas could be replaced in the electric-generating sector and made available elsewhere in the economy to substitute for fuel oil. In most industrial and commercial applications, oil burners can be rapidly converted to natural gas if pipeline distribution is available.

Thus, even in the electric-generating sector, the issue is not how much oil can be replaced to generate electricity, but rather how much oil imports can be reduced in the U.S. economy as a whole.

Transportation is by far the largest consumer of oil. Clearly, the largest oil savings in this area can be achieved through efficiency and conservation. But even here, electricity has the potential to assist our conservation efforts. Some electric vehicles are already in service, and may be making a substantial contribution in the 1990's.

Realistically, we do not expect any significant oil substitution in the transportation sector in the 1980's, and we therefore did not include them in our potential for this decade.

To illustrate the magnitude of the potential of electric substitution: If one assumes that in the 1980's electricity replaces half of the potential for space and water heating and for oil- and gas-fired electric generation, and only 10 percent of the potential for industrial use—and none in the transportation sector—the United States would reduce its oil consumption by 3.5 million barrels of oil per day—20 percent of current consumption—by this mechanism alone. But to do so, and also accommodate even a very modest 2-percent growth per year in electricity for nonsubstituting functions, would require that our total coal, hydro, and nuclear electric-power production be nearly doubled in this decade. In today's environment, that is an ambitious objective indeed. But we believe it to be achievable, practical, and desirable.

Announced schedules for nuclear powerplant projects as of the beginning of this year imply a total installed nuclear capacity of approximately 150,000 MWe by the end of this decade—approximately three times present capacity. If operated at only 60 percent capacity factor—representative of recent nuclear generating figures—this is an energy contribution equivalent to an additional 2.6 million barrels per day of oil.

With recent trends, however, that figure now appears optimistic. Many projects have been delayed or canceled in 1980, and announcements of further delays are probable in 1981.

In summary, we found that an increase of nuclear power production by 340 percent—the energy equivalent of an additional 3.8 million barrels of oil per day—could be achieved within 5 years of an energy emergency—by finishing the nuclear plants already started and by improving the performance of those already in operation.

If the question is posed: Just how much nuclear power do we need, and how much coal? My answer is that we need all we can get of both. At the national policy level, now is not the time to choose between them, but to encourage the growth of each of them.

Expansion of our nuclear- and coal-electric facilities should be started now. Regardless of whether or not a devastating energy emergency actually materializes, we believe the results would be highly beneficial to America. And we believe that completion of the existing nuclear backlog in this decade is an appropriate goal for nuclear power's contribution toward our essential objective of reduced oil dependence.

Thank you again, Mr. Chairman and members of the subcommittee, for this opportunity to appear.

Mr. MARKEY. Thank you, Mr. Taylor.

[Testimony resumes on p. 119.]

[Mr. John Taylor's prepared statement and attachments follow:]

TESTIMONY OF

JOHN J. TAYLOR

VICE PRESIDENT & GENERAL MANAGER

WATER REACTOR DIVISIONS

WESTINGHOUSE ELECTRIC CORPORATION

Mr. Chairman, members of the Subcommittee, on behalf of Westinghouse I want to thank you for the opportunity to be here this morning.

We at Westinghouse commend the Subcommittee in this effort to draw attention to, and enhance understanding of, one of the truly compelling issues of our time: our country's dangerous dependence on foreign oil.

I strongly believe that the overriding, immediate objective of our national energy policy should be to reduce this oil dependence. This objective has both economic and strategic aspects.

The economic needs are to achieve more stable energy prices and supplies at affordable costs to our society, and to reduce our balance of payments deficit.

Our strategic need is equally important. Our vulnerability to a shutoff of foreign oil is of vital concern, particularly in light of recent events in the Middle East. The possibility of even a major reduction in oil exports from the Middle East represents a deadly threat to national security.

A recent colloquium* addressed the possibility of a total shutoff of Middle East oil, which would result in a 45% reduction in oil supplies to the industrial democracies. Under existing international agreements, our share

* "Contingency Planning for an Energy Emergency," June 16-18, 1980 at Stanford University, co-sponsored by the Hoover Institution and Scientists and Engineers for Secure Energy. Proceedings to be published. Reprints available from Scientists and Engineers for Secure Energy, 570 Seventh Ave., Suite 1007, New York, NY 10018.

of that shortfall would be about 6 million barrels of oil per day, or approximately one-third of our current consumption. The colloquium concluded that the consequences of such a shutoff would be devastating: 8 million additional unemployed and a drop of $3,000 in annual disposable income per family. The final statement of the colloquium is attached (Attachment A).

Increased use of both nuclear and coal-fired electricity can bring us a giant step toward our objective of reduced dependence on foreign oil. And substituting electricity for oil consumption in our economy addresses both the economic and strategic needs of that objective.

For these reasons, we strongly endorse the conclusion of the recent National Academy of Sciences' report that every reasonable effort must be made to substitute coal and nuclear power for oil*.

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* "Every reasonable effort must be made to conserve both oil and natural gas by using them more efficiently, by substituting alternative domestic energy forms (initially coal and conventional nuclear power for the most part, and later synthetic liquids and gases, solar energy, breeder reactors, and other long-term energy sources), and by reducing growth in overall energy demands." Energy in Transition: 1985-2010, Final Report of the Committee on Nuclear and Alternative Energy Systems (CONAES), National Research Council, 1979, National Academy of Sciences, Washington, D.C., P.23.

To illustrate the point: A recent Canadian study concluded that Canada can reduce her oil imports (presently approaching 20% of consumption and rapidly rising) to zero within the next 10 to 15 years simply by re-establishing her traditional 7% per year growth rate in electric capacity*. Substitution of electricity for oil, the study found, would be expected to follow by the normal incentives of marketplace economics.

I do not suggest that the Canadian study is directly applicable to the United States. But it does emphasize that the fuel mix for the entire economy is our ultimate concern, rather than merely the oil burned to produce a certain amount of electricity.

I will address the potential for electric substitution for oil, and the contribution that nuclear power can make toward generating that electricity, focusing on the 1980's.

POTENTIAL FOR CONSERVING OIL WITH ELECTRICITY

There are numerous opportunities for replacement of oil with nuclear or coal-generated electricity. Most of these opportunities will require conversion of equipment over a period of time, but all are feasible with technology that exists today. Many are economically attractive now, and others will become competitive with rising oil prices. And all are heavily dependent upon the extent to which political and regulatory policies encourage or discourage the substitution of electricity for oil.

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* This study also finds that the required investment in power plants would be paid off by savings on imported oil by the year 2000, even with no further increases in the real price of oil. J. G. Melvin, "Energy: The Future Has Come," to be published in the Journal of Business Administration, University of British Columbia. Preprints available.

Industrial Usage

The industrial sector is both the largest and fastest growing user of electric power -- and a major consumer of oil and natural gas as well. Its diverse uses of fuel oil offer many opportunities for electric substitution. A recent report prepared for the Department of Energy concluded that existing technology would permit substitution of electricity for approximately 75% of the oil now being consumed by industrial processes, an amount equal to 2.7 million barrels per day of oil at present consumption*.

If an assured supply of electricity were available, a reasonable expectation might be that market forces would cause a 10% penetration by electricity into this potential market during this decade, or a saving of 300,000 barrels of oil per day in 1990.

Some examples of electric equipment and processes, using existing technology, that have the potential for substituting for oil or natural gas, are listed below.

Industry	Electrical Equipment or Process
Primary Metals	Electric furnaces Electric drives (substitutes for steam drives)
Food and Kindred Products	Electro-boilers

* The report notes that the economic aspects of electric substitution would substantially reduce, but by no means eliminate this substitution capability. J. R. Tallackson, "Electricity in Lieu of Natural Gas and Oil for Industrial Thermal Energy - A Preliminary Survey," ORNI/TH-5937, prepared by the Engineering Technology Division, Oak Ridge National Laboratories, for the Department of Energy, February, 1979.

Industry	Electrical Equipment or Process
Stone, Clay & Glass	Induction glass furnaces Dry cement process (indirect substitution) Electric arc heaters
Process Steam (all industries)	Industrial heat pump; e.g., Templifier

Space and Hot Water Heating

Space and hot water heating, in homes and stores, offers a large potential in this decade for oil conservation through electrification.

In 1979, 3.4 million barrels of oil per day were consumed in the residential and commercial sector, the great majority of which was used for space and hot water heating. Electric energy in the form of resistance heating or heat pumps could replace this oil consumption.

Approximately half of all new homes in the United States are equipped with electric space heating systems, but electricity has not yet made a significant penetration into the replacement heating market. We believe national economics favor a much larger contribution from electricity*.

* Recent studies at Argonne National Laboratories concluded that the economics of electric heating designed to use off-peak electricity (present technology) are highly attractive: The commercialization problem is to adjust the electric rate schedule to equitably share the true costs between the utility and the consumer. (J. G. Asbury, et al, "Electric Heat: The Right Price at the Right Time," Technology Review, December/January 1980). Also, for a recent survey of electric heating applications in the Northeast, see "Electricity for Heating is Making a Comeback," New York Times, September 28, 1980. This article reports numerous and diverse instances in which dramatic savings have been realized by conversion to electric heat.

In most of the U.S., electric heating has favorable economics today. The best type of electric heating varies from one area of the country to another*.

If existing oil-fired space and water heating were replaced over a 10-year period (10% per year), and not used in new construction, the fuel oil savings in 1990 would be 3 million barrels per day. This replacement could come from various sources, including electricity, conservation, natural gas, solar, and wood or coal stoves. The fraction replaced by electricity would depend on economics and regulatory pricing policies, national policy and outlook for long-term supply.

Looking at probable future economics, electricity is in an even stronger position to substitute for oil heating. Its price relative to oil and gas has been dropping for a half century or more. This trend is expected to continue**.

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* The heat pump is an ideal space heating technology in areas where utility electric loads are highest in the summer such as much of the mid-Atlantic region (provided, of course, that the electricity need not be generated by expensive oil). In these areas, large investments for new electric generating and distribution equipment would not be needed. Where utility electric loads are highest in the winter, such as in much of the Northeast, electric storage heating systems are very attractive. These systems have been commercialized in both Britain and Germany through off-peak electric pricing. In both countries, market penetration was very rapid, growing from less than 800 megawatts of electricity in 1963 to approximately 20,000 megawatts by 1973. In some areas, solar systems combined with heat pumps provide the lowest cost heating for many applications.

** A review of the recent major studies conducted by Resources for the Future National Energy Strategies Project concludes: "Virtually all studies surveyed assume real energy price increases, with gas prices expected to rise fastest and coal and electricity prices the least rapidly." (Schurr, Sam, "Energy in America's Future: The Choices Before Us," a study by the staff of the Resources for the Future, National Energy Strategies Project, Johns Hopkins University Press, Baltimore, 1979, p. 183.

Oil and Gas Usage - Electric Generation

A major reduction in both oil and gas for generating electricity has already been established as a national objective by the Fuel Use Act of 1978*. We consider replacement of either oil or gas for electric generation to be equally effective in reducing oil imports.

According to Department of Energy figures, the United States consumed 1.6 million barrels of oil per day to generate electricity in 1979**. Much of this 1.6 million barrels of oil per day could be replaced by coal or nuclear generation.

Equally important is the 1.7 million barrels per day oil equivalent of natural gas consumed for electric generation. Much of this gas could be replaced in the electric generating sector and made available elsewhere in the economy to substitute for fuel oil. In most industrial and commercial applications, oil burners can be rapidly converted to natural gas if pipeline distribution is available.

Thus, even in the electric generating sector, the issue is not how much oil can be replaced to generate electricity, but rather how much oil imports can be reduced in the U. S. economy as a whole.

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* The Fuel Use Act of 1978 prohibits the building of major new oil or gas-fired electric power plants and calls for replacement or conversion of many existing plants.

** The large majority (about 90%) of this was residual fuel oil, mostly (about 70%) imported, at close to the same price per barrel as crude. Note that residual fuel oil can be made available for other uses with additional processing.

Transportation

Transportation is by far the largest consumer of oil. Clearly, the largest oil savings in this area can be achieved through efficiency and conservation. But even here, electricity has the potential to assist our conservation efforts. Some electric vehicles are already in service, and may be making a substantial contribution in the 1990's*.

Realistically, we do not expect any significant oil substitution in the transportation sector in the 1980's, and we therefore did not include them in our potential for this decade.

We do, however, suggest that serious consideration should be given to the proposal to include electric vehicles in the auto industry's computation of "corporate average fuel economy**."

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* In Britain, some 45,000 electric trucks are already in service to deliver milk. In the United States, the Postal Service operates a fleet of about 400 electric vehicles -- and reports that their annual operating costs are less than for gasoline-powered vehicles. See, for example, "An Electric Car in Every Garage," IFEE Spectrum, September 1980.

** The Department of Energy has supported a proposal that electric vehicles be included in the auto industry's "corporate average fuel economy computation" to encourage mass production of electric cars. If a manufacturer's output of electric cars amounted to 5% of their total production, their "corporate average fuel economy" would be increased 1 mile per gallon. Since automobile manufacturers are spending between $1 and $2 billion for an improvement of one mile per gallon, the Department of Energy feels manufacturers would be encouraged to add electric vehicles to their inventories.

Summary of Potential Markets for Electric Substitution

The potential market for which electric energy can substitute for oil is impressive indeed. If assured suppliers of electricity (whether from coal or nuclear or hydro) are available, and appropriate national policy and regulatory pricing policies are adopted, we believe electricity can and will capture a significant portion of this potential through marketplace forces. The result would be substantially less dependence on imported oil.

To illustrate the magnitude of the potential of electric substitution: If one assumes that in the 1980's electricity replaces half of the potential for space and water hearing and for oil and gas-fired electric generation, and only 10% of the potential for industrial use (and none in the transportation sector), the United States would reduce its oil consumption by 3.5 million barrels of oil per day (20% of current consumption) by this mechanism alone*. But to do so, and also accommodate even a very modest 2% growth per year in electricity for nonsubstituting functions, would require that our total coal, hydro, and nuclear electric power production be nearly doubled in this decade**.

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* At present oil prices, this is a saving of over $40 billion per year. With expected oil price increases, 1990 savings for imported oil would be substantially higher.

** To replace 3.5 million barrels of oil per day in the heating, electric generating, and industrial sectors would require approximately 900 billion kilowatt-hours of electricity (4.1 million barrels per day oil equivalent). Two percent per year growth from total 1979 electric consumption of 2200 billion kw-hrs would add another 500 billion kw-hrs, for a total increase of 1400 billion kw-hrs in 1990, compared to 1979 production of 1580 billion kw-hrs from coal, nuclear, and hydro combined.

In today's environment, that is an ambitious objective indeed. But we believe it to be achievable, practical, and desirable*.

Most energy analysts recognize the increasing importance of electricity and its role in reducing our dependence on oil**.

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* Using somewhat different assumptions and bases, the Department of Commerce has considered a 1990 savings of 4.0 million barrels of oil per day as a feasible possibility with electric substitution. ("Forecast of Likely U.S. Energy Supply/Demand Balances for 1985 and 2000 and Implications for U.S. Energy Policy", PB-266 240, prepared by Office of Energy Programs, Domestic & International Business Administration, U.S. Department of Commerce, January 20, 1977.)

** This is reflected in the results of studies by three nationally recognized organizations: Resources for the Future, The Institute for Energy Analysis, and the U.S. Department of Energy. Although the three represent a variety of opinions, assumptions, and interests, the forecasts which they each developed for total U.S. energy and electricity to the year 2000 are similar. In all three cases, total energy was projected to increase at an average annual rate of between 1.5% and 2.0% while electricity was projected to increase at an average annual rate of between 3.2% and 4.0%. In each case, electricity's share of total energy is projected to increase significantly, from less than 30% in 1976 to between 40% and 48% in the year 2000. These three studies are: Energy In America's Future: The Choices Before Us, A study by the staff of the Resources for the Future National Energy Strategies Project, Sam Schurr (Project Director). Baltimore: John Hopkins University Press, 1979, ("primary emphasis" scenario); Energy and Economic Growth in the United States, Institute for Energy Analysis, Edward L. Allen, Oak Ridge Associated Universities, The MIT Press, Cambridge, 1979 (average of upper and lower scenarios); and Market Oriented Program Planning Study, U.S. Department of Energy, Review Draft of Final Report, Vol. 1 "Integrated Summary," 1977.

THE POTENTIAL FOR INCREASING NUCLEAR POWER PRODUCTION

Announced schedules for nuclear power plant projects as of the beginning of this year imply a total installed nuclear capacity of approximately 150,000 MWe by the end of this decade -- approximately three times present capacity. If operated at only 60% capacity factor (representative of recent nuclear generating figures), this is an energy contribution equivalent to an additional 2.6 million barrels* per day of oil.

With recent trends, however, that figure now appears optimistic. Many projects have been delayed or cancelled in 1980, and announcements of further delays are probable in 1981.

But consider the contribution that nuclear power can make if called upon. Westinghouse studies** have concluded that in a national energy emergency in which we needed all the electric energy that could be generated, the nuclear industry is capable of rapid and dramatic increases in power generation: The prerequisites for rapid expansion are already in place. In six months, for instance, the output of existing nuclear plants could be increased by the equivalent of 500,000 barrels of oil per day through managed maintenance programs and -- most important -- better cooperation between regulators and utilities.

* For consistency, we have placed energy figures in million barrels of oil per day energy equivalent; i.e., the amount of oil needed to generate a given amount of electricity. (1 million barrels per day oil equivalent equals 212 billion kilowatt hours of electricity per year. Conversion factors for substitution of electricity for oil will vary with the efficiency of the process.)

** J.J. Taylor, "The Potential Contribution from Nuclear Power in an Energy Emergency", paper presented at the Hoover Institution, Stanford University, June 16-18, 1980. Reprint provided to this Subcommittee, or available from the author.

There are now 12 nearly completed nuclear plants across the country. Their operation dates are primarily determined by expected licensing schedules. These plants represent 12 million kilowatts (the energy equivalent of 430,000 barrels of oil per day) that could be put into service within a year in an emergency.

Another 27 plants representing 30 million kilowatts (the energy equivalent of 1 million barrels of oil per day) could be operational within three years. And completion of an additional 66 plants under construction or on order could also be accelerated, provided the regulatory process was streamlined.

In summary, we found that an increase of nuclear power production by 340% (the energy equivalent of an additional 3.8 million barrels of oil per day) could be achieved within five years of an energy emergency -- by finishing the nuclear plants already started and by improving the performance of those already in operation*.

If the question is posed: Just how much nuclear power do we need, and how much coal? My answer is that we need all we can get of both! At the national policy level, now is not the time to choose between the, but to encourage the growth of each of them.

Expansion of our nuclear <u>and</u> coal electric facilities should be started <u>now</u>. Regardless of whether or not a devastating energy emergency actually materializes, we believe the results would be highly beneficial to America. And we believe that completion of the existing nuclear backlog in this decade is an appropriate goal for nuclear power's contribution toward our essential objective of reduced oil dependence.

Again, Mr. Chairman, I thank you and the Subcommittee for the opportunity to appear. I will be happy to respond to any questions the members may have.

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* The study assumed many conditions consistent with a national emergency, but did <u>not</u> assume any reduction in safety or environment requirements.

July 24, 1980

SCIENTISTS AND ENGINEERS FOR SECURE ENERGY
and
THE HOOVER INSTITUTION

STATEMENT OF COLLOQUIUM

CONTINGENCY PLANNING FOR AN ENERGY EMERGENCY

A sense of urgency permeated a meeting of 60 of the nation's leading academicians and industrialists concerned with energy problems, convened June 16-18 at Stanford University. Entitled "Contingency Planning for an Energy Emergency", the colloquium dealt with the consequences of a sudden cut-off of oil from the Persian Gulf.

The prolonged interruption of oil supplies from the Gulf by any one of a number of scenarios (for example: revolution or Soviet expansionism) is a real possibility. There was nearly unanimous agreement that the economy of the United States and of its allies would be in jeopardy if this occurred, and that immediate programs to reduce this vulnerability should be instituted.

The colloquium was sponsored by Scientists and Engineers for Secure Energy and by the Hoover Institution. The participants considered how the energy requirements of the United States could be met if the contingency occurred. The physical limits of a national response covering a period of five years from the cut-off were investigated. Topics discussed included: emergency conservation measures; possible expansion of oil supplies from alternate sources; substitution, when possible, of gas, coal and electricity

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for oil; effects on electric power generation; rationing and other forms of allocation; economic effects and changes in life style; and advance preparations to reduce our vulnerability.

The colloquium findings are:

The initial situation faced by the industrial democracies after a complete cut-off (which is a limiting case of more probable partial cut-offs) would be a short-fall of about 45% of their oil supplies, or 16 million barrels/day. According to the existing oil-sharing agreements between the U.S. and the other members of the International Energy Agency, the short-fall would be distributed as follows:

- U.S. oil supply would be reduced about 35%, by 6 million barrels/day,
- Oil supply of our allies would be reduced about 55%, by 10 million barrels/day.

As a result, in the United States a Mideast cut-off would:

- cause the transportation system to be greatly disrupted. Private automobile use would be reduced about 50%, and other vehicle transportation would be cut about 30%;
- cause massive additional unemployment of over 8 million workers, and reduce annual disposable income by over $3,000 per household;
- impair our ability to mobilize effectively to defend ourselves, and imperil the security of the free world;
- lower the Gross National Product by $350-650 billion dollars per year (about 15 to 25%).

Further,

- depending on the timing of the cut-off and the region of the country, one could expect the closing off of some housing space, or abandonment of some types of housing which the users might not be able to heat; accelerated movement of people to a warmer climate; relocation of people closer to their places of work; and perhaps even dormitory housing for younger workers near industrial enterprises (as occurred, for example, at Oak Ridge during World War II);
- shopping habits would undergo dramatic changes, and recreational and cultural activities would be greatly curtailed.

In the five years subsequent to an oil cut-off, assuming only present technologies could be effective on a large-scale, replacement of the U.S. oil supply deficit by determined expansion of domestic and other foreign oil supplies, and by substitution of other fuels, would be substantial but still only partial (40-60%).

To avoid the vulnerability of our society to these consequences, participants recommended a number of measures. While further measures may be necessary or advisable, there was general agreement that the following should be adopted:

1. The security of the United States requires the implementation of an aggressive program to increase both energy production and the more efficient use of oil. The object of this program should be to reduce vulnerability to loss of imported oil as quickly as possible. Examples of opportunities for increased sources of energy supply are: coal, gas, nuclear power, biomass, and on a longer time scale, shale oil. As was proven during World War II, high level policy organization is an absolute

prerequisite for organizing and implementing an effective program.

2. Rapid decontrol of oil and gas prices and abolition of entitlements are the most important ways of providing needed incentives to displace oil imports by inducing real conservation and increasing supply. Equity concerns, such as undue burdens on people with low incomes, should be dealt with by income transfers rather than by manipulating prices or by allocations.

3. Environmental laws should be administered and perhaps amended to encourage energy production as well as to protect the environment, thus reducing the danger that curtailments caused by an oil cut-off will harm the health and welfare of the American people.

4. Licensing for operation of completed nuclear plants should be expedited in order that the plants may be put in production immediately. Partially completed power plants (both coal and nuclear) should be completed on an accelerated schedule. Unnecessary regulatory impediments to other energy facilities (such as pipe-lines, port facilities and drilling platforms) should be removed.

5. Oil for non-transportation uses should be replaced by natural gas and coal- and nuclear- generated electricity as soon as possible. Limitations on production and use of natural gas

and electricity should be reduced to permit price competition to determine their relative market shares. Electric utility rates should more nearly reflect the marginal costs of new power plants.

6. The energy industries should with government encouragement jointly prepare emergency plans against an oil cut-off. Among other measures, acquiring spare production and storage capacity should be encouraged.

7. The automotive industries should be encouraged to increase their efforts to produce more fuel efficient automobiles, including electrical and hybrid vehicles.

8. Contingency plans should be made to curtail energy consumption, and to suspend temporarily some procedural requirements and environmental standards, in the event of an oil cut-off. Wide public discussion of these plans at the community and the factory levels should be inaugurated.

9. In addition to our present commercial operational oil reserve (about 30-40 days of total imports), we should begin to fill the Strategic Petroleum Reserve at a rate of more than 300,000 bbl/day. Note that at a rate of 100,000 bbl/day, it would take 20 years to accumulate an amount of oil which would cover the maximum projected deficit (6 million bbl/day) for four months. To the extent possible, the SPR fill should be achieved by reduction of current oil consumption according to the preceding recommendations.

10. Since the use of oil in Western Europe and Japan for generating electricity is about 3 million barrels per day, it is in our mutual interest to reduce their vulnerability by encouraging and assisting their conversion to nuclear energy and coal.

Implementing the foregoing recommendations would, as time passes, progressively reduce the severity of the initial shock of an oil cut-off and the duration of the recovery period.

The undersigned participants subscribe to the general sense of the above statement as individuals (affiliation for identification only):

SIGNATORIES AS OF JULY 24/1980

Robert K. Adair	Yale University
Donald G. Allen	New England Electric Co. (ret.)
Hans A. Bethe	Cornell University
Elliot Bloom	Stanford Linear Accelerator Center
Harvey Brooks	Harvard University
Arthur M. Bueche	General Electric Company
Toby Burnett	Westinghouse Electric Corporation
Peter Camp	General Electric Company
Roger S. Carlsmith	Oak Ridge National Laboratory
Karl Cohen	Stanford University
Thomas Connolly	Stanford University
Gordon R. Corey	Commonwealth Edison Co. (ret.)
W. Kenneth Davis	Bechtel Power Corporation
R. Leslie Dugan	SE_2
Lloyd E. Elkins	Petroleum Consultant, Tulsa, OK
Robert Erdmann	Science Applications, Inc.
Gary J. Feldman	Stanford Linear Accelerator Center
John S. Foster, Jr.	TRW, Inc.
Michehl R. Gent	National Electric Reliability Council
Tsahi Gozani	Science Applications, Inc.

Elmer E. Hall	Pacific Gas & Electric Co.
Carl E. Hedeen	General Motors Corporation (ret.)
Carolyn Meinel Henson	L5 Society
Frederick A. L. Holloway	Treasurer, National Academy of Engineering
Richard J. Kessler	Center for Strategic and International Studies
George Marotta	Hoover Institution
Sullivan S. Marsden, Jr.	Stanford University
John McCarthy	Stanford University
Robert R. Nathan	Consulting Economist, Washington, D.C.
Kenneth D. Nichols	U.S. Army (ret.)
W. E. Parkins	Rockwell International
Norman Parlee	Stanford University
S. S. Penner	University of California at San Diego
Robert B. Richards	General Electric Company
Larry E. Ruff	Brookhaven National Laboratory
Andrew Safir	Business & Transportation Agency, State of California
Benjamin Schlesinger	American Gas Association
Herman E. Schroeder	E.I. DuPont de Nemours & Co. (ret.)
Paul Seabury	University of California at Berkeley
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Rudolf Sher	Stanford University
George P. Shultz	The Bechtel Group
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Eugene P. Wigner	Princeton University
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October 9, 1980

Hon. Bob Eckhardt
Chairman
Subcommittee on Oversight and Investigations
of the
Committee on Interstate and Foreign Commerce
U.S. House of Representatives
Washington, D.C. 20515

RECEIVED
OCT 13 1980
BOB ECKHARDT, M.C.

Dear Mr. Eckhardt:

Thank you for your letter of September 30, 1980, concerning the potential contribution of nuclear power in an energy emergency.

As you requested, I am enclosing a copy of my complete manuscript prepared for that colloquium. As stated in the abstract on the title page, "we conclude that within six months [of a severe energy emergency], nuclear electric production can be increased by 0.7 million barrels of oil per day energy equivalent, and increased by 3.8 million barrels per day energy equivalent within five years". This conclusion was accurately reported by Science Magazine in their July 11 issue. Our basis for this conclusion is described in Section 2 of the attached manuscript. Also, I stated, "With standardized design, a preselected site, and elimination of regulatory delays, a new land-based nuclear plant can be placed in operation within five or six years of the decision to proceed". (See page 2-10 of manuscript, and discussion on pages 2-6 and 2-10.)

I am also enclosing a copy of my September 23, 1980 letter to the editor of Science Magazine responding to George Weil's criticisms.

In answer to your specific questions:

1. My figures are based on energy equivalence, not replacement. In accordance with the theme of the colloquium, we tabulated potential nuclear energy production in terms of millions of barrels of oil per day energy equivalent. This does not necessarily imply that a one-for-one displacement directly results. In fact, however, there are numerous opportunities for replacement of oil with nuclear or coal-generated electricity. For example, 3.3 million barrels of fuel oil per day are now being burned for commercial and residential heating that could also be done with electricity or natural

gas. Further, the United States is burning natural gas at the rate of 1.7 million barrels per day oil equivalent to generate electricity. This natural gas could be substituted for oil elsewhere in the economy if the electricity were generated with coal or nuclear power. These areas are in addition to the 1.7 million barrels of fuel oil per day (most of which is imported) which is burned to produce electricity. This topic is discussed in more detail in Section 4 of the manuscript.

2. My analyses were not based on a 100% capacity factor as Weil charged. Our study concluded that, in a protracted energy emergency, an 80% capacity factor is achievable as an industry average with close cooperation between regulators and utilities, managed maintenance programs, and capital improvements. As discussed on pages 2-13 through 2-16 of the manuscript, my figures were based on existing plants (those already in operation) achieving an average 80% capacity factor within 12 months, and new plants (not yet in commercial operation) achieving an 80% capacity factor after their third annual refueling. In addition, we also found that both existing and new nuclear plants could be uprated; i.e., increased in nameplate rating, by an average of 5% within 18 months. (See page 2-16.) Such upratings have already been achieved in some nuclear plants.

3. We do not agree with Weil's finding that a large portion of the 91 or so nuclear plants under construction would displace coal-fired electric plants and that only 6 would displace oil-fired plants. Please note that of just the 15 nuclear plants nearest completion (shown on Table 2.2 of page 2-4), 6 are directly located in areas with substantial dependence on oil-fired electricity (California, New York, New Jersey, and Virginia). Also, intersystem transmission lines can transport some excess electric power (whether generated from coal or nuclear) from one area to another. However, the question of whether a given nuclear plant displaces electricity from coal or oil or natural gas obscures the more important issue: Substitution of nuclear and coal-fired electric power for oil. This is the area addressed in Section 4 of the manuscript. We found that there were substantial opportunities for replacement of oil with electricity, and are thus in agreement with the recent CONAES Report, "Energy in Transition, 1985-2010", by the National Academy of Sciences. Their study found that, "Every reasonable effort must be made to conserve both oil and natural gas by using them more efficiently, by substituting alternative domestic energy forms (initially coal and conventional nuclear power for the most part, and later synthetic liquids and gases, solar energy, breeder reactors, and other long-term energy sources), and by reducing growth in overall energy demands" (page 23).

Again thank you for your inquiry. The vulnerability of our country to a shutoff of foreign oil is clearly of vital concern, particularly in light of recent events in the Mideast. I would be pleased to provide whatever assistance I can to you in the future on this very important issue.

Sincerely,

John J. Taylor

John J. Taylor

Westinghouse
Electric Corporation

Water Reactor
Divisions

J J Taylor
Vice President & General Manager

Nuclear Center
Box 355
Pittsburgh Pennsylvania 15230

September 18, 1980

The Editor
Science
American Association for the
Advancement of Science
1515 Massachusetts Avenue, NW
Washington, D.C. 20005

Dear Sir:

George L. Weil's letter printed in your 1 August 1980 issue commented on my paper, "The Potential Contribution of Nuclear Power in an Energy Emergency".

He first cited Eliot Marshall's "News & Comment" (11 July, p.246) that the "catch" in my projection was assuming "an extraordinary degree of government and financial support". That paper was presented at a colloquium on "Contingency Planning for an Energy Emergency" at Stanford last June. The scenario being addressed assumed a prolonged interruption of Persian Gulf oil, causing a 45% reduction in oil supplies to the industrial democracies of the world. My paper addressed the potential for nuclear power in such an emergency. In a national emergency with priority on energy projects, our studies concluded it was quite practical to increase nuclear electric power production by 60% within six months (equal to 0.7 million barrels of oil per day energy equivalent), and by 340% within five years (the energy equivalent of 3.8 million barrels of oil per day) -- by finishing the nuclear plants already authorized. The support required is to forego the luxury of unnecessarily protracted licensing delays in a national emergency entailing widespread economic dislocation and human suffering.

With respect to Weil's comment on achievable nuclear plant capacity factors: He correctly notes that nuclear plant capacity factors were quite low in 1979 (largely as a result of revaluations and backfitting requirements stemming from the Three Mile Island accident). We believe a substantial improvement can be made in nuclear plant capacity factors. Our study concluded that, in a protracted energy emergency, an 80% capacity factor is achievable as an industry average with close cooperation between regulators and utilities, managed maintenance programs, and capital improvements. My conclusions are based on this figure and not on "a capacity factor close to 100%", as Weil alleges. In addition, we found that both existing and new nuclear power plants could be uprated;

i.e., increased in nameplate capacity, by an average of 5%. Such upratings have already been achieved in some nuclear plants to give credence to this conclusion.

Regarding the potential of nuclear electric power to substitute for oil: In accordance with the theme of the colloquium at Stanford University, we tabulated potential nuclear energy production in terms of millions of barrels of oil per day energy equivalent. This does not necessarily imply that a one-for-one oil displacement directly results. In fact, however, there are numerous opportunities for replacement of oil with nuclear or coal-generated electricity. For example, 3.3 million barrels of fuel oil per day are now being burned for residential and commercial heating that could also be done with electricity or natural gas. Further, the United States is burning natural gas at the rate of 1.7 million barrels per day oil equivalent to generate electricity. This natural gas could be substituted for oil elsewhere in the economy if the electricity were generated with coal or nuclear power. These areas are in addition to the 1.7 million barrels of residual fuel oil per day (most of which is imported) which is burned to produce electricity.

I would be pleased to provide a complete text of my manuscript to anyone requesting it.

Sincerely,

J. J. Taylor

Mr. MARKEY. Mr. Weiner, could you identify yourself.

TESTIMONY OF RICHARD WEINER

Mr. WEINER. My name is Richard E. Weiner. I am Director of the Department of Energy's Division of Power Supply and Reliability. I have been requested to appear before you to present various data and information related to electric utility generation and fuel use.

The Division of Power Supply and Reliability is charged with the mission of assuring the continuance of the high level of reliability of the U.S. electric power system and preservation of the integrity of the supporting system. The Division is also responsible for encouraging more rational utilization, by utilities, of the country's indigenous fuel sources, thus reducing oil and gas consumption. The Division operates under several legislative authorities derived from the Federal Power, Atomic Energy, Fuel Use, and Public Utility Regulatory Policies Acts.

My role is not to advocate one type of resource in favor of another. I will try to present data to give a fair depiction of the reliance one may place on future electric-generating resources. My primary concern is the assurance of an adequate supply of electricity and the displacement of fuel oil consumed by the electric utility sector. In areas where there are adequate supplies of electricity produced from nonoil fuels, that electricity can provide for a reduction of home fuel oil use as a second-order effect. As will be shown by the statistics presented, nuclear- and coal-fueled generation have been important to the Nation as providers of electric energy and have each, as a resource, reduced oil consumption. The electric utility industry has placed a great deal of reliance on both coal and nuclear sources to continue this displacement of fuel oil and to supply the increasing energy requirements of its customers. It is clear from the data to be presented that there is not a one-for-one correlation between nuclear and coal generation and the displacement of fuel oil. Because of the complex interaction of the electric utility grids, these new generating units will displace varying quantities of oil. In some cases, a new nuclear unit will save an amount of oil equivalent to the entire amount of energy produced by the unit. The same may be true for coal-generating units.

However, even the lowest of possible electric utility growth rates still require the installation of new non-oil-fueled resources. This requirement is necessary to keep electric utility costs from increasing at too great a rate. New facilities also permit the retirement of older equipment and assure that the supplies of electricity are available upon demand. A 2-percent growth rate based on the 1980 summer load of 427 GW would require 8.5 GW of new generation each year simply to keep pace.

In today's statement, I will attempt to present as much information as it has been possible to gather since the day I received your request. I will rely on this information and my personal expertise to provide responses to your several questions.

Among the information to be provided today will be:

The depiction of the current and future use of oil, coal, and nuclear fuel by electric utilities to generate electricity.

Anticipated trends in electric utility fuel use and new plant construction.

The recent history of electric utility plant construction.

The historical philosophy and planning decision process utilized by the industry in selecting the type of plant to be constructed.

Information on the ability of existing and future coal and nuclear plants to reduce oil consumption.

The reliability impact of not having generation available from nuclear- and coal-fueled plants under construction.

If the committee members find that they require additional information beyond that which is presented today, or if because of the short timeframe in which we had to prepare this data, more detail is necessary, I will be more than happy to submit a followup presentation.

I will be referring to the various tabulations and graphs in the appendix to this testimony to answer the questions described above. [See appendix, p. 126.]

Table I shows the projected use of fossil fuel for electric generation based on both an anticipated and a minimum projection of load growth. The figures to the right on this table show the actual use of fossil fuels for electric generation in 1979. It is important to point out that any major conversion to, or increase in, the installation rate of electricity-consuming devices to replace customer use of oil will cause much higher long-range growth than has been shown.

The projections of fuel consumption are based on 50- and 60-percent capacity factors for coal-unit production and for scenarios envisioning a low and high installation rate of new nuclear units and low and high production from hydroelectric resources. These ranges are shown to present the sensitivity of fuel oil consumption to coal or nuclear electricity production.

Table II shows actual 1979 and projected 1985 electric energy production by various fossil-fuel types. These projections are also shown for maximum-minimum anticipated energy requirements of electric utility customers. Table III presents the allocation of energy production among the various types of fuel for 1979 and projected 1985.

Table IV shows that a net total delay in construction of coal-fired units expected in service by 1985 of greater than 345,000 megawatt-months has occurred in the past year. It is rather dramatic to compare this value to a computation done earlier this year by my division that showed 130,000 megawatt-months of slippage for the same time period.

The present construction schedules for new coal units have been analyzed by the division. A comparison of anticipated in-service dates for new coal units over the period of a year has raised great concern for the assurance that these new units will be in service when required. This concern is both for fuel oil displacement and electric supply adequacy. Tables IV and V demonstrate the impact of this slippage on construction schedules. These figures consider the size of the new coal-fueled units and the number of months of slippage that has occurred in the period of 1 year. This delay has been translated at the bottom of page 2 of table V into approximate additional barrels of oil per day that will be consumed because these coal units will not be available. The groups of construction delay are shown by electric reliability council regions; for example, the WSCC region shown on page 2 of table V represents the Western States. Attachment A to table V is a map showing the delineation of the various electric reliability councils. Attachment B to table V is a map showing the various electrical subregions delineated in the table.

Table V at page 2 shows that this delay in construction of new coal-fueled generation will cause an increase in anticipated oil consumption by electric utilities of 20,000 barrels a day over the 6-year period 1980–85, with a peak increase of almost 35,000 barrels a day expected in 1984.

An analysis was also done for nonlicensing, or delays in the licensing, of new nuclear powerplants. This analysis was compared to a study by the division in December of last year to determine the effect of a nonlicensing scenario for nuclear plants and if this would cause unanticipated increased consumption of fossil fuel and possibly electric supply adequacy and reliability problems.

Table VI shows the probable additional fuel oil consumption if the 53 nuclear units scheduled for commercial operation through 1985 are not placed in service. In this extreme case, an increase in fuel oil consumption above anticipated levels could reach as high as an average of almost 700,000 barrels a day or 33.5 percent increase above the anticipated national electric utility consumption for 1985. Coal consumption would increase by 151,000 tons per day or 7.4 percent, and gas would increase by 932 million cubic feet per day or 22.1 percent.

One must be careful when using these values by themselves. A combination of this information and that presented in the earlier tables—tables IV and V—on coal unit delays will yield a more accurate picture of the future utility fuel requirements. In other words, the increase in coal consumption in the nonnuclear scenario cannot take place unless the new coal units are in service. The construction delays encountered show that reliance to be doubtful. This has obvious implications towards oil consumption and power supply reliability. The attachment A to table VI is an excerpt from a report which discusses the impact of lower-than-anticipated energy growth in the nuclear analysis. The consumption of oil greater than projected will, of course, be lower than shown in the table, but still represents a definite increase. This would be an 11.4-percent increase instead of 33.5 percent. A higher-than-anticipated growth rate, if one assumes intensified electrification will, of course, cause a significant increase in oil usage.

In summation, it is shown that new nuclear- or coal-fueled plants can be anticipated to displace both oil and coal usage. The quantity of displacement will vary, depending upon the region in which the new nuclear generator or the new coal-fueled generator will operate. The division's analysis considered the "logical electrical operating region" in which the new plant will be located and analyzed the displacement characteristic within each region. These calculations considered the use of the electric grid to transfer energy between the regions. The New England region is currently consuming 17 percent of the fuel oil the Nation uses for electricity generation. A new nuclear unit in New England, for example, will displace consumption of residual fuel oil by the electric utilities because that is the primary fuel within that region—see table VII. A nuclear unit placed within the TVA system will displace a much greater quantity of coal-fired generation and lesser amounts of fuel oil, because coal is the primary fuel in that region. Greater oil displacement would occur if the power could be sold to other regions. A national generalization of fuel displacement by a new generating unit cannot be logically made. Individual operating regions must be considered, as must the transfer of electric energy from one system to another over the transmission grid. Generating reserve margins within the region and the region's avaiable capacity must also be evaluated. Without new resources, a region may not have enough generation to supply the needs of its own customers and, therefore, would not be able to displace fuel oil in adjacent regions.

I cite New England as an example of large fuel oil displacement potential because there is currently more generation capacity in that region than is necessary to supply near-term requirements, and yet a new nuclear or coal-fueled resource will reduce fuel oil consumption. When this excess capacity situation exists, the most expensive generation will be reduced; in the case of New England, this is, of course, oil. The cost of generation by fuel oil when compared to nuclear or coal alternatives will cause the reduction in oil consumption. Florida and California are also examples of regions where such high correlation of oil reduction for nuclear additions exists.

It may be appropriate in some regions to convert existing oil-fueled generation to alternative fuels even though it is not cost-justified.

Attachment A to table VII graphically shows the historical use of fuel types for electric generation.

Table VIII shows historical annual fuel use for the Nation. These consumption values show dependence on the various fuels as discussed above.

One of the committee's questions concerns data on the recent history of electric utility plant construction. Table IX shows the number of new coal units announced for construction in the past 2 years. Thirty new units—11,744 megawatts—were announced in 1979 and 32—13,917 megawatts—more new coal-fueled units were announced in 1980.

Exhibit I is a map which shows the location of nuclear power reactors in the United States. The location of operating reactors, plants under construction, and new units planned are shown on this map. This map should be used in conjunction with table X which lists new nuclear generating units grouped by the anticipated commercial operation date. Also shown in table X is the expected oil displacement for each of these new nuclear generating units.

The relationship between the map—exhibit I—the numbers on this table X, and attachments A and B to table X, implies the electric utility planning philosophy in the past decade. As is evident from the display, in the 1970's electric utilities relied heavily on new nuclear generating units to meet their capacity expansion requirements—see attachment B to table X. There are various reasons for this dependence. It is quite evident that load growth in the industry, economies of scale of nuclear units, and the environmental impact of new coal generating plants combined to reduce the use of coal as a competitive resource.

In fact, during the late 1960's and early 1970's many utilities converted their coal plants to oil operation, based on price and environmental concerns raised within their States. It was in this timeframe and within these environmental constraints and cost considerations that the nuclear units were a viable option and a proper choice. The 1973 oil embargo only increased this viability. Therefore, there was the large number of construction permits issued for new nuclear plants, as shown in attachment B to table X. This display gives the pictorial representation of past electric utility reliance on the nuclear option.

Earlier this year, proposed legislation was presented to the Congress to provide for the back-out of electric utility use of oil in both coal-capable and noncoal-capable units. This bill envisioned paying for the conversions, in large part with Government funds. The table XI listing shows by electric region those generating units which were considered to be reasonable candidates for this conversion. The anticipated oil displacement for each of these generating units is also shown on this table.

With present consumption of fuel oil for electric generation in New England averaging 205,000 barrels a day—table VII—these conversions represented a 47-percent reduction in New England's present fuel oil consumption.

Exhibit II shows the projected new nuclear capacity by year in service. This information will help to formulate the answers to the questions you had on the near-term electric utility reliance on nuclear power for generating requirements.

The exhibits presented are a display of historical statistics and various future projections to set a frame of reference for the future power supply scenarios. In summarizing of this information, I feel that the electric utility industry had placed a high degree of reliance upon nuclear and coal to reduce their consumption of oil and supply necessary capacity for present requirements and anticipated growth. But, in this context, it is important to note that the electric utility industry has been plagued by several barriers to expansion. These include construction delays, inability to market securities, high interest rates, regulatory delays, and environmental concerns. Also, many utilities have been unable to obtain the necessary rate relief to permit reasonable system expansion. Because of these barriers, the additions of new capacity have calibrated closely with the reduced current lower rate of load growth. Even using the most conservative estimates of growth rate, it still can be shown that new generating plants will be needed for both oil reduction and adequate electric supply.

A special analysis, for demonstration purposes, was made for the New England region for 1990. New England was chosen for this analysis because of its anticipated high dependence on oil-fueled generation. Two scenarios were compared. The first scenario assumes the additions of generating capacity within the region as anticipated. This expansion included four new nuclear units, 1,600 megawatts of coal conversion, and an addition of a new coal-fired generating unit. The year 1990 was considered the test year, with all available generating capacity utilized and interties providing all anticipated contractual purchases. In this expansion, the New England area consumption would drop to some 140,000 barrels of oil per day—present rate of consumption is 205,000 barrels per day. An alternative study was performed for the same period of time without the four new nuclear units. Since these nuclear units would provide 4,600 megawatts of capacity to the region, their absence, for the most part, must be made up by existing oil-fueled generators. This alternative scenario showed New England consuming over 275,000 barrels of oil per day—an increase of almost 134,000 barrels of oil per day over the first scenario. There is, therefore, a dependence on the new coal and nuclear generating units for both oil displacement and customer energy requirements.

Table XII shows for 1985 the generating reserve margins without the planned additions of nuclear capacity for the various regions in the country. This calculation was based on existing electric utility growth projections of approximately 4.5 percent per year, and also for a lower projection of 2.2 percent per year. It is of interest to note that even with the lower growth projection, certain parts of the country will experience reserve margins below adequate levels. For example, even at the low growth rates, the Commonwealth Edison area will not be able to supply customer requirements for the peak period. Since electric utility growth rate has been depressed over the past few years, reserve margins in some regions have been greater than necessary for reliability purposes. These margins are shrinking, and since oil is the marginal fuel in many areas, its consumption will increase as generating capacity margins are reduced.

Tables XIII and XIV show that electric utility reliability is fast becoming of concern, even today. As can be seen from the tables, the list is growing of those regions which are expected to experience lower-than-desirable electric reserve margins. The tables considered the average historical capacity unavailable during the time of the electric system peak—table XV. After these outages are accounted for, reserve margin values near zero or negative should be considered critical. It is with these displays in mind that one can have an appreciation for reliability in the systems.

One of the concerns that has been expressed is the relative ability of coal and nuclear units to supply energy effectively.

Table XVI shows a comparison of average capacity factors for 3 consecutive years for various size coal and nuclear generating units. This sample demonstrates that any general conclusion concerning the capacity factor for such units is, at best, arguable. Because of the large variance in unit size and characteristics, no generalizations can be made other than that capacity factors for nuclear and coal generation are close.

Table XVII demonstrates the variance in such a statistic as capacity factor. It is noted in this table that generating units within the sample ranges can have capacity factors varying from 17 percent to 93 percent. The important point to remember when observing these characteristics for either nuclear or coal is that either type of unit will displace oil by varying amounts and the energy produced from both types of resources will supply customer requirements.

Table XVIII is provided for the committee's information to show the relative cost of new powerplant construction in various parts of the country.

This concludes the prepared portion of my testimony. I will be pleased to answer any further questions the committee might have.

[The attachments of Mr. Weiner follow:]

[Testimony resumes on p. 166.]

[The attachment to Mr. Weiner's prepared statement follows:]

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APPENDIX

TABLE I

U.S. FOSSIL FUEL USE FOR ELECTRIC ENERGY

PROJECTED BASE LINE 1985 (4.44% GROWTH) ACTUAL 1979

	1/a	1/b	2/a	2/b	Actual 1979
Coal	783	783	652	652	527
Oil	530	321	723	513	523
Gas	4,496	2,708	6,125	4,348	3,491

PROJECTED MINIMUM 1985 (2.46% GROWTH) ACTUAL 1979

	1/a	1/b	2/a	2/b	Actual 1979
Coal	783	783	652	652	527
Oil	307	97	501	290	523
Gas	2,602	825	4,232	2,454	3,491

Coal - Million Tons Annually
Oil - Million Barrels Annually
Gas - Million Mcf Annually

1/ Capacity Factor of all Coal-fired Capacity = 0.60
2/ Capacity Factor of all Coal-fired Capacity = 0.50
a/ Minimum energy production from all non-fossil sources
b/ Maximum energy production from all non-fossil sources

TABLE II

U.S. ELECTRIC ENERGY PRODUCTION

GWH x 10^3

PROJECTED BASE LINE 1985 (4.44% Growth)	1/a	1/b	2/a	2/b	ACTUAL 1979
Coal	1,597	1,597	1,331	1,331	1,076
Oil	307	186	419	297	303
Gas	425	256	579	411	330
Total Fossil	2,329	2,039	2,329	2,039	1,709
Non-Fossil	580	870	580	870	539
Total	2,909	2,909	2,909	2,909	2,248

PROJECTED MINIMUM 1985 (2.46% Growth)	1/a	1/b	2/a	2/b	ACTUAL 1979
Coal	1,597	1,597	1,331	1,331	1,076
Oil	176	56	290	168	303
Gas	246	78	400	232	330
Total Fossil	2,021	1,731	2,021	1,731	1,709
Non-Fossil	580	870	580	870	539
Total	2,601	2,601	2,601	2,601	2,248

1/ Capacity factor of all coal-fired capacity = 0.60

2/ Capacity factor of all coal-fired capacity = 0.50

a/ Minimum energy production from all non-fossil sources

b/ Maximum energy production from all non-fossil sources

TABLE III

U.S. PERCENT ENERGY PRODUCTION

PROJECTED BASE LINE 1985 (4.44% GROWTH)	1/a	1/b	2/a	2/b	ACTUAL 1979
Coal	54.9	54.9	45.8	45.8	47.9
Oil	10.6	6.4	14.4	10.2	13.5
Gas	14.6	8.8	19.9	14.1	14.7
Total Fossil	80.1	70.1	80.1	70.1	76.1
Non-Fossil	19.9	29.9	19.9	29.9	23.9
Total	100.0	100.0	100.0	100.0	100.0

PROJECTED MINIMUM 1985 (2.46% GROWTH)	1/a	1/b	2/a	2/b	ACTUAL 1979
Coal	61.4	61.4	51.2	51.2	47.9
Oil	6.8	2.2	11.1	6.5	13.5
Gas	9.5	3.0	15.4	8.9	14.7
Total Fossil	77.7	66.6	77.7	66.6	76.1
Non-Fossil	22.3	33.4	22.3	33.4	23.9
Total	100.0	100.0	100.0	100.0	100.0

1/ Capacity Factor of all Coal-fired Capacity = 0.60
2/ Capacity Factor of all Coal-fired Capacity = 0.50
a/ Minimum energy production from all non-fossil sources
b/ Maximum energy production from all non-fossil sources

TABLE IV

SUMMARY OF CHANGES IN SCHEDULED IN-SERVICE DATES OF COAL-FIRED GENERATING UNITS[1/] (1980-1985)

SLIPPAGE (MONTHS)	300 MW OR LARGER NO. OF UNITS	MW	MEGAWATT-MONTHS (MW X MONTHS)	LESS THAN 300 MW NO. OF UNITS	MW	MEGAWATT-MONTHS (MW X MONTHS)
48-59	1	650	31,200	-	-	-
36-47	1	750	17,250	-	-	-
24-35	5	2,704	79,120	-	-	-
12-23	14	9,824	146,937	5	1,050	11,850
1-11	25	13,738	63,378	3	620	2,650
TOTAL	46	27,666	337,885	8	1,670	14,500
ADVANCEMENT (MONTHS)						
12-23	2	891	12,465	-	-	-
1-11	3	1,649	2,090	2	487	694
TOTAL	5	2,540	14,555	2	487	694
NET SLIPPAGE	41	25,126	323,330	6	1,183	13,806

1/ Comparison of scheduled in-service dates in the FPC Form 12E-2 as of September 30, 1979, with those shown in the FPC Form 12E-2 Reports as of September 30, 1980.

TABLE V
(PAGE 1 of 2)

ADDITIONAL POTENTIAL BARRELS OF OIL CONSUMED DUE TO SLIPPAGE OF COAL-FIRED GENERATING UNITS[1/]
(1980-1985)

RELIABILITY COUNCIL AND ELECTRIC REGION	1980	1981	1982	1983	1984	1985	TOTAL
ECAR	-	-267,733	-301,200	287,995	1,330,707	922,050	1,971,819
1	-	-	-	-	-	-	
2	-	-	-	-	-	-	
13	-	-	-	-	-	-	
14	-	-	-	-	-	-	
15	-	-	-	-	-	-	
16	-	-267,733	-301,200	287,995	408,657	-	127,719
18	-	-	-	-	922,050	922,050	1,844,100
ERCOT	-	-	-	-	-	-	
23	-	-	-	-	-	-	
MAAC	-	-	4,399,227	4,799,157	1,999,648	-	11,198,032
5	-	-	4,399,227	4,799,157	1,999,648	-	11,198,032
MAIN	-	87,274	1,756,399	1,633,153	1,514,764	728,544	5,720,134
6	-	-	-	-	-	-	
17	-	87,274	964,107	-	607,120	728,544	2,387,045
19	-	-	792,292	1,633,153	907,644	-	3,333,089
MARCA	-	1,047,236	68,298	-	1,457,024	728,512	3,301,070
20	-	1,047,236	68,298	-	1,457,024	728,512	3,301,070
NPCC	-	-	-	-	-	-	
3	-	-	-	-	-	-	
4	-	-	-	-	-	-	

TABLE V
(PAGE 2 of 2)

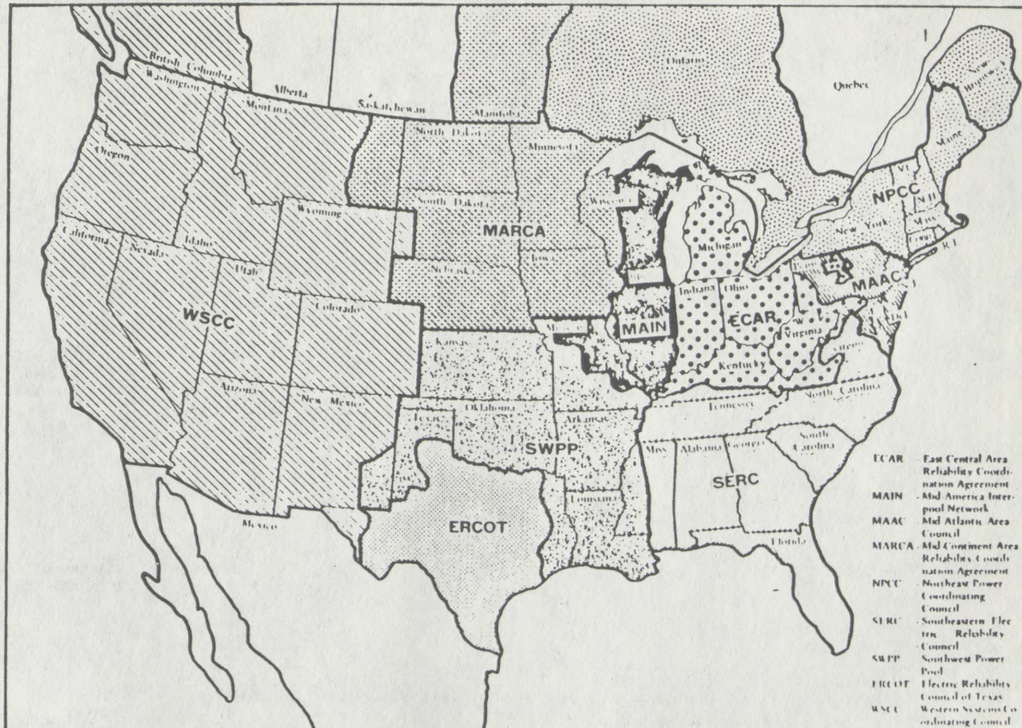
ADDITIONAL POTENTIAL BARRELS OF OIL CONSUMED DUE TO SLIPPAGE OF COAL-FIRED GENERATING UNITS 1/
(1980-1985)

LIABILITY COUNCIL) ELECTRIC REGION	1980	1981	1982	1983	1984	1985	TOTAL
SERC	491,746	694,247	2,070,782	1,666,446	4,245,079	1,739,273	10,907,573
7	-	757,992	-	-	3,302,605	-	4,060,597
9	-	-	595,545	1,174,700	1,762,050	2,251,508	5,783,803
11	-	-	-	-	-	-	
12	491,746	-63,745	1,475,237	491,746	-819,576	-512,235	1,063,173
SWPP	-	-	-	-	-	-	
8	-	-	-	-	-	-	
10	-	-	-	-	-	-	
21	-	-	-	-	-	-	
22	-	-	-	-	-	-	
WSCC	520,818	802,516	0	227,664	2,268,862	6,557,938	10,377,798
24	-	-	-	-	-	-	
25	-	-	-	-	-	-	
26	-	-	-	-	-	-	
27	-	-	-	-	-	-	
28	-	-	-	-	-	-	
30	-	-	-	-	-	-	
TOTAL	1,012,564	2,363,540	7,993,506	8,614,415	12,816,084	10,676,317	43,476,426
APPROX. EQUIVALENT BBLS/DAY	2,722	6,354	21,488	23,157	34,452	28,700	19,479

1/ Comparison of scheduled in-service dates in the FPC Form 12E-2 as of September 30,1979 with those shown in the FPC Form 12E-2 report as of September 30, 1980.

ATTACHMENT A TO TABLE V

DEPARTMENT OF ENERGY - ENERGY INFORMATION ADMINISTRATION



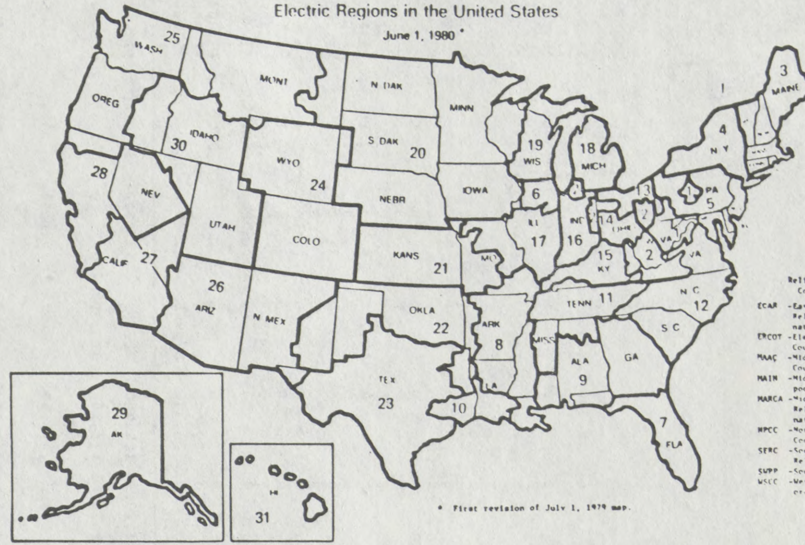
REGIONAL ELECTRIC RELIABILITY COUNCIL AREAS

ATTACHMENT B TO TABLE V

Department of Energy   Economic Regulatory Administration

Electric Regions in the United States

June 1, 1980 *



Reliability Council	
ECAR	-East Central Area Reliability Coordination Agreement
ERCOT	-Electric Reliability Council of Texas
MAAC	-Mid-Atlantic Area Council
MAIN	-Mid-America Interpool Network
MARCA	-Mid-Continent Area Reliability Coordination Agreement
NPCC	-Northeast Power Coordinating Council
SERC	-Southeastern Electric Reliability Council
SWPP	-Southwest Power Pool
WSCC	-Western Systems Coordinating Council

* First revision of July 1, 1979 map.

Electric Region		Identification
	ECAR	
1		Allegheny Power System (APS)
2		American Electric Power System (AEP)
13		Central Area Power Coordination Group (CAPCO)
14		Cincinnati, Columbus, Dayton Group (CCD)
15		Kentucky Group
16		Indiana Group - All Indiana Utilities except I&M Electric Co.
18		Michigan Electric Coordinated Systems (MECS)
	ERCOT	
23		Texas Interconnected Systems Group (TIS)
	MAAC	
5		Pennsylvania-New Jersey-Maryland Interconnection (PJM)
	MAIN	
6		Commonwealth Edison Co.
17		Illinois-Missouri Group (ILLMO)
19		Wisconsin Upper Michigan Systems Group (WUMS)
	MARCA	
20		Mid-Continent Area Power Pool (MAPP)
	NPCC	
3		New England Power Pool (NEPOOL)
4		New York Power Pool (NYPP)
	SERC	
7		Florida Coordinating Group (FCG)
9		Southern Company Group
11		Tennessee Valley Authority Group (TVA)
12		Virginia-Carolinas Group (VACAR)
	SWPP	
8		Middle South Utilities Group
10		Gulf States Group
21		Missouri-Kansas Group (MOKAN)
22		Oklahoma Group
	WSCC	
24		Rocky Mountain Power Pool (RMPP)
25		Northwest Power Pool (NWPP) Except for Idaho-Utah Group
26		Arizona-New Mexico Group
27		Southern California-Nevada Group
28		Northern California-Nevada Group
30		Idaho-Utah Group of the Northwest Power Pool

Table VI
Page 1 of 3

REGIONAL INCREASE IN OIL USE
DUE TO NUCLEAR LICENSING DELAYS
(Includes Impact of Interregional Transfers
to Reduce Energy Shortage)

PROBABLE ADDITIONAL OIL CONSUMPTION
(BBL/DAY)

REGION		1980	1981	1982	1983	1984	1985
1.	APS	0	0	0	0	0	0
2.	AEP	0	0	0	0	0	0
3.	NEPOOL	0	0	0	23,600	31,500	66,800
4.	NYPP	0	0	0	21,300	21,300	23,900
5.	PJM	0	18,000	42,500	69,100	80,400	116,200
6.	CECo	1,300	17,100	37,700	60,600	88,600	99,200
7.	F.C.G.	0	0	0	3,100	18,500	20,800
8.	MSU	0	0	0	0	0	0
9.	So. Co.	1,500	4,400	5,000	6,600	15,300	21,500
10.	GSU	0	0	0	0	0	0
11.	TVA	0	5,800	16,500	21,300	19,800	17,700
12.	VACAP	1,400	17,100	24,000	29,600	45,600	52,700
13.	CAPCo	0	0	0	0	1,000	1,200
14.	CCD	0	0	0	0	0	0
15.	Kentucky	0	0	0	0	0	0
16.	Indiana	0	0	0	0	0	0
17.	ILL-MO.	0	0	0	0	1,200	1,200
18.	MECS	0	0	11,200	13,500	19,100	33,600
19.	WUMS	0	0	0	0	1,100	1,900
20.	MAPP	0	0	0	0	0	2,100
21.	MO-KAN	0	0	0	0	0	0
22.	Oklahoma	0	0	0	0	0	0
23.	Texas	0	0	0	0	0	0
24.	RMPP	0	0	0	0	1,600	2,400
25/30	NWPP	0	0	0	22,600	22,600	47,700
26.	Ariz-NM	0	0	0	12,200	31,000	42,000
27.	So. Cal-Nev.	0	22,000	32,200	70,900	77,300	71,200
28.	No. Cal-Nev.	0	25,300	57,900	77,100	70,700	75,300
Total Increase		4,200	109,700	227,000	431,500	546,600	697,400
(1) Total NERC Oil Use (BBL/DAY)		1,852,300	1,974,900	2,036,300	2,027,600	2,001,600	2,082,500
% of Total NERC Oil Use		0.2%	5.6%	11.1%	21.3%	27.3%	33.5%

(1) Data from "Summary of Projected Peak Load, Generating Capability, and fossil fuel Requirements", NERC, July, 1979.

Table VI

Page 2 of 3

REGIONAL INCREASE IN COAL USE
DUE TO NUCLEAR LICENSING DELAYS

(Includes Impact of Inter-regional Transfers
to Reduce Energy Shortages)

PROBABLE ADDITIONAL COAL CONSUMPTION (TONS/DAY)

Region	1980	1981	1982	1983	1984	1985
1. APS	0	0	0	0	0	0
2. AEP	0	0	0	0	4,300	9,600
3. NEPOOL	0	0	0	0	0	0
4. NYPP	0	0	0	200	200	300
5. PJM	0	700	1,600	2,500	3,000	4,300
6. CECO	200	2,900	6,400	10,300	15,100	16,900
7. P.C.G.	0	0	0	100	700	800
8. MSU	0	0	2,800	3,400	2,900	4,000
9. So.Co.	1,200	3,700	4,100	5,500	12,800	18,000
10. GSU	0	0	0	0	400	1,100
11. TVA	0	4,800	13,700	17,800	16,500	14,800
12. VACAR	700	8,300	11,700	14,400	22,200	25,600
13. CAPCO	0	0	0	0	3,900	4,800
14. CCD	0	4,500	4,500	5,100	5,100	5,100
15. Kentucky	0	0	0	0	0	1,800
16. Indiana	0	0	0	0	0	0
17. ILL-MO.	0	0	1,700	9,600	11,700	11,700
18. MECS	0	0	2,900	3,400	4,900	8,600
19. WUMS	0	0	0	0	900	1,600
20. MAPP	0	0	0	0	0	1,000
21. MO-KAN	0	0	0	3,900	6,000	6,600
22. Oklahoma	0	0	0	0	400	400
23. Texas	0	500	1,300	2,800	3,800	3,700
24. RMPP	0	0	0	0	1,000	1,500
25/30. MWPP	0	0	0	1,600	1,600	3,300
26. ARIZ-NM	0	0	0	1,700	4,300	5,800
27. So.Cal-Nev	0	0	0	0	0	0
28. No.Cal-Nev	0	0	0	0	0	0
Total Increase	2,100	25,400	50,700	82,300	121,700	151,300
Equiv. BBLS/Day	8,400	101,600	102,800	329,200	486,800	605,200
Total NERC (1) Coal USC (Tons/ Day)	1,610,200	1,692,300	1,784,200	1,847,400	1,925,200	2,035,300
% of Total NERC Coal Use	0.1%	1.5%	2.8%	4.5%	6.3%	7.4%

(1) Data from "Summary of Projected Peak Load, Generating Capability, and Fossel Fuel Requirements," NERC, July, 1979.

Table VI

Page 3 of 3

REGIONAL INCREASE IN GAS USE
DUE TO NUCLEAR LICENSING DELAYS
(Includes Impact of Interregional Transfers
to Reduce Energy Shortage)

PROBABLE ADDITIONAL GAS CONSUMPTION (MCF/DAY)

REGION	1980	1981	1982	1983	1984	1985
1. APS	0	0	0	0	0	0
2. AEP	0	0	0	0	0	0
3. NEPOOL	0	0	0	0	0	0
4. NYPP	0	0	0	0	0	0
5. PJM	0	0	0	0	0	0
6. CECo	0	0	0	0	0	0
7. F.C.G.	0	0	0	0	0	0
8. MSU	0	0	240,700	290,600	252,200	346,100
9. So. Co.	0	0	0	0	0	0
10. GSU	0	0	0	0	38,200	91,700
11. TVA	0	0	0	0	0	0
12. VACAR	0	0	0	0	0	0
13. CAPCo	0	0	0	0	0	0
14. CCD	0	0	0	0	0	0
15. Kentucky	0	0	0	0	0	0
16. Indiana	0	0	0	0	0	0
17. ILL-MO.	0	0	0	0	0	0
18. MECS	0	0	0	0	0	0
19. WUMS	0	0	0	0	0	0
20. MAPP	0	0	0	0	0	0
21. MO-KAN	0	0	0	28,300	42,900	47,600
22. Oklahoma	0	0	0	0	15,600	15,600
23. Texas	0	62,900	151,000	320,600	439,000	431,100
24. RMPP	0	0	0	0	0	0
25/30 NWPP	0	0	0	0	0	0
26. ARIZ-NM	0	0	0	0	0	0
27. So. Cal-Nev.	0	0	0	0	0	0
28. No. Cal-Nev.	0	0	0	0	0	0
Total Increase	0	62,900	391,700	639,500	787,900	932,100
Equivalent BBL/Day	0	10,500	65,300	106,600	131,300	155,400
Total NERC (1) Gas (MCF/Day)	6,649,700	5,776,100	5,413,200	5,263,200	5,068,700	4,223,400
Total % of NERC Gas Use	0%	1.1%	7.2%	12.2%	15.5%	22.1%

(1) Data from "Summary of Projected Peak Load Generating Capability, and Fossil Fuel Requirements", NERC, July, 1979.

Attachment A to Table VI

Impacts of Lower Than Forecasted Growth Rates on Energy Shortages, Reserve Margins and Fuel Use:

A sensitivity analysis was performed for those regions having either energy supply or reserve margin problems to determine the extent to which lower growth rates might alleviate these problems. It was assumed that the schedule of capacity additions would remain unchanged.

Table VII-2-10 compares the 1980-85 growth rates projected by the reliability councils with the lower growth rates projected by ERA staff for the purposes of this sensitivity analysis.

The lower growth rates were chosen by examining the historical forecasting errors made by each of the nine reliability councils, and scaling down their current forecasts accordingly. See Section III and IV for a further description of this method. The exceptions to this method were TVA and VACAR where a "lower limit" growth rate of 1.0% was used.

Impact of Lower Growth Rates on Energy Supply

The origional analysis projected three areas as having energy shortage in the 1980-85 timeframe (see Table VII-2-3). Using lower growth rates than those projected by the reliability councils, no energy shortage problems would be anticipated.

Impact of Lower Growth Rate on Reserve Margins

Table VII-2-4 lists nine areas having reserves below 12% under the origional growth assumptions. Using lower growth rates reduces the number of critical areas to three as shown on Table VII-2-11. Those areas are the Commonwealth Edison Co., the Middle South Utilities Group, and the Northern California-Nevada Group.

Attachment A to Table VI

Impact of Lower Growth Rates on Fuel Use

Tables VII-2-5, VII-2-6, and VII-2-7 lists the additional coal, oil, and gas use that would result, under the original growth rates, if the nuclear units do not come on line as planned. These same increases in coal, oil and gas use would occur, even with reduced growth rates, because nuclear units are operated in base load. Delays in bringing these units on line would necessitate some other type of base load generation taking its place resulting in the increased fossil fuel use shown.

These increases in fossil fuel use are due to the nuclear units not coming on line as planned. If energy growth rates are lower than those projected by the reliability councils, there would be a partially offsetting reduction in fossil use due to the lower system energy requirements. The total energy requirement for the contiguous U.S., as reported by the reliability councils, is projected to increase from 2,421,676 GWH in 1980 to 3,072,369 GWH in 1985. This represents a compound annual growth rate of 4.87%. If the compound annual growth rate is 2.06%, the reduction in the energy requirement in 1985 would be 390,770 GWH. Allocating this reduction in generation over available coal, oil, and gas units would result in the following approximate decreases in fossil fuel use: Coal 316,300 tons/day; oil - 460,400 BBL/day; and Gas - 976,400 MCF/day.

This reduction in coal would more than offset the coal increases shown in Table VII-2-5. Similarly, the reduction in gas use would effectively cancel out the increases shown in Table VII-2-7.

The situtlon for oil is different. Combining the increases in oil use due to licensing delays in 1985 (697,400 BBLS/day) and the decrease in oil use if lower growth occurs (460,400 BBL/day) results in an net increase in oil use of 237,000 BBL/day.

Methodology:

The immediate impact of further delays in issuing nuclear unit licenses would be a reduction in the future amount of nuclear energy generated by the electric utility industry. Since customer energy requirements must still be supplied, this will produce a corresponding increase in fossil-fueled generation and fossil fuel consumption. The underlying assumption in this report is that all energy that would have been produced by nuclear generation if there were no licensing delays would now need to be made up by some combination of additional coal, oil and gas fired generation.

Attachment A to Table VI

(1)
Lower Growth Rates Assumed by ERA Staff
For Sensitivity Studies
1980-1985

Electric Region	Peak Demand Growth Rate 1980-85 (Council Projection)	Lower Growth Rate Assumed by ERA Staff 1980-85 (1)
1 - APS	4.6% (Winter)	2.6%
6 - CECO	4.4% (Summer)	1.7%
8 - MSU	5.6% (Summer)	4.8%
10 - GSU	6.0% (Summer)	5.2%
11 - TVA	4.0% (Winter)	1.0%
12 - VACAR	5.1% (Summer)	1.0%
13 - CAPCO	3.7% (Summer)	2.1%
23 - TEXAS	5.2% (Summer)	3.5%
25/30 - NWPP	4.3% (Winter)	2.2%
26 - ARIZ - NM	6.3% (Summer)	3.3%
28 - No.Cal-Nev	3.3% (Summer)	1.7%

(1) Same growth rate assumed for peak demand and energy.

Table VII

HISTORICAL FOSSIL FUEL CONSUMPTION
FOR THE
ELECTRIC UTILITY INDUSTRY

	Coal (Tons x 10^3/yr)		Oil (Bbls. x 10^3/day)		Gas (BCF/yr.)	
	Total U.S.	New England	Total U.S.	New England	Total U.S.	New England
1976	448,431	771	1,523	199	3,081	4
1977	477,216	981	1,709	195	3,191	3
1978	481,633	802	1,742	205	3,188	2
1979	527,319	1,138	1,434	197	3,490	9
1980[1.]	569,357	1,988	1,169	205	3,839	8

Source: Form 4 data base maintained by DOE/EIA.

1. Data for 1980 is actual through September but extrapolated through December.

Attachment a to Table VII

Historical Generation by Fuel Type

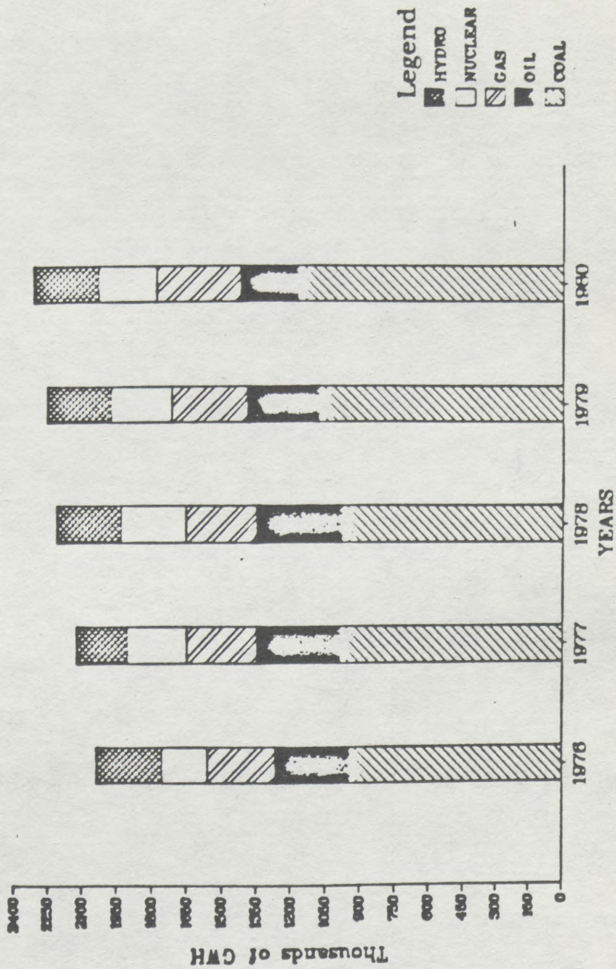


TABLE VIII

HISTORICAL GENERATION BY FUEL TYPE
AS A
PERCENTAGE OF TOTAL GENERATION 1/

%	Coal		Oil		Gas		NUC		Hydro	
Year	Total U.S.	New England	Total U.S.	New England	Total U.S.	New England	Total U.S.	New England	Total U.S.	New England
1976	46	3	16	57	15	0	9	33	14	7
1977	46	3	17	56	14	0	12	33	10	6
1978	44	2	17	57	14	0	13	35	13	5
1979	48	4	14	55	15	1	11	34	12	6
1980 2/	50	7	11	59	16	1	11	29	13	4

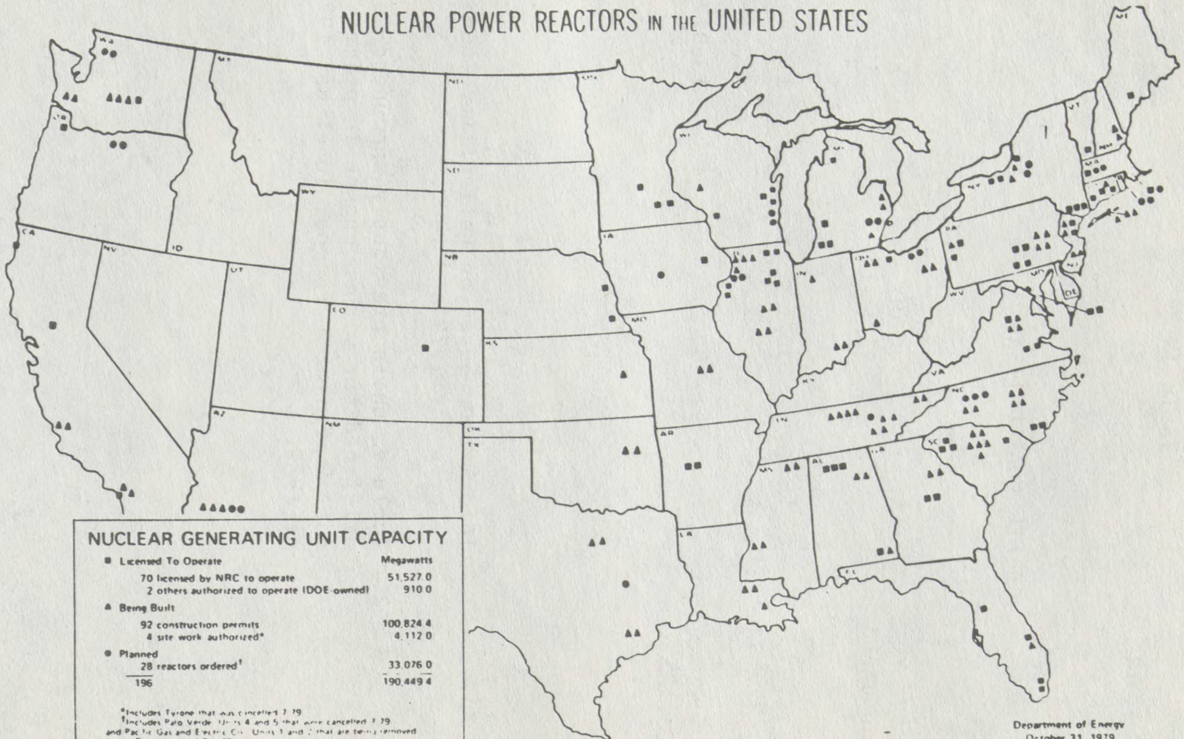
Source: Form 4 data base maintained by DOE/EIA.

1/ Percentages may not sum to 100 due to independent rounding.

2/ Data for 1980 is through September.

EXHIBIT I

NUCLEAR POWER REACTORS IN THE UNITED STATES



NUCLEAR GENERATING UNIT CAPACITY

	Megawatts
■ Licensed To Operate	
70 licensed by NRC to operate	51,527.0
2 others authorized to operate (DOE-owned)	910.0
▲ Being Built	
92 construction permits	100,824.4
4 site work authorized*	4,112.0
● Planned	
28 reactors ordered†	33,076.0
196	190,449.4

*Includes Tyrone that was cancelled 7/79

†Includes Palo Verde Units 4 and 5 that were cancelled 7/79 and Pacific Gas and Electric Co. Units 1 and 2 that are being removed from "Planned" as of 8/1/79

There are no symbols for units planned but not sited

Because of space limitations symbols do not reflect precise locations

(over)

Department of Energy
October 31, 1979

Table IX

NEW COAL UNIT ANNOUNCEMENTS

Year Announced	Number of Units	Capacity (MW)
1979	30	11,744
1980	32	13,917

Notes: 1. Information based on Reliability Council reports for 1979 and 1980.

2. Includes units previously announced as oil-fired but with a change in primary fuel designation to coal in either 1979 or 1980.

Table X

POTENTIAL OIL DISPLACED BY NUCLEAR GENERATING UNITS 1/

(1981-1993)

YEAR/ERA ELECTRIC REGION	GENERATING UNIT	CAPACITY (MW)	OPERATING LICENSE ISSUANCE DATE 2/	COMMERCIAL OPERATION DATE 3/	PROB. ADDITIONAL OIL CONSUMED (BBLS/DAY)
1981					
(6) CECO	LASALLE 1	1,048	12/80	6/81	15,051
	LASALLE 2	1,048	2/81	8/81	15,051
(12) VACAR	MCGUIRE 1	1,180	11/80	5/81	9,244
(28) NO. CAL-NEV	DIABLO CANYON 1	1,084	1/81	7/81	28,305
SUBTOTAL	4 UNITS	4,360	-	-	67,651
1982					
(5) PJM	SUSQUEHANNA 1	1,050	12/81	6/82	23,305
(8) MSU	GRAND GULF 1	1,250	8/81	2/82	0
(11) TVA	SEQUOYAH 2	1,148	7/81	1/82	5,995
	WATTS BAR 1	1,177	11/81	5/82	6,147
(12) VACAR	SUMMER 1	900	8/81	2/82	7,050
	MCGUIRE 2	1,180	6/82	12/82	9,244
(14) CCD	ZIMMER 1	792	11/81	5/82	0
(23) TEXAS	COMANCHE PEAK 1	1,150	2/82	8/82	0
(27) SO. CAL-NEV	SAN ONOFRE 2	1,100	2/82	8/82	28,723
(28) NO. CAL-NEV	DIABLO CANYON 2	1,106	9/81	3/82	28,880
SUBTOTAL	10 UNITS	10,853	-	-	109,344

Table X

POTENTIAL OIL DISPLACED BY NUCLEAR GENERATING UNITS 1/

(1981-1993)

YEAR/ERA ELECTRIC REGION	GENERATING UNIT	CAPACITY (MW)	OPERATING LICENSE ISSUANCE DATE 2/	COMMERCIAL OPERATION DATE 3/	PROB. ADDITIONAL OIL CONSUMED (BBLS/DAY)
1983					
(4) NYPP	SHOREHAM 1	820	9/82	3/83	20,341
(5) PJM	SUSQUEHANNA 2	1,050	4/83	10/83	23,305
(6) CECO	BYRON 1	1,120	4/83	10/83	16,085
(8) MSU	WATERFORD 3	1,110	10/82	4/83	0
(11) TVA	WATTS BAR 2	1,177	8/82	2/83	6,147
(17) ILL-MO	CALLOWAY 1	1,150	12/82	6/83	6,006
	CLINTON 1	948	3/83	9/83	4,951
(18) MECS	FERMI 2	1,093	11/82	5/83	12,843
(25) NWPP	WPPS 2	1,100	7/82	1/83	21,542
(26) ARIZ-NM	PALO VERDE 1	1,270	12/82	6/83	19,897
(27) SO. CAL-NEV	SAN ONOFRE 3	1,100	10/82	4/83	28,723
SUBTOTAL	11 UNITS	11,938	-	-	159,840
1984					
(3) NEPOOL	SEABROOK 1	1,150	2/84	8/84	30,029
(5) PJM	LIMERICK 1	1,055	11/83	5/84	23,416
(6) CECO	BYRON 2	1,120	4/84	10/84	16,085
(7) F.C.G.	ST. LUCIE 2	795	12/83	6/84	17,645
(10) GSU	RIVER BEND 1	940	3/84	9/84	0
(11) TVA	BELLEFONTE 1	1,213	6/84	12/84	6,335
(12) VACAR	CATAWBA 1	1,145	10/83	4/84	8,969
	HARRIS 1	900	6/84	12/84	7,050
(13) CAPCO	PERRY 1	1,179	7/83	1/84	1,539

Table X

POTENTIAL OIL DISPLACED BY NUCLEAR GENERATING UNITS 1/

(1981-1993)

YEAR/ERA ELECTRIC REGION	GENERATING UNIT	CAPACITY (MW)	OPERATING LICENSE ISSUANCE DATE 2/	COMMERCIAL OPERATION DATE 3/	PROB. ADDITIONAL OIL CONSUMED (BBLS/DAY)
1984 CONTINUED					
(18) MECS	MIDLAND 2	783	10/83	4/84	9,201
	MIDLAND 1	505	4/84	10/84	5,934
(21) MO-KAN	WOLF CREEK 1	1,150	10/83	4/84	0
(23) TEXAS	SOUTH TEXAS 1	1,250	9/83	3/84	0
	COMANCHE PEAK 2	1,150	2/84	8/84	0
(26) ARIZ-NM	PALO VERDE 2	1,270	12/83	6/84	19,897
SUBTOTAL	15 UNITS	15,605	-	-	146,100
1985					
(6) CECO	BRAIDWOOD 1	1,090	4/85	10/85	15,654
(9) SO. CO.	VOGTLE 1	1,150	11/84	5/85	6,006
(11) TVA	BELLEFONTE 2	1,213	2/85	8/85	6,335
(12) VACAR	CATAWBA 2	1,145	2/85	8/85	8,969
(25) NWPP	WPPS 1	1,250	12/84	6/85	24,480
(26) ARIZ-NM	PALO VERDE 3	1,270	12/84	6/85	19,897
SUBTOTAL	6 UNITS	7,118	-	-	81,341

Table X

POTENTIAL OIL DISPLACED BY NUCLEAR GENERATING UNITS 1/

(1981-1993)

YEAR/ERA ELECTRIC REGION	GENERATING UNIT	CAPACITY (MW)	OPERATING LICENSE ISSUANCE DATE 2/	COMMERCIAL OPERATION DATE 3/	PROB. ADDITIONAL OIL CONSUMED (BBLS/DAY)
1986					
(3) NEPOOL	MILLSTONE 3	1,150	12/85	6/86	30,029
(6) CECO	BRAIDWOOD 2	1,090	4/86	10/86	15,654
(8) MSU	GRAND GULF 2	1,250	8/85	2/86	0
(25) NWPP	WPPS 4	1,250	12/85	6/86	24,480
SUBTOTAL	4 UNITS	4,740	-	-	70,163
1987					
(12) VACAR	HARRIS 2	900	6/87	12/87	7,050
(13) CAPCO	PERRY 2	1,179	5/87	11/87	1,539
SUBTOTAL	2 UNITS	2,079	-	-	8,589
1988					
(5) PJM	LIMERICK 2	1,055	10/87	4/88	23,416
SUBTOTAL	1 UNIT	1,055	-	-	23,416
1989					
NONE					
1990					
(3) NEPOOL	SEABROOK 2	1,150	1/90	7/90	30,029
(17) ILL-MO	CALLOWAY 2	1,150	1/90	7/90	6,006
	CLINTON 2	948	1/90	7/90	4,951
SUBTOTAL	3 UNITS	3,248	-	-	40,986

Table X

POTENTIAL OIL DISPLACED BY NUCLEAR GENERATING UNITS 1/

(1981-1993)

YEAR/ERA ELECTRIC REGION	GENERATING UNIT	CAPACITY (MW)	OPERATING LICENSE ISSUANCE DATE 2/	COMMERCIAL OPERATION DATE 3/	PROB. ADDITIONAL OIL CONSUMED (BBLS/DAY)
1991					
(12) VACAR	HARRIS 4	900	6/91	12/91	7,050
SUBTOTAL	1 UNIT	900	-	-	7,050
1992					
NONE					
1993					
(12) VACAR	HARRIS 3	900	6/93	12/93	7,050
SUBTOTAL	1 UNIT	900	-	-	7,050
TOTAL	58 UNITS	62,796	-	-	721,530

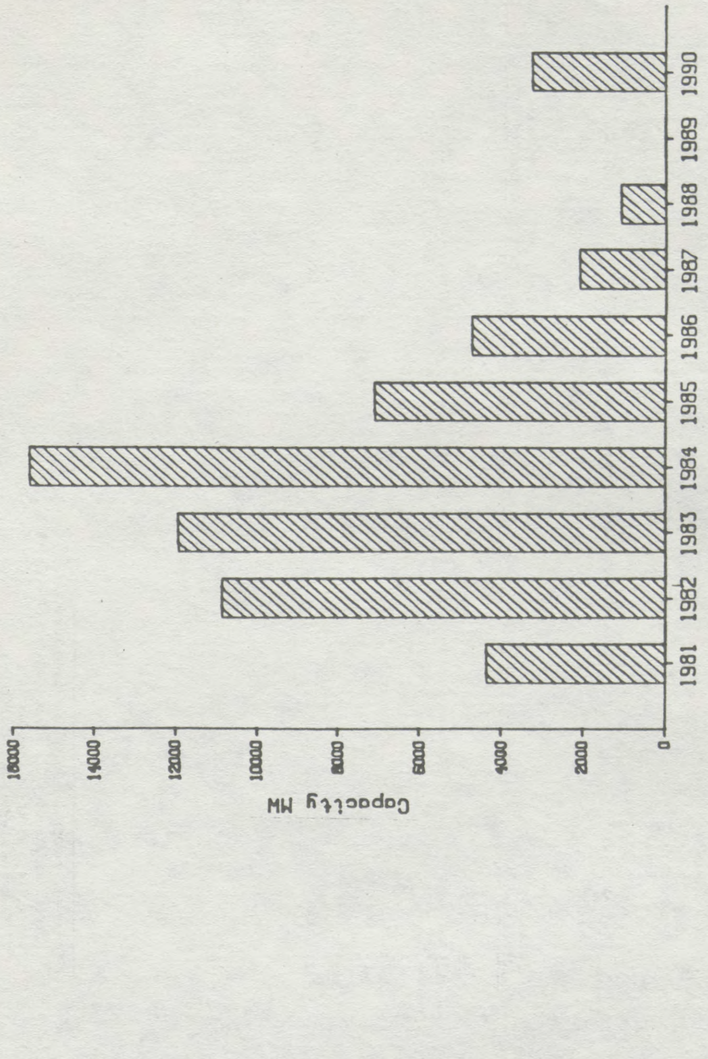
1/ Computed by DOE using the following formula:
barrels displaced = C x 8760 x .64 x 1.7 ÷ 365 x F
where C = capacity in megawatts
8760 = number of hours in a year
.64 = capacity factor
1.7 = U.S. average barrels of oil burned per megawatt-hour generated
365 = number of days in a year
F = regional generation by oil as a decimal fraction of total generation

2/ As projected by the Nuclear Regulatory Commission.

3/ Estimated by DOE to be six months after issuance of operating license.

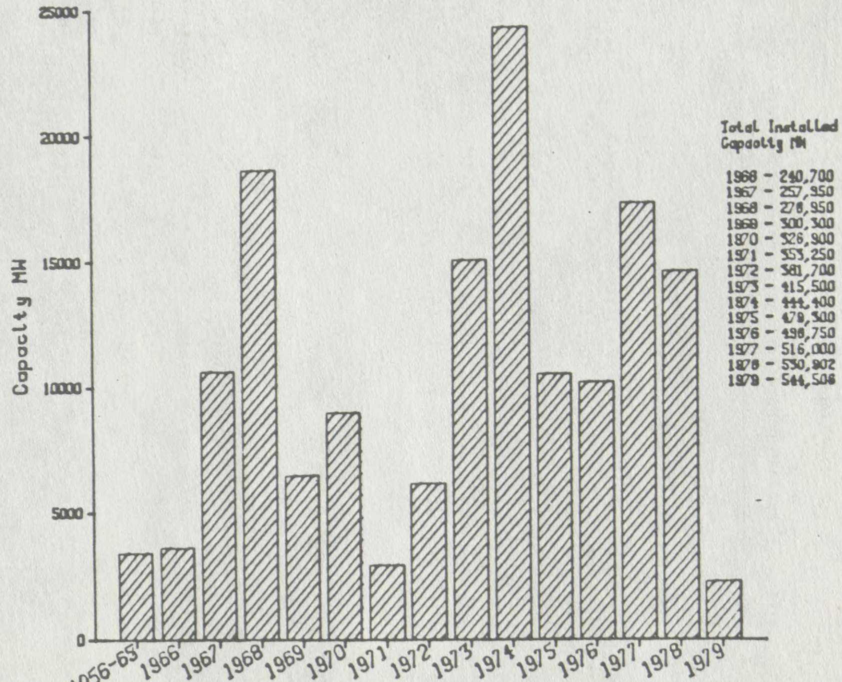
ATTACHMENT A TO TABLE X

ojected Nuclear Generating Capacity Additions Based on
NRC Operating License Issuances



ATTACHMENT B TO TABLE X

Nuclear Unit Construction Permits Granted by the NRC



1/ The Source for the Nuclear Data is the NRC

2/ The Source for the 1966 - 1977 Installed Capacity Data is EEI: The 1978 and 1979 was Obtained from NERC

ATTACHMENT C TO TABLE X

Nuclear Generating Unit Construction Permits Granted by NRC

Calendar Year	Construction Permits Issued	Capacity (MW)	Number Units	Total Installed Capacity [2] (MW)
1956-1965	18	3,386	18	—
1966	5	3,633	5	240,700
1967	9	10,635	14	257,950
1968	18	18,667	23	278,950
1969	5	6,467	7	300,300
1970	8	8,987	10	326,900
1971	3	2,943	3	353,250
1972	6	6,184	8	381,700
1973	9	15,059	14	415,500
1974	13	24,340	23	444,400
1975	5	10,504	9	479,300
1976	4	10,220	9	498,750
1977	8	17,312	15	516,000
1978	6	14,628	13	530,902
1979	1	2,300	2	544,506
	118	155,265	173	

1. The source for the nuclear data is the NRC.

2. The source for the 1966-1977 installed capacity data is EEI; the 1978 and 1979 data was obtained from NERC.

Table XI

Page 1 of 4

POTENTIAL OIL DISPLACEMENT RESULTING FROM PASSAGE OF OIL BACKOUT LEGISLATION

ELECTRIC REGION	STATION &	UNITS	NAME PLATE CAPACITY	ESTIMATED OIL DISPLACEMENT 1/ (bbl/day)
NEPOOL	Devon	7	104	2,500
		8	104	2,500
	Norwalk Harbor	1	163	4,000
		2	163	4,000
	Bridgeport Harbor	3	400	9,800
	Mason	3	33	800
		4	33	800
		5	33	800
	Mystic	4	125	3,100
		5	156	3,800
		6	156	3,800
	Canal	1	543	13,300
	Mt. Tom	1	136	3,300
	Brayton Point	1	241	5,900
		2	241	5,900
		3	643	15,700
	Salem Harbor	1	82	2,000
		2	82	2,000
		3	170	4,200
	West Spring-field	1	51	1,200
		2	51	1,200
		3	114	2,800
	Schuler	4	50	1,200
		5	50	1,200
		6	50	1,200
	South Street	12	62	1,500
Subtotal			5,036	97,000

Table XI

Page 2 of 4

POTENTIAL OIL DISPLACEMENT RESULTING FROM PASSAGE OF OIL BACKOUT LEGISLATION

ELECTRIC REGION	STATION &	UNITS	NAME PLATE CAPACITY	ESTIMATED OIL DISPLACEMENT 1/ (bbl/day)
NYPP	Danskammer	3	147	3,400
		4	239	5,600
	Arthur Kill	2	376	8,700
		3	535	12,400
	Ravenswood	3	1,028	23,900
	E.F. Barrett	1	188	4,400
		2	188	4,400
	Port Jefferson	3	188	4,400
		4	188	4,400
	Albany	1	100	2,300
		2	100	2,300
		3	100	2,300
		4	100	2,300
	Lovett	4	197	4,600
		5	202	4,700
Subtotal			3,876	90,100
VACAR	Chesterfield	3	113	800
		4	188	1,400
		5	359	2,600
		6	694	5,100
	Portsmouth	3	185	1,400
		4	239	1,800
	Possum Point	3	114	800
		4	239	1,800
	Yorktown	1	188	1,400
		2	188	1,400
Subtotal			2,507	18,500

Table XI

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POTENTIAL OIL DISPLACEMENT
RESULTING FROM PASSAGE OF OIL
BACKOUT LEGISLATION

ELECTRIC REGION	STATION &	UNITS	NAME PLATE CAPACITY	ESTIMATED OIL DISPLACEMENT 1 (bbl/day)
PJM	Deepwater	7	23	500
		8	75	1,600
		9	23	500
	Sayreville	4	122	2,500
		5	125	2,600
	Bergen	1	325	6,800
		2	325	6,800
	Burlington	7	195	4,100
	Hudson	1	455	9,500
	Edge Moor	1	70	1,500
		2	70	1,500
		3	75	1,600
		4	177	3,500
	Brandon Shores	1	610	12,700
		2	610	12,700
	C.P. Crane	1	190	4,000
		2	209	4,300
	H.A. Wagner	1	132	2,700
		2	136	2,800
	Cromby	2	230	4,800
Subtotal			4,177	87,000

Table XI

POTENTIAL OIL DISPLACEMENT
RESULTING FROM PASSAGE OF OIL
BACKOUT LEGISLATION

ELECTRIC REGION	STATION &	UNITS	NAME PLATE CAPACITY	ESTIMATED OIL DISPLACEMENT 1/ (bbl/day)
F.C.G.	F.J. Gannon	1	125	2,600
		2	125	2,600
		3	179	3,700
		4	187	3,900
Subtotal			616	12,800
So. Co.	Effingham	1	163	800
Subtotal			163	800
	Collins	4	520	7,000
DECo		5	520	7,000
	River Rouge	1	283	3,800
	St. Clair	5	358	4,800
Subtotal			1,681	22,600
Total			18,056	328,800

1/ Estimated oil displacement = $\frac{\text{Capacity(MW)x8760x.6x1.7BBLS/MWHxoil displacement factor}}{365}$

Exhibit II

Projected Nuclear Capacity Additions as Reported in the Construction Status Report Issued by NRC

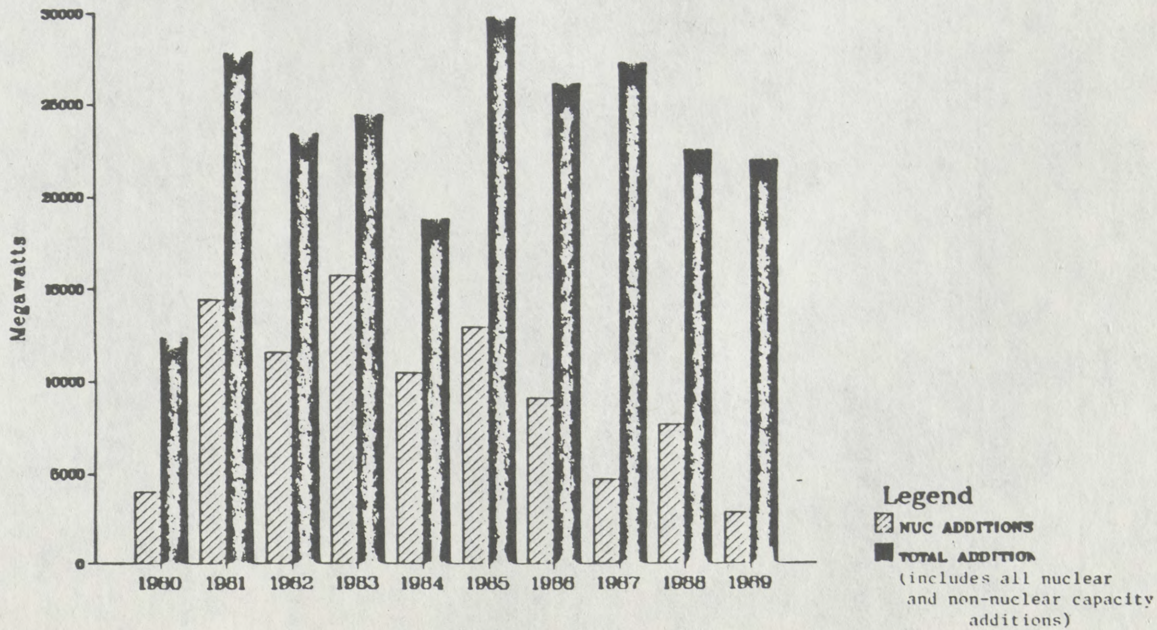

Table XII

Page 1 of 2

PROJECTED 1985 GENERATING CAPACITY RESERVE MARGINS 1/
(SUMMER/WINTER; %)

ELECTRIC REGION	BASE GROWTH W/NUC. UNITS	BASE GROWTH W/O NUC. UNITS	1/2 BASE GROWTH W/NUC. UNITS	1/2 BASE GROWTH W/O NUC. UNITS
APS	NO	NUCLEAR	UNITS	BY 1985
AEP	NO	NUCLEAR	UNITS	BY 1985
NEPOOL	11.0/2.2	4.4/-4.3	14.2/10.4	6.4/3.5
NYPP	9.5/14.2	6.0/10.5	15.9/21.7	12.2/17.8
PJM	5.9/9.9	-0.1/3.3	16.9/23.4	10.3/16.1
CECo	-11.4/-5.2	-40.3/-45.1	3.1/6.7	-7.4/-38.2
FCG	5.4/-4.4	2.4/-7.0	22.3/-3.2	18.9/-5.8
MSU	10.7/28.4	-4.7/7.7	28.0/47.5	10.2/23.8
SO.CO.	4.3/11.4	0.8/7.5	18.5/28.7	14.4/24.2
GSU	3.4/20.2	-5.7/8.2	26.3/45.0	15.2/30.5
TVA	1.9/-2.8	-17.1/-18.8	18.3/13.9	-3.8/-4.9
VACAR	-1.9/-3.0	-15.4/-16.4	12.9/13.2	-2.7/-2.5
CAPCo	-11.5/-17.1	-20.1/-26.3	-0.3/-7.8	-9.1/-18.0
CCD	-4.2/-0.6	-13.0/-9.9	10.1/18.5	0.0/7.5
KENTUCKY	NO	NUCLEAR	UNITS	BY 1985
INDIANA	3.6/-6.3	3.6/-6.3	19.4/16.7	19.4/16.7
ILLMO	8.0/6.1	-6.2/-10.4	19.2/26.0	3.5/6.4
MECS	12.4/25.0	-3.3/7.1	26.1/38.4	8.5/18.6
WUMS	NO	NUCLEAR	UNITS	BY 1985
MAPP	NO	NUCLEAR	UNITS	BY — 1985

1/ Includes effect of generating unit outages. Outages used were average values for the summer and winter peak periods for 1977, 1978 and 1979.

Table XII

Page 2 of 2

ELECTRIC REGION	BASE GROWTH W/NUC. UNITS	BASE GROWTH W/O NUC. UNITS	1/2 BASE GROWTH W/NUC. UNITS	1/2 BASE GROWTH W/O NUC. UNITS
MOKAN	6.5/27.5	-2.1/16.2	36.0/70.2	25.0/55.1
OKLAHOMA	NO	NUCLEAR	UNITS	BY 1985
TIS	5.1/15.0	-3.6/3.2	25.5/34.0	15.1/20.2
RMPP	NO	NUCLEAR	UNITS	BY 1985
NWPP	12.3/6.7	5.0/1.1	32.3/21.9	23.7/15.5
AR-NM	21.4/30.2	0.0/1.3	48.0/54.8	21.9/20.5
SO. CAL.-NV.	5.5/23.8	-3.6/12.7	14.5/40.1	4.6/27.6
NO. CAL.-NV.	8.1/5.5	-3.0/-7.6	20.3/21.2	8.1/6.1

Table XIII

ELECTRIC REGIONS WITH POSSIBLE CAPABILITY PROBLEMS PROJECTED FOR THE 1980 SUMMER PEAK

No.	Electric Region Name	% Reserve 1/	Council in Which Region Is Located
12	VACAR	(1.7)	SERC
10	Gulf States Utilities Group	1.6	SWPP
28	Northern California-NEV	2.3	WSCC
11	TVA	5.4	SERC
7	Florida Coordinating Group	6.6	SERC

() = Negative Number

1/ After allowance for scheduled maintenance, inoperable capacity, and scheduled exchanges with other electric regions, all as projected by Council and utility report, and allowance for probable forced outages as computed by Staff.

2/ The source of this information is the DOE report, "Electric Power Supply and Demand for the Contiguous United States 1980-1989" issued in June 1980.

Table XIV

Electric Regions
Power Supply and Demand
Winter Peak Period 1980-1981

Electric Region	Total Capability 1/ MW	Estimated Peak Load MW	Total Reserve MW	Total Reserve %	Estimated Outages 2/ MW	Reserve After Outages MW	Reserve After Outages %	
APS	8,045	5,260	2,785	52.9	3,270	(485)	(9.2)	*
AEP	24,469	17,397	7,072	40.7	5,581	1,491	8.6	
CAPCo	16,120	10,954	5,166	47.2	5,352	(186)	(1.7)	*
CD	6,973	4,666	2,307	49.4	1,526	781	16.7	
KENTUCKY	8,290	5,858	2,432	41.5	832	1,600	27.3	
INDIANA	11,628	9,200	2,428	26.4	2,640	(212)	(2.3)	*
MECS	16,951	10,892	6,059	55.6	3,875	2,184	20.1	
ERCOT	43,256	22,424	20,832	92.9	13,097	7,735	34.5	
MAAC	47,981	29,440	18,541	63.0	11,818	6,723	22.8	
CECo	18,241	10,780	7,461	69.2	7,553	(92)	(0.9)	*
ILLMO	14,994	10,224	4,770	46.7	3,179	1,591	15.6	
WUMS	8,707	6,369	2,338	36.7	1,341	997	15.7	
MAPP	24,901	16,834	8,067	47.9	2,157	5,910	35.1	
NEPOOL	21,643	16,075	5,568	34.6	3,542	2,026	12.6	
NYPP	31,141	20,023	11,118	55.5	6,538	4,580	22.9	
FLORIDA	23,995	19,090	4,905	25.7	4,376	529	2.8	*
SOCO	27,777	17,913	9,864	55.1	6,000	3,864	21.6	
TVA	29,644	20,952	8,692	41.5	4,861	3,831	18.3	
VACAR	37,182	28,298	8,884	31.4	7,626	1,258	4.4	
MSU	14,879	8,106	6,773	83.6	4,573	2,200	27.1	
GULF	9,213	6,029	3,184	52.8	3,339	(155)	(2.6)	*
MOKAN	13,285	7,735	5,550	71.8	2,189	3,361	43.5	
OKLA	17,680	10,048	7,632	76.0	2,308	5,324	53.0	
RMPP	6,559	5,148	1,411	27.4	369	1,042	20.2	
NWPP	42,204	33,245	8,959	26.9	3,665	5,294	15.9	
A-NM	12,640	6,914	5,726	82.8	2,486	3,240	46.9	
SC-N	26,798	16,394	10,404	63.5	4,775	5,629	34.3	
NC-N	16,916	12,906	4,010	31.1	2,881	1,129	8.7	

/ Includes the net of scheduled imports and exports.
/ The sum of scheuled maintenance, estimated full and partial forced outages and capability unavailable for other reasons.

*"Reserve after outages" is too low for consistently reliable service. If these reserves are actually experienced, reliability of service will be jeopardized, but could be maintained by transmission of power from other Regions within the Council area.

Table XV

GENERATING UNIT OUTAGES AS A PERCENTAGE OF INSTALLED CAPABILITY

ELECTRIC REGION	SUMMER	WINTER
APS	32.5	39.6
AEP	16.8	19.9
NEPOOL	25.9	20.6
NYPP	23.0	23.9
PJM	18.0	26.0
CECo	27.2	44.3
FCG	18.2	21.3
MSU	12.9	24.5
So.Co.	17.8	23.5
GSU	17.6	30.0
TVA	18.4	22.6
VACAR	23.5	24.2
CAPCo	26.7	37.1
CCD	22.6	32.9
KENTUCKY	9.2	19.5
INDIANA	19.8	23.2
ILLMO	13.4	23.6
MECS	18.3	21.6
WUMS	10.5	14.8
MAPP	9.1	12.6
MOKAN	14.6	23.1
OKLAHOMA	5.9	13.8
TIS	13.1	30.5
RMPP	6.3	7.9
NWPP	17.6	7.6
AR-NM	5.3	22.1
So. CAL-NV.	15.9	20.0
No. CAL-NV.	8.0	21.8

NOTE: The above values are the average unavailable capability as a percentage of installed capability for the years 1977, 1978 and 1979. This information was extracted from schedule 1 of the Form 12E-2.

Table XVI

COMPARISON OF CALENDAP YEAR AVERAGE
CAPACITY FACTORS FOR COAL AND NUCLEAR PLANTS

Year	Coal No. Units	Coal Avg.	Nuclear No. Units	Nuclear Avg.
	(400 - 749 MW)		(400 - 749 MW)	
74	77	56	13	63
75	84	57	16	70
76	87	58	16	69
	(750 - 949 MW)		(750 - 949 MW)	
74	23	58	12	53
75	25	58	17	62
76	25	56	22	62
	(> 950 + MW)		(> 950 MW)	
74	6	56	4	32
75	8	56	8	45
76	11	64	9	45

SOURCE: STATISTICAL ANALSYIS OF 400 MW AND LARGER NUCLEAR AND COAL-FIRED GENERATING UNIT CAPACITY FACTORS; BY ORNL FOR DOE.

Table XVII

SAMPLE RANGE OF CAPACITY FACTORS FOR 1976

COAL UNITS

SIZE UNIT (MW)	CAPACITY FACTOR
234	91
950	80
1080	79
900	77
565	70
754	46
500	42
580	40
560	35
580	17

NUCLEAR UNITS

SIZE UNIT (MW)	CAPACITY FACTOR
883	93
503	87
810	50
812	48
670	43

Table XVIII

POWER PLANT INVESTMENT COSTS 1/

$/KW - 1990 Operation

Location	1139 MW LWR	795 MW Coal	1232 MW Coal
New Orleans	1570	1240	1120
Birmingham	1590	1290	1150
Dallas	1580	1280	1160
Atlanta	1620	1290	1170
Denver	1660	1310	1190
Minneapolis	1620	1320	1190
Baltimore	1700	1350	1220
Kansas City	1710	1360	1230
Pittsburgh	1700	1380	1240
U.S. Average	1700	1370	1240
Boston	1750	1390	1250
St. Louis	1690	1380	1250
Chicago	1730	1410	1270
Cleveland	1730	1410	1270
Philadelphia	1730	1410	1270
Seattle	1750	1400	1270
Cincinnati	1760	1420	1280
Middletown	1750	1420	1280
San Francisco	1760	1430	1290
Los Angeles	1730	1440	1290
Detroit	1790	1450	1310
New York	1770	1460	1310

1/ DOE/NE-0009 October 1979 (Published June 1980) Power Plant Investment Cost Estimates: Current Trends and Sensitivity To Economic Parameters. P. 54

Mr. MARKEY. Dr. Komanoff, would you identify yourself?

TESTIMONY OF CHARLES KOMANOFF

Mr. KOMANOFF. Thank you, Mr. Chairman.

My name is Charles Komanoff. My 8 years as an energy analyst include authorship of two books, one published by the Masschusetts Institute of Technology Press concerning pollution from combustion of fossil fuels, the other published by the Council on Economic Priorities concerning the generating performance and economics of nuclear and coal powerplants; consulting work for the Congress, eight States, and three publicly owned electric utilities; a position as senior energy economist for the city of New York; and invited testimony before three congressional committees and the Select Committee on Energy of the House of Commons, United Kingdom.

I have a prepared statement entitled "Cost Outlook for Nuclear and Coal Power Plants," and in addition I have two recent articles to submit for the hearing record, one entitled "Pollution Control Improvements in Coal Fired Electric Generating Plants, What They Accomplish, What they Cost," from the September 1980 Journal of the Air Pollution Control Association, and the other entitled "U.S. Nuclear Plant Performance," from the November 1980 edition of the Bulletin of Atomic Scientists. I would like to put my prepared statement and these articles aside.

Mr. MARKEY. Without objection, we will include your testimony in the record. [See p. 172.]

Mr. KOMANOFF. I would like to speak somewhat extemporaneously to two primary points. One is occasioned by the presence of Congressman Lent from Long Island. Is it the Fifth Congressional District?

Mr. LENT. The fourth.

Mr. KOMANOFF. I used to live in the Fifth Congressional District. I grew up on Long Island. I think they redistricted you so you no longer represent Long Beach, my home town. I am a native Long Islander and you brought up the Shoreham Nuclear Plant under construction on Long Island. I would like to speak in a minute to some of your specific concerns. I think they are a good microcosm for the whole issue we are addressing here today.

Second, I will have some several limited comments to make concerning some of the other remarks that have preceded me.

As Representative Lent stated, there is under construction on Long Island the Shoreham Nuclear Plant which the Long Island Lighting Co. hopes to bring into service in 1983. Long Island is one of the regions in the country, a minority of the country, in which the operation of nuclear powerplants does and would displace a virtually equivalent amount of fuel oil.

Other such regions, as Dr. Vince Taylor pointed out, are most of New York State, all of New England, Virginia, to a greater or lesser extent, Florida, and California.

Mr. Congressman, you may be familiar with a plant under construction in Ohio by Cincinnati Gas & Electric, the Zimmer Plant, which is a virtual twin of Shoreham. If for some reason Zimmer were not to be completed, if new safety developments should preclude it completion, this would have virtually no effect no oil requirements because Ohio generates almost all of its electricity from coal.

The Department of Energy analysis concludes that any nuclear plant that would be cancelled in Ohio would be replaced 82 percent by coal, 2 percent by gas and only 16 percent by oil. I happen to think the percentage of oil you would need to replace Zimmer in Ohio would be even less than 16 percent. But in the case of Shoreham on Long Island, I acknowledge that there is virtually a one to one tradeoff with oil.

Let's see what this amounts to. First of all, Lilco would not require 8 million barrels a year of oil to replace Shoreham, it would be somewhat under 7 million if Shoreham were to follow the performance trend of General Electric nuclear reactors to date.

Second, let's look at the national picture. As Dr. Vince Taylor pointed out, if all of the nuclear plants to be brought on line between today and 1985 in these oil dependent regions were not to be completed, this would increase oil requirements about 300,000 barrels a day. That is not an insignificant amount of oil.

But in just the past 2 years, from 1978 to 1980, 600,000 barrels of oil per day have already been saved and are being saved today because electric utilities have begun converting from oil to coal and are transmitting large blocks of power from coal-rich areas of the country to oil dependent areas, such as New York and New England. So, if all of the nuclear plants scheduled for the next 5 years were to be precluded, that would be much less of an impact than we have already achieved on oil supplies and are going to achieve in the future.

Now, further, what could we do on Long Island, because you have a local problem with this utility dependence on oil. What could we do to get off of oil?

Well, the first thing we could do would be to convert some of the oil fired plants on Long Island to coal.

I recognize that Lilco's Northport plant, was not built to burn coal, so it is not a candidate to convert to coal because Lilco would have to build a brand new coal plant.

However, Lilco's plants at Port Jefferson and Island Park have about the same total capacity as the Shoreham plant. These plants are technologically capable of being converted to coal within several years—probably 2 to 3 years—with advanced pollution controls, scrubbers, precipitators that would make them burn more clearly than they currently do burning oil. You say, "come on." I understand your skepticism.

Mr. Lent. I don't want to interrupt the witness. Let me tell you that Island Park for years was a coal burning plant. It was ordered to switch years ago from coal to oil because of the pollution problems that the coal involved, because of the fact that hundreds and hundreds of railroad cars had to go through Long Island every day bringing the coal to Island Park, and at night for hours and hours, railroad trains would have to go through every single community holding up traffic at every bridge, at every grade crossing, to take the dust and the residue of the coal.

Don't tell me that coal is going to be cleaner than the oil because the community is in an uproar right now over the fact that they are under orders from the Government to now convert from oil back to coal.

One of the reasons that plant has been selected for reconversion is the fact that it initially was constructed for coal. But don't tell me it is going to be cleaner because it is going to be a mess.

Mr. KOMANOFF. I will tell you——

Mr. LENT. If you tell every housewife in Island Park to wash her curtains twice a week, that coal is cleaner than oil, you will be run right out of this room on a rail.

Mr. KOMANOFF. Let me reach back into the past if I may.

In 1972, I coauthored "The Price of Power," a book on pollution control problems in the electric utility industry published by MIT press. The book denounced the electric utilities industry for its pollution problems with coal fired plants. At that time, I was opposed the construction of any more coal fired plants because of the pollution burden.

However, this pollution burden is an artifact of past policies and of past technology. The technological strides that the electrical utilities industry has made in the last 10 to 15 years now enable any coal fired plant in the country to be considerably cleaner than before. There would be less ash coming out of coal fired smokestacks with 99.5 percent efficient elecrostatic precipitators than there is with oil. There would also be less sulphur dioxide than today through the use of scrubbers.

This is available with present technology. And the cost of this equipment would be paid for within 2 to 3 years by the fuel savings resulting from converting from very expensive imported oil to considerably cheaper domestic coal.

Mr. LENT. You would agree that domestically mined nuclear energy fuel is even cheaper than coal?

You are familiar, of course, with the Arthur D. Little study which indicated that the kilowatt-hour cost of nuclear energy is 5 cents per kilowatt-hour and the cost for coal is 7.4 cents per kilowatt-hour, and the cost for oil is 9.2 cents per kilowatt-hour. So certainly you would agree with me that if we could go ahead in Long Island with the Shoreham plant, which is going to produce 820,000 megawatts a day, that the need for conversion of these smaller plants from oil over to coal with the cost of putting in scrubbers and the problems of disposing of very highly toxics loaded with heavy metals and arsenic sludge, might be eliminated.

So the nuclear option appears to me to be not only cheaper—it can produce the energy for a nickel a kilowatt-hour as opposed to 7.4 cents for a kilowatt-hour for coal.

In addition to this, you don't have the transportation problem. In the East we don't have any low sulphur coal that we can burn that will meet——

Mr. KOMANOFF. We don't need it with the scrubbers. That is the point.

Mr. LENT. Who pays for the scrubbers?

Mr. KOMANOFF. Lilco's customers, but after 2 to 3 years of operation the conversions would be paid off. The cost of converting per thousand megawatts would be about $200 to $300 million, but the fuel savings are $100 to $150 million per year.

Mr. LENT. Do you still live in Long Beach?

Mr. KOMANOFF. No, my family does.

Mr. LENT. Anyone who lives in Long Beach, which has been in relatively close proximity——

Mr. KOMANOFF. I know the plant well, I visited it in 1972.

Mr. LENT. They have all kinds of civic associations out there dedicated to the proposition that the Island Park or Barrett Station plant, as it is known, will not be——

Mr. KOMANOFF. You know why?

Mr. LENT. Because they remember—

Mr. KOMANOFF. And because Lilco is adamantly opposed to the use of scrubbers and the best available smoke control technology. This is another lesson. If the Congress holds firm on the Clean Air Act and insists that conversions from oil to coal be done in the most environmentally acceptable and technologically advanced manner, there will be a great increase in public acceptance of coal.

I am an environmentalist. I was bitterly opposed to coal 10 years ago. I am not now because circumstances have changed. The new pollution controls can make coal cleaner as well as cheaper than oil. If the Congress requires electric utilities and if electric utilities get a little backbone and begin doing what is technologically possible——

Mr. LENT. How are you going to get the coal to Island Park?

Mr. KOMANOFF. I am not a transportation expert. I agree with you that rail problems could be considerable. I would imagine, being familiar with Reynolds Channel in that area, that the coal could and would be barged in from Newport News, Va. You wouldn't truck it, rail it through New York City anyway. You would barge it up through Reynolds Channel. For the Port Jefferson plant, which is on Long Island Sound, Lilco would bring the barge in through Long Island Sound. There is very little transportation impact.

Mr. LENT. As far as the rate payer for Long Island Lighting Co. is concerned, the cost per kilowatt-hour of electricity that comes from coal is almost 7½ cents a kilowatt-hour, and the cost per kilowatt for nuclear energy is 5 cents a kilowatt-hour, so you are imposing a 50-percent increase on the rate.

Mr. KOMANOFF. If that were the case, I wouldn't be taking the position that I am today. The Shoreham plant is already so expensive, at $2.2 billion, that even if its cost didn't go up another cent, and the uranium were free and the nuclear waste disposal and operational and maintenance were free and no new safety problems were discovered that would require backfits or redesign after Shoreham goes into service, if all of that were free, Shoreham would still cost about 7 cents a kilowatt-hour because of the huge construction costs the rate payers will have to pay off for the next 30 years.

Shoreham is the worst nuclear plant in the country in this respect, and I don't want to imply all nuclear plants are in quite the same boat as Shoreham. The Zimmer plant, which is a twin, its cost only tripled since it got its construction permit, whereas the cost of Shoreham went up about sixfold.

Mr. LENT. Do you know how the Island Park plant, once it is converted to coal and has this scrubber—I understand a scrubber is a fancy name for chemical factory?

Mr. Komanoff. Right.

Mr. Lent. And where is the sludge byproduct of this chemical factory, which you would like to call a scrubber, going to be disposed of? I understand it is highly toxic, loaded with lime, arsenic, heavy metal. Do you know where they are going to take that stuff?

Mr. Komanoff. No; I don't know where they are going to take that. I do know——

Mr. Lent. You are aware of the fact Long Island is a sole source acquifer and there is no way they can put it in the ground, it has to be carted out of there and taken someplace else?

Mr. Komanoff. Well, I would say there are several options. One is to wait about 2 more years before the scrubber is built and at that time, based on current progress, there will be available for utilities the so-called recycling or regenerative scrubbers that make virtually none of this sludge. This is a second generation type of technology. It doesn't make sludge. It makes sulfur, or gypsum which is salable as an industrial commodity.

Mr. Lent. I hope you are right.

Mr. Komanoff. What I am saying is that, finally, some money and brains are going into problems of burning coal, of mining coal, and of disposing of the waste. We no longer have to regard coal with the formerly justified apprehension that we had.

Let me go on.

Well, another thing Lilco could do, if Shoreham were not to be completed on Long Island, Lilco could build a brandnew coal fired plant as well, but I won't dwell on that.

Another thing that I think also deserves the attention of this committee is that we could take tremendous steps to improve the efficiency with which electricity is used by customers and businesses on Long Island or anywhere in the country.

Let me give you one example that I am very excited about. In 1981, General Electric and Norelco are both planning to introduce for mass distribution a fluorescent screw-in bulb that will fit into an electric light bulb socket. It will consume only 18 watts of electricity but will give the same lighting as a 60-watt incandescent bulb. This is better than a 3 to 1 efficiency improvement. I imagine Westinghouse is also getting involved in this.

I haven't done any calculations on how much of our electricity we use for lighting, but it is a massive amount. In places such as Long Island, the electricity savings would translate directly into oil savings. If we are going to talk about subsidies for nuclear power, maybe we should talk about giving away the light bulb so people could afford them. These light bulbs are going to cost about $15.

This is not a commercial for GE or anything, but these light bulbs apparently are going to last five times as long as typical light bulbs. If you use one for 4 to 8 hours a day, you would pay back the $15 purchase price in about a year at Lilco's electric rates.

The nuclear powerplants you would start licensing today will not displace oil for another 10 years. Think about the timeframe, think about the things we can do with energy efficiency and the things we are already doing that we can accelerate.

And to amplify Dr. Weil on what we are already doing to back out oil in the utility sector, we are burning a third less oil to make electric power. It is going to continue going down. Any new nuclear plants we might embark upon today, like the ill-fated Jamesport project, would be displacing coal because by the time they would be finished there would be very little oil burned for electricity.

Let me move on to respond to several previous panelists. The big electricity growth that is used to justify nuclear, is not going to happen almost regardless of what we do in public policy.

In the 7 years since the oil embargo, consumption of electricity has gone up only about as fast as real gross national product, a little less than 3 percent a year. I would like to see the gross national product go up at least 3 or 4 percent a year in the eighties and nineties, but this is very unlikely.

It seems we have reached a point in the economy where electricity grows only as fast as the gross national product. We could get it down to much less with a policy oriented at improving energy efficiency. If we don't have a lot of electric growth, we don't need both coal and nuclear. We need coal, yes, and we should encourage coal. The best way to encourage coal is to not weaken the Clean Air Act.

Mr. Walske referred to the difficulty in financing nuclear powerplants. Why is there such difficulty? Because nuclear powerplants embarked on today would cost about twice as much to construct as coal-fired plants. That is a huge difference.

He talked about regulatory uncertainties. Why is there regulatory uncertainty? There is the Three Mile Island accident. There is the partial failure to scram the control rods at Browns Ferry last year. The problem at Indian Point 2 months ago. The rate at which safety problems are being discovered in nuclear power operations is greater today than at any time in the past, and this is the underlying reason for regulatory uncertainty.

Mr. MARKEY. Can I ask you to sum up in 30 seconds?

Mr. KOMANOFF. I think I have said what I need to say. Thank you.

[Testimony resumes on p. 192.]

[Mr. Komanoff's prepared statement and attachments follow:]

KOMANOFF ENERGY ASSOCIATES

Cost Outlook for Nuclear and Coal Power Plants

Testimony of Charles Komanoff

before the

Subcommittee on Oversight and Investigations

of the

House Committee on Interstate and Foreign Commerce

December 9, 1980

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My name is Charles Komanoff. My eight years as an energy analyst include authorship of two books, one published by the Massachusetts Institute of Technology Press concerning pollution from combustion of fossil fuels, the other published by the Council on Economic Priorities concerning the generating performance and economics of nuclear and coal power plants; consulting work for the Congress, eight States, and three publicly owned electric utilities; a position of senior energy economist for the City of New York; and invited testimony before three Congressional committees and the Select Committee on Energy of the House of Commons (U.K.).

My presentation today concerns the capital (construction) costs of nuclear and coal-fired power plants in the United States. Capital costs will determine two-thirds of total lifetime generating costs for new nuclear plants and almost one-half for coal plants. In turn, projected generating costs will strongly influence the choice of nuclear fuel or coal for new electric-generating plants.

The capital costs of the first U.S. nuclear plants completed on a commercial basis in the early 1970s were only slightly greater than those of contemporaneous coal plants. The power industry and the Department of Energy contend that this cost relationship will continue. If it does, new nuclear plants, which cost relatively little to operate, will have lower life-cycle generating costs than new coal plants.

This forecast is open to two fundamental criticisms, however. First, it is belied by empirical data, which show that nuclear capital costs increased more than twice as much as those for coal in the 1970s. Using a data base of all 46 nuclear plants completed in the U.S. from the end of 1971 to the end of 1978, I have calculated that the average cost to construct nuclear plants increased at a rate 142 percent greater than the rate of inflation in power construction factors (measured by increases in

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construction wages and material prices -- see Figure 1). The corresponding rate of increase for coal plants was not quite half as great, 68 percent, based on the 116 coal plants (over 100 megawatts capacity) completed in the same period. Virtually all this cost increase was for scrubbers, precipitator upgradings, and other pollution control improvements which reduced coal plant emissions of pollutants by two-thirds from 1971-plant levels (Figure 3).

Thus, although the average 1971 nuclear plant had only a 6 percent higher per-kilowatt capital cost than the average coal plant completed at the same time, the difference had swelled to 52 percent by the end of 1978 (Figure 2).

The second weakness in the power industry's projections of capital costs is that they are devised through engineering estimation, a technique employing conceptual plant designs to compute the labor, materials, equipment and engineering effort required to construct a plant. This technique requires that the scope of construction, including environmental and safety standards, be clearly defined. It is reasonably accurate in estimating coal capital costs, since most regulatory requirements for coal plants are known at the start of construction. In contrast, nuclear plants, as Bechtel Power Corporation noted even before the March 1979 accident at Three Mile Island (TMI), are subject to "new requirements...imposed after the design and construction are well advanced, requiring substantial rework that increases both schedule and cost." The TMI accident has provoked a sweeping reappraisal of nuclear regulation and compounded the difficulty of anticipating future nuclear standards. Accordingly, the power industry's method of projecting future nuclear capital costs has dubious value, since it is dependent upon design requirements which cannot be fully known until plant completion (and which can change even then, requiring costly "backfits").

I offer an alternative cost projection method. It draws upon the hypothesis -- supported by my statistical analysis -- that the primary cause of real nuclear cost escalation in the United States has been the implementation of increasingly stringent safety standards intended to contain the risks of expanded use of nuclear power. These standards have arisen, first, from the endeavor to reduce the permissible risk to public health and safety per reactor, in order to limit the overall accident probability as the population of reactors has increased; and second, from new information discovered in licensing reviews and in reactor operating experience indicating that current standards are inadequate to achieve the intended low risk levels.

In short, expansion of the nuclear sector has required increased effort to reduce the hazards of new reactors. This resulted in costly design changes and equipment modifications in virtually every aspect of nuclear plants in the 1970s. Major structures were strengthened and pipe restraints added to absorb seismic shocks and other postulated "loads" identified in accident analyses. Barriers were installed and distances increased to protect redundant divisions of safety systems from fires and other "common-mode" failures, and to shield vital equipment from high-speed missile fragments that might be loosed from rotating machinery and from the pressure and fluid effects of postulated pipe ruptures. Instrumentation, control, and power systems were expanded to monitor more indicators of plant status under a broadened set of operating conditions and to reduce the rate of power interruption to vital equipment. Components deemed important to safety were "qualified" to perform under more demanding conditions, requiring more rigorous fabrication, testing, and documentation of their manufacture.

These changes approximately doubled the amounts of materials, equipment, and labor, and tripled the design engineering effort, required per unit of nuclear capacity during the 1970s. Moreover, many changes were mandated during construction, as new information relevant to safety emerged. Reactors were thus built increasingly in what the Atomic Industrial Forum called an "environment of constant change" that hampered control or even estimation of costs. Much construction therefore lacked a fixed scope and had to be let under cost-plus contracts that undercut efforts to economize. Completed work was sometimes modified or removed, often with a "ripple effect" on related systems. New regulations and design changes altered construction sequences and upset schedules for equipment delivery, contributing to poor labor productivity and hindering management efforts to improve construction efficiency.

If the past relationship between expansion of nuclear capacity and real increases in reactor costs shown in Figure 1 were to extend into the future, then nuclear plants begun today would cost close to $1,400/kW (in 1979 construction dollars) -- 55 percent more than the $900/kW average cost of recent completed reactors (see Figure 2). And indeed, such an increase could probably be accounted for by new design requirements issued prior to TMI that are not reflected in recent costs due to "regulatory lag," and by measures that will be required to resolve the many long-pending "unresolved safety issues." In contrast, coal capital costs need increase only 35 percent from 1978-plant costs to reduce coal pollution emissions by another three-fourths, producing a 90 percent reduction from 1971-plant emissions. (See Figure 3, which is drawn from my article on coal pollution-control improvements and costs in the September 1980 Journal of the Air Pollution Control Association, which I have submitted for the hearing record.)

Such coal plants would be three times as clean as the new EPA emission standards require -- considerably cleaner than currently operating oil-fired plants -- a factor that would considerably ease the political and environmental obstacles to constructing new generating facilities in order to retire existing oil- or gas-fired plants. And despite these dramatic pollution reductions, the capital costs of new nuclear plants would be far greater, exceeding those for coal plants by approximately 75 percent, as Figure 2 shows -- three times the largest difference between nuclear and coal capital costs projected by nuclear proponents.

These figures are based on the past cost-safety balance in nuclear regulation and do not incorporate the almost certainly significant costs of further new standards stemming from TMI. That accident has toppled basic precepts of nuclear safety regulation, tightened surveillance of operating experience to detect additional safety problems, tempered NRC's sensitivity to the costs of new regulatory standards, and stimulated development of a 500-page NRC "TMI Action Plan" that will impose major new design and equipment requirements and substantially upgrade the oversight of reactor design and construction. It would not be surprising if these impacts pushed the capital costs of new reactors to more than twice those of the ultra-clean coal plants just described.

These regulatory and cost trends are not lost on the electric utilities, although the power industry still contests them and evinces confusion over their causes. Some segments of the industry still blame inflation and anti-nuclear interventions for rising capital costs, even though the steep nuclear cost increase rate described above is net of construction inflation (and over twice the coal rate); similarly, nuclear costs have not been affected significantly by licensing stretch-outs or other intervenor actions. Moreover, some in the industry still insist that large reactors will eventually "mature" and match the generating performance of smaller units, despite overwhelming evidence that age differences explain only a small fraction of the difference in performance rates.

Still, only two reactors have been ordered (without subsequent cancellation) in the United States since 1974, and their contracts include lenient cancellation provisions. Dozens of previously ordered reactors have been scrapped during this period, but the coal sector, with an ordering rate equivalent to 8 to 10 large reactors per year, has been far from dormant. The message is getting through, even to the strongly pro-nuclear utility industry, that nuclear power is too burdensome economically to allow construction of new reactors.

Will electricity consumers suffer from the abandonment of nuclear power? Not likely. Even under very conservative assumptions, new reactors undertaken today would average 25 percent higher generating costs than new ultra-clean coal plants. These assumptions include: (1) no cost impact from Three Mile Island; (2) a 60 percent capacity factor for new reactors -- equal to the cumulative U.S. reactor average but 6 percentage points above the average for large (800 MW or greater) units (see my article, "U.S. Nuclear Plant Performance," in the November 1980 Bulletin of the Atomic Scientists, which I have submitted for the record); (3) an annual increase rate in the cost of coal fuel 2-2½% greater than that of other industrial commodities (to pay for further health, safety, and environmental improvements in mining); and (4) only 8 percent of total nuclear costs accounted for by disposal of irradiated fuel and decommissioning of reactors.

Assumptions (1), (2), and (4) are, however, unlikely to be realized. Relaxing them to a realistic extent would double or even triple the cost differential from the 25 percent projected, indicating that even reactors which are well beyond the initial construction stage could be economically abandoned in favor of new, clean coal-fired plants.

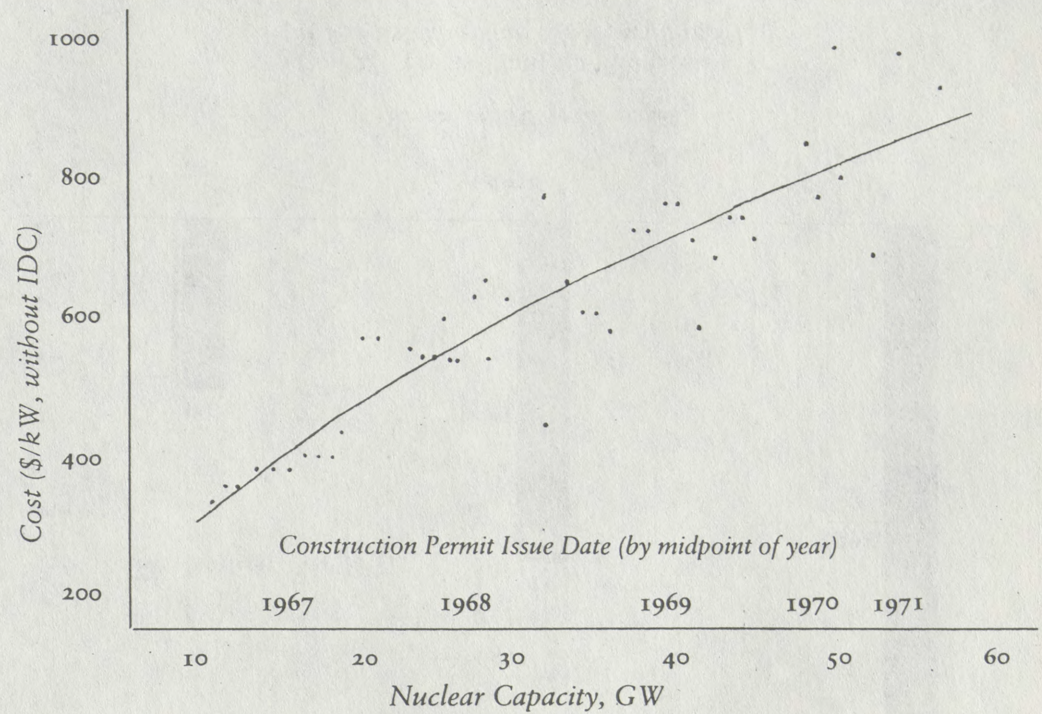
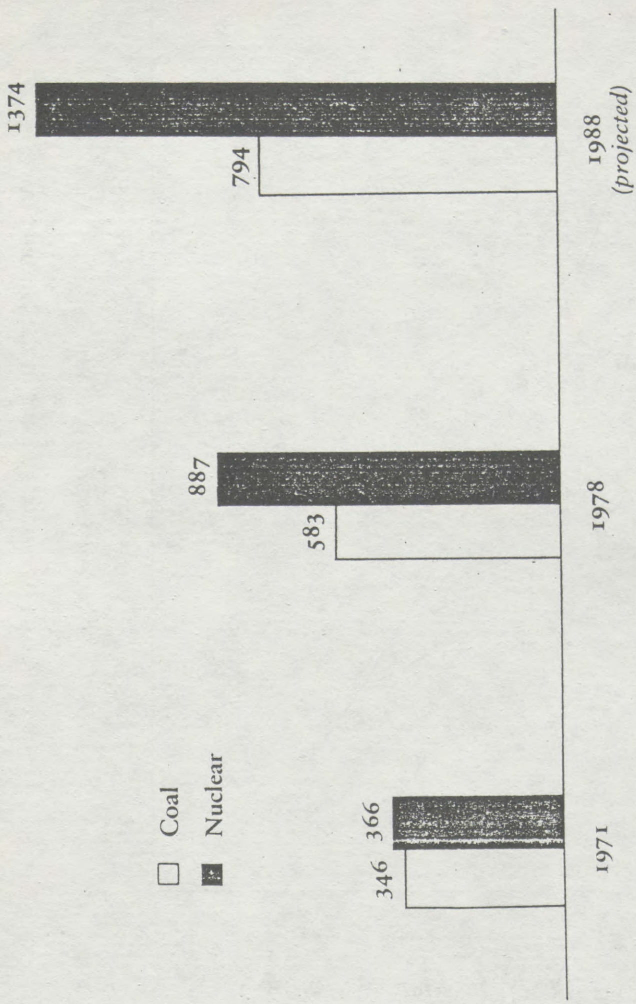


Figure 1: **Costs of Nuclear Plants in the United States**

(Normalized to typical plant characteristics and 1979 construction price levels)

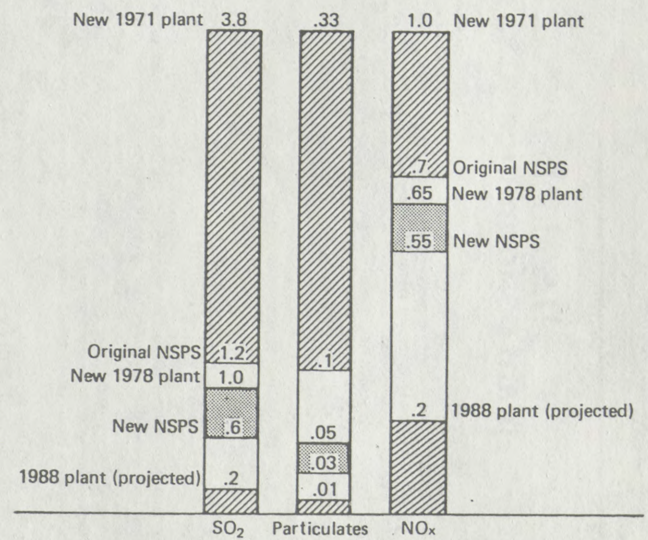


Years refer to date completed

Figure 2: **Power Plant Capital Costs**
(in 1979 steam-plant $/kW, with real IDC)

Figure 3: Emissions of Criteria Air Pollutants by Typical New Coal Plants

(pounds of pollutant per million Btu of fuel burned)



Source: C. Komanoff, Journal of the Air Pollution Control Association (Sept., 1980)

THE bulletin
OF THE ATOMIC SCIENTISTS
a magazine of science and public affairs

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CHARLES KOMANOFF

U.S. nuclear plant performance

U.S. nuclear power plants have suffered a significant performance decline since early 1979, raising doubts about reactor operating reliability and further eroding the economics of nuclear power. The 62 licensed commercial-size reactors (over 400 megawatts capacity) averaged slightly under 57 percent "capacity factor" from January 1979 through June 1980. This is the industry's poorest operating record over any sustained period in five years, and is over four percentage points below the 61 percent cumulative average through 1978.

Design errors, equipment failures and the accident at Three Mile Island have led to widespread shutdowns. The 39 large plants (over 800 megawatts), which are more representative of reactors being built and planned, have been especially affected, averaging only 51 percent capacity factor during the past 18 months. The downturn was especially pronounced in the first half of 1980, with a performance average of 51 percent, and only 48 percent for the large plants.

The March 1979 loss-of-coolant accident at Three Mile Island has been a major cause of the performance drop. The accident closed both units indefinitely and caused the other seven Babcock & Wilcox reactors to shut down in order to upgrade equipment. As a result of these outages and others involving cooling system failures, the Babcock & Wilcox plants averaged only 41 percent capacity factor for the past year-and-a-half. Other reactors incurred lesser, one-to-two-week closings to make Three Mile Island–related technical fixes. Major backfitting work will begin for some plants in 1981, causing more shutdowns.

Capacity factors have also been affected by seismic design problems. The March 1979 discovery of errors in one architect-engineer's calculations of potential earthquake stresses on coolant piping closed four reactors for re-analyses and piping modifications taking 10 to 22 weeks. (A fifth affected plant was already down for steam generator replacement.) Another dozen plants have sustained outages ranging from several weeks to several months to rebuild piping systems and structures that deviated from seismic design specifications.

Although less publicized than Three Mile Island or the seismic shutdowns, equipment and material failures have also contributed to the performance decline. Westinghouse reactors have been particularly affected by cracks in steam generators, turbines, piping welds and pipe-support anchor bolts. The 13 Westinghouse units over 800 megawatts capacity averaged only 46 percent capacity factor for 1979 and the first half of 1980, with two operating below 20 percent over the period.

The cumulative average capacity factor of U.S. reactors now stands at 60 percent through June 1980. This performance shortfall has made nuclear electricity about one-fourth costlier than was envisioned in the early 1970s, when 80 percent capacity factors were assumed. Nuclear power costs have also suffered even greater impacts from construction overruns, as well as lesser increases from uranium price rises and the inclusion of anticipated costs for waste management and decommissioning. Together, these factors have caused projected generating costs of new reactors to exceed those of new coal-fired plants with advanced pollution controls.[1]

Performance outlook. Nuclear capacity factors are determined by several elements in addition to intrinsic design and mechanical integrity. These include regulatory pressure to reduce reactor mishaps, the willingness of utilities to commit funds to enhance performance, and the rate at which safety-related defects emerge in reactor operations and lead to widespread 'generic' shutdowns. Although it is difficult to measure the past effects of these elements and impossible to predict their precise future impacts, the industry's sizeable operating history is our best guide for estimating future capacity factors.

The data base of commercial reactor operating experience in the United States reached 362 reactor-years in mid-1980. This equals the level the nuclear industry has considered sufficient for extrapolating future performance from past statistics.[2] On the basis of this record, particularly that of the past 18 months, Babcock & Wilcox plants appear to have little chance of becoming reliable power producers, and large Westinghouse reactors seem to be saddled with major equipment and materials problems. Recent performance has been somewhat better for the other two vendors, General Electric and Com-

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(Author's note: Komanoff Energy Associates' definitive study of nuclear and coal capital cost escalation will be released in early 1981. Write to KEA for ordering information)

bustion Engineering, but they are hardly assured of high capacity factors over the long term.

• Babcock & Wilcox plants have been plagued by a "too sensitive" reactor cooling design that has magnified minor control perturbations into large-scale mishaps at six out of nine operating plants. They were troubled by valve and pump breakdowns and control system problems before Three Mile Island and averaged only 60 percent capacity factor through 1978. This is now down to 54 percent. With major modifications likely to be required in instrument, control and cooling systems, and with utilities reconsidering their commitments to this company's partially completed plants, the curtain may be falling on nuclear power for Babcock & Wilcox.

• Westinghouse reactors, once the undisputed cream of the U.S. crop, had only a 56 percent average capacity factor during 1979 and the first six months of 1980, their lowest rating since 1968, when only two of their reactors were operating. The perennial performance gap between the largest and smallest Westinghouse plants widened to immense proportions, as the eight smallest reactors (all under 600 megawatts) averaged 72 percent capacity factor while the 13 large units (over 800 megawatts) averaged 46 percent.

The small Westinghouse plants have consistently had the highest industry performance, boasting five of the seven best lifetime nuclear capacity factors and a 72 percent average overall. Conversely, their large reactors, with a 52 percent cumulative average, have performed the worst. Although the small units have benefitted from longer operating lives than the large plants—about nine years versus four and a half—statistical analysis shows that only a fraction of the performance gap can be attributed to age differences.[3]

Most of the major recent Westinghouse problems reflect vendor, not architect-engineer, deficiencies and are hardware, not regulatory issues. Cracks in welds connecting feedwater piping (carrying heated water from the reactor core) to steam generators caused shutdowns of two to six weeks at half the Westinghouse reactors in 1979. Cracked low-pressure turbine disc assemblies have required inspections and repairs at many of their plants since late 1979. Three units were recently closed for eight months to repair cracks in concrete bolts used for anchoring pipe supports or to repair reactor coolant pumps and piping. Another plant was closed for over a year to replace corroded and cracked steam-generator tubes, and four other units will undergo the same process between mid-1980 and early 1982.

• Combustion Engineering's seven plants averaged 66 percent capacity factor in 1979, and their 67 percent average for 1977–79 was the highest among the four reactor vendors. But mechanical problems have begun to increase, including steam generator denting and primary coolant impurities and pump failures. These problems limited the company's average capacity factor to 52 percent for the first half of 1980. Moreover, none of these reactors exceeds 850 megawatts, so there is no experience with the ultra-large (1,200–megawatt) units now being built, nor will there be for several more years, based on current schedules. A new 900–megawatt Combustion Engineering reactor began generating in December 1978 but ran at only 11 percent capacity factor in 1979 and could not be declared in commercial operation until March 1980. (It is not included in the data averages.)

• *General Electric*'s boiling water reactors embarrassed the nuclear industry for years with 55 percent capacity factors, and rumors abounded that the company would quit the reactor business. But General Electric is now digging in its heels, encouraged by its 66 percent average capacity factors in both 1978 and 1979, by accidents and shutdowns at pressurized water reactors, and by the belief that the deteriorating oil situation will rejuvenate the prospects for nuclear power.

Technical fixes have eased some long-standing boiling water reactor ills, such as fuel leakage caused by rapid increases in reactor power. But the average General Electric reactor capacity factor fell back to 53 percent for the first half of 1980, as some refuelings were extended to repair cracks in primary system piping and emergency core sprays (a frequent problem in former years) and to modify "suppression pool" structures to improve their stability during postulated accidents.

Similarly, although the company is touting the 74 percent average 1979 performance by its five "flagship" 1,000-megawatt reactors, these units still averaged only 57 percent capacity factor through 1979 and have remained at that level during 1980. In addition, future boiling water reactor performance may be limited by other design problems under regulatory review. One example was the recent failure of some control rods to insert automatically in a reactor. And there are at least two other possible sources of trouble: that steam could prevent emergency coolant from reaching fuel assemblies during a loss-of-coolant accident; and that the vibratory pressures released in such

Capacity factor statistics in this article are based on *original design electrical ratings* when reactors enter commercial service. They differ from data published by utilities and the Nuclear Regulatory Commission, which employ either "maximum dependable capability" or "revised design rating." These reflect mechanical or regulatory constraints on capacity and average about 3 and 1.5 percent less, respectively (and, therefore, yield higher capacity factors), than the original design ratings.

Current NRC statistics exclude Three Mile Island-2, a curious omission in that the TMI accident epitomizes the mishaps that often prevent reactors from operating at their intended capacity.

In the table, then, capacity factor measures a power plant's net generation of electricity as a percentage of maximum possible generation based on original design ratings. Cumulative data exclude any operation prior to the first New Year's Day in which the unit was in commercial operation. Years indicate age at end of 1980.

Units under 400 megawatts are excluded as unrepresentative of present or future reactors. All averages are unweighted—each reactor-year is counted equally—and are generally 1 to 1.5 percentage points greater than capacity weighted averages.

BW = Babcock & Wilcox;
W = Westinghouse;
GE = General Electric;
CE = Combustion Engineering.

U.S. Reactor capacity factors through June 1980

Unit	*Mega-Watts*	*Vendor*	*Years*	*Cumulative Capacity Factor (percent)*	*Rank*
Arkansas-1	850	BW	6	58.4	33
Beaver Valley-1 (Pa.)	852	W	4	27.2	61
Browns Ferry-1 (Ala.)	1,098	GE	6	43.1	56
Browns Ferry-2	1,098	GE	5	55.9	41
Browns Ferry-3	1,098	GE	3	62.3	22
Brunswick-1 (N.C.)	821	GE	3	57.3	38
Brunswick-2	821	GE	5	43.9	55
Calvert Cliffs-1 (Md.)	845	CE	5	68.0	13
Calvert Cliffs-2	845	CE	3	76.4	2
Connecticut Yankee	575	W	13	76.3	3
Cook-1 (Mich.)	1,090	W	5	62.3	21
Cook-2	1,100	W	2	68.0	12
Cooper (Neb.)	778	GE	6	61.9	25
Crystal River-3 (Fla.)	825	BW	3	40.8	57
Davis-Besse-1 (Oh.)	906	BW	3	36.5	59
Dresden-2 (Ill.)	809	GE	10	57.4	37
Dresden-3	809	GE	9	52.8	50
Duane Arnold (Iowa)	538	GE	6	49.3	52
Farley-1 (Ala.)	829	W	3	57.0	39
Fitzpatrick (N.Y.)	821	GE	5	53.0	48
Fort Calhoun (Neb.)	457	CE	6	63.8	17
Ginna (N.Y.)	490	W	10	64.5	16
Hatch-1 (Ga.)	786	GE	5	57.8	36
Hatch-2	786	GE	1	52.8	51
Indian Point-2 (N.Y.)	873	W	7	54.9	46
Indian Point-3	965	W	4	58.5	32
Kewaunee (Wis.)	560	W	6	70.7	7
Maine Yankee	790	CE	8	65.6	15
Millstone-1 (Conn.)	690	GE	10	61.9	24
Millstone-2	828	CE	5	62.2	23
Monticello (Minn.)	545	GE	9	73.1	6
Nine Mile Point-1 (N.Y.)	610	GE	11	61.6	26
North Anna-1 (Va.)	907	W	2	55.3	45
Oconee-1 (S.C.)	886	BW	7	58.0	35
Oconee-2	886	BW	6	58.9	31
Oconee-3	886	BW	6	62.6	19
Oyster Creek (N.J.)	650	GE	11	62.5	20
Palisades (Mich.)	821	CE	9	34.6	60
Peach Bottom-2 (Pa.)	1,065	GE	6	60.9	27
Peach Bottom-3	1,065	GE	6	63.3	18
Pilgrim-1 (Mass.)	670	GE	8	53.4	47
Point Beach-1 (Wis.)	497	W	10	73.1	5
Point Beach-2	497	W	8	80.6	1
Prairie Island-1 (Minn.)	530	W	7	69.0	10
Prairie Island-2	530	W	6	75.3	4
Quad Cities-1 (Ill.)	809	GE	8	60.1	29
Quad Cities-2	809	GE	8	56.8	40
Rancho Seco (Ca.)	913	BW	5	55.3	44
Robinson-2 (S.C.)	707	W	9	69.9	8
Salem-1 (N.J.)	1,090	W	3	44.6	54
San Onofre-1 (Ca.)	450	W	13	67.7	14
St. Lucie-1 (Fla.)	810	CE	4	68.7	11
Surry-1 (Va.)	823	W	8	52.9	49
Surry-2	823	W	7	45.8	53
Three Mile Island-1 (Pa.)	819	BW	6	55.4	43
Three Mile Island-2	906	BW	2	11.1	62
Trojan (Ore.)	1,130	W	5	39.5	58
Turkey Point-3 (Fla.)	745	W	8	60.5	28
Turkey Point-4	745	W	7	59.5	30
Vermont Yankee	514	GE	8	69.3	9
Zion-1 (Ill.)	1,050	W	7	55.6	42
Zion-2	1,050	W	6	58.4	34

an accident might cause the containment to fail.

Overall outlook. The overall outlook for nuclear performance is uncertain. In fact, there seems little prospect of reaching even the industry's reduced goal of 65 to 70 percent average performance. True, climbing costs for replacement power have raised utilities' incentive to pay more to improve reactor performance, especially for the approximately half of current reactors that are replaced by costly oil- or gas-fired plants during shutdowns. Accordingly, many utilities now build in greater design margins, stock more spare parts, and employ more overtime repair work in an effort to keep their reactors running. Yet design and hardware problems persist, especially at plants over 800 megawatts, which through mid-1980 had averaged only 54 percent lifetime capacity factor.

Regulatory pressures on operating plants are intensifying, moreover. In addition to initial Three Mile Island-related backfits recently completed or underway, many plants will need to add other equipment during the next several years to implement the "long-term lessons learned" from that accident and to accommodate other concerns, such as fire protection. Although hardware is often installed during refueling, this sometimes prolongs outages and diverts engineering effort and skilled labor from other maintenance and performance-improvement programs.

Furthermore, the Nuclear Regulatory Commission inspection and enforcement division appears to be monitoring reactor operations more closely since Three Mile Island, a trend that may result in more frequent shutdowns. If the Commission's increased awareness of accident hazards continues, it will be difficult for the industry to exceed 60 percent average capacity factor over the next several years.

Hanging over nuclear power is the possibility of another major accident that could lead to even more widespread shutdowns and backfits. U.S. reactor experience is expected to double in the next four to five years, which will provide ample opportunity (at least statistically) for new major mishaps. This would further dim the likelihood of exceeding the 60 percent level.

The reduction in reactor capital costs gained through experience as more reactors were built has been more than offset by the costs of new safety measures that were needed to prevent the chances of a serious accident from growing as fast as the number of plants.[4] Similarly, increased operating experience, which the nuclear industry has always claimed would provide the necessary information to improve performance, is also demonstrating that, as designed, reactors are too accident-prone and need closer surveillance and a myriad of backfits. The result may be that nuclear capacity factors are destined to fall rather than rise as the nuclear sector expands.

Fortunately, the decline in nuclear generation is not causing a corresponding increase in utility use of oil. Contrary to power industry rhetoric equating any lost nuclear kilowatt-hours with added barrels of oil, consumption of oil for electrical generation fell 18 percent in 1979—300,000 barrels per day—despite an 8 percent drop in nuclear output. Both declines were offset by a 10 percent increase in generation with coal, which now produces over twice as much U.S. electricity as oil and nuclear power combined. Substitution of coal for oil has accelerated in 1980, both through conversion of oil-fired generators to coal and through displacement of oil generation by long-distance transmission of power from coal-based utilities.□

Cumulative U.S. Nuclear Capacity Factors Through June 1980

	Plants Under 800 Megawatts	Plants Over 800 Megawatts	All Plants
Pressurized Water Reactors	69% *13/104*	53% *27/120*	61% *40/224*
Westinghouse	70% *11/91*	52% *13/57*	63% *24/148*
Babcock & Wilcox	(none)	54% *9/39*	54% *9/39*
Combustion Engineering	65% *2/13*	56% *5/24*	59% *7/37*
Boiling Water Reactors (General Electric)	62% *10/70*	56% *12/68*	59% *22/138*
All Reactors	66% *23/174*	54% *39/188*	60% *62/362*

Figures in italics are, respectively, number of plants and cumulative number of plant-years

Table excludes plants under 400 Megawatts

(This table was added to the article by the author)

1. C. Komanoff, "Cost Escalation at Nuclear and Coal Power Plants" (Komanoff Energy Associates: New York, 1980).
2. M.E. Lapides, Nuclear Systems and Materials Branch, Electric Power Research Institute, to C. Komanoff, May 24, 1976.
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Pollution Control Improvements in Coal-Fired Electric Generating Plants: What They Accomplish, What They Cost

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The cost to construct coal-fired electric generating plants in the United States increased significantly during the 1970s. Although inflation in construction wages and material prices was a contributory factor, increased environmental standards played a particularly important role.

A statistical analysis of the capital costs of recently completed U.S. coal-fired generating units indicates that the cost to build a typical coal plant increased by 68% from the end of 1971 to the end of 1978, in addition to inflation in construction labor and materials. Approximately 90% of this *real* dollar increase was spent for improvements in pollution control. In return, emissions of criteria pollutants (sulfur oxides, particulates, and nitrogen oxides) from 1978 plants average approximately 64% less than those from 1971 plants.

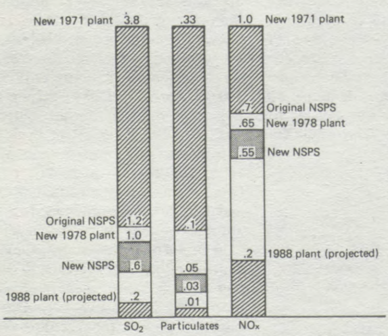

Figure 1. Emissions of criteria air pollutants by new coal plants (lb pollutant/10^6 Btu of coal burned. (Pollutants not drawn to same scale.) 1971 figures are based upon C. Komanoff, *et al.*, *The Price of Power: Electric Utilities and the Environment* (MIT Press, Cambridge, MA 1972), and assume 11,000 Btu/lb coal, 14% ash, 2.2% sulfur, dry bottom boiler, and 97% particulate collection. 1978 figures assume 99.5% particulate collection and 74% SO_2 collection; 1988 projections assume 99.9% particulate collection, 95% SO_2 collection, and 80% NO_x reduction.

For plants completed in the late 1980s, advanced control systems under development appear capable of further reducing emissions by an average of 76%, for an additional 36% in capital costs (in constant dollars). Compared to a 1971 coal plant, this advanced plant would cost approximately 130% more to build (not including construction inflation), but its emissions of criteria pollutants would average 91% less.

Emission Standards for 1970s Plants

The use of coal to generate electricity expanded rapidly in the 1960s and 1970s. U.S. coal-fired generating capacity increased by 80% from 1961 to 1971, and by another 53% to 1978. The resulting increase in coal generated emissions provoked national concern, inspired by massive new pollution sources such as the Four Corners plant in northern New Mexico. Accordingly, starting in the mid-to-late 1960s, some state and local authorities ordered utilities to reduce emissions of particulate matter and sulfur dioxides through fuel switching or improved control devices. And in 1970 Congress passed amendments to the Clean Air Act which created a framework for reducing emissions from existing plants and set national standards for new plants.

The New Source Performance Standards (NSPS) promulgated by the Federal Environmental Protection Agency pursuant to these amendments limited emissions of particulates, sulfur dioxide, and nitrogen oxides from fossil fuel plants whose construction started after August 1971. The NSPS required emissions of these pollutants from new coal plants to be 55% less per unit of fuel burned, on average, than emissions from plants installed in 1971. Some new plants have surpassed the NSPS levels, as Figure 1 shows, as a result of stricter local regulations, state measures needed to satisfy national ambient air quality standards, or utility efforts to keep ahead of regulations. Actual emission rates for coal plants completed in 1978 thus average approximately 64% less than for their 1971 counterparts, as shown in Table I.

Costs of Emission Abatement in the 1970s

The average cost to construct coal plants increased from \$346/kilowatt of capacity for late-1971 completions to

Reprinted from **APCA JOURNAL**, *Vol. 30, No. 9, September 1980*

Table I. Emission reductions by typical new coal plants.

	1971–78 Actual	1978–88 Projected	1971–88 Projected
SO_2	74%	80%	95%
Particulates	83%	80%	97%
NO_x	35%	69%	80%
Average reduction	64%	76%	91%

$583/kW for late-1978 plants, as measured in an analysis by Komanoff Energy Associates of the costs of all 116 U.S. coal plants over 100 megawatts completed during 1972–1977.[1] (These and all cost figures in this article are in constant mid-1979 dollars, that is, they have been adjusted to reflect the prevailing prices of labor, materials, and equipment in 1979. They assume, moreover, that the 1978 plant includes a scrubber to remove SO_2, although about half of recent coal plants lack scrubbers, employing low-sulfur coal instead to comply with the NSPS). Approximately 90% of the increase, or $210-215/kW, was accounted for by pollution control systems.

Sulfur Dioxide

The highest cost item added to coal plants during 1971–78 was the SO_2 scrubber. Fifteen plants in the study sample have scrubbers, designed to remove an average of 74% of the SO_2 leaving the boiler, or 3.7 lb of SO_2/million Btu of fuel burned, based on the types of coal used. This is sufficient to reduce emissions to below the 1.2 lb NSPS limit. The scrubbers are "first-generation" devices producing sludge waste.

Controlling for factors such as chronology, location, and multi-unit siting, the scrubber-equipped plants had a 26% higher average cost than the 101 nonscrubber plants in the sample. Based on the $583/kW average cost for a 1978 coal plant with a scrubber, the average scrubber cost was $120/kW, including sludge handling and disposal systems. This is identical to EPA's cost estimate for an equivalent scrubber, but 35% below the estimate in a study of coal plant costs by the Bechtel Corporation for the Electric Power Research Institute (EPRI).[2]

Particulates

Although SO_2 control has dominated most discussions of coal pollution control, utilities achieved greater proportional reductions in particulate emission rates from 1971 to 1978 for new plants. These reductions averaged 83% while SO_2 emission rates fell 74%.

Particulates from coal-fired boilers have traditionally been controlled by electrostatic precipitators (ESP). Typical 1971 plants were equipped with 97%-efficient ESP costing roughly $20/kW. By the end of 1978, average ESP efficiencies had increased to 99.5%, costing $35/kW for conventional high-sulfur coal, and $85/kW for low-sulfur coal.[3] The latter produces highly resistive particulates requiring a much larger ESP collection area and stronger electrostatic field. The average ESP cost of $60/kW is one-half of the cost of a typical first generation scrubber.

The components of the 200% average real cost increase for ESP were approximately as follows:

- 130% increase for efficiency improvements from 97% to 99.5% for a specific coal grade;
- 20% increase for greater collection area needed for lower-sulfur coal (average new-plant sulfur content fell 25–30% from 1971 to 1978);
- 5–10% increase for greater collection area to provide redundancy for higher collection reliability.

(Note: cost increases are multiplicative, not additive.)

Nitrogen Oxides

The average 1978 coal plant emits NO_x at a 35% lower rate than its 1971 counterpart—the smallest reduction among the three criteria pollutants. This has been achieved by replacing horizontal or vertical burner locations with tangential firing, and by boiler modifications to enable boilers to be fired with low excess air and in two combustion stages.

These modifications reduce combustion temperatures, which in turn reduces formation of NO_x. But in the absence of corrective measures they tend to corrode furnace walls and increase formation of *slag*—solidified molten ash—on boiler tubes, leading to combustion control problems and boiler tube leaks. Many new coal boilers thus have more sophisticated combustion monitors and controls—metered orifices and finely tuned nozzles to enhance air-fuel mixing—and wider spacing between boiler tubes to reduce slagging. Others rely on expanded combustion volume and more widely spaced burners to achieve lower temperatures which inhibit NO_x formation. These design changes added an average of $10/kW to capital costs for a 1978 plant.

Other Environmental Measures

The criteria air pollutants were not the only targets of increased pollution controls in the 1970s. Other areas of expenditures were noise attenuation features, $10/kW; pollution abatement during plant construction, $5/kW; liquid waste systems to treat normal plant waste drains for reuse in the plant or for external discharge, $10/kW; improved ash disposal, $5/kW (fixation and ponding of scrubber sludge are included in the scrubber cost); air pollution monitoring systems, $2/kW; and preparation of environmental reports to state and federal agencies, $3/kW.[4] Increasing usage of cooling towers also added an average of $5/kW.

Table II. Pollution control costs for new coal plants (in mid-1979 $/kW).[a]

Pollutant	1971	1978	1988
Particulates	20	60	65–80
SO_2		120	140–180
NO_x		10	60–90
Solid waste	0–5	5	30–45
Other	5	45	65–75
Total	25–30	240	360–470
Increase	210–215		120–230

[a] Costs include IDC accounting for 8% of total costs.

Recent plants also incurred an average cost of $10/kW for boiler improvements to accommodate variations in coal grade caused by mine safety rules—another environment-related capital cost. The combined cost of the above "miscellaneous" pollution-control improvements for a typical 1978 plant was $50/kW, vs. only $5–10/kW for the same measures in 1971.

Total Costs

As Table II shows, environmental concerns absorbed an average of $240/kW in capital costs for 1978 coal plants, an increase of $210–215/kW above the corresponding expenditures in 1971. This increase equals 90% of the total average 1971–78 increase of $237/kW in the capital costs of typical coal plants reported earlier. The difference, approximately $25/kW, was spent primarily on equipment to improve performance reliability: larger, more durable coal pulverizers, control systems for cycling operation (particularly by utilities with reduced load growth and/or expanded nuclear capacity), greater equipment margins, improved quality assurance, and larger stocks of spare parts.

Emission Standards for 1980s Plants

A revised set of New Source Performance Standards, approximately twice as stringent as the original NSPS, was promulgated by Federal EPA in 1979 pursuant to the Clean Air Act Amendments of 1977. The new NSPS, shown in Figure 1, pertain to plants which commenced construction after September 18, 1978, and thus may affect plants coming into service as early as 1982 or 1983.

The 1977 Amendments also require that new utility and industrial plants built in or near designated pristine ("Prevention of Significant Deterioration" or PSD) areas or polluted ("Nonattainment") areas install the "best available control technology" or achieve the "lowest achievable emission rate," respectively. These guidelines are defined, ambiguously, as the maximum reduction possible for each pollutant, taking into account energy, environmental and economic impacts. They are intended to be "technology-forcing," i.e., to push the utility industry to develop improved controls surpassing the new NSPS. The actual reductions required will be determined by EPA on a case-by-case basis in "new source reviews" performed by EPA in its permitting process.

The new NSPS will thus serve as a floor, rather than a ceiling, to pollution control practice for many new coal plants. Over half of the country either is in a PSD or nonattainment area or will affect such an area via plume transport, and so a majority of new plants may be required to better the NSPS. Some utilities may opt for stricter controls to avert drawn-out negotiations with EPA. Finally, the NSPS are subject to further strengthening as coal-fired generating capacity continues to expand. Although the growth in electricity sales since 1973 has fallen to less than half the historical annual rate, the prohibition of new oil- or gas-fired generators and the worsening prospects for nuclear power ensure that coal plants will provide well over half of whatever capacity increase is required in the 1980s and almost all in the 1990s.

Costs of Emission Abatement in the 1980s

In estimating the costs of additional pollution controls beyond those employed by 1978 coal plants, emission rates for 1988 plants have been assumed to be one-third of those dictated by the NSPS. This will ensure that the cost of control improvements is not underestimated. The cost of these improvements is estimated to be approximately $190/kW, almost equal to the cost of the controls added between 1971 and 1978.

Sulfur Dioxide

The new NSPS replace the old 1.2 lb/10^6 Btu standard with a set of limits varying with coal sulfur content, as shown in Table III. 90% SO_2 removal is required except when emissions are less than 0.6 lb; below that mark, only 70% reduction is needed. Any SO_2 removed by precombustion coal cleaning or in bottom ash or fly ash (typically 5%) is credited as a reduction.

Table III. SO_2 reductions required under new NSPS (assumes 11,000 Btu/lb coal).

Sulfur content,%	Sulfur content (lb/10^6 Btu)	SO_2 reduction	SO_2 emissions (lb/10^6 Btu)
3.3—6.6	3.0—6.0	90%	0.6—1.2
1.1—3.3	1.0—3.0	70—90%	0.6
Below 1.1	Below 1.0	70%	Below 0.6

The SO_2 reduction required for an average 2%-sulfur coal is 84% (higher for coal with a heating value below 11,000 Btu/lb, and vice-versa). But since sulfur content varies among coal shipments, a higher design efficiency, perhaps as high as 90%, is needed to meet the 30-day continuous averaging requirement, for 2%-sulfur coal.

The 15 scrubbers in the data base employed in this study had an average cost of $120/kW and an average design removal efficiency of 74%. Studies for EPA suggest that raising SO_2 removal efficiency from 74% to 90% increases scrubber costs by only 1–1½%, or $1–2/kW.[5] This figure appears questionable, however. Larger pumps are required for the increased volume of liquid needed to ensure that the SO_2 is contacted by the scrubbing reagent. Limestone feed and scrubber sludge handling systems must be expanded proportionally with the amount of SO_2 removed. Additional scrubber modules may also be required to back up malfunctioning modules. Aside from these equipment requirements, design improvements may be needed to eliminate problems of corrosion, scaling, and plugging that have affected many scrubbers to date. Although cost estimates are not readily available, an additional $20–40/kW beyond the $120/kW cost of a typical 1978 scrubber appears sufficient to ensure reliable 90% collection.

Further design changes appear likely for most 1988 plants. First, SO_2 removal efficiencies averaging 95% should be anticipated as efforts accelerate to control acid rain. Moreover, as the cost to dispose of scrubber wastes increases to meet new federal regulations and to accommodate public concerns, utilities will move toward regenerable scrubbers which reduce or eliminate production of sludge. Fortunately, these improvements may not require much additional cost beyond the $20–40/kW increment projected above to comply with the new NSPS. Although the several commercially available regenerable scrubbers appear to be about 15% more expensive than current scrubbers, "third-generation" scrubbers now under development, designed for 95% SO_2 removal while producing saleable gypsum or elemental sulfur, may actually prove less costly than today's regenerable devices.

The advanced scrubbers, all being developed in projects sponsored jointly by utilities and the Electric Power Research Institute, are the Chiyoda Thoroughbred process, the absorption/steam-stripping/Resox process, and the aqueous carbonate process. EPRI expects that all three systems will be ready for commercial orders in 1983 or 1984,[6] at a cost range of $120–160/kW.[7] But since unforeseen problems may add to costs, it is assumed here for conservatism that the advanced scrubbers will cost $140–180 per kW, $20/kW above EPRI's estimate and $20–60/kW more than the average 1978 scrubber.

Particulates

The new NSPS reduce allowable emissions of particulates from 0.1 to 0.03 lb/10^6 Btu of fuel input. The corresponding increase in the collection efficiency required for an average coal grade (14% ash, 11,000 Btu/lb) is from 99.1% to 99.7%. Electrostatic precipitators at new plants were already averaging 99.5% design efficiencies in 1978, with 99.7% at many plants.

An average emission rate of 0.01 lb/10^6 Btu is assumed here, requiring 99.9% collection efficiencies. This would substantially reduce emissions of fine particulates, the most difficult to capture under current practice. Fine particulates are especially injurious because they more easily bypass the lung's defenses, are the principal carriers of trace metals in coal ash, including toxic compounds containing lead, cadmium, and arsenic, and act as a magnet for other air pollutants, providing them with a passageway into the lungs. They also contribute to the reduction of visibility by scattering visible light—a particular concern in PSD areas.

If electrostatic precipitators are used to attain the higher efficiencies, then the increase from 99.5% to 99.9% collection would almost double particulate control costs, from \$35/kW to \$65/kW for high-sulfur coal, and from \$85/kW to \$150/kW for low-sulfur coal.[8] However, the cost of a 99.9%-efficient ESP for low-sulfur coal would almost certainly far exceed the cost of baghouses providing the same control level.

The baghouse, or fabric filter, is a veteran particulate control device in cement- and steel-making consisting of numerous suspended filter bags which trap the particulates from flue gases. It has only recently begun to be applied to utility boilers, with the advent of synthetic fibers (primarily fiberglas) that can withstand combustion gases from coal. The half-dozen small coal-fired boilers with baghouses have all performed reliably for several years, with particulate emission rates averaging 0.02 lb/10^6 Btu, within the new 0.03 lb standard.[9] Although the largest of these boilers is only 44 MW, baghouses are built in small modules, leading EPA to conclude that scaling up to larger boilers should pose no problem. The Agency has cited the successful initial operation of a baghouse on the new 350-MW Harrington-2 unit of Southwestern Public Service, with 28 12.5-MW baghouse modules, to support this view.[10]

EPA estimates that baghouses will cost approximately \$54/kW for low-sulfur coal and \$48/kW for high-sulfur, in 1979 dollars.[11] (Baghouse performance efficiency is primarily a function of the fabric used and is only slightly dependent on coal type.) Although these costs pertain to the new NSPS 0.03 lb standard, baghouses guaranteed to this standard may achieve 0.01 lb in actual operation. However, in view of the embryonic status of baghouses on full-size utility boilers, utilities would insist upon more conservative design and construction to be assured of achieving a 0.01 lb emission rate. Thus, 25 to 50% is added to the EPA figures, giving baghouse costs of \$60–72/kW and \$68–80/kW for high- and low-sulfur coal, respectively.

The high-sulfur baghouse cost is comparable to the \$65/kW estimate for an equivalent ESP. For low-sulfur coal, a baghouse is clearly cheaper than a 99.9%-efficient ESP at \$160/kW (indeed, the cost of a baghouse is roughly equivalent to that of a 99.3%-efficient ESP for low-sulfur coal). Averaging the two coal types, the cost of 99.9% particulate control for a 1988 coal plant should range from \$65/kW to \$80/kW, or \$5–20/kW more than the \$60/kW average for a 1978 plant. In this instance, a new control technology appears likely to reduce, significantly, the rate of cost increase required to improve pollution control.

Nitrogen Oxides

The new NSPS reduce the former NO_x limit of 0.7 lb/10^6 Btu to 0.6 lb for bituminous coal and 0.5 lb for subbituminous coal. These levels can be achieved with further application of staged combustion and low excess furnace air which, in conjunction with tangentially-fired burner design, have enabled recent plants to meet the 0.7 lb limit.

The only cost associated with this modest NO_x reduction would be approximately \$5–10/kW for further design modifications to prevent the changed combustion practices from corroding boiler tubes, and for monitoring and control systems to maintain combustion parameters within the requisite narrow range. Although EPA contends that operating boilers within the 0.5–0.6 lb limit need not cause tube damage, utilities are likely to incorporate preventive design features.

The new NO_x limit appears to be the minimum average level achievable through combustion modification with present boiler technology. This would explain why the new NSPS require only a 45% average reduction in NO_x emissions compared to 1971 plants, versus 91% for particulates and 84% for SO_2. Lenient treatment of NO_x will end, however, as utilities' coal use expands and pressure builds to reduce the conversion by sunlight of NO_x and hydrocarbons into smog in oxidant nonattainment areas. An emission rate around 0.2 lb/10^6 Btu for new plants is probably necessary to keep utility NO_x emissions constant to the end of the century,[12] and EPA is considering promulgating such a standard in the 1980s.

Reducing NO_x emissions below the new 0.5–0.6 lb standard will require further changes in furnace design and perhaps an NO_x flue gas treatment process. Two new furnace designs being tested at the pilot stage have achieved emission rates under 0.2 lb without reducing efficiency or corroding boiler surfaces.[13] These are the Distributed-Mixing Burner, which EPA is funding, and Babcock & Wilcox's Primary Combustion Furnace, cosponsored by EPRI. Both operate by staging combustion, first in a water-cooled, low-oxygen environment designed to retard corrosion and inhibit oxidation of nitrogen present in coal, and second in an oxygen-rich environment where carbon combustion can be completed. Costs have not been estimated but should not exceed \$20–30/kW (relative to uncontrolled 1971 plants), since essentially modifications rather than new systems are involved.

Ultimately, however, flue gas treatment of NO_x will be required, either if the new furnace designs prove inadequate or to reduce emissions well below 0.2 lb. In fact, the latter may be required for some new plants in PSD or nonattainment areas in the 1980s. This would provide an inroad for applying the new technology at all future plants.

The most promising NO_x treatment processes are several "dry" systems using gaseous ammonia to reduce NO_x to molecular nitrogen. Called "selective catalytic reduction" (SCR), these processes have recently been employed at Japanese oil-fired power plants, reducing emissions by 50% without affecting operating performance. They have been tested on coal-fired plants only at the 1 MW scale, however, and commercial development is said to be 5 to 10 years away.

An EPRI-sponsored study has estimated that SCR systems achieving NO_x emission rates of 0.05–0.1 lb with coal firing will cost \$40–90/kW.[14] The lower cost would obtain if new furnace designs enable partial treatment to be employed. Adding the estimated \$20–30/kW cost of furnace changes to the low end of the range, the cost to reduce NO_x emissions to 0.2 lb or below should be in a range of \$60–90/kW. This estimate is consistent with a \$60–80/kW range projected in a recent in-house EPRI study.[15]

Other Environmental Measures

New coal-fired plants are subject not only to air pollution standards but also to regulations governing solid and liquid waste, noise, and construction effluent. These regulations added approximately \$40–45/kW to the average cost to contruct coal plants from 1971 to 1978, and will require further cost increases in the 1980s.

Utility solid waste—fly ash, bottom ash and scrubber sludge—was brought under federal regulation by the 1976 Resource Conservation & Recovery Act (RCRA). Compliance will require that holding ponds for scrubber sludge and ash be lined, at costs estimated by Ebasco Services to be approximately \$30/kW and \$5/kW, respectively.[16]

The former cost could be reduced if regenerable scrubbers which recycle waste products are used, as was assumed in projecting scrubber costs earlier. Conversely, costs could rise if ash and sludge are designated as hazardous wastes under RCRA (final RCRA regulations will be promulgated in the early 1980s). Impermeable liners would be required to reduce leaching of trace metals, and disposal could be limited to

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special geological formations which may lie at considerable distances from the plant site. Balancing these considerations, a cost estimate of \$30–45/kW for improved waste disposal appears reasonable, although costs could be lower or higher than this range.

Other areas which contributed to 1971–1978 cost increases will also add new costs to late 1980s plants. Waste water treatment will become more demanding to reduce effluent discharged in conjunction with ash sluicing, boiler cleaning, feedwater and scrubber makeup, and general plant usage to zero or near-zero levels. EPA noise attenuation guidelines set under the Federal Noise Control Act will increasingly be applied by local regulators, adding to costs of pulverizers, fans and other noisy plant machinery. Concerns such as construction pollution, effluent monitoring, and fugitive emissions from coal piles may also precipitate increased requirements. Based on a literature review, the cost of these "miscellaneous" environmental protection measures could double from 1978 to 1988, contributing another \$30–40/kW for a total of \$65–75/kW.[17]

A final potential source of major costs is the use of dry cooling to reduce the water loss associated with wet cooling towers. Dry cooling towers would be extremely expensive, with costs estimated at \$140–185/kW (assuming successful development of an ammonia phase tower, and including \$10–30/kW to replace the generating capacity consumed by the towers during hot, peak periods).[18] Nevertheless, dry towers may eventually be required in the water-short West if steam–electric plants proliferate there. This would provide an example of a cost that is incurred because expansion of the number of facilities encounters a resource constraint.

Total Costs

The total increase in the capital costs of environmental controls estimated above for a typical 1988 plant, compared to 1978 practice, ranges from \$120–230/kW. The range reflects substantial conservatism in both the individual cost estimates and the projected emission targets (which are three times as stringent as the new NSPS). Moreover, the long lead times of most regulatory standards for coal plants makes it unlikely that regulations not anticipated here will significantly affect the costs of late-1980s plants. Nevertheless, using past cost experience as a guide, actual costs are more likely to be at the upper than the lower part of the range. For purposes of cost comparison, a single figure of \$190/kW is used here to project the average cost of 1978–1988 control improvements.

This would be only slightly less than the \$210–215/kW average cost of coal pollution control improvements from 1971 to 1978. The major sources of that increase were the first-generation scrubber (a cost actually shared by the 1971–78 and 1978–88 periods but explicitly assigned here to the prior period) and a high-efficiency electrostatic precipitator. The biggest new cost anticipated for 1978–88 is for improved nitrogen oxide control, with lesser increases for regenerable scrubbers and solid waste management. Despite the large, further reductions in SO_2 and particulate emission rates projected here for late-1980s plants, the necessary cost increases are likely to be limited by new control devices such as baghouses which are more expensive than current systems at today's control levels but appear less expensive at very high efficiencies.

Finally, an additional \$20/kW is likely to be absorbed in the cost of typical late-1980s plants to pay for improved operating reliability and for higher "real" interest costs as construction periods lengthen. The projected pollution control improvements would then account for 90% of the estimated cost increases (aside from construction inflation) in coal plant capital costs from 1978 to 1988—equalling the 1971–78 percentage. The 1988 coal plant would be 36% more expensive (in real terms) but 76% less polluting than a 1978 plant, and 129% costlier but 91% better controlled than its 1971 counterpart, with pollution equipment responsible for nine-tenths of the increased real costs (Figure 2). Finally, under these circumstances, the two periods, 1971–78 and 1978–88, would show the same percentage increase in coal plant capital costs relative to the expansion in coal generating capacity[19]—a not illogical result considering the role of coal sector expansion in forcing improvements in coal pollution control practice.

Other Pollution Control Costs

Although this article has addressed only the impact of coal pollution controls on plant capital costs, improved controls also affect fuel costs, operating and maintenance (O&M) costs, and performance reliability (capacity factor). The heat, steam, and electricity required to run pollution control equipment reduce thermal efficiency and increase fuel consumption. O&M costs are raised by the limestone and other material requirements of scrubbers, by disposal costs for ash and sludge, and by the personnel needed to operate control devices. And breakdowns in control equipment or gas and moisture carryover can impair plant availability, although increased use of redundant scrubber modules is reducing this effect.

Quantification of these costs is beyond the scope of this article, but the costs of improved controls clearly weigh far more heavily on capital costs than on fuel costs, O&M costs, or reliability. Capital costs tend to account for 40% of total coal generating costs, and will more than double in real terms from 1971 to 1988, almost exclusively because of improved pollution control. Fuel costs average 50% of total generating costs but will increase only 5–10% because of control equipment. O&M costs may double (or more for high-sulfur coal burning plants without regenerable scrubbers) but only account for 10% of base generating costs. And even a 5 percentage point drop in capacity factor caused by problems with control equipment, from 70% to 65%, could be offset through a modest 8% increase in installed capacity, i.e., in capital costs. Thus, although costs can vary greatly among different plants, capital costs appear to be the vehicle for more than two-thirds of the total impact of pollution control improvements on the cost of coal-generated electricity.

Alternative Coal Combustion Technologies

This article has not considered the potential of new coal-burning technologies to achieve pollution control levels comparable to those specified here for 1988 plants, at lower cost. Considerable R&D effort is being devoted to new technologies, however. The most promising is fluidized bed combustion, in which the fuel rests on a layer of small, inert par-

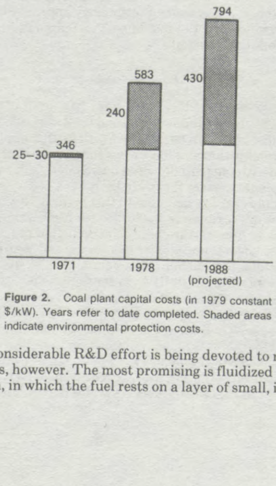

Figure 2. Coal plant capital costs (in 1979 constant \$/kW). Years refer to date completed. Shaded areas indicate environmental protection costs.

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ticles suspended by forced air. It has been used in specialized industrial applications for several decades but has only recently been examined for electricity generation.

Fluidized bed combustion has many prospective advantages over conventional combustion: ability to burn limestone directly with coal to capture SO_2 without a scrubber; combustion below the temperature of atmospheric generation of NO_x; and formation of a dry, powdery ash which is less damaging to plant equipment than conventional ash and also contains fewer heavy metals.[20]

The cost of coal plants employing fluidized bed combustion is widely predicted to be no greater and possibly less than that of conventional coal-fired plants, assuming both must meet the new NSPS. Similar forecasts have been applied to gas turbine cycles operating with fluidized bed combustors or integrated low-Btu coal gasifiers. Initial operation of commercial-size prototypes is not likely until 1984 at the earliest, however, so it is doubtful that commercial plants could be operating before 1990.

Moreover, cost estimates for these new technologies are somewhat speculative, and could rise if design modifications or flue gas treatment are required to meet new standards. Fluidized bed combustors, for example, can presently remove approximately 85% of SO_2 through contact of limestone with coal in the combustor, but higher control levels may require scrubbers (although refinements such as limestone recycle may allow 95% capture or greater).

A different technology, coal cleaning, holds the promise of reducing flue gas treatment costs by removing impurities from coal at the mine. Current physical cleaning processes using crushing and flotation separation can remove half or more of the ash and a third of the sulfur from coal, substantially reducing the design requirements of emission control devices. Although only a small fraction of utility coal is cleaned today, increased costs for coal transportation, waste disposal and boiler outages—all of which are mitigated by cleaning—may make physical cleaning more economically attractive. Physical cleaning may be especially attractive as an alternative to retrofitting controls to reduce emissions from existing coal plants.

References and Notes

1. The analysis is described in C. Komanoff, *Power Plant Escalation: Nuclear and Coal Capital Costs and Economics* (Komanoff Energy Associates, 1980, forthcoming). Costs include interest during construction in constant dollars, accounting for 8% of total costs.
2. "Cost Analysis of Lime-Based Flue Gas Desulfurization Systems for New 500-MW Utility Boilers," PEDCo Environmental, Inc., 1979, and "Coal-Fired Power Power Plant Capital Cost Estimates," Bechtel Corp., EPRI AF-342, 1977. All cost estimates have been adjusted to mid-1979 price levels.
3. "Electric Utility Steam Generating Units: Background Information for Proposed Particulate Matter Emission Standards," EPA, July 1978, Table 8.2. Costs converted to mid-1979 dollars, with $10/kW and $15/kW added for high- and low-sulfur coal, respectively, for conservatism.
4. These estimates are drawn, with modifications, from three valuable surveys of coal pollution control costs by the power industry: R. R. Bennett & D. J. Kettler, "Dramatic Changes in the Costs of Nuclear and Fossil-Fueled Plants," Ebasco Services, New York, 1978; K. E. Yeager, C. R. McGowin and S. B. Baruch, "Potential Impact of R & D Programs on Environmental Control Costs for Coal-Fired Power Plants," EPRI, Palo Alto, CA, 1979; and C. R. McGowin and K. E. Yeager, "Advanced Programs for Utilization of Coal for Electric Power Generation," EPRI, 1979.
5. PEDCo Environmental, Inc., *op. cit.*, Figures 4–1 and 4–2.
6. "Shifting SO_2 from the stack," *EPRI Journal* (18, July/August 1979).
7. K. E. Yeager *et al.*, *op. cit.*, with costs converted from 1976–1980 mixed current dollars (assuming 8% inflation and interest rates) to mid–1979 constant dollars.
8. The modified Deutch equation predicts a 70% cost increase to improve ESP efficiency from 99.5% to 99.9%, but it may understate cost increases at very high efficiencies.
9. EPA, July 1978, *op. cit.*, Table 4–5.
10. "New Stationary Source Performance Standards, Electric Utility Steam Generating Units," Part II, EPA, *Federal Register* 33600 (June 11, 1979).
11. EPA, July 1978, *op. cit.*, Table 8–1, adjusted to 1979 price levels.
12. EPRI projects a 60% increase in utility NO_x emissions between 1979 and 2000 even if a 0.2 lb standard takes effect in 1985. However, the projection assumes 6% annual growth in fossil-electric generation. (*EPRI Journal*, "Controlling oxides of nitrogen" (26 June 1979).) This is over twice the post-1973 rate and far greater than would obtain under energy policies fostering improvements in end-use efficiency.
13. *Ibid.*, p. 25.
14. "NO_x Control for Western Coal-Fired Boilers: Feasibility of Selected Post-Combustion NO_x Control Systems Study," Stearn-Rogers, Inc., 1978. EPA estimates the installed cost of SCR systems to be approximately $36/kW, or less than half EPRI's estimate for a full system. (J. David Mobley, "Status of EPA's NO_x Flue Gas Treatment Program," in EPRI FP-1109-SR, "Proceedings: Second NO_x Control Technology Seminar," July 1979. See also Session B Questions & Answers in same volume.)
15. D. P. Teixeira, "NO_x Control Technology for Coal Fired Power Plants," EPRI, 1979.
16. R. R. Bennett & D. J. Kettler, *op. cit.*, estimate $21/kW (lined sludge pond) and $4/kW (lined ash pond), expressed in mixed current dollars concluding in 1978. Assuming a mid-1975 midpoint for expenditures and incorporating the 37% inflation in coal plant construction from mid-1975 to mid-1979 gives the costs in the text.
17. The 1978 base cost of $30/kW for "other measures" which was doubled to estimate 1988 costs excludes $10/kW for increased boiler flexibility to accommodate varying coal grades.
18. K. E. Yeager, *et al.*, *op. cit.*
19. Installed coal-fired capacity increased 53% during 1971–78 and is likely to increase approximately 60% during 1978–88. The respective average real cost increases are 33% and 36%, not counting scrubbers—a cost increase which could reasonably be apportioned equally to the two periods.
20. See *Power Engineering, 83*(11): (1979), for a current review of fluidized bed development status and design features.

Mr. Komanoff is director of Komanoff Energy Associates, 475 Park Avenue South, New York, NY 10016.

Mr. MARKEY. Can I go back to you, Dr. Weil. Perhaps we could examine your testimony in just a little bit more detail.

I think perhaps some of the people missed the point of your testimony because of the inadequacies of the sound system at the point at which you were testifying.

The way I understand your testimony is that you surveyed the U.S. utilities and you asked the utilities if they did not have the option to go nuclear, what kind of plant would they have built, if not nuclear. That is for the plants in existence today; is that not correct?

Mr. WEIL. That is correct.

Mr. MARKEY. And your historical analysis showed that the actual oil displacement by nuclear power is somewhere between 67 and 108 million barrels of oil in 1979, and that the median is 88 million per year or 241,000 barrels per day, and your conclusion was nuclear from a historical perspective displaces coal 65.5 percent of the time, oil 15.6 percent of the time, and a combination of all fossil fuels, 18.9 percent of the time.

Is that a fair summary of your analysis of the existing powerplants and the decision utility executives would have made if they had to choose between nuclear and coal and other fossil fuels, if the nuclear option was not available?

Mr. WEIL. I think that covers it very well, Mr. Chairman. I would add only one other point. In those cases where more than one fossil fuel—for example, a combination of oil and coal or oil and gas—were the options at the time instead of the nuclear choice, I allocated for example, in the case of oil and coal, half to oil and half to coal. It seemed the fairest way to handle such situations that apportionment accounts for the difference between the base estimate of 68 million barrels of oil displaced in 1979 and the high estimate of 108 million barrels.

So, the median has a plus or minus 20 percent uncertainty.

Mr. MARKEY. How did you establish this data?

Mr. WEIL. I established it primarily from information provided by the utilities. In terms of percentage of energy produced by nuclear plants, it ran around, I believe, 80 or 90 percent of the energy which had been produced by nuclear plants in 1979, was specifically allocated to the fossil fuel option categories by the utilities themselves.

In those cases where the utilities did not respond, about 10 percent, I believe, in terms of megawatt-hours, I examined Federal energy agencies statistics as to which what fossil fuels were used in their areas and on the basis of these statistics, assigned the nuclear plants as either displacing oil, coal or gas or a combination.

As I say, that was a fairly relatively small fraction of the total amount of energy produced by nuclear plants in 1979.

Mr. MARKEY. So your conclusion was, based on plants in existence today, that utilities would have gone 65 percent of the time to coal, 15 percent to oil and 18 percent to all combinations of fossil fuels.

You also did a study on the 91 nuclear plants under construction today and your conclusion was that 61 of these plants would displace coal, not oil; that 24 would displace oil, coal, and gas, and just six would displace oil. Is that a correct summary of your findings?

Mr. WEIL. That is correct, Mr. Chairman.

Mr. MARKEY. Where did you gather this information from?

Mr. WEIL. From information compiled for the 1979 study from the Department of Energy statistics and from news items. May I add one comment? If you apportion the plants that displaced more than one fossil fuel, as I did with the first study to get the plus or minus, then you wind up with perhaps 12 plants displacing oil, 6 of them surely and 6 of them maybe.

I am sorry to interrupt you.

Mr. MARKEY. Thank you.

Dr. Weiner, you have heard Dr. Weil's testimony. You have had a chance, I assume, to take a look at some of his assumptions. Do you agree with them or disagree with them?

Mr. WEINER. I haven't had an opportunity to see his testimony but listening carefully to what he has described, I do have some concerns about the two approaches that have been taken.

As I said in my prepared statement, a national generalization is impossible. A single nuclear plant will not have a one-for-one correlation except in such cases of New England, Long Island, Florida, and California. Most plants do displace some amount of oil.

It is not correct to go ask a utility what they would have chosen. If I were the utility planner at the time, of course, I would have chosen a coal plant because oil was not an option to me. That would have been my choice. That doesn't mean that is what the nuclear unit is displacing. The nuclear unit is part of the system and that system considers the generation that is within the system and the ability to transport excess quantities of generation to neighboring systems.

The other problem that I have is the extrapolation of data from our various reports in trying to combine those to come up with a conclusion. We have taken great care to make sure that each of our analyses are consistent within themselves and there is great danger in trying to use a combination of analyses when drawing conclusions.

We do find that the nuclear displacement values for oil are much greater than those presented, and this was shown in our analysis of potential moratoriums. Values of 1985 were in the 500,000 to 700,000 barrels per day range because of the slippages in both coal and nuclear units. As I pointed out in my prepared statement, those numbers would have been modified.

Mr. MARKEY. Let me just follow up, then, because I think your testimony to a certain extent builds upon what Dr. Weil had stated in the work that he has done.

Dr. Weil has focused on the choices that utilities face when building a plant, while you are more concerned with the operation of the plants after they are constructed. The two are related aspects of the general backout question before the subcommittee this morning.

I would like to ask you whether you generally agree that since the Arab oil embargo nuclear and coal, rather than oil-fired plants are by far the more likely option for new plant construction by utilities?

Mr. WEINER. Yes sir, and nuclear and coal are the only options for central large-scale generation.

Mr. MARKEY. So the choice for the future then is between nuclear and coal, not between nuclear and oil?

Mr. WEINER. Yes, sir; and I point out that we have to be very careful of the timeframes we are talking about. The choice for the next 5 years has already been made. We have plants under construction to take us almost to the end of the decade. We are not talking of an alternative in that timeframe; we are talking——

Mr. MARKEY. If you saw an ad like this one and if you were dealing with the options that America was facing between 1980 and 1990, would you call it a somewhat deceptive or misleading advertisement?

[The following advertisement was received for the record:]

If he were our only source of oil,

you'd probably be reading this ad in the dark.

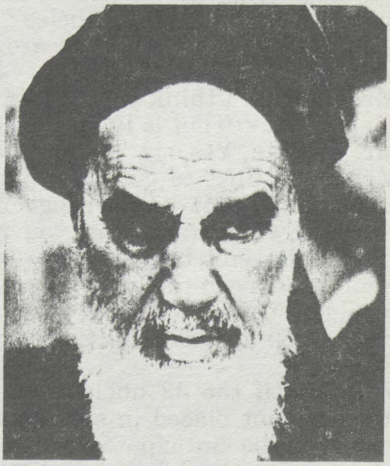
With the way things are today, it's very clear to the electric utility companies of New England that we must end our dependency on foreign oil for generating electricity.

We can't afford not to. In 1979 almost 55% of New England's electricity was produced by oil as compared to only 14% for the rest of the country. Add that to the skyrocketing prices and the always uncertain availability of foreign oil and it's obvious we need alternative energy sources for electricity.

Luckily, we have them. Like coal, water power, wind, nuclear and the development of solar power.

But of all of these, the most important, reliable and economical source is nuclear energy. Seven plants are already providing one third of New England's electrical needs. In 1979 they reduced our oil consumption by 44 million barrels, saving $771 million in customer electric bills.

And by completing four new



plants, Seabrook 1 and 2, Millstone 3 and the second Pilgrim unit, we can save an additional 44 million barrels. At today's per barrel price, that could mean more than a billion dollars' worth of oil that would never be burned. And at the projected 1988 price of $80 a barrel, it's around $3.5 billion.

The power companies of New England want to make sure you have the electricity you need. And with nuclear energy as part of our energy mix, the future is anything but dark.

Boston Edison
Public Service Company
of New Hampshire
New England Gas and Electric Assoc.

Mr. WEINER. No, sir; I would conclude, because of the data that we have analyzed, that failure to pursue both the nuclear and coal options will give us definite problems. Through our analyses, we have shown that if nuclear construction is not continued, there are areas of the country that will most assuredly not have enough electricity supply.

The same is true with coal. If coal unit construction continues to slip at the rate it is slipping, no matter what the load growth scenario is, we will not have enough electricity to assure our supply to the end of this decade.

Mr. MARKEY. The choice is not really when we are going to import more oil or fire a nuclear generating plant, the real choice in our country is whether we are going to build coal or nuclear; is that it?

Mr. WEINER. I think that is fair.

Mr. MARKEY. That is fair; is it not?

Mr. WEINER. Yes, sir.

Mr. LENT. Just to go back to the point on not completing coal plants versus not completing nuclear plants. On page 6, Mr. Weiner, of your statement, you indicate that you have tables attached—I haven't had a chance to analyze those in detail—that if there is a delay in the construction of coal-fueled generation plants, it would cost the Nation between 20,000 barrels a day over a 6-year period—1980 to 1985—and cost almost 35,000 barrels of oil a day by 1984.

Whereas, if the 43 nuclear units which are under construction were to be not placed in service, the increase in fuel oil consumption above the anticipated levels could go up as high as 700,000 barrels of oil a day?

Mr. WEINER. Yes, sir.

Mr. LENT. Can you explain why the impact is so much greater if nuclear plants are installed than if coal plants are installed?

Mr. WEINER. If I may, the figures on coal are what we have already lost. Those units, the coal units in the construction stream to date, have already slipped enough to cost us that much oil, 20,000 barrels a day average, 35,000 barrels peak in 1984.

In the past year of analysis, there has been that much delay on bringing those units in line. The delays have resulted from a myriad of reasons, but the delays have occurred.

The analysis discussed below was an either/or option to 53 of the nuclear plants that were anticipated to be in service by that period of time. The analysis looked at the possibility of those plants just being nonlicensed due to some sort of nuclear moratorium, and it said that if you did moratorium those 53 plants, that this would be the maximum possible impact. We looked at the minimum possible impact that could occur. We said that was something on the order of 200,000 barrels a day minimum possible looking at what we felt was the very lowest possible growth rate in the electric utility industry at that period of time.

Mr. VINCE TAYLOR. Maybe I could ask a question here that could amplify.

Mr. MARKEY. Fine.

Mr. VINCE TAYLOR. In your table for 1985, you say that at the maximum, the failure to put those plants in may result in an increased amount of oil consumption of 700,000 barrels a day. I would like to ask you how you think——

Mr. MARKEY. Let me clarify so we will understand what you are talking about. You are referring to plants that are now under construction?

Mr. VINCE TAYLOR. Yes.

Mr. MARKEY. And will come on line before 1985?

Mr. VINCE TAYLOR. Yes; I wonder how you think that this is compatible with the fact that we are now consuming only 800,000 barrels of oil a day in the electric utility sector? It is dropping at a rate of about 150,000 to 200,000 per year, so that by 1982, if we just continue the trends that are there today—these are not due to nuclear plant construction; as you understand, these trends have been going on in the last 2 years. Nuclear power generation dropped by about 10 percent during this period of time. So this is not something that has occurred because of increased nuclear generation. We will, by 1982, have only about 500,000 barrels of oil in total, so, how is this compatible with adding another 700,000 barrels in just the next few years? The trends are down. If these plants are completed or not, the trends are down. How is this trend going to be reversed, in your analysis?

Mr. WEINER. First of all, the present rate of utility oil consumption is closer to 1.3 million, not 800,000.

Mr. KOMANOFF. It is 1.1.

Mr. WEINER. That is a rate you are adding——

Mr. VINCE TAYLOR. It will be at 800,000 in 1982. I am sorry.

Mr. WEINER. My projections don't agree with that. Very simply stated, the electric utility industry had bought those particular plants for another reason. The reason was to supply both existing customer requirements and to retire existing units in place and to supply such things as the gas that was not supposed to be available, and to back off the oil units that are supposed to be backed off and to supply economical electricity, and the last point was the key—that was one of the key decision factors that the electric utilities used. Those plants fit into the dispatch, if you will, of electric utilities at the bottom and are the lowest cost option for supplying day-to-day customers' needs, and they will show up in the dispatch curve in the most economic fashion.

Mr. VINCE TAYLOR. Hasn't this been true the last few years, all plants scheduled for construction in this period of time that were delayed?

Mr. WEINER. If I may finish—the electricity growth rate has continued the past few years at a much lower rate than anticipated by the industry when they planned to put those units on line, and because of that lower growth rate we are reducing oil consumption by electric utilities.

I do not believe that value is going to keep continuing down. It has to be turned around. There is increased electrification in the home use. New homes are being built with heat pumps that are supplied by electricity. The society is headed for some growth. As I pointed out in my prepared statement, there is only a small growth of electric consumption.

Mr. KOMANOFF. How small?

Mr. WEINER. Even the smallest——

Mr. Komanoff. Which is 2 percent.

Mr. Weiner. What has it been in the last 7 years?

Mr. Komanoff. The past 7 years it has averaged under 3 percent a year, and the lowest DOE can conceive for the future is 2 percent a year, and their base case is 4½ percent a year. That is absurd.

Mr. Markey. You have another scenario, do you not, Mr. Weiner? You also use a 2.4-percent growth rate per year.

Mr. Weiner. That was over 5 years. That had been identified as 2 percent for the first 3 years and 3.2 or 3.3 for the following 2 years.

Mr. Markey. In the case where you are assuming an average capacity factor of coal-fired plants of 0.6 and the maximum energy production for nonfossil sources, the table indicates in your testimony that in 1985 utility oil consumption could fall as low as 97 million barrels, or about 18 percent of the 1979 level of consumption. Isn't that correct?

Mr. Weiner. Are you in the nuclear or nonnuclear scenario?

Mr. Sims. Table 1 and table 3.

Mr. Vince Taylor. How about in the real world?

Mr. Markey. Table 1.

I am going to ask staff to clarify the question.

Mr. Sims. Thank you, Mr. Chairman.

I am referring to your table 1. First, let me clarify one other point. The 4.87 per annum growth rate is that suggested by the Electric Reliability Council and stands in contrast to 2.46, which is the DOE staff estimate for the same period.

Now, just to demonstrate how sensitive utility oil use may be to nuclear, I was looking at the DOE estimate in table 1 of your prepared testimony, and you have now four cases. You have a 50- and 60-percent capacity factor for coal plants, and you have what you call a high and low nonfossil-energy production. Subsequently, we find that this refers to a moratorium on nuclear plants coming online as opposed to coming online approximately as scheduled, I take it. Is that correct?

Mr. Weiner. That is correct.

Mr. Sims. Now, the significant factor, looking further at table 1, where it says projected minimum 1985 assuming a 2.46 growth rate, in each of the four cases, with or without a moratorium on nuclear plants, every one of your values is below actual 1979; is that correct? 1979 is 523 million barrels of oil. If you just read across, every one of the other numbers is below that.

Mr. Weiner. Yes, sir.

Mr. Sims. Your most optimistic projection is 97 million barrels?

Mr. Weiner. Yes, sir.

Mr. Sims. Now, if I can do long division, that is approximately 18 percent of the 1979 actual level. Is that correct?

Mr. Weiner. Yes, sir; you have to be careful of these numbers, because they do consider the coal units coming in service as they were anticipated coming in service.

Mr. Sims. Thank you, Mr. Chairman.

Mr. Weil. Could I ask a question? I would like to settle, Mr. Weiner, what you use as heat rates or thermal plant efficiencies for oil, coal, and gas. I found two different values. I think you probably heard in my opening statement the same report. Could you give me consistent values?

Mr. WEINER. I would be glad to supply that information to you on a consistent basis if you want to acquire that from our staff. My point that I made earlier, I urged great caution about extracting the values differently from different analyses. What you are referring to is three or four different analyses we had done, and you combined those analyses to come up with a conclusion. We are trying to keep our analyses consistent within themselves.

Mr. WEIL. Another point when estimating the increase in fossil fuel consumption, in the case of a moratorium on nuclear plants, it turns out in Mr. Weiner's report the assumption is that the historical growth rate of electricity demand is normal in the sense of 7 percent a year, doubling about every 10 years. However, the same report points out that the impact of half the rate of growth, which is what we are experiencing now and have been experiencing for some time, would eliminate all of Mr. Weiner's estimated excess consumption of coal and gas, and would reduce his excess oil consumption estimate from about 700,000 barrels a day to, I believe, less than 200,000.

This low growth in electricity demand is, I believe, the scenario that most of the people at this table are accepting at this time.

Mr. MARKEY. Dr. Walske?

Mr. WALSKE. I just wanted to make two comments. One, I wanted to answer Dr. Komanoff, who made some references to my remarks. He pointed out that I said there was difficulty in financing nuclear plants. That is not quite what I pointed out. I pointed out there is difficulty in financing nuclear and coal plants, and it is very important to remember that. He gave his own figure that in the future nuclear plants will cost twice as much as coal plants. The projections that I have available say about 1⅓ times as much as a coal plant, but the nuclear plants do make up the difference, of course, on the fuel costs.

Mr. KOMANOFF. What are they costing today to finish?

Mr. MARKEY. Why don't we let Dr. Walske finish?

Mr. WALSKE. He said that I talked about the regulatory difficulties affecting nuclear plants, and I did, but I also talked about the regulatory difficulties affecting coal plants. The electric industry is in trouble in this country as far as additional future construction is concerned, but it is very important to understand that both the coal and nuclear options are in trouble. Unless that is understood, I think you can miss the point.

The other thing I wanted to say is about the general question of a nuclear plant displacing oil used under boilers for electric generation. I think both Mr. Taylor, of Westinghouse, and I, in our statements, tried to make the point that when you study at the interaction between a new coal plant or a new nuclear plant, and oil consumption in this country, you only begin by looking at the question of what it may replace in the way of oil used under a boiler.

Beyond that, if the plant saves natural gas, the natural gas saved is a very flexible fuel which can replace oil someplace else. If the plant makes electricity, that electricity may save oil by running a heat pump in a home which otherwise would be using oil or by being used in industry, in a use that otherwise would use oil. It is much too narrow a view to take of oil substitution to look simply at oil burned under boilers used by electric utilities.

Mr. KOMANOFF. I would like to make a comment and then ask Mr. Walske a question. If we are going to look at the potential of electricity to take over more and more of the energy economy and move more fully into industrial energy supply and home heating, et cetera, I think we should understand that that is a process that is going to occur only gradually; it is going to take a long period of time to do that, long enough that it is incumbent upon us to ask whether the increased electric powerplants that might be required to supply the electrification, whether these plants will be or should be nuclear- or coal-fired plants.

Most of the industrial conversions we are talking about, most of the new housing construction that might use heat pumps and certainly any prospect of electrification of automobiles, this is far enough in the future that it is not going to be affected by nuclear and coal plants under construction. It will be tied in to nuclear or coal plants that are not even on the drawing boards today.

Any electricity that can displace oil in these uses could just as easily be provided by coal-fired plants as nuclear plants.

My question relates to the desirability of whether it should be nuclear or coal. Mr. Walske and I have a very different view of what it is going to cost to construct new nuclear- and coal-fired plants.

Mr. Walske feels that new nuclear plants will have construction plants that are only about one-third higher than new coal-fired plants.

I will acknowledge that if this were to be the case, then nuclear could compete with coal on a lifetime-costing basis.

I believe that new nuclear plants are going to cost twice as much to construct as coal-fired plants and that with this differential there is no contest on the economics of new nuclear versus new coal. New coal wins hands down.

Now I rest this projection on an actual analysis of the completed costs of all the nuclear and coal plants built in the United States in the past 10 years.

I would like to ask Mr. Walske if he has anything more than projections to support his contention. What is your current ratio of costs of recently completed coal plants versus nuclear?

Mr. WALSKE. The coal costs about three-quarters as much per installed kilowatt-hour.

Mr. KOMANOFF. Can you cite a reference for this?

Mr. WALSKE. Nuclear makes up the difference on the fuel costs. The Department of Energy 1979 Report on Total Costs would be one reference for Dr. Komanoff to refer to in which these figures are, by and large, borne out. There are others, also.

As far as projections for the future, it is not my opinon against Dr. Komanoff's opinion. It is Dr. Komanoff's opinion against the opinion of the electric utilities of the United States whose opinion is the opinion I am repeating here.

I think Mr. Taylor, of Westinghouse, could add something to this discussion, too.

Mr. MARKEY. Mr. Taylor, does Westinghouse construct coal-fired as well as nuclear plants?

Mr. JOHN TAYLOR. We build turbine generators for coal-fired plants.

Mr. MARKEY. You don't have the same commitment to coal as you do nuclear?

Mr. JOHN TAYLOR. We have a major commitment to coal. We have a pilot plant near Pittsburgh that is pursuing the utilization of gas from coal. We are interested in every aspect of the improvement of the use of coal. We are developing super-conducting generators to generate electricity from coal. We have magneto hydrodynamic direct conversion ducts which utilize coal as the fuel source.

Mr. MARKEY. Could you give us your view of the economic competitiveness of nuclear versus coal?

Mr. JOHN TAYLOR. I would repeat what Mr. Walske has said. Every source of information that we have, the consultants such as A. D. Little, United Engineering or DOE state that the increase in the capital cost of major generating stations, be they nuclear or coal, are all going up and the ratio will be staying about the same.

I am inclined to agree with Carl. The people who believe this are the people who are making decisions in the industry over what they built. I think Mr. Weil's survey has shown them to be pretty smart. When they made the choice to go nuclear they made the right choice because the nuclear plants that they chose at the time have proven to be economic.

The choice was made on economics since those decisions were made before we were shaken up by the recognition that oil was no longer coming so easily and cheaply from overseas. If they didn't go nuclear, he said they would have chosen coal.

Since these decisions were made before the oil embargo, they indicate perspicacity on the part of the nuclear industry. The industry believes these nuclear plants will produce cheaper power even if authorized today. When the time comes that they see the need for increased generation to overcome the problems Mr. Walske has discussed with you, I think they will show you that in a decision to go ahead with nuclear power.

Mr. MARKEY. I think we are going to be led astray here. I want Mr. Komanoff to respond for maybe 2 minutes because we don't want this to get into a debate on the economics of coal versus nuclear. The real question we are trying to raise, and perhaps settle, is that the future of America and its relationship with electricity is going to be a choice between nuclear and coal, and not oil. Then we can agree to disagree as to the economics of nuclear versus coal.

Mr. Komanoff?

Mr. KOMANOFF. Mr. Walske was kind enough to give the basis of his contention that there is a relatively small difference between recent nuclear and coal construction costs. He cited a Department of Energy analysis which happens to be the July–August 1980 update. I have that report. It indicates on page 73 in table 5 that the capital costs of a sample of nuclear plants which is, I guess, supposed to be all the nuclear plants, that their capital costs were 70 percent higher than the capital costs of coal-fired plants.

This is supposed to be for nuclear and coal plants operating in 1979. I acknowledge that the coal plants in this survey were not equipped with advanced pollution controls which they must and should have in the future but neither were the nuclear plants equipped with the backup and safety system, containments to handle molten cores and things of that sort which will be required for them in the future.

I am pointing out that there is no basis for Mr. Walske's contention that recent nuclear and coal capital costs have been fairly close. I will stack my analyses against those of the institutions that Mr. Walske referred to because none of those institutions have done what Komanoff Energy Associates has done which is to compile a data base of every nuclear and coal-fired plant built in this country in the last 10 years and statistically analyze that to determine true trends rather than relying on hearsay and conjecture as the Atomic Industrial Forum does.

Mr. MARKEY. That could be a subject for a future hearing. Maybe you could submit for the record your analysis of the economic competitiveness of these two energy sources. Maybe you, Mr. Walske, could submit for the record the evidence that you have been compiling.

[Testimony resumes on p. 378.]

[The following letter and attachments were received for the record:]

Atomic Industrial Forum, Inc.
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Washington, D.C. 20014
Telephone: (301) 654-9260
TWX 7108249602 ATOMIC FOR DC

Carl Walske
President

December 22, 1980

The Chairman
The Subcommittee on Oversight and Investigations
Committee on Interstate and Foreign Commerce
Room 2125, Rayburn House Office Bldg.
Washington, D. C. 20515

Dear Sir:

In response to Mr. Markey's request at the hearing on December 9, I herewith submit the following material on nuclear and coal-fired electricity capital and total generating costs:

1. DoE's "UPDATE-Nuclear Power Program Information and Data, September/October 1980", (see page 45 for U.S. average capital costs for nuclear plants operational in 1980, 1985 & 1989).

2. DoE's "UPDATE-Nuclear Power Program Information and Data", July/August 1980, page 73; May/June 1980, page 59; June 1978, page 34; and July 1977, page 50.

3. "The Economics of Nuclear versus Coal" by Leonard F. C. Reichle of Ebasco Services, Inc., October 30, 1979 (see pp 1&2, chart 1, for comparative capital costs in 1976-78 versus 1988-1990).

4. "Economic Comparison of Coal and Nuclear Electric Power Generation" by Gibbs & Hill, Inc., January 1980 (see pp 8&9 for comparative capital costs in 1979 and 1990-1992).

5. "Cost Comparison of Central Electric Power Generation Using Coal and Nuclear Fuels" by W. W. Brandfon of Sargent & Lundy Engineers, April 11, 1980 (see figs. 1&3 for comparative capital and total generating costs in 1991-1992).

6. "The Economics of Nuclear Power" by W. J. L. Kennedy and R. Murray Campbell of Stone & Webster Engineering Corporation, February 26, 1979 (see figs. 2&3 for comparative capital and total generating costs in 1978 versus 1990).

A summary (enclosure 7) of the relevant excerpts from the above documents is attached.

Sincerely,

Carl Walske

CW:cp

Source: *UPDATE _ Nuclear Power Program Information and Data*, September/October 1980, prepared by Office of Nuclear Reactor Programs, U.S. Department of Energy.

III. ECONOMICS

A. Analysis of Utility Reports on Nuclear Power Plant Capital Costs

The great majority of U.S. electric utilities with nuclear power plants under construction and/or on order provide estimated project schedules and capital costs for these units every 3 months to the Department of Energy. An updated analysis of nuclear unit capital costs reported as of June 30, 1980, including examination of the effects of time of entry into service, size and geographical location, follows.

The Department requests of the utilities that they report their capital cost estimates on an "as-disbursed" (current dollar) basis, including direct costs, indirect costs, escalation, and, where applicable, allowance for funds used during construction (AFUDC). The costs for nuclear fuel, transmission switchyard, and training of personnel are not included in the plant cost estimates. The unit costs of like units in a multi-unit station are determined by dividing the total of the costs of these units coming into service within a year or two of each other by the sum of the net electrical kilowatt (KWe) ratings of the units. The cost of each unit is then included in the sample corresponding to its year of initial commercial operation.

The costs included in the data base for this analysis are reasonably up to date. The projected capital costs of over two-thirds of the units represented in Table 1 were revised during the first half of this year, presumably due to changes in their schedules or the updating of economic assumptions such as price escalation rates. Some units were excluded from the analysis, notably those whose costs had not been revised for over a year and those whose schedules had been slipped with no corresponding changes in projected costs. This lag in updating costs has been more apparent of late and has diminished somewhat the size of the data base for this analysis.

It should be noted that this analysis is intended to afford an appreciation of the variation in average U.S. nuclear power plant capital costs with respect to time, unit size and regional location. The results of the analysis are not intended for use in determining whether or not the costs of a particular plant are high or low; the differences in regional conditions, in individual plant characteristics--a number of which are site related, and in the tax and financing situations of individual electric utilities can result in appreciable variations in individual plant costs from the cost averages in the analysis. It should be noted also that this analysis reflects schedules and costs reported by the utilities; it is not a Department projection.

Cost Variation with Time

In Table 1 appear the averages (weighted by plant size) of light water reactor (LWR) unit capital costs of generating units entering commercial service each year, by size category and in the aggregate,

Table 1

Average U.S. LWR Power Plant Unit Capital Costs
(as of June 30, 1980)

First Year of Commercial Operation	600-999 MWe 1/ No. of Units in Sample	600-999 MWe 1/ Average Unit Capital Cost ($/KWe)	1000 MWe and Up No. of Units in Sample	1000 MWe and Up Average Unit Capital Cost ($/KWe)	Sizes of All Units No. of Units in Sample	Sizes of All Units Average Unit Capital Cost ($/KWe)
1980	3	738	3	676	6	703
1981	1	*	4	949	5	944
1982	2	1294	8	933	10	992
1983	2	2026	9	1166	11	1283
1984	1	*	5	1087	6	1124
1985	0	–	6	1353	6	1353
1986	1	*	8	1662	9	1723
1987	1	*	5	1665	6	1669
1988	0	–	4	1503	4	1503
1989	0	–	4	1553	4	1553

1/ The only unit included here rated below 800 MWe is Bailly (644 MWe net).

*Costs for one-unit samples are not shown.

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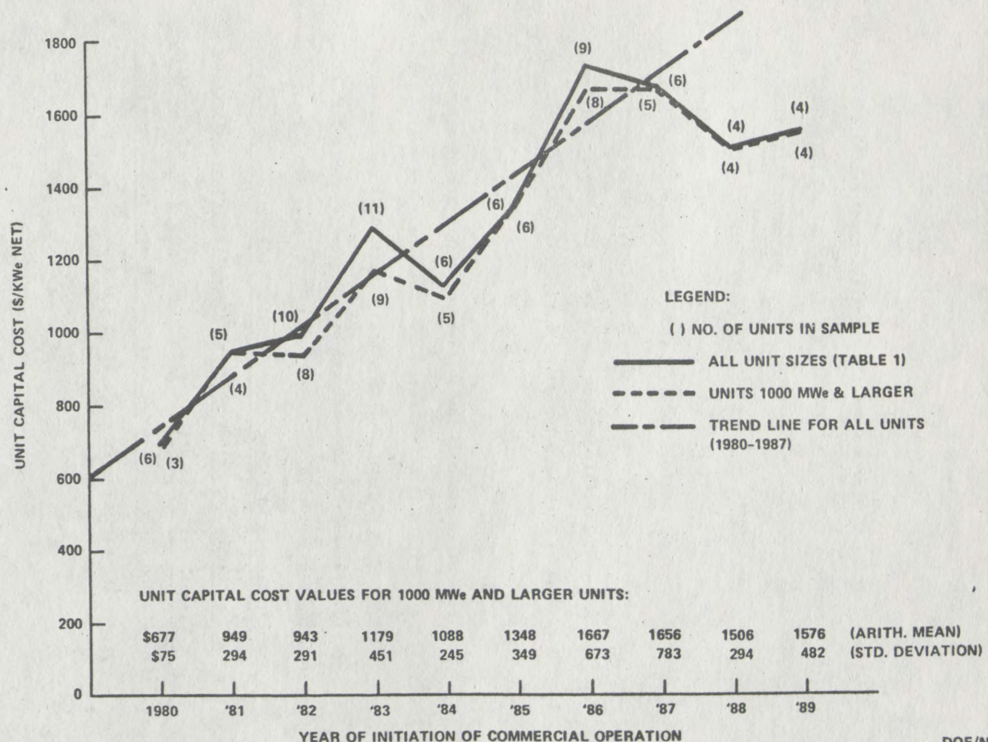
for the years 1980 through 1989. This information is presented graphically in Figure 1 for all sizes of units (solid line) and also for sizes 1000 MWe and larger (dashed line).

Examination of Figure 1 reveals a fairly steady annual rise in the average capital cost of all units over the period 1980-1986, although a regression occurs in 1984. The costs fall off after 1986, due perhaps to less detailed preparation of project costs and delay in their updating. A linear least-squares trend line for all units over the period 1980-1987 shows an average annual increase in unit costs of $138 per kilowatt-electric (KWe). The plot of average unit capital cost for units rated 1000 MWe or more evidences a general rise through 1987, although regressions occur in 1982 and 1984.

The rate of increase of the averages of unit costs of all units shown in Figure 1 is 13.1 percent annually over the period 1980-1987. This compares with an average annual rate of 12.1 percent for the period 1979-1986 in the analysis based on costs reported as of December 31, 1979 (March/April 1980 UPDATE, page 54). Thus, the newest reports of project costs exhibit expectations of continued high inflation in nuclear power plant capital costs, reflecting the incorporation in utility estimating assumptions of recent price escalation and cost of money trends. The same trends should affect the estimates of fossil-fuel power plant capital costs.

FIGURE 1

AVERAGE LWR POWER PLANT UNIT CAPITAL COSTS
BY YEAR OF ENTRY INTO SERVICE (REPORTED AS OF JUNE 30, 1980)



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The spread in the unit costs of individual units in the same size category for each year is large--sometimes more than two to one. For an appreciation of this variation the arithmetic mean and the standard deviation of unit cost values of units 1000 MWe and larger are shown for each year in Figure 1. A principal reason for the variation is regional location, which is discussed below. Other contributing factors are differences in site conditions (affecting seismic, containment and cooling water requirements, for instance), engineering and construction arrangements, labor costs, financing costs, taxes, and assumptions regarding future price escalation.

Cost Variation with Size

On balance, there is evidence of economy of scale in the average unit costs shown in Table 1 and in the plots of Figure 1. In all years where a comparison can be made the average unit costs of the units rated 1000 MWe and up are lower than the concurrent costs for the units in the 600-999 MWe category. The opportunity for annual comparison is limited, however, by the relative paucity of smaller units coming on line each year in the U.S. Furthermore, the unit costs correspond to plants located in different areas of the country and subject to different site and construction conditions. Evidence of economy of scale is more convincing where the average unit costs of a sufficient number of units in the two size categories are compared within a particular region, as reported later in this analysis.

Cost Variation by Region

Average unit capital costs by U.S. region, including both size categories, are shown in Table 2. These averages are weighted according to unit size. The states in each region are listed in Table 2.

As shown in column 3 of Table 2, the highest average unit cost occurs in the Northeast, followed in turn by the Far West and Middle Atlantic regional costs. Lower costs are reported for the East and West North Central and West South Central parts of the country, with the lowest occurring in the East South Central and South Atlantic regions.

The foregoing comparison takes no account of when the various units enter into service, however, which can affect the ranking of average regional costs. Comparison of average regional costs with concurrent national average costs affords a means of determining regional cost ranking where time of entry into service is taken into account. The results are shown in the rest of Table 2 and in Figure 2, explained as follows.

The averages of dates of entry into service of the units in each region are indicated in column 4 of Table 2. These dates can be considered as sort of "temporal centroids" for each region. In column 5 of Table 2 are shown the national average unit capital costs that correspond to the temporal centroids of the respective

Table 2

Ranking of U.S. LWR Power Plant Capital Costs by Region[1/]
(as of June 30, 1980)

(1) Region[2/]	(2) Number of Units in Sample	(3) Average Regional Unit Capital Cost $/KWe (A)	(4) Average of Dates of Entry into Service of Units (mo/yr) (B)	(5) National Average Unit Capital Cost at Time Shown in B $/KWe (C)	(6) Ratio $\frac{A}{C}$	(7) Ranking (lowest cost to highest)
Northeast	5	1725	7/85	1353	1.275	7
Middle Atlantic	8	1505	9/84	1183	1.272	6
South Atlantic	7	953	2/83	1213	0.79	2
East North Central	11	1234	8/84	1164	1.060	4
West North Central	3	1229	11/84	1217	1.01	3
East South Central	14	937	3/85	1279	0.73	1
West South Central	6	1240	2/84	1165	1.064	5
Far West	13	1625	9/84	1175	1.38	8

1/ For LWR units entering commercial service over the period 1980-1989.

2/ Northeast: New York and New England States
Middle Atlantic: Pennsylvania, New Jersey, Maryland and Delaware
South Atlantic: Virginia, North and South Carolina, Georgia, Florida
East North Central: Ohio, Indiana, Michigan, Illinois, Wisconsin, Kentucky and West Virginia
West North Central: Minnesota, Iowa, Nebraska, Kansas, Missouri, North and South Dakota
East South Central: Tennessee, Alabama, Mississippi
West South Central: Texas, Louisiana, Arkansas, Oklahoma
Far West: Mountain and Pacific States

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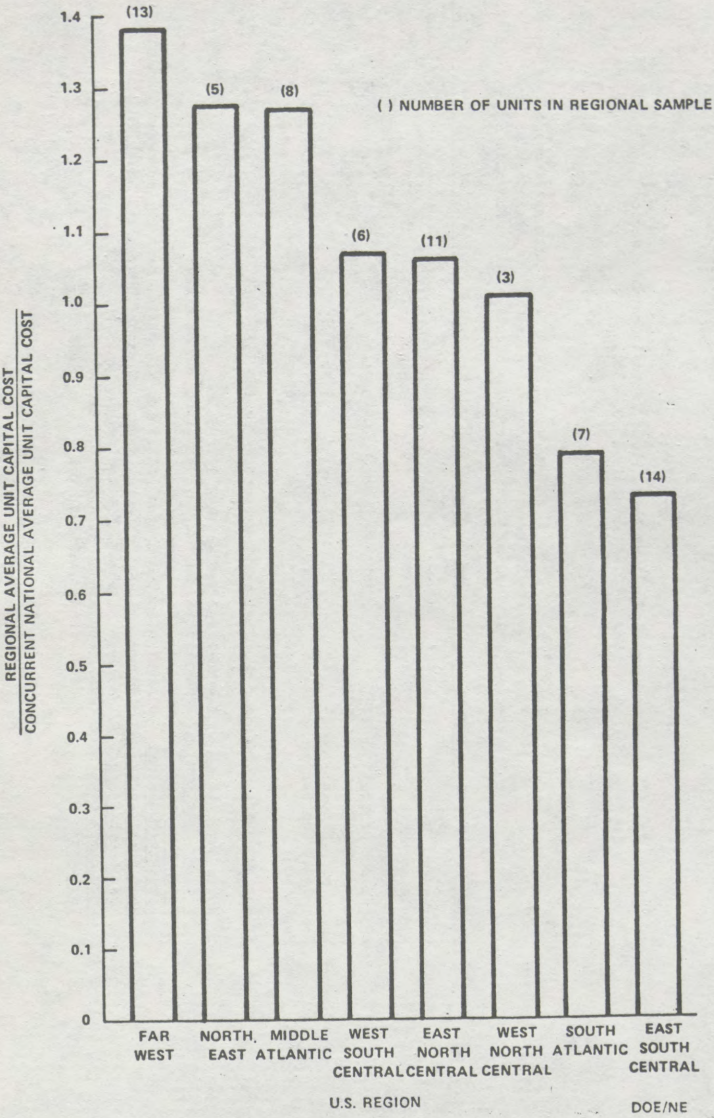
FIGURE 2

REGIONAL LWR POWER PLANT CAPITAL COSTS
COMPARED TO CONCURRENT NATIONAL LWR CAPITAL COSTS



regions. These national costs are interpolated from the unit costs shown in the last column of Table 1 and their corresponding averages of service entry dates. The average unit capital cost of each region is compared to the concurrent national average cost and the ratio of the two shown in column 6 of Table 2.

It is evident that the units in the Far West have the highest average cost compared to the concurrent national average cost (1.38). The East South Central region has the lowest ratio (0.73).

Measured against concurrent national cost levels, then, the Far West region can be said to experience the highest capital costs for its nuclear generating units, with the Northeast and Middle Atlantic regions about tied for the next to highest cost position. The average costs for the East South Central and South Atlantic areas are clearly lower than those of the other regions. The remaining regions are a little higher than the national averages for the same time periods.

The average unit cost rankings of the regions as determined by this method are shown in the last column of Table 2. The only change in the rankings from those apparent in column 3 of Table 2, where time of entry into service is not taken into account, is the reversal of the Far West and Northeast regions. In view of the service entry date averages for all regions occurring in the 1984-85 period, with the exception of that of the South Atlantic region, this is not surprising.

Lower costs for the East South Central and South Atlantic regions are also not unexpected. They reflect lower labor costs, less construction time lost due to inclement weather, and probably less weatherizing of buildings. Furthermore, 13 out of the 14 units in the East South Central region, the lowest cost area, are owned by the Tennessee Valley Authority, which utilizes its own engineering and construction forces and has certain financing advantages. Also, all but one of the East South Central units are over 1000 MWe in size.

In only the South Atlantic and East North Central regions does the data base for the analysis include more than one or two units rated less than 1000 MWe in size. Although only three such units are included in these regions, they afford some idea of the economy of scale of nuclear power plants. The information is shown in Table 3.

Table 3

LWR Power Plant Unit Capital Costs
by Size and Region
(as of June 30, 1980)

Region/Size Category	No. of Units in Sample	Avg. Unit Size (MWe)	Avg. Unit Capital Cost ($/KWe)	Avg. Date of Entry into Svc. (mo/yr)
South Atlantic				
800-999 MWe	3	872	992	11/81
1000 MWe & Up	4	1145	931	1/84
East North Central				
600-999 MWe 1/	3	796	1406	4/84
1000 MWe & Up	8	1131	1188	10/84

1/ In this group only the Bailly unit, rated at 644 MWe net, is smaller than 800 MWe.

Economy of scale is apparent in Table 3. The average unit capital cost of the four South Atlantic units in the 1000 MWe and over category is $61 per kilowatt lower than that of the three units in the smaller size category, despite the fact that the larger units enter service over 2 years later on the average and are therefore subject to greater price escalation. Similarly, in the East North Central region the eight units in the larger size category average $218 per kilowatt lower in cost than the three smaller units, although the larger units enter service one half year later on the average.

Source: *UPDATE - Nuclear Power Program Information and Data*, July/August 1980, prepared by Office of Nuclear Reactor Programs, U.S. Department of Energy.

III. ECONOMICS

A. Analysis of U.S. Nuclear Power Plant Production Costs for 1979

Introduction

The Nation's electric utilities submit annually (on Form 1) to the Energy Information Administration, Department of Energy, information on their operations for the previous year, including economic and operational data on existing generating stations.

This article reviews the production expenses for fuel, operation, maintenance and supplies included in the Form 1 data for 61 light water reactor (LWR) nuclear generating units rated 400 megawatts-electrical (MWe) or more (identified in the appendix following) that operated in commercial service for all of 1979. The capital costs of generating stations are also included in the Form 1 reports, but the fixed charges on these investments, which constitute the largest part of the total cost of nuclear generation, are not reported. It is not possible, then, from the Form 1 data to add actual capital cost to the production costs in order to report actual total generating costs. However, estimates of generating costs are discussed later in this article.

Results of the analysis of 1979 production costs of U.S. central station nuclear power plants follow.

Summary

- The average production cost (fuel, operation, maintenance and supplies) of U.S. nuclear power plants rose to 7.84 mills per kilowatt hour (mills/Kwh) in 1979, a 27 percent increase over the 1978 figure, following a 16 percent increase the previous year (the production cost does not include the fixed charges on plant capital cost, which constitute the largest component of total generating cost).

- The average fuel cost for 1979 was 3.73 mills/Kwh, a 16 percent increase over the 1978 figure (the increase the previous year was 13 percent). On the average, nuclear fuel costs in 1979 were less than one-third those of base-loaded coal-fired plants.

- Average operation, maintenance and suplies (O&M) cost was 4.11 mills/Kwh for nuclear power plants in 1979, a 39 percent increase over the 1978 figure (following a 20 percent increase the previous year). On the average, O&M costs were responsible for most of the increase in nuclear plant production costs during 1979.

- Evidence of economy of scale is mixed with respect to 1979 production costs. The average O&M and overall production costs for the 750-999 megawatts-electrical (MWe) size group are actually higher than those of the 400-749 MWe group. However, the 1000 MWe and above group, generally the newer units, evidence lower fuel and overall production cost averages for 1979 than both smaller size groups. The average fuel costs decline with increase in size over the three size categories.

- The lowest nuclear power plant production costs occurred in the West North Central and Far West regions of the country, and the highest in the Northeastern and Middle Atlantic states. Most of the regional variation is due to the O&M component of production cost.

- The average of total production costs for nuclear units was about one-half that of base-load coal-fired plants. Most of this advantage is due to the much lower fuel cost of the nuclear units. Addition of estimated capital costs to these actual production costs indicates that nuclear units generated at least as economically as coal-fired plants, and probably more so, during 1979, despite the disappointing productivity of nuclear power compared to former years.

National Average Production Costs

The national averages of nuclear power plant production costs for 1979 operation are shown in Table 1. Corresponding costs for 1977 and 1978 (reported in earlier issues of UPDATE) are also shown for comparison. It should be noted that the figures for 1977 include a few units rated less than 400 MWe, but their small size has little effect on the weighted averages indicated.

Table 1

National Averages of Recent Annual U.S. Nuclear Power Plant Production Costs

Cost Category	Average Unit Costs (mills/Kwh)		
	1979	1978	1977
Fuel	3.73	3.22	2.85
Operation, Maintenance and Supplies (O&M)	4.11	2.95	2.46
Production	7.84	6.17	5.31

Fuel costs rose to a national average of 3.73 mills per kilowatt-hour (mills/Kwh) in 1979. This represents a 15.8 percent increase over the 3.22 mills/Kwh of 1978, compared to a 13.0 percent increase the previous year. Contrary to the experience of the two previous years, fuel cost constituted less than half (47.6 percent) of the average production cost in 1979.

1979 production costs overall were about 27 percent higher than those of 1978. This followed an approximately 16 percent rise between 1977 and 1978. The greater part of the 27 percent rise is due to the increase in the O&M portion of the production costs during 1979. The 4.11 mills/Kwh O&M average for 1979 represents an 1.16 mills increase over the 1978 figure, whereas the 3.73 mills/Kwh 1979 fuel cost is 0.51 mills more than its 1978 counterpart.

An appreciable part of the increase in O&M costs between 1978 and 1979 can be attributed to the decline in generation by U.S. nuclear plants in 1979--255,154,623 megawatt-hours (MWH) in 1979 vs. 276,403,070 MWH in 1978, which largely reflects the effects of the accident at the Three Mile Island plant as well as the shutdowns in 1979 of five nuclear units for seismic adequacy checks of their piping systems. Part of the plant O&M costs are fixed regardless of the amount of electricity generated and these fixed costs were spread over less electricity production in 1979. On the other hand, nuclear fuel cycle costs are less susceptible to variations in annual generation, as indicated by their 15.8 percent rise in 1979 vs. the 39.3 percent rise in O&M costs.

Despite the more rapid increase in production cost last year, the national average is still only about three-quarters of a penny per kilowatt-hour. The 7.84 mills/Kwh compares very favorably with the 1979 average production cost of 14.74 mills/Kwh for baseload coal-fired plants mentioned later in this article.

Effect of Unit Size

The breakdown of nuclear plant production costs by size is shown in Table 2. The older units are generally in the 400 to 749 MWe size category, with the latest units to enter service in both larger categories.

Table 2

1979 Production Costs of U.S. Nuclear Generating Units Grouped by Size

Range 1/	Units	Average of Dates of Commercial Operation	Actual Average Capacity Factor (%) 2/	Unit Costs (mills/Kwh) Fuel (A)	O&M (B)	Production (A & B)
400-749 MWe	20	2/72	69.4	3.96	3.32	7.28
750-999 MWe	30	4/75	51.5	3.85	4.96	8.81
1000 MWe and above	11	10/75	62.3	3.28	3.44	6.72

1/ Ranges are in terms of NRC maximum continuous capability ratings of units.

2/ Based on the net generation reported in the Form 1 reports and the NRC maximum continuous capability unit ratings.

No economy of scale is evident short of the 1000 MWe size; in fact, the 8.81 mills/Kwh overall production cost of the 750-999 MWe category is 21 percent above the 7.28 mills of the 400-749 MWe group, due wholly to a higher O&M component. The 11 units in the 1000 MWe and above category do show economy of scale in production cost, evidencing an average 7.7 percent lower than that of the 400-749 MWe group and 23.7 percent below that of the 750-999 MWe category. The better average economic performance of the largest units is due to the lowest fuel cost, 3.28 mills/Kwh vs. 3.85 and 3.96 mills/Kwh for the smaller categories, and a 3.44 mills/Kwh O&M cost almost as good as the 3.32 mills/Kwh of the smallest category and decidedly better than the 4.96 mills/Kwh of the 750-999 MWe group.

Fuel costs demonstrate some economy of scale, particularly in the case of the largest units; the average for the 1000 MWe and above category is respectively 14.8 percent and 17.2 percent below the averages for the next two categories.

The manning and overhead advantages expected of larger units are not apparent in the O&M costs indicated in Table 2. The difference in capacity factors between the two smaller categories, 51.5 percent for the 750-999 MWe size range compared to 69.4 percent for the 400-749 MWe category, is not enough by itself to explain the 1.64 mills/Kwh differential on their O&M costs; part of the differential must be attributed to more maintenance, repair and refitting expenses for the 750-999 MWe units. The largest units operated at a 62.3 percent capacity factor. If they had produced at the 69.4 percent capacity factor average of the units in the smallest size category, their O&M costs might very well have averaged less than the 3.32 mills/Kwh of the latter, due to the spreading of the fixed components of O&M cost (salaries, etc.) over the larger amount of electricity generated at the higher capacity factor.

The average of the dates of entry into service of the units in each size category are shown in Table 2. There is no apparent correlation between these dates and the other statistics in Table 2, except possibly in the case of the fuel. Any other design and size advantages that could be expected from later and larger units are masked by the factors discussed above.

Regional Production Costs

Average nuclear power plant production costs for 1979 in the various regions of the U.S. are depicted in Table 3 and Figure 1. The lowest production costs occurred in the West North Central and Far West regions (the states in each region are listed in Table 3). It should be noted, however, that these regions have the smallest unit samples. The units in the Northeast and Middle Atlantic regions had the highest production costs. The production cost averages for the South and East North Central regions are in the middle of the range, both somewhat lower than the 7.84 mills/Kwh national average.

Table 3

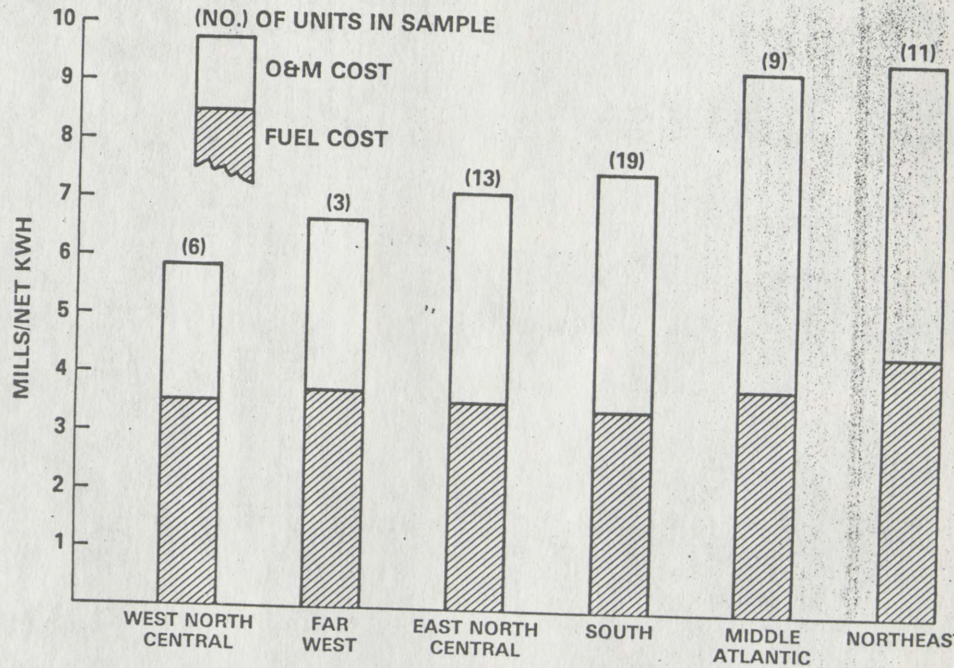
1979 Production Costs of U.S. Nuclear Power Plants Segregated by Regions
(mills/kwh)

Region[2/]	No. of Units[1/]	Fuel Cost (A)	O&M Cost (B)	Production Cost (A + B)	Ranking by Low Prod. Cost
Northeast	11	4.44	5.02	9.46	6
Middle Atlantic	9	3.83	5.46	9.29	5
South	19	3.46	4.05	7.51	4
East North Central	13	3.56	3.57	7.13	3
West North Central	6	3.54	2.32	5.86	1
Far West	3	3.72	2.93	6.65	2
U.S.A.	61	3.73	4.11	7.84	

1/ Rated 400 MWe and over.

2/ Northeast: New York and New England States
Middle Atlantic: Pennsylvania, New Jersey, Maryland and Delaware
South: Virginia, North and South Carolina, Georgia, Florida, Tennessee, Alabama, Mississippi, Texas, Louisiana, Arkansas, and Oklahoma
East North Central: Ohio, Indiana, Michigan, Illinois, Wisconsin, Kentucky, and West Virginia
West North Central: Minnesota, Iowa, Nebraska, Kansas, Missouri, and North and South Dakota
Far West: Mountain and Pacific States

FIGURE 1
1979 NUCLEAR POWER PLANT PRODUCTION COSTS BY U.S. REGION
(Includes Generating Units Rated 400 MWe and Over)



In fuel costs the Northeast and Middle Atlantic regional averages exceed the national average of 3.73 mills/Kwh for operable units over 400 MWe in size, with the average for the Far West about at the national average and the rest below it. The regional fuel cost averages vary from 19 percent above (Northeast) to a litte more than 7 percent below (South) the national average.

The regional O&M costs vary considerably more from the national average of 4.11 mills/Kwh. The figure for the Middle Atlantic is almost 33 percent above the national average while the average for the West North Central is about 44 percent below it.

Comparison with Coal-Fired Plant Costs

In the previous issue of UPDATE, the average production costs of nuclear units operated by U.S. investor-owned electric utilities and a sample of large coal-fired generating units of similar vintage were compared. A comparison of the 1979 production costs of all U.S. nuclear units, owned by both public and private utilities, as shown in Table 1 above, and a large sample of coal-fired generating plants, including some owned wholly or partly by public utilities,[1/] is presented in the following table.

1/ The nuclear generating units and coal-fired plants included for the comparison are identified in Appendix 1 of this article.

Table 4

National Averages of U.S. Electric Utility Nuclear and Coal-Fired Power Plant Production Costs for 1979

Cost Category	Average Unit Costs (mills/Kwh) Nuclear	Coal
Fuel	3.73	12.48
Operation, Maintenance and Supplies (O&M)	4.11	2.26
Production	7.84	14.74

The nuclear costs shown in Table 4 are somewhat lower than the average costs indicated previously for investor-owned utility units only.[2/] Including the eight public utility units (identified in Appendix 1 hereto) in the data base for Table 4 lowers the national average fuel cost for 1979 operation from 3.92 mills/Kwh (private units only) to 3.73 mills/Kwh and the O&M costs from 4.25 to 4.11 mills/Kwh.

Expansion of the coal-fired plant sample to include the aforementioned public utility participation does not change the national averages appreciably; the fuel cost decreases slightly from the 12.52 mills/Kwh for private utility plants only to the 12.48 mills/Kwh shown in Table 4 while the O&M cost increases from 2.19 to 2.26 mills/Kwh, resulting in a bare 0.03 mills increase in overall production cost to 14.74 mills/Kwh. The principal reason for the

2/ May/June 1980 UPDATE, page 55, Table 1.

minimal changes noted is the small amount of public utility capacity introduced to the large private utility coal-fired sample, partly because the data for some modern coal-fired units could not be separated out from the Form 1 statistics for whole plants. Also, four of the plants in the public utility coal-fired plant data base are jointly owned with private utilities and their production expenses would be expected to be similar.

The foregoing analysis does not include annual fixed charges on plant capital costs, for the reason explained previously. A comparison of the total generating costs of nuclear and coal-fired stations would require, of course, the inclusion of such capital costs. Another deterrent to a definitive comparison of generating costs is the fact that the production expenses and capital costs of multi-unit generating stations are reported in the aggregate in Form 1, so that the costs of newer, large coal-fired units installed in stations with older units cannot be broken out for comparison with the nuclear units. Nevertheless, a reasonable approximation of how nuclear and coal-fired generating economics compared in 1979 can be had for the data bases available by using the same fixed charge rates for both fuel types. If a 17 percent rate for private utility units and 11 percent for public utility units is applied to the actual capital costs in the Form 1 reports for coal-fired and nuclear units, the results are as shown in Table 5.

Table 5

National Averages of U.S. Electric Utility Nuclear and Coal-Fired Power Plant Generating Costs for 1979[1/]

Cost Category	Average Unit Costs (mills/Kwh) Nuclear	Coal
Fuel (actual)	3.73	12.48
Operation, Maintenance and Supplies (O&M) (actual)	4.11	2.26
Capital (estimated)	12.83	7.61
Generating (estimated)	20.67	22.35

1/ The generating units included in the data base for this tabulation are identified in Appendix 1.

The average nuclear generating cost shown in Table 5 is about 7 percent lower than that of the coal-fired plants. Because the fixed charges on capital cost are estimated rather than actual and because some additional coal-fired units (though not many) could be added to the data base, the best conclusion that can be drawn from the figures in Table 5 is that nuclear power compared very well with base-load coal-fired generation despite its disappointing performance relative to previous years.

Sensitivity checks on the results shown in Table 5 support such a conclusion. Even if the capital cost fixed charge rate on private utility plants were assumed at 20 percent, which would favor the less capital intensive coal-fired plants, nuclear power at 22.79 mills/Kwh would still be a little under the 23.65 mills/Kwh of the coal-fired plants. The productivities of the two types of plants were sufficiently close (59.8 percent weighted average capacity factor for the nuclear units and a 58.0 percent average for the coal-fired plants) that raising the coal-fired capacity factor to that of the nuclear units would not make up the difference in the estimated generating costs. As mentioned previously, the 59.8 percent average capacity factor of the nuclear units during 1979 was a disappointment, brought on largely by the Three Mile Island accident and its aftermath as well as the shutdown of five nuclear units for checks on the safety calculations for their piping. In 1977 and 1978 the average nuclear capacity factors were in the mid 60's range.

Appendix 1

Nuclear Generating Units Included in 1979
Gernerating Cost Analysis
(Includes only units rated over 400 MWe)

San Onofre 1
Haddam Neck (Conn. Yankee)
Oyster Creek
Nine Mile Point 1
Dresden 2, 3
Indian Point 2, 3*
Ginna
Robinson 2
Millstone Point 1, 2
Point Beach 1, 2
Monticello
Palisades
Quad Cities 1, 2
Vermont Yankee
Pilgrim 1
Surry 1, 2
Maine Yankee
Turkey Point 3, 4
Oconee 1, 2, 3
Zion 1, 2
Browns Ferry* 1, 2, 3
Fort Calhoun*
Peach Bottom 2, 3
Prairie Island 1, 2
Duane Arnold
Cooper*
Kewaunee
Three Mile Island 1, 2
Arkansas One-1
Hatch 1
Rancho Seco*
Calvert Cliffs 1, 2
Fitzpatrick*
Cook 1, 2
Brunswick 1, 2
Trojan
St. Lucie 1
Beaver Valley 1
Salem 1
Crystal River 3
Davis-Besse 1
Farley 1
North Anna 1

*Owned by a public utility.

Coal-Fired Generating Plants Included in
1979 Generating Cost Analysis

(Includes only units rated 500 MWe and
larger, entering service from 1965 on)

Plant (State)	
Belews Creek	(N.C.)
Marshall	(N.C.)
Dan E. Karn 3, 4	(Mich.)
Monroe	(Mich.)
Mitchell	(W. Va.)
Miami Fort 7, 8	(Ohio)
Columbia	(Wisc.)
Collins 1, 4	(Ill.)
Powerton	(Ill.)
Gibson	(Ind.)
Bull Run*	(Tenn.)
Cumberland*	(Tenn.)

Cayuga	(Ind.)
Martin Lake	(Tex.)
Monticello	(Tex.)
Wansley**	(Georgia Power and Municipal Electric Authority of Georgia parts only, 68.7 percent) (Ga.)
Bowen	(Ga.)
Miller 1	(Ala.)
Four Corners** 4,5	(So. Cal. Edison, Arizona P.S. and Salt River Project parts only, 73 percent) (N.M.)
Navajo**	(Arizona P.S. and Salt River Project parts only, 35.7 percent) (Ariz.)
Mohave**	(So. Cal. Edison and Salt River Project parts only, 66 percent) (Nev.)
Coffeen	(Ill.)
Newton	(Ill.)
Baldwin	(Ill.)
Ghent	(Ken.)
Welsh	(Tex.)
Allen S. King	(Minn.)
Sherburne County	(Minn.)
Labadie	(Mo.)
Sioux	(Mo.)
Rush Island	(Mo.)
Roxboro	(N.C.)
Conesville 4	(Ohio)
J. M. Stuart	(Ohio)
James M. Gavin	(Ohio)
Cheswick	(Pa.)
Bruce Mansfield	(Pa.)
Homer City	(Pa.)
Montour	(Pa.)
Hatsfields Ferry	(West Penn. Power and Monongahela Power parts only, 80 percent) (Pa.)
Big Brown	(Tex.)
Monticello	(Tex.)
Mount Storm	(W. Va.)
Harrison	(West Penn. Power and Monongahela Power parts only) (W. Va.)
Fort Martin	(West Penn. Power and Monongahela Power parts only) (W. Va.)
Centralia	(Wash.)
Jim Bridger	(Wyo.)

* Wholly owned by a public utility.
** Partly owned by a public utility.

Source: "UPDATE - Nuclear Power Program Information and Data," May/June 1980, Prepared by Office of Nuclear Reactor Programs, U.S. Department of Energy.

III. ECONOMICS

A. Comparison of Private Utility Nuclear and Coal-Fired Power Plant Generation Costs in 1979

Introduction

The Nation's investor-owned electric utilities submit annually (on Form 1) to the Energy Information Administration, Department of Energy, information on their operations for the previous year, including economic and operational data on existing generating stations. This article reviews the economic performance of nuclear and coal-fired generating stations included in the Form 1 reports for 1979 operations.

The data bases for this analysis of power plant generating costs include all private utility nuclear generating units rated over 400 megawatts-electric (MWe) in power capacity that were in commercial operation for the entire year of 1979 and the great majority of coal-fired power plants with units rated 500 MWe or over installed from 1965 on. A few coal-fired plants were omitted because of lack of complete data. The coal-fired units are large units, generally in the age bracket of the nuclear units,[1/] and of higher than average plant thermal efficiency, so that most are suitable for base-loading and for comparison with nuclear units.

1/ The size-weighted mean date for entry into commercial service of the nuclear units occurs in July 1974, while that of the coal-fired units occurs about a year earlier.

The nuclear units and coal-fired plants included in this analysis are identified in the appendix to this article. The nuclear units listed generated 78.7 percent of all nuclear powered electricity produced in the U.S. in 1979 and the coal-fired plants identified produced about 31 percent of all 1979 U.S. electric generation fueled by coal.

National Average Production Costs

The Form 1 data includes the capital cost and the production expenses (fuel, operation, maintenance and supplies) of each nuclear and coal-fired generating station identified in the appendix. The national averages of the production costs for 1979 are shown in Table 1.

Table 1

National Averages of U.S. Private Utility Nuclear and Coal-Fired Power Plant Production Costs for 1979

	Average Unit Costs (mills/Kwh)	
Cost Category	Nuclear	Coal
Fuel (actual)	3.92	12.52
Operation, Maintenance and Supplies (O&M) (actual)	4.25	2.19
Production (actual)	8.17	14.71

The average production cost of 14.71 mills per kilowatt-hour (mills/Kwh) shown in Table 1 for the coal-fired plants is 80 percent higher than the 8.17 mills/Kwh for the nuclear units.

This is due to the much higher fuel costs experienced by the coal-fired plants (12.52 mills/Kwh vs. 3.92 mills/Kwh for nuclear plants), which easily overshadows their lower O&M expenses (2.19 vs. 4.25 mills/Kwh).

National Average Generation Costs

Although the capital cost of each generating station is reported in Form 1, the fixed charges on plant investment that contribute to the station's cost of generating electricity are not included. Consequently, the total generating cost (production cost plus fixed charges related to the plant investment) cannot be obtained directly from the Form 1 data. Nevertheless, reasonable assumptions regarding fixed charges can be made, and estimated total generating costs can be calculated for the purpose of comparing nuclear plant generating costs with those of coal-fired power plants on a consistent basis.

A fixed charge rate (FCR) of 17 percent is used for estimation of the 1979 generating costs shown in Table 2. It corresponds to the costs of money and tax rates of recent years[2/] and, since the same FCR was used for similar analyses over the past several years, it facilitates discussion of recent generating cost trends. Of course, the FCR varies for individual utilities because of different

2/ The makeup of a 16.84 percent FCR on depreciating assets is presented in Appendix A of Nuclear Regulatory Commission publication NUREG-0480, entitled "A Comparison of the Cost of Generating Baseload Electricity by Region, October 1978," by J. O. Roberts, S. M. Davis, and D. A. Nash of the NRC. The 9.57 percent weighted cost of capital included in the 16.84 percent is based on statistics over the period 1973-1977.

debt servicing costs, returns on equity, tax rates, etc. The effect of variation of the FCR is footnoted in Table 2.

Estimated average 1979 generating costs of investor-owned nuclear and coal-fired plants are shown in Table 2.

Table 2

National Averages of U.S. Private Utility Nuclear and Coal-Fired Power Plant Generating Costs for 1979

Cost Category	Average Unit Costs (mills/Kwh)	
	Nuclear	Coal
Fuel (actual)	3.92	12.52
O&M (actual)	4.25	2.19
Capital (estimated)	14.03	7.81
Generating (estimated)	22.20	22.52

Note: The average capital costs shown in Table 2 are calculated using an assumed fixed charge rate of 17 percent. If an FCR of 18 percent were assumed the estimated generating costs would be: nuclear, 23.02 mills/Kwh and coal, 22.98 mills/Kwh. If the FCR were 16 percent, the results would be: nuclear, 21.37 mills/Kwh and coal, 22.06 mills/Kwh.

The results shown in Table 2 indicate a standoff in 1979 generating costs between the nuclear and coal-fired plants considered in the analysis. This contrasts with previous experience, where nuclear power exhibited significantly lower generating costs.

The difference in 1979 was due not so much to the increased capital costs of new nuclear units in service in 1979 or to higher fuel costs. Rather, it was due to the severe drop in the generation of electricity by nuclear plants resulting from nuclear unit shutdowns brought about by the Three Mile Island (TMI) accident and other unusual causes. As reported by the Nuclear Regulatory Commission (NRC), the average availability of U.S. nuclear units in 1979 was 67.9 percent, compared to 74.8 percent in 1978 and 73.4 percent in 1977.3/ This six to seven percentage point drop in average nuclear unit availability largely reflects the effects of the accident at TMI unit 2 and the shutdowns for piping system seismic adequacy checks required by the NRC for five nuclear units. These events alone were responsible for about a five percentage point decline in the average availability and productivity of U.S. nuclear units in 1979.4/ The result is that nuclear plants generated less electricity in the U.S. in 1979 than in 1978, despite the entry into commercial service of two additional units. Thus, a higher nuclear capital cost investment in 1979 was spread across a reduced production of electricity by U.S. nuclear units, resulting in an unusual

3/ See March/April 1980 UPDATE, page 91, "NRC Data on 1979 Nuclear Power Plant Performance."
4/ Ibid, page 92.

jump in the capital cost portion of the generation cost and in the generating cost itself.

The amount of this increase in capital and generating cost compared to former years is shown in Table 3.

Table 3

National Averages of U.S. Nuclear Power Plant Generating Costs

Cost Category	Average Unit Costs (mills/Kwh) 1977	1978	1979
Fuel (actual)	2.85	3.22	3.92
O&M (actual)	2.46	2.95	4.25
Capital (estimates)1/	9.15	10.53	14.03
Generating (estimated)	14.46	16.70	22.20
Capacity Factor (%)2/	64.6	66.6	58.2

1/ The fixed charges on capital costs for investor-owned utility nuclear units are calculated using a FCR of 17 percent for all years shown. The capital cost averages indicated for 1977 and 1978 include the costs of nuclear units owned by public utilities as well, where a FCR of 11 percent was assumed. Elimination of the public utility units in 1978 would increase the average capital cost and generating cost only 0.46 mills.

2/ Capacity factor is the ratio of the electric energy produced by a generating station over a certain period of time to that which would be produced if the station generated continuously at its full capacity over the whole period (usually expressed as a percent).

That portion of the average unit generating cost due to a fixed charge on the plant capital cost rose from 10.53 mills/Kwh in 1978 to 14.03 mills/Kwh in 1979, a 33 percent increase in one year (a 28 percent increase if the comparison is limited to units owned by investor-owned utilities). In contrast, the rise a year previous was 15 percent. The reduced generation from nuclear plants in 1979 is largely responsible for this rise in unit capital cost, as evidenced by the 58.2 percent capacity factor last year compared to 66.6 percent the previous year.

The effect of the decline in productivity in 1979 is also noticeable in the 44 percent rise in operating and maintenance (O&M) unit cost, from 2.95 mills/Kwh in 1978 to 4.25 mills/Kwh in 1979; part of the plant O&M costs are fixed regardless of the amount of electricity generated. On the other hand, fuel cycle costs are less susceptible to the annual productivity of the plant, as exemplified by the 22 percent increase in the nuclear fuel unit cost between 1978 and 1979. Still, this was greater than the 13 percent increase a year earlier, and reflects to some extent rising uranium concentrate and processing cost levels over the past several years as well as allowances for spent fuel storage and disposal.

It should be noted that the capacity factor of 58.2 percent shown for 1979 in Table 3 corresponds to the NRC net generation and the "net maximum dependable capacity" (MDC net) reported for each nuclear unit by the NRC. These NRC MDC net ratings are identical or usually very close to the "net continuous plant capability" ratings given in the Form 1 reports for nuclear plants. Interestingly enough, the capacity factor average for the coal-fired plants included for Table 2 is also 58.2 percent, based on their Form 1 net generation and net continuous plant capability ratings.

Regional Costs

A regional breakdown of the generating costs in Table 2 is shown in Table 4. Examination of the information in Table 4 reveals the following:

(a) For investor-owned utilities the East North Central and West North Central regions exhibit the lowest estimated nuclear plant generating costs. The lowest estimated coal-fired plant generating costs occur in the South and in the West North Central and Far West regions. Such would be expected in the case of the coal-fired plants because of the cheaper delivered cost of nearby coal.

(b) The generating costs of nuclear and coal-fired plants for 1979 shown in Table 4 do not fit the pattern usually projected for future comparative costs, which call for nuclear power generally to be most competitive east of the Mississippi River and coal-fired plants to be relatively more economical when sited near cheap western coal. Table 4 shows a small number of nuclear units in the West North Central region generating at 4.6 mills/Kwh less than coal-fired plants in the same area,

Table 4
1979 Private Utility Nuclear and Coal-Fired Steam-Electric Generating Station
Generating Costs by U.S. Region

Region 1/	Fuel	No. of Units	Capacity Factor (%) 2/	Generation (Mwh Net)	Costs (mills/Kwh) Fuel (A) 3/	O&M (B) 3/	Production (A&B) 3/	Capital (C) 4/	Generating (A&B&C) 4/
Northeast	Nuclear	9	69.2	36,326,235	4.77	4.61	9.38	10.13	19.51
	Coal	0	-	-	-	-	-	-	-
Middle Atlantic	Nuclear	9	50.5	34,729,381	3.83	5.46	9.29	21.54	30.83
	Coal	12	66.7	38,701,319	12.92	2.48	15.40	8.64	24.04
South	Nuclear	16	50.6	54,622,899	3.83	4.50	8.33	16.14	24.47
	Coal	28	64.3	97,485,726	11.00	2.15	13.15	6.30	19.45
East North Central	Nuclear	13	61.8	53,629,387	3.56	3.57	7.13	10.75	17.88
	Coal	44	53.2	135,283,884	14.92	1.78	16.70	8.37	25.07
West North Central	Nuclear	4	80.0	13,525,865	3.79	2.41	6.20	9.87	16.07
	Coal	11	59.0	32,249,291	11.26	2.01	13.27	7.43	20.70
Far West	Nuclear	2	64.9	7,931,325	3.72	3.32	7.04	13.73	20.77
	Coal	13	55.0	26,509,875	6.79	4.23	11.02	9.76	20.78
U.S.A.	Nuclear 5/	53	58.2	200,765,092	3.92	4.25	8.17	14.03	22.20
	Coal 5/	108	58.2	330,230,095	12.52	2.19	14.71	7.81	22.52

1/ States in each region are listed on the next page.
2/ Capacity Factor: Ratio of plant's generation in 1979 to product of plant maximum dependable capacity and hours in 1979, expressed as a percentage.
3/ Actual cost, as reported by utilities to the DOE.
4/ Estimated cost at 17 percent fixed charge rates.
5/ Costs are weighted averages.

DOE/NPDD

Table 4 (cont.)

Definitions of regions:

Northeast: New England States and New York

Middle Atlantic: Pennsylvania, New Jersey, Maryland and Delaware

South: Virginia, North and South Carolina, Georgia, Florida, Tennessee, Alabama, Mississippi, Texas, Lousiania, Arkansas, Oklahoma

East North Central: Ohio, Indiana, Michigan, Illinois, Wisconsin, Kentucky and West Virginia

West North Central: Minnesota, Iowa, Nebraska, Kansas, Missouri, North and South Dakota

Far West: Mountain and Pacific States

two nuclear units generating at the same cost level as coal-fired plants in the Far West, and coal more economical than nuclear power by 5 to 7 mills/Kwh in the South and Middle Atlantic regions.

(c) The foregoing results are largely explained by the relative productivity of the plants. In the western states the nuclear units on the average operated at high capacity factors, having correspondingly low capital cost components of generating cost. The four nuclear units in the West North Central region operated at an average of 80 percent capacity factor, 21 percentage points higher than the coal-fired plants in the same region, whereas the two nuclear units in the Far West enjoyed an average capacity factor almost 10 percentage points higher than the corresponding coal-fired units. In the Middle Atlantic states and the South the story was different; the nuclear units performed at little more than 50 percent capacity factor, compared to 66.7 percent and 64.3 percent respectively for the coal-fired units in these regions.

(d) If the average regional costs in Table 4 were adjusted to reflect operation of all plants at the same capacity factor, the results would be closer to the pattern mentioned in (b), although an actual change in status would be likely to occur only in the Far West. At universal 65 percent capacity factor operation, for instance, the average generating costs of nuclear and coal-fired plants would be within about 5 percent of each other in the South and Middle Atlantic regions; those of the coal-fired plants would still be lower. In the East North Central and West North Central regions nuclear power would still be more economical, although by smaller margins - less than 10 percent in the case of the West North Central region. In the Far West, a 10 percentage point increase in average capacity factor for the large coal-fired plants, which are located near the mining of inexpensive coal, would put their average generating cost close to 10 percent below that of the two nuclear units.

(e) As might be expected, nuclear fuel costs were fairly uniform over the Nation, the largest variation occurring in the Northeast at 21.7 percent above the 3.92 mills/Kwh national average. The coal-fired cost varied more, that for the Far West being little more than half the national average of 12.52 mills/Kwh, while the average for the East North Central region was 19.2 percent higher than the national figure.

o The O&M costs in Table 4, which include fixed costs such as the salaries of plant and support personnel, reflect partially the variation in plant productivity. For the nuclear units, only in the instance of the Northeast region does the O&M cost fail to vary inversely with the regional capacity factor. In said case the 4.61 mills/Kwh of the region is higher than the 4.25 mills national average, even though the Northeast region capacity factor is well above the 58.2 percent national average. The O&M costs for the coal-fired plants do not seem to be as closely related to plant productivity.

No coal-fired plants are included for the Northeast region in Table 4. Oil is still the predominant fuel in New England and southern New York, and is no match economically for either nuclear power or coal-fired plants in generating base-load electric energy. A recent report by Northeast Utilities states that the fuel cost alone of oil is 42 mills/Kwh in New England.5/

Postscript

Since the foregoing analysis of investor-owned utility generation economics was written, Form 1 data on public utility power plants has become available. Inclusion of the data on the eight public utility nuclear units6/ with that of the private utility nuclear units identified in the appendix yields the national average nuclear generation cost components for 1979 shown in Table 5.

In view of lack of time, it was not possible to expand this article to a comparison of private and public utility nuclear plants with base-load coal-fired plants that include representative public utility units. It is planned to do this in the next issue of UPDATE.

5/ November/December 1979 UPDATE, page 113.

6/ Brouns Ferry 1, 2 and 3, Fort Calhoun, Cooper, Indian Point 3, Rancho Seco, and Fitzpatrick.

Table 5

National Averages of U.S. Nuclear Power Plant Generating Costs for 1979

Cost Category	Average Unit Costs[1/] (mills/Kwh)
Fuel (actual)	3.73
O&M (actual)	4.11
Capital (estimated)[2/]	12.83
Generating (estimated)	20.67

1/ The fuel and O&M unit costs are based on production expenses reported for all 53 private utility units and 8 public utility units. The capital unit costs are based on data for all units except Fitzpatrick and Indian Point-3, for which capital costs were not reported.

2/ An assumed fixed charge rate of 17 percent is applied to the capital costs of the private utility units and 11 percent to those of 6 public utility units. The size-weighted capacity factor for all 61 units is 59.8 percent, compared to the 58.2 percent reported for the private utility units only.

Appendix

Nuclear Generating Units Included in 1979 Generating Cost Analysis

(Includes only units rated over 400 MWe)

San Onofre 1
Haddam Neck (Conn. Yankee)
Oyster Creek
Nine Mile Point 1
Dresden 2, 3
Indian Point 2
Ginna
Robinson 2
Millstone Point 1, 2
Point Beach 1, 2
Monticello
Palisades
Quad Cities 1, 2
Vermont Yankee
Pilgrim 1
Surry 1, 2
Maine Yankee
Turkey Point 3, 4
Oconee 1, 2, 3
Zion 1, 2
Peach Bottom 2, 3
Prairie Island 1, 2
Duane Arnold 1/
Kewaunee
Three Mile Island 1, 2
Arkansas One-1
Hatch 1 1/
Calvert Cliffs 1, 2
Cook 1, 2
Brunswick 1, 2
Trojan
St. Lucie 1
Beaver Valley 1
Salem 1
Crystal River 3
Davis-Besse 1
Farley 1
North Anna 1

1/ Partly owned by public utilities; data corresponding to public utility participation not included.

Coal-Fired Generating Plants Included in 1979 Generating Cost Analysis

Plant (State)	
Belews Creek	(N.C.)
Marshall	(N.C.)
Dan E. Karn 3, 4	(Mich.)
Monroe	(Mich.)
Mitchell	(W. Va.)
Miami Fort 7, 8	(Ohio)
Columbia	(Wisc.)
Collins 1, 4	(Ill.)
Powerton	(Ill.)
Gibson	(Ind.)

Cayuga	(Ind.)
Martin Lake	(Tex.)
Monticello	(Tex.)
Wansley	(Ga.)
Bowen	(Ga.)
Miller 1	(Ala.)
Four Corners 4, 5	(So. Cal. Edison and Arizona P.S. parts only, 63 percent) (N.M.)
Navajo	(Arizona P.S. part only, 14 percent) (Ariz.)
Mohave	(So. Cal. Edison part only, 56 percent) (Nev.)
Coffeen	(Ill.)
Newton	(Ill.)
Baldwin	(Ill.)
Ghent	(Ken.)
Welsh	(Tex.)
Allen S. King	(Minn.)
Sherburne County	(Minn.)
Labadie	(Mo.)
Sioux	(Mo.)
Rush Island	(Mo.)
Roxboro	(N.C.)
Conesville 4	(Ohio)
J. M. Stuart	(Ohio)
James M. Gavin	(Ohio)
Cheswick	(Pa.)
Bruce Mansfiled	(Pa.)
Homer City	(Pa.)
Montour	(Pa.)
Hatsfields Ferry	(West Penn. Power and Monongahela Power parts only, 80 percent) (Pa.)
Big Brown	(Tex.)
Monticello	(Tex.)
Mount Storm	(W. Va.)
Harrison	(West Penn. Power and Monongahela Power parts only) (W. Va.)
Fort Martin	(West Penn. Power and Monongahela Power parts only) (W. Va.)
Centralia	(Wash.)
Jim Bridger	(Wyo.)

June 78 UPDATE

III. ECONOMICS

A. Analysis of U.S. Nuclear Power Plant Generating Costs for 1977

Summary

Review of the cost information for 1977 nuclear power plant operations reported by the Nation's electric utilities in their annual Form 1 returns to the Department of Energy reveals encouraging economic results, which are summarized as follows:

- Actual production costs, consisting of fuel and operation and maintenance costs, were still in the one-half cent per kilowatt-hour (Kwh) range for 1977 (5.3 mills/Kwh vs. 5.0 mills/Kwh for 1976).

- Estimated total generating costs for 1977 remained almost constant compared to 1976 (14.5 mills/Kwh vs. 14.6 mills/Kwh for 1976).

- The newer nuclear units showed somewhat better fuel cycle costs, although the improvement is slight for units entering service from 1971 on.

- Although 1977 production costs were about the same for units entering service from 1971 on, the 1977 generating costs of the later vintage plants were higher, due to the effect of price escalation, higher financing costs and longer lead times on their capital costs.

- Production costs demonstrated economy of scale; for units entering service in the period 1973-1976 production costs decreased from 5.32 mills/Kwh for units in the 400-749 megawatt-electric (MWe) size category to 4.61 mills/Kwh for units rated 1000 MWe and above.

- On the other hand, when estimated fixed charges on capital are added to the foregoing production costs to calculate estimated total generating costs, the latter are higher for the bigger units (15.4 mills/Kwh for 1000 MWe units and larger vs. 14.0 mills/Kwh for units in the 400-749 MWe category). This phenomenon is due to the operation of the larger units at a lower average capacity factor and consequent relatively higher unit capital costs. Even if all units in service in 1977 were to operate at the same capacity factor, little economy of scale would be demonstrated in the capital cost portion of generating costs.

- On a regional basis, the highest production costs during 1977 were experienced in the Northeast and Middle Atlantic sections of the country, and the lowest in the South and East North Central regions. The same was true for estimated total generating costs.

Introduction

The Nation's electric utilities submit annually (on Form 1) to the Energy Information Administration, Department of Energy (formerly to the Federal Power Commission), information on their operations for the previous year, including economic and operational data relating to their operable generating stations. This article reviews the economic performance of 62 nuclear generating units (identified in the appendix following) included in the Form 1 reports for 1977 operations. Results are analyzed in terms of their age, size and regional location.

National Average Costs

The Form 1 data includes capital cost and the production expenses (fuel, operation, maintenance and supplies) of each generating station (these costs are not reported for individual units within each station). The national averages of these production costs are shown on the following page in Table 1, which also includes corresponding costs for 1976 (reported in the June, 1977 issue of UPDATE).

Production costs overall rose about 6 percent in 1977 compared to those of 1976 (a rise about equal to the national inflation rate), with the increase almost equally divided between fuel and O&M costs. They are still within the half-penny per kilowatt-hour range, however, and the 2.85 mill/Kwh fuel cost

Table 1

National Averages of U.S. Nuclear

Power Plant Production Costs for 1977

Cost Category	Average Unit Costs (mills/Kwh) 1977	1976
Fuel (actual)	2.85	2.7
Operation, Maintenance and Supplies (O&M) (actual)	2.46	2.3
Production (actual)	5.31	5.0

compares favorably with the 11 to 23 mill/Kwh 1977 fuel costs reported elsewhere for fossil-fuel generating stations.1/

Although the capital cost of each generating station is reported in Form 1, fixed charges on plant investment allocated to the station's cost of generating electricity are not included. Consequently, the total generating cost (production cost plus fixed charges related to the plant investment) cannot be obtained directly from the Form 1 data. Nevertheless, reasonable assumptions regarding fixed charges can be made, and estimated total generating costs can be calculated for purposes of determining variations in nuclear generating costs and comparing them with those of fossil-fuel power plants on a consistent basis.

1/ Atomic Industrial Forum "Info" News Release of 4/20/78.

The fixed charges on capital costs used for estimation of the 1977 generation costs indicated in this article are the same as used previously for calculation of 1976 generating costs.[2/] The fixed charges were calculated based on a constant fixed charge rate (FCR), or constant percentage of the total capital cost. Discussions with several utility and trade association cost analysts have indicated considerable variance within the utility industry in the method for determining this rate. Even if the same accounting methods were used, the FCR would vary considerably from utility to utility because of different debt servicing rates, returns on equity, and tax rates. For investor-owned utilities an average FCR of 17% was used, based on the following assumptions:

cost of debt and return on equity	8.7%
depreciation (30-year straight line)	3.3%
taxes, insurance and miscellaneous	5.0%
Total FCR	17.0%

Discussions with a number of investor-owned utility cost analysts in 1977 indicated that 17% was a reasonable average for the private industry at that time. For publicly-owned utilities the FCR used was 11%.

2/ June 1977 UPDATE, pages 28 and 29.

The results of applying these fixed charge rates to the actual plant capital costs reported by the utilities are shown in Table 2 below:

Table 2

National Averages of U.S. Nuclear Power Plant Generating Costs for 1977

Cost Category	Average Unit Costs (mills/Kwh) 1977	1976
Fuel (actual)	2.85	2.7
O&M (actual)	2.46	2.3
Capital (estimated)	9.15	9.6
Generating (estimated)	14.46	14.6

It is evident that the capital cost portion of the generating cost was lower in 1977 than in 1976 (9.15 mills/Kwh vs. 9.6 mills/Kwh). The reason is not due to lower capital costs for the nuclear units operating in 1977 but rather to their higher productivity compared to that of the previous year -- a significantly greater number of kilowatt hours were generated by nuclear units in 1977 than in 1976; thus the base over which the fixed capital charges could be spread is enlarged. The size-weighted average capacity factor in 1977 for the nuclear units was 64.6% whereas that for 1976 was 59.7%.

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The drop in capital fixed charges in 1977 from 1976 almost offset the increase in production costs, so that the average total generating cost in 1977 was less than one percent higher than in 1976.

Effect of Unit Age

In order to examine the effect of unit age on costs the nuclear generating units were segregated by year of initial commercial operation. The components of the average 1977 generating cost for each age group are shown in Table 3 and Figure 1. The plots depict a fairly constant 1977 production cost for each group that entered service from 1971 on, but the capital charges were significantly higher for the later vintage plants, with consequently higher generating costs. This demonstrates graphically the impact of price escalation, rising financing costs and longer project lead times on capital costs over the 1970's and the consequent effect on generating costs. For units that entered service in 1970 the fixed charges on the capital cost represent 46% of generating cost; for units initiating service in 1976 the capital cost portion had risen to 77%.

Effect of Unit Size

The influence of price escalation, increasing financing costs for utilities and longer nuclear plant project lead-times during the 1970's has masked the effect of economy of scale

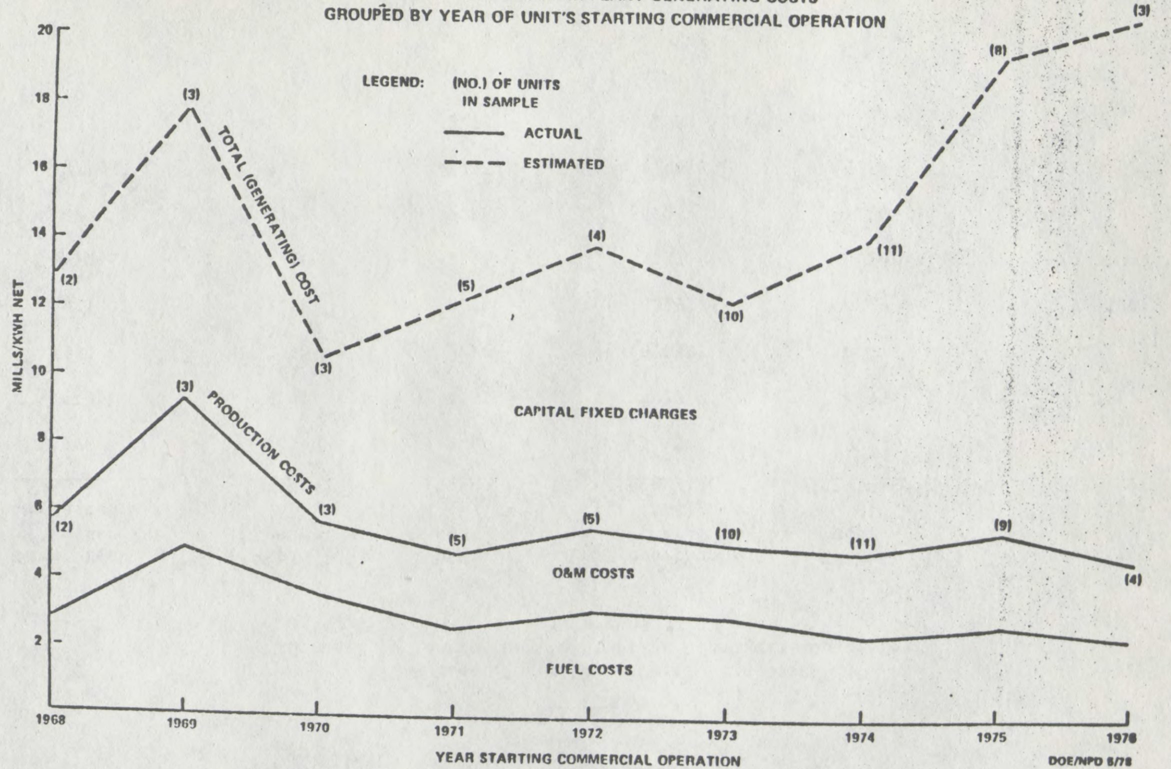
Table 3

1977 Nuclear Power Plant Generating Costs
Grouped by Year of Unit's Starting Commercial Operation
(mills/kwh)

First Year of Commercial Operation	Fuel Costs (A) (actual)	O&M Cost (B) (actual)	Production Cost (A&B) (actual)	Capital Cost (C) (estimated)	Generating Cost (A&B&C) (estimated)
1968	2.79	2.86	5.65	7.23	12.88
1969	4.91	4.31	9.22	8.55	17.77
1970	3.48	2.17	5.65	4.87	10.52
1971	2.58	2.21	4.79	4.79	9.58
1972	3.16	2.41	5.57	8.20	13.77
1973	2.98	2.08	5.06	7.16	12.22
1974	2.46	2.45	4.91	9.14	14.05
1975	2.82	2.73	5.55	13.84	19.39
1976	2.42	2.25	4.67	15.90	20.57

Figure 1

1977 NUCLEAR POWER PLANT GENERATING COSTS
GROUPED BY YEAR OF UNIT'S STARTING COMMERCIAL OPERATION



expected of the larger nuclear units coming into operation in recent years. The results of an examination of the 1977 generating costs for evidence of economy of scale are presented in Table 4.

Averages of 1977 generating costs for these size ranges of nuclear units put into commercial service over the period 1973-1976 are shown in Table 4. The 1973-1976 vintage period was chosen because greater numbers of the larger size units began coming on line in 1973; the four-year period also affords a larger number of units in each size category for statistical treatment than would be the case for individual years.

It is evident in Table 4 that the production costs decreased somewhat with unit size (5.32 mills/Kwh for the 400-749 MWe category, 5.16 mills for the 750-999 MWe category and 4.61 mills for 1000 MWe units and larger). This is not surprising in view of the reduced manning and overhead per unit of power rating of the larger plants. However, the capital costs corresponding to the actual generating output of the plants are higher for the larger units than for those in the 400 to 749 MWe size category. The explanation for this lies in the fact that the units in the 400 to 749 MWe range operated at an average capacity factor of about 73% during 1977 while the larger units operated at 57 to 58%. If the capital costs

Table 4

1977 Generating Costs of U.S. Nuclear Power Plants
Entering Service in 1973-1976, Grouped by Size

			Unit Costs (mills/Kwh)				
		Actual Average Capacity Factor (%)	Production	Capital (estimated)		Generating (estimated)	
Size Range	No. of Units		Actual	At Actual C.F.*	Adjusted to 65% C.F.*	At Actual C.F.*	Cap. Cost Adjusted to 65% C.F.*
400-749 MWe	7	73.3	5.32	8.68	9.82	14.0	15.14
750-999 MWe	17	57.3	5.16	10.84	9.27	16.0	14.43
1000 MWe and above	7	57.8	4.61	10.82	9.63	15.43	14.24

*Capacity Factor

were adjusted to an arbitrary 65% capacity factor operation for all sizes of units, the average for the larger units would be lower than the average for the 400-749 MWe category, but only slightly so. Most of the economy of scale seems to reside in production costs, at least in the case of the 1977 generating costs.

Regional Costs

Average nuclear power plant production costs and estimated total generating costs for 1977 in the various regions of the U.S. are depicted in Figure 2. Regardless of the effect of when the units in each region entered service, the lowest production costs occurred in the South and East North Central regions (the states in each region are listed in Table 5), while units in the Northeast and Middle Atlantic regions had the highest production costs. The lowest estimated average generating cost is shown as occurring in the East North Central region, with the South having the next lowest generating cost. The highest generating cost is indicated as occurring in the Middle Atlantic region, followed by that of the Northeast region.

Again it should be noted that the capital cost portion of the total generating cost (shown by the dashed lines) is a calculated value based on consistent treatment of actual plant capital costs reported by the utilities, and, therefore, probably varies somewhat with the average of the actual

Figure 2

1977 NUCLEAR POWER PLANT GENERATING COSTS BY U.S. REGION

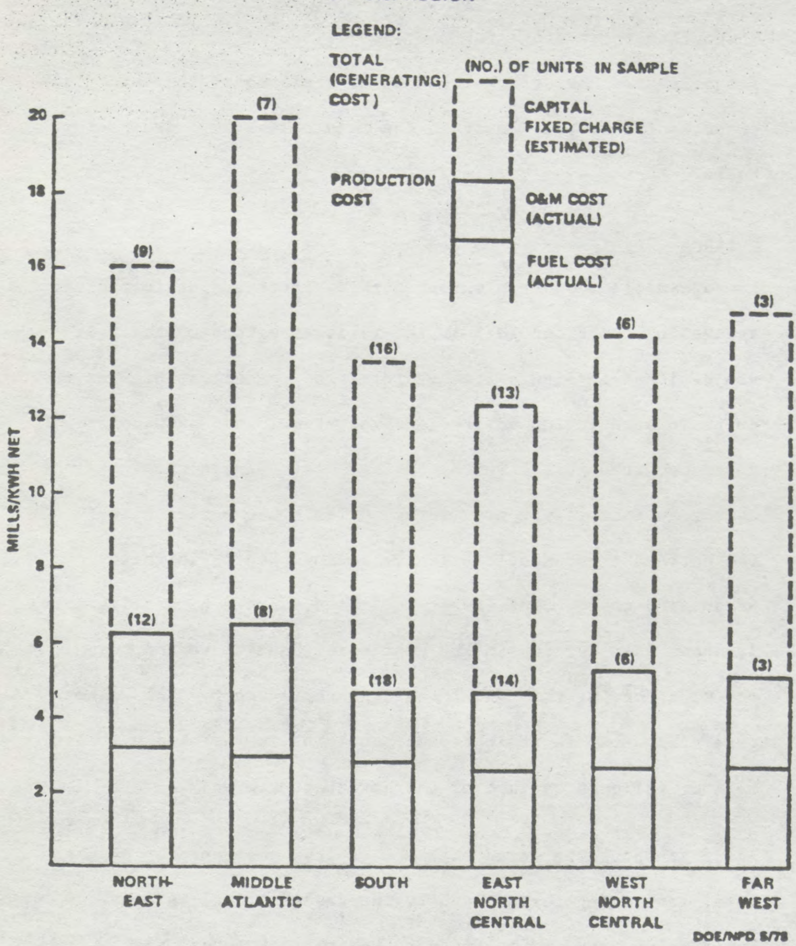


Table 5

1977 Generating Costs of U.S. Nuclear Power Plants
Segregated by Regions

Region	Average Unit Cost (mills/Kwh) (A)	Average Year of Initial Commercial Operation	U.S. Average Generating Cost Corresponding to Initial Year of Commercial Operation (from Figure 1) (B)	Ratio A/B	Ranking by Cost
Northeast	16.10	1970.1	10.6	1.52	6
Middle Atlantic	19.99	1974.1	14.6	1.37	5
South	13.53	1974.1	14.6	0.93	1
East North Central	12.37	1972.5	13.0	0.95	2
West North Central	14.31	1973.3	12.9	1.11	3
Far West	14.85	1973.0	12.2	1.22	4

Northeast: New York and New England States

Middle Atlantic: Pennsylvania, New Jersey, Maryland and Delaware

South: Virginia, North and South Carolina, Georgia, Florida, Tennessee, Alabama, Mississippi, Texas, Louisiana, Oklahoma, Arkansas

East North Central: Ohio, Indiana, Michigan, Illinois, Wisconsin, Kentucky and West Virginia

West North Central: Minnesota, Iowa, Nebraska, Kansas, Missouri, North and South Dakota

Far West: Mountain and Pacific States

generating costs in each utility's own accounts. The comparative relationship between average regional generating costs should not vary too much, however, from that shown in Figure 2.

A factor that could affect the ranking of the costs indicated in Figure 2 is the age of the units in each region -- units entering service in the last few years were more expensive to build and have higher charges related to their capital costs, as indicated in Figure 1.

The data shown in Table 5 affords a measure of how the time when the units in each region entered service affects the ranking of regional generating costs. The utility schedules for entry into service are known by month and year for each unit. The average of these schedules for each region ("average year") is indicated in the third column of Table 5. The national average unit cost for all units corresponding to each regional "average year" (Figure 1) is listed in the fourth column of Table 5. The average unit generating cost in each region (second column) is then compared to the national average cost of the same time period, and the ratio of the two is shown in the next-to-last column of Table 5. It is evident that the average cost of the Northeast region has the highest ratio (1.52) compared to the national average cost for its "average year". The South has the lowest ratio (0.93).

Measured against concurrent national cost levels, then, the Northeast region can be said to experience the highest generating costs for its nuclear units, with the Middle Atlantic region next highest. The lowest costs occur in the South and East North Central areas.

Appendix

Nuclear Generating Units Included in 1977 Generating Cost Analysis

Dresden 1, 2, 3
Yankee (Rowe)
Indian Point 2, 3
Big Rock Point
San Onofre 1
Haddam Neck (Conn. Yankee)
La Crosse (Genoa)
Oyster Creek
Nine Mile Point 1
Ginna
Robinson 2
Millstone Point 1, 2
Point Beach 1, 2
Monticello
Palisades
Quad Cities 1, 2
Vermont Yankee
Pilgrim 1
Surry 1, 2
Maine Yankee
Turkey Point 3, 4
Oconee 1, 2, 3

Zion 1, 2
Browns Ferry, 1, 2, 3
Fort Calhoun
Peach Bottom 2, 3
Prairie Island 1, 2
Cooper
Duane Arnold
Kewaunee
Three Mile Island 1
Arkansas One-1
Hatch 1
Rancho Seco
Calvert Cliffs 1, 2
Fitzpatrick
Cook 1
Brunswick 1, 2
Trojan
St. Lucie 1
Beaver Valley 1
Salem 1
Crystal River 3
Davis-Besse 1
Farley 1

B. Examination of 1977 Fossil-Fuel Plant Generating Costs

In the preceding article an analysis is presented of nuclear power plant generating costs for 1977, based on data reported to the Energy Information Administration, Department of Energy (DOE) by U.S. electric utilities. For purposes of comparison with these nuclear costs, 1977 cost information available from the same source on a number of fossil-fuel plants is analyzed here. In most cases these fossil-fuel plants are part of utility systems that presently include at least one operating nuclear power station or for which nuclear power stations are planned in the future. Time and resources allowable for this analysis prevented inclusion of all fossil-fuel steam-electric generating stations suitable for base-load operation in its scope, so that the comparisons of generating costs in this article are to be taken as indicative only.

National Cost Averages

The results of these analyses of U.S. nuclear and coal-fired plant costs, averaged on a national basis, are presented in Table 1.

Table 1

Nuclear and Fossil-Fuel Generating Costs
National Averages for 1977
(Mills/Kwh)

Costs	Nuclear	Coal
Fuel (actual)	2.85	9.40
O&M (actual)	2.46	1.68
Production (actual)	5.31	11.08
Capital (estimated)	9.15	6.18
Generating (estimated)	14.46	17.26
Capacity Factor (%)	64.6	60.0

NOTES:

1. Costs are based on utility data reported to the DOE on 45 nuclear plants (totaling 62 units) and 34 multiunit coal-fired plants.

2. Production costs (fuel + O&M) are averages of actual costs reported by the utilities. Capital costs (and therefore generating costs also) are estimated, based on assumed fixed charge rates and reported actual investment costs, as explained in the text.

The coal-fired power plant costs shown in Table 1 are based on a data sample consisting of 34 multi-unit stations that generated about 26% of the total electricity produced by U.S. coal-fired power plants in 1977. These stations are of fairly recent construction, consisting mostly of large units having higher than average thermal efficiencies, and are therefore suitable for base-loading and for comparison with nuclear units.

The average production cost shown in Table 1 for the coal-fired stations is more than twice that of the nuclear plants. This is largely due to the much higher average fuel costs of the coal-fired plants, 9.40 mills/KWh, compared to 2.85 mills for the nuclear units.

The fixed charges on fossil-fuel plant capital costs were calculated on the same basis as for the 1977 nuclear generating costs (see preceding article). Thus a fixed charge rate (FCR) of 17% was used for investor-owned utilities, and 11% for publicly-owned utilities. The 1977 estimated fixed charges on capital cost shown in the foregoing tabulation for the coal-fired plants on the average are only 68% of those of the nuclear plants (6.18 mills/KWh vs. 9.15 mills). However, the almost 6.0 mills differential in production costs favoring nuclear plants more than offsets the capital cost differential. The result is a national average of 14.5 mills/KWh nuclear plant generating cost compared to a coal-fired plant average of about 17.3 mills for essentially base-load operation.

Regional Costs

A breakdown of 1977 coal-fired power plant average costs by region (based on the data reported to the DOE) is shown in Table 2. Costs for representative oil-fired plants in the Northeast (New England and New York) and the South are also tabulated.

Table 2

1977 Fossil-Fuel Steam-Electric Generating Station Generating Costs
(by U.S. Region)

Region 1/	Plants in Sample	Capacity Factor (MDC) 2/ %	Generation Million KWh Net	Fuel Cost 3/ Mills/KWh (A)	O&M Cost 3/ Mills/KWh (B)	Production Cost 3/ Mills/KWh (A&B)	Capital Cost 4/ Mills/KWh (C)	Generating Cost 4/ Mills/KWh (A&B&C)
A. Coal								
Middle Atlantic	4	60.5	25502	13.40	2.16	15.56	5.47	21.03
South	10	61.0	82881	9.82	1.72	11.54	4.77	16.31
East North Central	12	58.9	96954	9.75	1.28	11.03	6.67	17.70
West North Central	2	50.2	16157	7.33	2.08	9.41	9.23	18.64
Far West	6	66.6	32264	5.16	2.15	7.31	7.55	14.86
Total	34	60.0 5/	253758	9.40 5/	1.68 5/	11.08 5/	6.18 5/	17.26 5/
B. Oil								
Northeast (only)	7	52.0	28559	20.41	1.49	21.90	6.86	28.76
South (only)	6	48.3	20876	17.66	0.92	18.58	4.69	23.27

1/ States in each region are listed on next page.
2/ Capacity Factor: Ratio of plant's generation in 1977 to product of plant maximum dependable capacity and hours in 1977, expressed as a percentage.
3/ Actual cost, as reported by utilities to the FERC.
4/ Estimated cost.
5/ Weighted average.

Table 2 (cont.)

Definitions of regions:

Northeast: New England States and New York

Middle Atlantic: Pennsylvania, New Jersey, Maryland and Delaware

South: Virginia, North and South Carolina, Georgia, Florida, Tennessee, Alabama, Mississippi, Texas, Louisiana, Arkansas, Oklahoma

East North Central: Ohio, Indiana, Michigan, Illinois, Wisconsin, Kentucky and West Virginia

West North Central: Minnesota, Iowa, Nebraska, Kansas, Missouri, North and South Dakota

Far West: Mountain and Pacific States

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Examination of these regional coal-fired plant costs and equivalent nuclear plant costs in the preceding article reveals the following with respect to 1977 generation:

- o Lowest production costs (7.31 mills/KWh) and estimated total generating costs (14.86 mills/KWh) for coal-fired plants occurred in the Far West. Lowest capital costs, estimated at 4.77 mills/KWh, were experienced in the South, which evidences the next to lowest total generating cost (16.31 mills/KWh).

- o Nuclear power plant generating costs are lower than those of competing fossil-fuel steam-electric generating plants in all regions except in the Far West, where costs are about equal. The regional comparisons follow:

Region	Estimated Generating Cost (Mills/KWh) Nuclear	Fossil-Fuel	Ratio of Nuclear Cost to F.F. Cost
Northeast	16.10	28.76 (oil)	0.56
Middle Atlantic	19.99	21.03 (coal)	0.95
South	13.53	16.31 (coal)	0.83
East North Central	12.37	17.70 (coal)	0.70
West North Central	14.31	18.64 (coal)	0.77
Far West	14.85	14.86 (coal)	1.00

The competitive position of coal-fired plants in the Far West is due to their low fuel costs, 5.16 mills/KWh average, which is only a little over half the national average. The Far West sample of coal-fired plants includes several new, large, efficient stations located close to inexpensive Western coal deposits.

The closeness of the estimated generating cost of nuclear and coal-fired plants in the Middle Atlantic states deserves mention. In the first place, the number of plants in each sample is small, six in the case of nuclear and four in the case of coal, so that any conclusions drawn should be tempered by realization of this fact. In the case of both fuels, the generating costs are significantly higher than the national averages, indicated in Table 1, particularly in the nuclear case. Greater than average capital costs and O&M costs account for almost all of the difference in nuclear power plant costs in the Middle Atlantic region with respect to the national average -- the estimated capital increment is over four mills and the O&M cost increment is slightly over one mill. On the other hand, fuel cost is primarily responsible for the higher than average generating costs of the coal-fired plants in the Middle Atlantic region, the four mill/KWh coal cost increment representing slightly more than the difference between the regional and national generating cost averages.

Oil is the predominant fossil fuel in New England and southern New York and also is extensively used for generation in the South Atlantic and Gulf states. The average generating costs of representative plants in these areas are shown in Table 2. In both instances the generating costs are much higher than comparative nuclear plant costs, 28.76 mills/KWh vs. 16.10 mills/KWh in the Northeast and 23.27 mills/KWh vs. 13.53 mills/KWh in the South. Coal, at 16.31 mills/KWh, is also more economical than oil in the South as a whole.

III. ECONOMICS

A. Examination of 1976 Fossil-Fuel Plant Generating Costs

In section III of the June 1977 UPDATE an analysis is presented of nuclear power plant generating costs for 1976, based on data reported to the Federal Power Commission (FPC) by U.S. electric utilities. For purposes of comparison with these nuclear costs, 1976 cost information from the same source on a number of fossil-fuel plants is analyzed here. These fossil-fuel plants are part of utility systems that presently include at least one operating nuclear power station or for which nuclear power stations are planned in the future.

National Cost Averages

The results of these analyses of U.S. nuclear and coal-fired plant costs, averaged on a national basis, are presented in Table 1 under the heading of "Source: ERDA/FPC." Similar cost averages appearing in a recent report on an Atomic Industrial Forum survey are also presented for comparison.

TABLE 1

NUCLEAR AND FOSSIL-FUEL GENERATING COSTS (Mills/KWh)
Averages for 1976 Operation

	Source: ERDA/FPC		Source: AIF			
Costs	Nuclear 1/	Coal 2/	Nuclear 1/	Coal 2/	Coal 1/	Oil 1/
Fuel	2.7	8.2	3.0	9.0	10.0	21.0
O&M	2.3	1.8	-	-	-	-
Production	5.0	10.0	-	-	-	-
Capital	9.6	5.9	-	-	-	-
Generating	14.6	15.9	15.0	16.0	18.0	35.0

1/ Industry average
2/ Essentially base

NOTES: 1. ERDA costs are based on utility data reported to the FPC on 40 nuclear plants (totaling 51 units) and 49 multiunit coal-fired plants. AIF costs are based on data reported directly to the AIF by 36 utilities.

2. ERDA/FPC production costs (fuel + O&M) are averages of actual costs reported by the utilities. ERDA/FPC capital costs (and therefore generating costs also) are estimated, based on assumed fixed charge rates and reported actual investment costs, as explained in the text.

3. No meaningful FGD (Flue Gas Desulfurization) costs are available for 1975 and 1976.

4. ERDA generating costs correspond to a weighted average capacity factor (C.F.) of 59.7% for nuclear and 56.4% for coal (based on 44 of the 49 plants examined). AIF costs correspond to C.F. of 61.6% nuclear, 58.7% (base load) and 56.0% (industrial average) for coal, and 33.4% (industrial average) for oil.

The ERDA/FPC coal-fired power plant costs shown in Table 1 are based on a data sample consisting of 49 multi-unit stations that generated about 23% of the total electricity produced by U.S. coal-fired power plants in 1976. These stations are of fairly recent construction, consisting mostly of large units having higher than average thermal efficiencies, and are therefore suitable for base-loading and for comparison with nuclear units.

The average production cost shown in Table 1 for the coal-fired stations is twice that of the nuclear plants. This is largely due to the much higher average fuel costs of the coal-fired plants, 8.2 mills/KWh, compared to 2.7 mills for the nuclear units.

The fixed charges on fossil-fuel plant capital costs were calculated on the same basis as for the 1976 nuclear generating costs (see June 1976 UPDATE). Thus a fixed charge rate (FCR) of 17% was used for investor-owned utilities, 12% for TVA, and 11% for other publicly-owned utilities. The 1976 estimated fixed charges on capital cost shown in the foregoing tabulation for the coal-fired plants on the average are only 61% of those of the nuclear plants (5.9 mills/KWh vs. 9.6 mills). However, the 5.0 mills differential in production costs favoring nuclear plants more than offsets the capital cost differential. The result is a national average of 14.6 mills/KWh nuclear plant generating cost compared to a coal-fired plant average of about 16 mills for base-load operation.

Regional Costs

A breakdown of the 1976 coal-fired power plant costs by region (based on the FPC data) is shown in Table 2. Costs for oil-fired plants in the Northeast (New England and New York) and oil/gas-fired plants in California are also tabulated.

Examination of these regional coal-fired plant costs together with equivalent nuclear plant costs in the June 1977 UPDATE reveals the following:

o Lowest 1976 total generating costs (14.8 mills/KWh) for coal-fired plants occurred in the South, as well as lowest capital costs (4.3 mills/KWh). However, nuclear plant generating costs in the South were lower still (12.8 mills/KWh).

- Almost as low in total generating costs were coal-fired plants in the Far West (Mountain and Pacific states) and in the West North Central states (15.4 and 15.5 mills/ KWh respectively). These coal-fired plant generating costs are about the same as the average for nuclear plants in the West North Central states (15.5 mills/KWh) but are lower than the average of the four nuclear units in the Far West data sample. The competitive position of coal-fired plants in these two regions is due to their low fuel costs, 4.3 mills/KWh average for the Far West plants and 7.0 mills for the West North Central plants. The Far West sample of coal-fired plants includes several new, large, efficient stations located close to inexpensive Western coal deposits.

- In all the other regions average nuclear generating costs were lower than the coal-fired plant averages for 1976.

The generating costs for oil fired plants in the Northeast were examined because oil is the predominant fuel in New England and southern New York. The generating cost obtained for these plants averaged 30.9 mills/KWH, much higher than the nuclear generating costs for this region (16.1 mills/KWH). The generating costs for oil/gas-fired plants in California were examined also, since at present there is no coal fired generation in that state. The California oil/gas fired generating cost averaged 26.6 mills/KWH, which is higher than the nuclear generating cost for this state (19.5 mills/KWH).

TABLE 2

1976 Fossil-Fuel Plant Generating Costs
(By U.S. Region)

Region[1/]	Stations In Sample	Electric Production In Sample GWH*	(1) Fuel Cost Mills/KWH**	(2) O&M Cost Mills/KWH**	(3) Production Cost Mills/KWH** (1)+(2)	(4) Capital Cost Mills/KWH***	Total Generating Cost Mills/KWH*** (3)+(4)
A. Coal							
Northeast	2	7,263	12.9	1.7	14.6	6.2	20.8
Middle Atlantic	8	18,149	10.1	2.0	12.1	6.4	18.5
South	15	92,289	9.0	1.5	10.5	4.3	14.8
East North Central	13	47,163	8.0	2.0	10.0	6.8	16.8
West North Central	6	27,983	7.0	1.9	8.9	6.6	15.5
Far West	5	24,454	4.3	2.4	6.7	8.7	15.4
Total U.S.	49	217,301	8.2	1.8	10.0	5.9	15.9
B. Oil							
Northeast only	13	44,613	19.7	2.4	22.1	8.8	30.9
C. Oil/gas							
California only	5	38,360	21.2	0.9	22.1	4.5	26.6

1/ States in each region are listed on next page.
* Gigawatt-Hours
**Actual
***Estimated

Table 2 (cont.)

Definitions of regions:

Northeast: New England States and New York

Middle Atlantic: Pennsylvania, New Jersey, Maryland and Delaware

South: Virginia, North and South Carolina, Georgia, Florida, Tennessee, Alabama, Mississippi, Texas, Louisiana, Arkansas, Oklahoma

East North Central: Ohio, Indiana, Michigan, Illinois, Wisconsin, Kentucky and West Virginia

West North Central: Minnesota, Iowa, Nebraska, Kansas, Missouri, North and South Dakota

Far West: Mountain and Pacific States

Note: Stations of utilities serving several states are assumed to be in the predominate region served by the particular utility (e.g., TVA plants located in Kentucky are included in the Southern region)

THE ECONOMICS

OF

NUCLEAR VERSUS COAL

Presented by

Leonard F C Reichle

Executive Vice-President

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Before the

Richmond Society of Financial Analysts

Richmond, Virginia

October 30, 1979

Before discussing what appears to be "The Economics of Nuclear Versus Coal" in 1979, I would like to point out what happened to costs of both nuclear and coal-fired electric generating plants during the prior 10 years, i.e. 1969-78.

1969 Estimates vs 1978 Estimates of Nuclear and Coal

Plant Investment Costs - Chart 1 compares estimates made in 1969 and in 1978 of nuclear and coal-fired electric generating plant investment costs. These estimates were for steam-electric generating stations comprised of 2 - 1,200 MWe nuclear units and of 3 - 800 MWe bituminous coal-fired units. The 1969 estimate was based on commercial operation of the 2 nuclear units in 1976 and 1978 and of the 3 coal-fired units in 1976, 1977 and 1978. The 1978 estimate was based on commercial operation of the 2 nuclear units in 1988 and 1990 and of the 3 coal-fired units in 1988, 1989 and 1990. Both the 1969 estimate and the 1978 estimate included all facilities required to meet regulations existing at the time of the estimates. They reflect average United States wage rates and field productivity, no unusual site conditions, and a typical plant design as of the estimating dates.

In 1969, the average cost of two 1,200 MWe nuclear units was estimated to be $226 per KWe, including $66 per KWe for escalation to the operating date. In 1969, the average cost of three 800 MWe coal-fired units was estimated to be $183 per KWe, including $61 per KWe for escalation.

In 1978, the average cost of two 1,200 MWe nuclear units was estimated to be $1648 per KWe, including $735 per KWe for escalation to the operating date. In 1978, the average cost of three coal-fired units was estimated to be $1266 per KWe, including $627 per KWe for escalation.

Plant Cost Breakdown - Chart 2 indicates the causes of the dramatic cost increase between the 1969 and 1978 estimates. The 1978 estimate for materials, equipment and installation of the nuclear plant as compared with the 1969 estimate increased almost six-fold from $160 per KWe to $913 per KWe. Had there been no changes in plant design, escalation during construction of the 1969 plant would have raised the originally estimated materials, equipment and installation costs by only $162 per KWe to a total plant cost of only $332 per KWe. The additional increase of $591 per KWe in 1978 dollars is the result of added complexity and delay due to increased statutory and regulatory requirements - an increase of 184 percent.

The 1978 estimate for materials, equipment and installation of the coal-fired plant as compared with the 1969 estimate increased more than five-fold from $122 per KWe to $639 per KWe. Had there been no change in plant design, escalation during construction of the 1969 plant would have raised the originally estimated materials, equipment and installation costs by only $120 per KWe to a total plant cost of only $242 per KWe. The additional increase of $397 per KWe in 1978 dollars is the result of added complexity and delay due to increased statutory and regulatory requirements - an increase of 164 percent.

Added Statutory & Regulatory Requirements - Chart 3 identifies some of the major differences between 1969 and 1978 requirements for nuclear plants. From a total of 4 in 1970, the number of Nuclear Regulatory Guides and revisions of Guides plus Nuclear Regulatory Technical Branch Positions and revisions of Positions which must be factored into the design, construction and operation of nuclear power plants increased to a cumulative total of 323 in 1978. These are in addition to all of the environmental criteria for cooling water, waste water, etc. that apply to coal-fired plants.

Chart 4 identifies some of the major differences between 1969 and 1978 requirements for an 800 MWe coal-fired plant. Cooling water requirements changed from open-cycle discharge into a river, to cooling towers. Removal of stack emissions changed from electrostatic particulate removal equipment with an efficiency of 95 percent to equipment with an efficiency of 99+ percent, plus SO_2 scrubbers, lined sludge ponds, lined ash ponds, and NOX removal. Stack height increased from 600 feet to 800 feet. Additional auxiliary equipment became required. Liquid waste handling changed from multiple discharge with oil separation only, to a complete waste management system with single discharge or re-use. Noise attenuation became mandated. Single-application licensing was superseded by the need for a complete environmental report, with review by Federal and State agencies and public hearings. Protection of the environment during construction became a requirement.

Energy Costs - Not only have estimates of plant investment costs for both nuclear and coal-fired power plants increased dramatically over the past 10 years, but estimates of fuel costs have increased almost as much. These increased fuel costs are the result not only of inflation, but of increased environmental requirements on all steps of fuel supply from mining through waste disposal, supply-demand imbalances due to shortages of oil and gas and, in the case of coal, rapidly escalating transportation costs.

Chart 5 illustrates for our generalized case, considering both fixed charges on investment and fuel and O&M expenses, the striking difference between 1969 estimates and 1978 estimates of energy cost. Estimates of the cost of energy produced in the nuclear plant increased from 7.9 mills per Kwh as of 1969 to 63.8 mills per Kwh in 1978 - 708 percent! Estimates of the cost of energy produced in the coal-fired plant increased from 10.7 mills per Kwh in 1969 to 65.2 mills per Kwh in 1978 - 509 percent!

Energy Cost of Existing Plants

As to the actual cost of electricity generated in existing nuclear and coal-fired plants, nuclear appears to be the clear winner. According to a survey of the Atomic Industrial Forum, comparative average costs for 1978 were: nuclear - 15 mills per Kwh, coal - 23 mills per Kwh, and oil - 40 mills per Kwh (see Chart 6).

1979 Estimates of Nuclear and Coal Assumptions - Now, let us consider 1979 estimates of nuclear versus coal-fired steam-electric generating stations. Let's make a comparison, assuming an electric utility requirement for additional generating plant capacity of 2,400 MWe between June 1990 and June 1992 (see Chart 7). Let's compare two 1,200 MWe nuclear units, the first achieving commercial operation in June 1990 and the second in June 1992, with three 800 MWe coal-fired units, the commercial operating dates of which would be in June of 1990, 1991 and 1992. Let's compare these nuclear units with the coal-fired units (see Chart 8) at (a) a typical Midwestern Station in the Iowa-Nebraska area, burning low-sulfur Western coal hauled 900 miles by rail and (b) a typical Eastern Station in the Carolina-Virginia area, burning high-sulfur coal hauled 350 miles by rail. Local labor rates are used. Cooling towers are included. SO_2 removal is included for the coal-fired plant. Decommissioning costs of 1 mill per Kwh are included, but fuel reprocessing and Pu recycle are not included for the nuclear plant. Land, other owner's costs, and sales and use taxes are not included.

Investment Costs - The capital investment in plant for the 2,400 MWe stations is now estimated as follows (see Chart 9):

For Midwestern Station:		$ per Kwe
	Coal	1445
	Nuclear	1804
For Eastern Station:		
	Coal	1231
	Nuclear	1670

The nuclear units at both sites are clearly more costly than the coal-fired units in plant investment. Moreover, the nuclear units require substantial more investment in fuel as shown below and Chart 10:

For Midwestern Station:	$ per Kwe
Coal (90 day stockpile)	44
Nuclear	150
For Eastern Station:	
Coal (90 day stockpile)	62
Nuclear	150

Coal Prices - A 1979 price for 12,500 Btu/lb Eastern bituminous coal from District 8 is estimated at $30 per ton f.o.b. Rail shipment to a site in the Virginia-Carolina area would add about $10 per ton. With mine costs expected to escalate at 5 percent per year and shipping costs at 7 percent, a 10 year, levelized delivered cost (1990-2000) of $98.40 per ton ($3.95 per MM Btu) is considered typical.

For Western sub-bituminous coal (8200 Btu/lb) from the Powder River Basin of Wyoming, a typical 1979 price at the mine tipple is $8 per ton f.o.b. Rail shipment to Western Iowa would add about $10 per ton. Applying the same escalation factors as to Eastern coal, a 10 year levelized cost of $42.60 per ton ($2.60 per MM Btu) is considered typical.

Nuclear Fuel Costs - The elements of cost in the nuclear fuel cycle are yellowcake, conversion to UF_6 enrichment, fabrication and recovery (including reprocessing, transportation and waste disposal). Typical values for these elements of cost and unit price projections as shown on Chart 11, are arrived at as follows:

1 - Yellowcake - \$43/lb U_3O_8 is the estimated NUEXCO exchange price for 1979 delivery, escalated at 7 percent per year to \$90/lb in Year 1990.

2 - Conversion to UF_6 - \$5 per Kg U for conversion to UF_6 is based on 1979 commercial prices, escalated at a rate of 5 percent per year to \$8.50/lb in Year 1990.

3 - Enrichment - \$105/SWU for enrichment of uranium in 1979, escalated at 5 percent per year to \$295/SWU in Year 1990.

4 - Fabrication - \$130/KgU for fabrication is based on 1979 commercial prices, escalated at 5 percent per year to \$222/KgU in Year 1990.

5 - Spent Fuel Management - \$245 per kg in 1979 is consistent with DOE estimates for the cost of shipping, off-site storage and/or disposal of spent fuel assemblies, assuming a continuing ban on reprocessing, escalated at 5 percent per year to \$419 per kg in 1990.

Nuclear fuel cycle costs at both the Midwestern Station and at the Eastern Station are estimated to be essentially the same. Differential costs for shipping nuclear fuel are negligible.

The 1979 estimate of the nuclear fuel cycle costs, on a ten year levelized basis, with 17% fixed charges, 70% capacity factor, no reprocessing and no recycle, is 18.45 mills per KWh. (see Chart 13) Initial fuel investment is \$150 per KWe, and fuel investment on a ten year levelized basis is \$102.49 per KWe.

Energy Costs - At the Midwestern Station, the fossil-fired units because of their lower plant investment costs would generate electricity at a slightly lower cost than the nuclear units at the same station, i.e. 70 mills per KWh as compared with 73 mills per KWh for the nuclear units (see Chart 14). At the Eastern Station, the nuclear units would generate electricity at a substantially lower cost than the fossil-fired units, i.e. 68 mills per KWh as compared with 77 mills per KWh for the coal-fired units.

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A relative advantage of nuclear units is their low incremental production costs. Production costs are fuel costs plus operating and maintenance costs. In an operating electric utility system, a generating unit is "cut in" or "cut out" of service on the basis of whether its incremental generating costs compare favorably with the incremental generating costs of other units in the system. Chart 15 shows that, because of nuclear's relatively low fuel cycle costs, the incremental cost of 19 mills per KWh in nuclear units at both the Eastern Station and the Midwestern Station is roughly half of the incremental 41 mills per KWh for the fossil-fired units at the Eastern Station and about one-third less than the incremental 29 mills per KWh for the fossil-fired units at the Midwestern Station. Moreover, total nuclear generation costs of 68 mills per KWh at the Eastern Station is less than the incremental 72 mills per KWh required to cover fuel and operating cost only of an oil-fired station burning oil at $18 per barrel in 1979, escalated at 7% per year.

Nuclear Fuel Cost Sensitivity - It is sometimes feared that increases in the prices of uranium and enrichment services may nullify the relative advantages of nuclear plants. This is not likely. Chart 16 shows the sensitivity of nuclear electric generation costs to changes in the prices of uranium, enrichment services, fabrication and spent fuel management. A $10/lb increase in the price of U_3O_8 will raise electric generation cost by only 0.78 mills per KWh. A price increase in enrichment services of $10 per Separative Work Unit (SWU) will raise electric generation costs by only 0.17 mills per KWh. A $10/Kg increase of uranium fabrication costs will raise electric generation costs by only 0.05 mills per KWh. A $10/Kg of spent fuel management services will raise electric generating costs by only 0.04 mills per KWh.

Changing of assumptions regarding plant capacity factor has a significant but not large impact on nuclear fuel cycle cost. If capacity factor is increased from 70% to 80%, nuclear fuel cost will be decreased by 0.37 mills per KWh. If capacity factor is decreased from 70% to 60%, electric generation cost will be increased by 0.50 mills per KWh. If spent fuel is processed and uranium and Pu recycled, electric generation costs would be decreased by 2.0 mills per KWh.

Conclusions

The facts relating to investment costs and fuel plus O&M expense appear to justify the following conclusions: (see Chart 17)

1 - The cost of electricity generated from existing nuclear units is well below fossil-fired generation in the same utility systems.

2 - Costs of electricity from future nuclear and coal plants will be substantially higher due to regulation and escalation.

3 - Nuclear plant investment costs are higher but nuclear fuel costs are lower than comparable costs for coal-fired plants.

4 - Base-load electric generation is generally lower in cost in nuclear units than in coal-fired units, but coal-fired units will be cheaper at some sites.

5 - Detailed engineering study is required to determine relative advantages in specific cases.

However, just because nuclear and fossil-fired plants are economic as well as safe, reliable, environmentally compatible and commercially available, does not assure that electric utility companies can or will make committments necessary for the additional units required to assure a healthy energy future. Needed commitments are being hampered seriously by (a) excessive federal and state statutory and regulatory requirements and delays and (b) excessive legal challenges and delays by certain no-growth, anti-nuclear and environmental groups. It is imperative that we eliminate excessive regulation and delay.

Abundant quantities of safe, economic, reliable, environmentally compatible, commercially available, electric energy are essential to maintain our American way of life and to provide jobs for the 2 million young people entering the labor market each year. For the foreseeable future, i.e. to the Year 2000 and perhaps beyond, the only realistic sources of base-load electricity are nuclear and coal. Neither nuclear or coal alone can to the job. Both are required.

CHART 1

PLANT INVESTMENT COSTS, 1969 - 78 ESTIMATES

(DOLLARS PER KW)

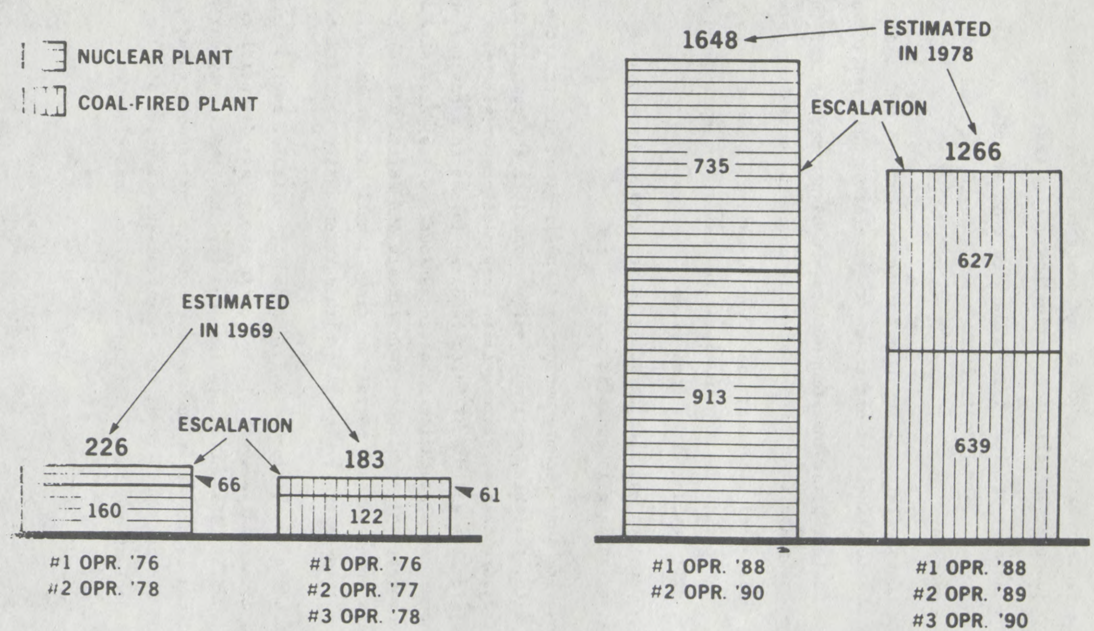


CHART 2

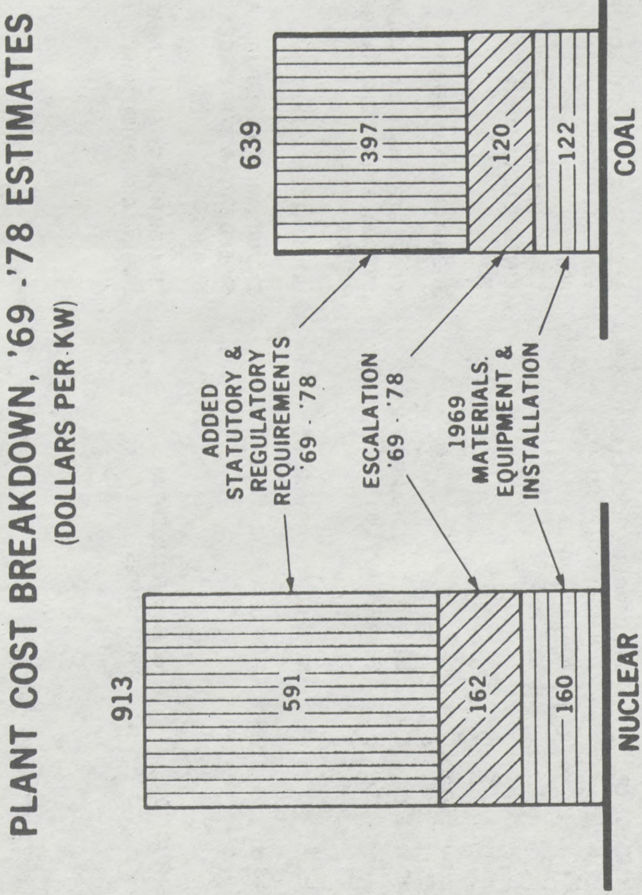

PLANT COST BREAKDOWN, '69 -'78 ESTIMATES
(DOLLARS PER KW)
913
591
162
160
NUCLEAR
639
397
120
122
COAL
ADDED STATUTORY & REGULATORY REQUIREMENTS '69 - '78
ESCALATION '69 - '78
1969 MATERIALS, EQUIPMENT & INSTALLATION

CHART 3

ADDED STATUTORY & REGULATORY REQUIREMENTS, '69-'78
(COAL-FIRED PLANTS)

	1969	1978
COOLING WATER	OPEN CYCLE ON RIVER	COOLING TOWER
STACK EMISSION	ELECTROSTATIC COLLECTORS-95% UNLINED ASH POND 600 FT STACK	ELECTROSTATIC COLLECTORS-99+% LINED ASH POND 800 FT STACK SO_2 SCRUBBER LINED SLUDGE POND NO_X
AUXILIARY LOAD	–	HIGH AUXILIARY LOAD
LIQUID WASTE	MULTIPLE DISCHARGE, OIL SEPARATION ONLY	COMPLETE WASTE MANAGEMENT SYSTEM. SINGLE DISCHARGE OR RE-USE
NOISE	NO SPECIAL PROVISION	NOISE ATTENUATION
LICENSING	SINGLE APPLICATION	ENVIRONMENTAL REPORT, REVIEW BY FEDERAL & STATE AGENCIES, HEARINGS
CONSTRUCTION	NO ENVIRONMENTAL PROVISIONS	PROTECTION OF ENVIRONMENT DURING CONSTRUCTION

CHART 5

ENERGY COSTS, 1969 - 78 ESTIMATES

(MILLS/Kwh, LEVELIZED FIRST 10 YEARS OPERATION, 70% CF)

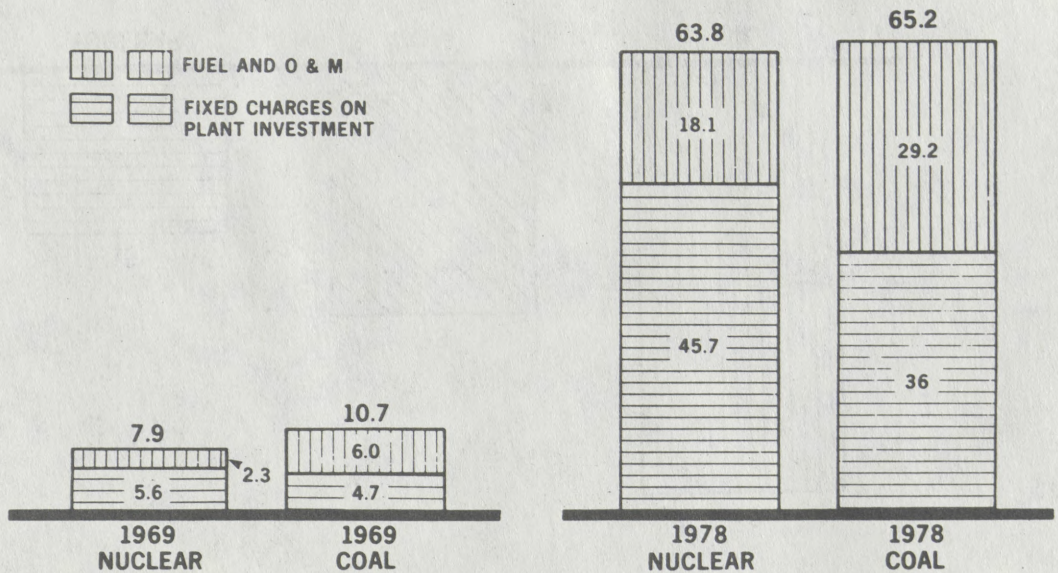


CHART 6

COST OF NUCLEAR & FOSSIL ELECTRICITY
(AVERAGE MILLS/Kwh FROM EXISTING PLANTS, 1978)

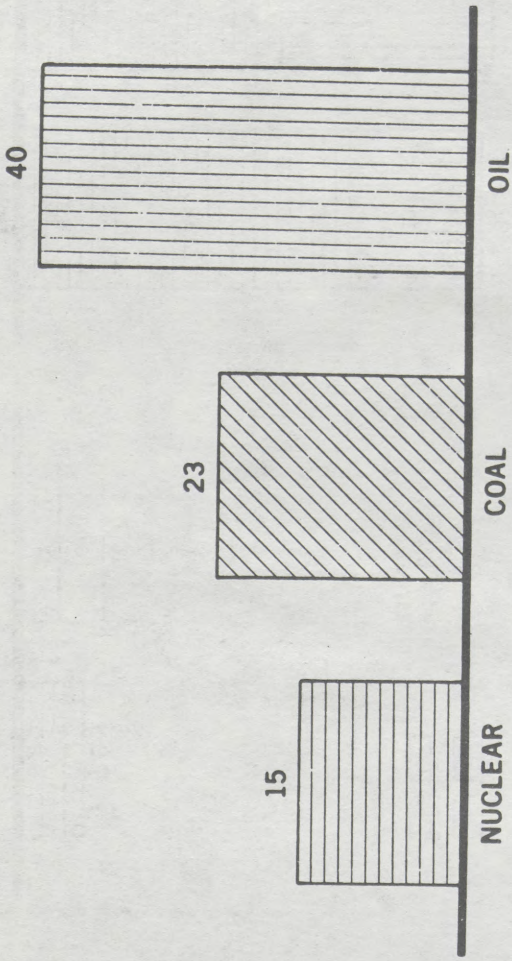


CHART 7

NUCLEAR VS COAL COST COMPARISON-1979 ESTIMATE
(ASSUMPTIONS OF SIZE, AND COMMERCIAL OPERATING DATES)

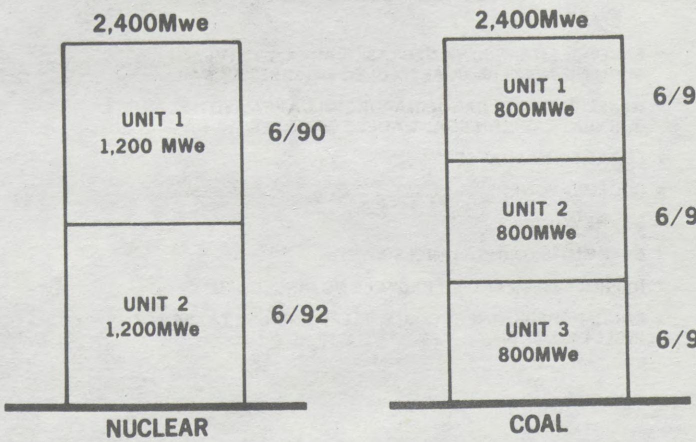


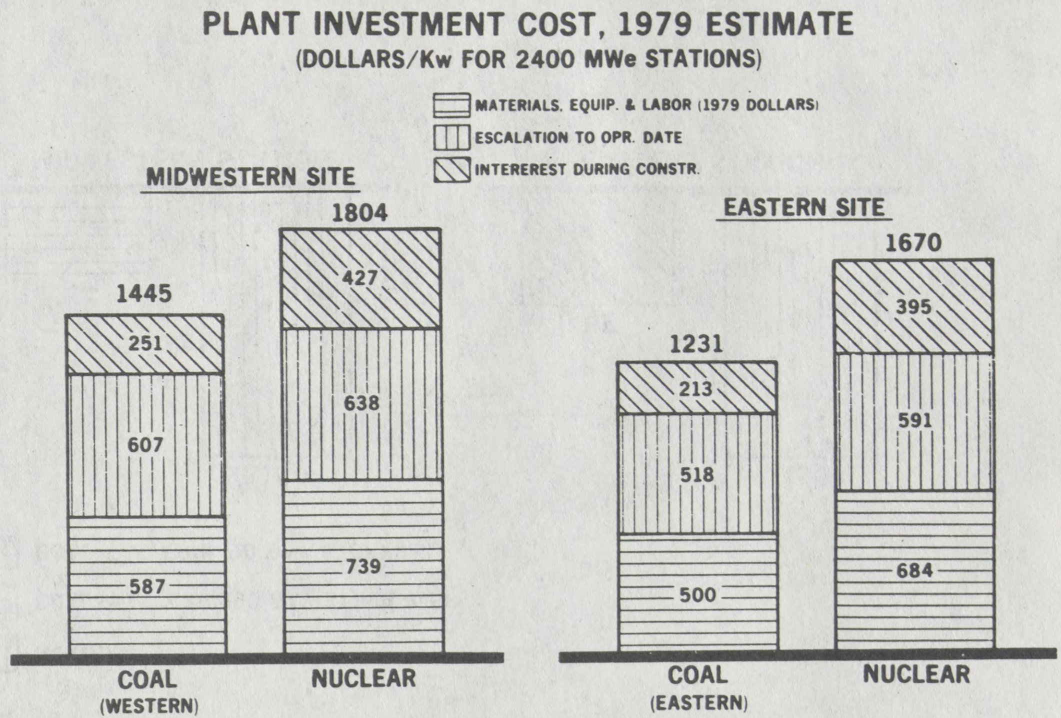
CHART 8

NUCLEAR VS COAL COMPARISON-1979 ESTIMATE

(OTHER ASSUMPTIONS)

- EASTERN SITE IN IOWA-NEBRASKA AREA, WITH PLANT BURNING WESTERN COAL HAULED 900 MILES BY RAIL
- WESTERN SITE IN CAROLINA-VIRGINIA AREA, WITH PLANT BURNING EASTERN COAL HAULED 350 MILES
- LOCAL LABOR RATES
- COOLING TOWERS
- SO_2 REMOVAL
- DECOMMISSIONING (1 MILLS/KWH)
- REPROCESSING AND PU RECYCLE NOT INCLUDED
- LAND, OTHER OWNERS COSTS, SALES AND USE TAXES NOT INCLUDED

CHART 9



PLANT INVESTMENT COST, 1979 ESTIMATE
(DOLLARS/Kw FOR 2400 MWe STATIONS)
MATERIALS. EQUIP. & LABOR (1979 DOLLARS)
ESCALATION TO OPR. DATE
INTEREREST DURING CONSTR.
MIDWESTERN SITE
1445
251
607
587
COAL
(WESTERN)
1804
427
638
739
NUCLEAR
EASTERN SITE
1231
213
518
500
COAL
(EASTERN)
1670
395
591
684
NUCLEAR

CHART 10

INITIAL CAPITAL INVESTMENT FOR FUEL - 1979 ESTIMATE

(DOLLARS/KWe FOR 2400 MWe STATIONS)

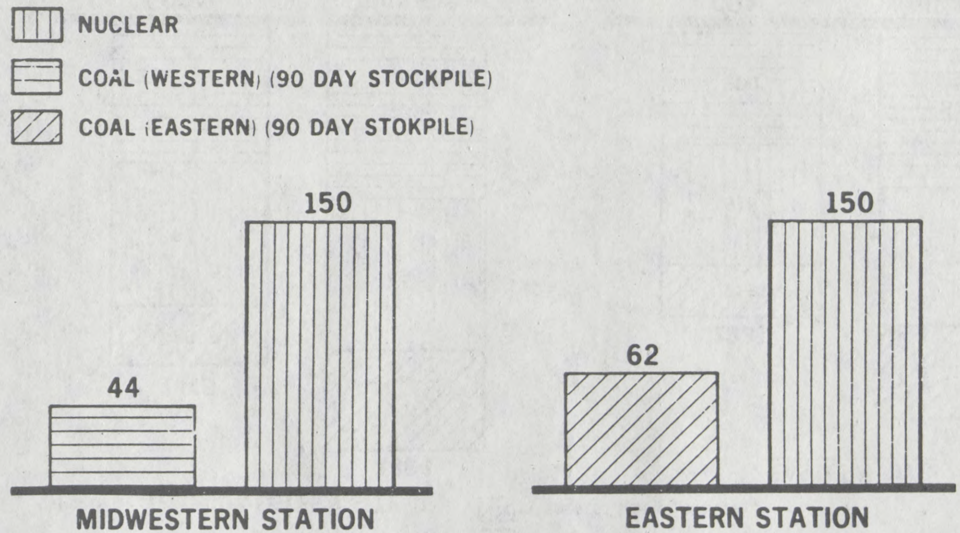


CHART 11

COAL PRICES - 1979 ESTIMATE
(TYPICAL, PER TON)

EASTERN COAL (12,500 BTU/LB)	PRICE PER TON 1979	1990	% ESCALATION	LEVELIZED PRICE PER TON (1990-2000)
COAL AT MINE	30.00	54.30	5.0%	70.80
RAIL SHIPPING (350 MILES)	10.00	21.05	7.0%	27.60
DELIVERED COST	40.00	75.35		98.40
WESTERN COAL (8,200 BTU/LB)				
COAL AT MINE	8.00	12.40	5.0%	15.00
RAIL SHIPPING (900 MILES)	10.00	21.05	7.0%	27.60
DELIVERED COST	18.00	33.45		42.60

CHART 12

NUCLEAR FUEL COSTS - 1979 ESTIMATE

(UNIT COSTS OF MATERIAL & PROCESS STEPS)

ITEM	UNIT	BASE PRICES 1979	ESCALATION PER YEAR	PROJECTED PRICES 1990	1995	2000
YELLOW CAKE	\$/LB U_3O_8	43	7%	90	127	178
CONVERSION TO UF_6	\$/KgU	5	5%	8.50	10.90	14
ENRICHMENT	\$/SWU	105	5%	180	230	295
FABRICATION	\$/KgU	130	5%	222	284	363
RECOVERY 1/	\$/KgU	400	5%	685	875	1120
SPENT FUEL MANAGEMENT 2/	\$/KgU	245	5%	419	535	685

1/ FUEL REPROCESSING, SHIPPING AND WASTE DISPOSAL.

2/ SHIPPING, OFF-SITE STORAGE AND/OR DISPOSAL.

CHART 13

NUCLEAR FUEL COSTS - 1979 ESTIMATE

(LEVELIZED 1990-2000, 17% F.C., 70% C.F. NO REPRO., NO RECYCLE)

	10-YEAR LEVELIZED		
FUEL EXPENSE-MILLS/kWh	BURNUP	CARRYING CHARGES	TOTAL
URANIUM UF6	7.38	2.16	9.54
ENRICHMENT	3.83	1.13	4.96
FABRICATION	1.26	0.35	1.61
RECOVERY 1/	0	0	–
SPENT FUEL MANAGEMENT 2/	2.98	–0.80	2.18
	15.45	2.84	18.29

FUEL INVESTMENT-$/kWe	INITIAL	10-YEAR LEVELIZED
URANIUM	87.30	77.80
ENRICHMENT	43.00	40.90
FABRICATION	19.50	12.50
RECOVERY 1/	–	–
SPENT FUEL MANAGEMENT 2/	–	–28.70
	149.80	102.50

1/ FUEL REPROCESSING, TRANSPORTATION, AND WASTE DISPOSAL

2/ SHIPPING, OFF-SITE STORAGE AND/OR DISPOSAL

CHART 14

ENERGY COSTS - 1979 ESTIMATE

(MILLS PER Kwh)

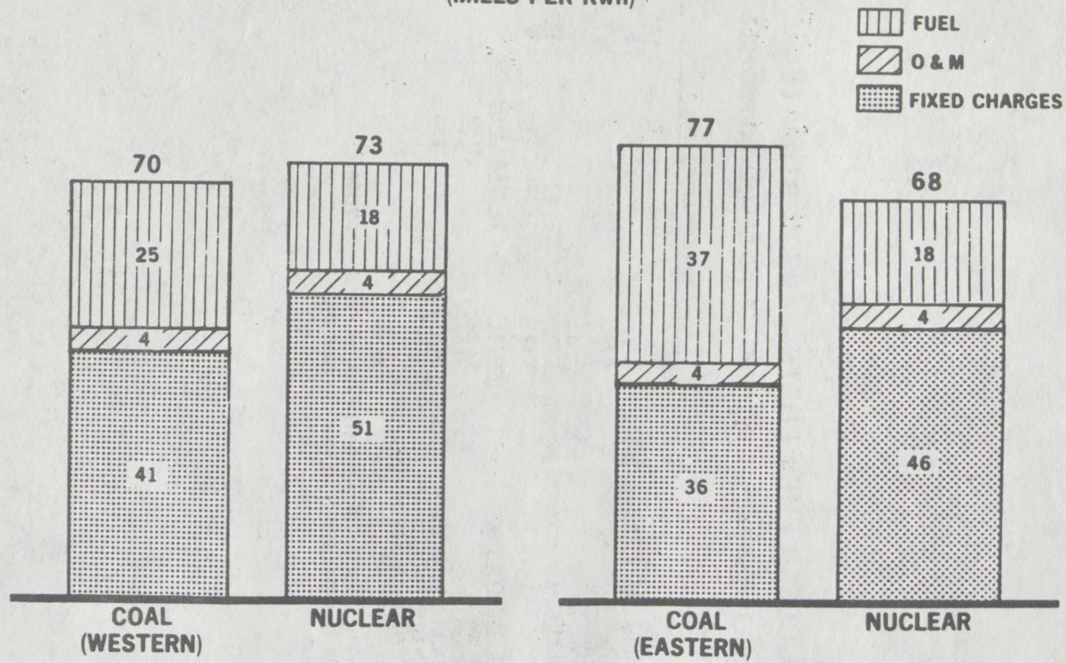


CHART 15

INCREMENTAL PRODUCTION COST - MILLS/Kwh

(LEVELIZED 1990-2000, 17% F.C., 70% C.F., NO REPRO. NO RECYCLE)

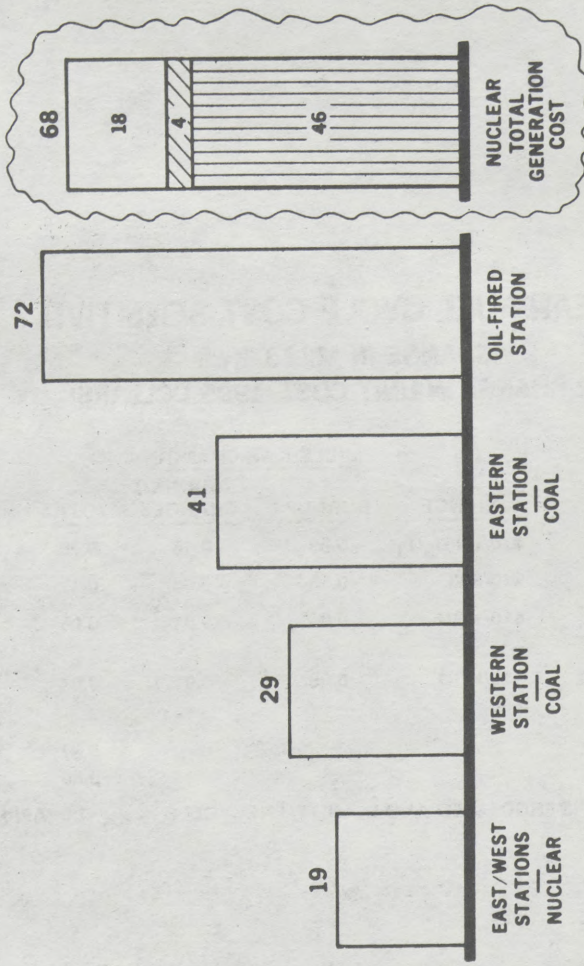


CHART 16

NUCLEAR FUEL CYCLE COST SENSITIVITY

(CHANGE IN MILLS/Kwh PER CHANGE IN UNIT COST, 1995 DOLLARS)

		MILLS/KWH CHANGE		
	CHANGE	BURNUP	CARRYING CHARGES	TOTAL
URANIUM	\$10/LB U_3O_8	0.59	0.19	0.78
ENRICHMENT	\$10/SWU	0.13	0.04	0.17
FABRICATION	\$10/KGU	0.04	0.01	0.05
SPENT FUEL MANAGEMENT	\$10/KGU	0.05	–0.01	0.04
PLANT C.F.				
70% ► 80%				0.37
70% ► 60%				+0.50
IF SPENT FUEL IS PROCESSED AND U AND PU RECYCLED				–2.0 (APPROX)

Chart 17

CONCLUSIONS

- THE COST OF ELECTRICITY GENERATED FROM EXISTING NUCLEAR UNITS IS WELL BELOW FOSSIL-FIRED GENERATION IN THE SAME UTILITY SYSTEMS
- COSTS OF ELECTRICITY FROM FUTURE NUCLEAR AND COAL PLANTS WILL BE SUBSTANTIALLY HIGHER DUE TO REGULATION AND ESCALATION
- NUCLEAR PLANT INVESTMENT COSTS ARE HIGHER BUT NUCLEAR FUEL COSTS ARE LOWER THAN COMPARABLE COSTS FOR COAL-FIRED PLANTS
- BASE-LOAD ELECTRIC GENERATION IS GENERALLY LOWER IN COST IN NUCLEAR UNITS THAN IN COAL-FIRED UNITS, BUT COAL-FIRED UNITS WILL BE CHEAPER AT SOME SITES
- DETAILED ENGINEERING STUDY IS REQUIRED TO DETERMINE RELATIVE ADVANTAGES IN SPECIFIC CASES

INFO Atomic Industrial Forum, Inc.
Public Affairs and
Information Program

ECONOMIC COMPARISON OF COAL AND NUCLEAR ELECTRIC POWER GENERATION

JANUARY 1980

Gibbs & Hill, Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
NEW YORK, TEXAS, NEBRASKA, CALIFORNIA

PREFACE

The dramatic cost increases in oil coupled with rigorous national conservation policies have essentially eliminated oil and natural gas as fuels for electric power generation. Combined-cycle plants are being considered as possible partial short-term alternatives for delayed nuclear units. However, their dependence on oil and natural gas precludes their long-term use. The Power Plant and Industrial Fuel Use Act of 1978 effectively prohibits the use of oil and natural gas in central station power plants. Thus, coal-fired and nuclear power plants remain as the two more likely alternatives.

The impact of the Three Mile Island incident on the cost and lead time of nuclear power plants is already being felt today by the domestic electric utility industry. The full consequences have not yet been determined, and they may not be completely evident for many months to come. There is also a growing concern regarding the cost of decommissioning a nuclear power plant at the end of its useful life, and in particular, how these costs will be borne by the present and future consumers of electric power. The disposal of nuclear wastes and solid wastes from coal-fired plants is also under active scrutiny.

The effects of these and other factors which lie ahead will have an impact on the cost of electric power generation. The magnitude of the economic impact may differ for nuclear and coal-fired power plants. Accordingly, an analysis of bus bar generation costs for each of these fuel options under a range of economic conditions may prove helpful to utility executives in establishing future system growth plans. Such an analysis is presented herein.

I. INTRODUCTION

This study examines the comparative economics of large domestic coal-fired and nuclear power plants over the next three decades. Economic projections are subject to varying degrees of uncertainties, and this is particularly true of the future cost of fuels. The first part of this analysis avoids this issue by eliminating the predicted cost of fuel as an input. Instead, the other components that make up the bus bar generation costs are estimated; from these costs, the break-even coal and nuclear fuel costs are computed for three inflation cases.

In the second part of this analysis, coal and nuclear fuel costs are estimated through the year 2012. These costs are used to estimate the comparative bus bar generation costs of the coal and nuclear fuel options. A range of values for the following variables are investigated:

A. Inflation rate

B. Capacity factor

C. Fixed charge rate

In arriving at the ranges, recognized independent studies and published statistical data are used, as well as economic data from our own experience in serving the electric utility industry.

Capital cost estimates for each of the fuel options are based on the results of our recent actual plant construction experiences. Although capital cost estimates vary widely throughout the United States, the cost differentials are representative for the comparisons presented in this study.

The analysis provides trends and differentials in generation costs for the fuel options within a realistic range of economic and operational variables. The report does not include a specific recommendation for lowest cost generation. Such a recommendation requires a detailed study of specific conditions facing an electric utility.

II. BASES OF ANALYSIS

Plant Types

The following plant types are evaluated:

A. A nuclear electric generating station with two 1150-MWe LWR units using cooling towers

B. A supercritical coal-fired electric generating station with three 750-MWe units using eastern high-sulfur coal with flue gas desulfurization (FGD), sludge disposal facilities, and cooling towers

Units of this size and type are practical options for future baseload additions. It is assumed that the units would be duplicated in a "slide-along" expansion sequence.

As a result of the Clean Air Act Amendments of 1977 and subsequent EPA regulations related to "Best Available Control Technology" (BACT), an inherently low-sulfur coal can no longer be used as a means of avoiding the use of scrubbers (or other sulfur removal technologies) in new coal-fired power plants. The coal-fired power plant considered in this study is equipped with a flue gas desulfurization system capable of meeting the new EPA New Source Performance Standard (NSPS) requiring 70 to 90 percent sulfur removal depending on the coal's sulfur content.

A representative site in the southeast United States has been used to develop construction and transportation costs. It is assumed that none of the plants will experience unusual site, regulatory, or environmental impact problems that will significantly increase capital costs. Clearly, this is an important assumption for each of the fuel options. Moreover, the transportation costs to a specific site could have a significant impact on the results of this study.

Plant Design and Construction Parameters

Plant design and construction parameters are as follows:

Coal-Fired Generating Plant Schedule	
Engineering and construction period	7 years
Commercial operation dates	7/90, 7/91 and 7/92
Nuclear Generating Plant Schedule	
Engineering and construction period	11 years
Commercial operation dates	7/90 and 7/92
Eastern High-Sulfur Coal Quality	
Calorific value	12,500 Btu/lb
Sulfur content	2.5%
Ash content	10%
Total moisture	5%
Net Plant Heat Rates	
Nuclear	10,500 Btu/kWh
Coal with FGD	9,600 Btu/kWh

III. INFLATION RATE

Forecasting of economic indices is an inexact science. Recognizing that uncertainties exist, we have examined the effects of inflation over a range of projections that are designated as low, moderate, and high. The rates for the moderate-inflation case have been developed from recently published values. The low- and high-inflation cases reflect Gibbs & Hill judgment as to a possible range that may result.

Although current inflation rates are in excess of 13 percent, the long term average inflation rates are anticipated to be lower. The rates that have been used for the economic indices in each inflation case are as follows:

	Low (%)	Moderate (%)	High (%)
Composite of materials, equipment, and construction labor	7	9	11
Operating and maintenance supplies, and labor	7	9	11
Nuclear fuel	8	9	11
Coal	8	9	11
Coal transportation	8	9	11

The bases for selecting the rates in the moderate-inflation case are described in the following paragraphs.

A composite inflation rate for material, equipment, and construction labor has been derived from published construction industry statistics.[1][2] The composite rate is a weighted average of the relative contribution each index makes to the overall capital cost estimate.

The operating and maintenance labor inflation rate has been developed from both experience and historical records maintained by Gibbs & Hill Plant Betterment and Plant Testing and Startup Departments.

The coal inflation rate has been obtained from statistical data published by the United States Department of Commerce.[3] The range reflects Gibbs & Hill judgment of the price of coal as it may be influenced by such factors as the price of oil, the potential use of coal, and the growth in electric power demand.

The nuclear fuel inflation rate has been developed from information in the technical literature.[4] The values used for the range impart Gibbs & Hill judgment as to variations in the inflation of nuclear fuel price as it may be affected by possible changes in the cost of the nuclear fuel cycle, the impact of the price of oil, the growth in electric power demand, and uncertainties with respect to the price of yellowcake.

The coal transportation inflation rate is based on information maintained by the Gibbs & Hill Transportation Department.

IV. ESTIMATED PLANT CAPITAL COSTS

The 1979 plant capital cost estimate for each fuel option is presented in Exhibit 1. These costs have been broadly allocated in direct and indirect categories. The direct costs include site preparation, materials, equipment, structures, and installation. Land costs are not included. A contingency of 10 percent has been used for the coal plant and 15 percent for the nuclear plant; the difference reflects the more numerous criteria changes, lower productivity, and uncertainty over the longer construction period of the nuclear power plant. Contingency is part of the indirect costs, along with the cost of engineering, construction management, and client expenses.

The cost of the FGD and sludge disposal systems is shown separately for the coal plant to illustrate its contribution to the overall capital cost estimate. The sludge disposal system selected is one of the less capital intensive systems.

Exhibit 2 shows the effect of inflation and Interest During Construction (IDC) on each plant cost for the three inflation cases. Costs are expressed in terms of dollars per kWe, coinciding with the scheduled commercial operation dates stated previously. These costs include escalation and IDC.

Based on historical experience, IDC rates for the average utility have ranged from 2 to 3 percentage points above construction inflation rates. In this study, IDC rates of 9, 10, and 12 percent are used corresponding to the 7-, 9-, and 11-percent construction inflation rates described in Section III. Although current interest rates are higher than the average rates used in this study, the values used anticipate a future decline in interest rates.

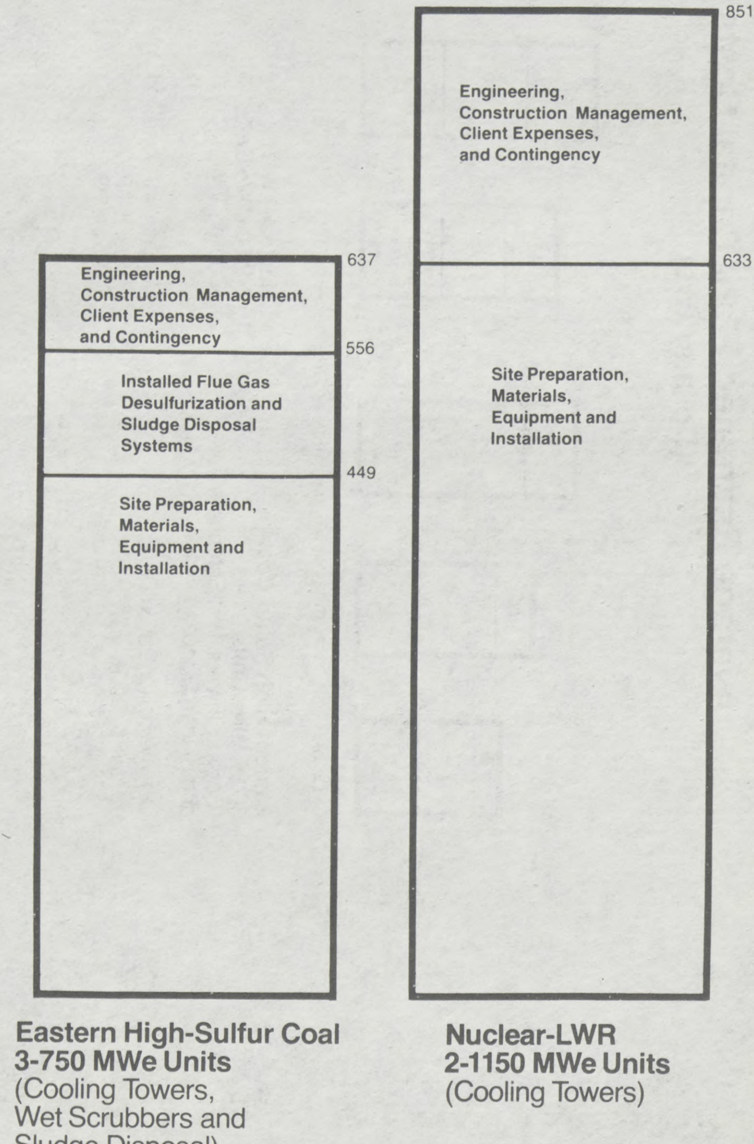
Having arrived at the IDC rates, the actual interest charges are computed using cash flow disbursement estimates developed by Gibbs & Hill for current power plant projects.

The capital cost estimate for each fuel option, in 1979 dollars, is $637/kWe for the coal plant with FGD and sludge disposal and $851/kWe for the LWR nuclear plant. In the period 1990 to 1992, these plants will have increased in cost as a result of inflation and IDC about 130 percent for the moderate-inflation case, 180 percent for the moderate-inflation case, and 240 percent for the high-inflation case.

In this analysis, Interest During Construction (IDC) is treated as a debt-financed construction cost. In actuality, an electric utility finances construction costs with a mix of debt and equity financing. The resulting financing charges are capitalized through an accounting principle known as Allowance for Funds Used During Construction (AFUDC). The difference between IDC and AFUDC, while of great importance to utilities, is not significant enough to change the results of this analysis.

Also of significance in determining costs per kWe is an alternative accounting principle, namely, Construction Work in Progress (CWIP), which a number of Public Utility Commissions now allow to be included in the rate base. Inclusion of CWIP in the rate base allows a utility to recover a portion of the construction funds as they are incurred, thus alleviating the burden of interest payments which would otherwise accumulate and not be recovered until after the plant commences commercial operation. Thus there is a reduction in the interest cost, and hence the capital cost, of a power plant. Because of its higher capital cost and longer schedule, the effect of CWIP is more beneficial to the nuclear option than the coal option. While CWIP has been widely adopted, although only on a case by case basis, recent decisions indicate that substantial variations exist among different state Public Utility Commissions regarding the extent to which CWIP is allowed in the rate base. Therefore, the use of AFUDC is still felt to be more representative, and for this reason, the effect of CWIP has not been included in this study. Where any utility believes CWIP will influence its decision, appropriate adjustments can be made to fit the specific case.

Exhibit 1
Estimated 1979 Plant Capital Costs
(Dollars/kWe)



Southeastern Site

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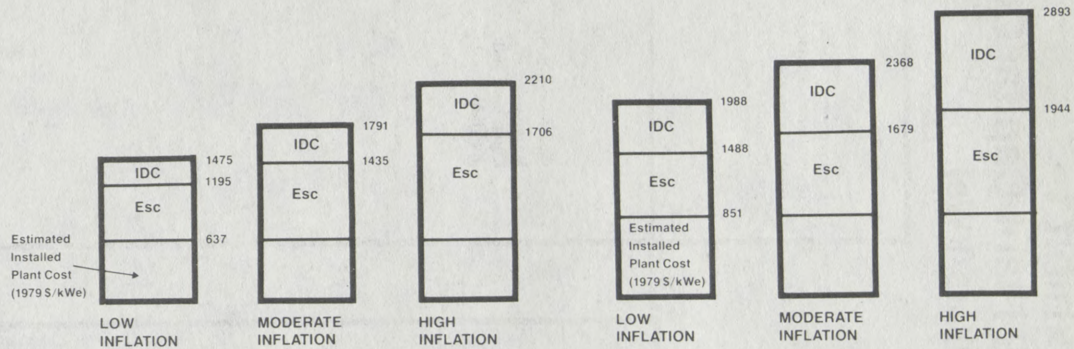
Exhibit 2
Average Estimated Plant Capital Costs
(Dollars/kWe)



Eastern High Sulfur Coal
3-750 MWe Units
(Cooling Towers, Wet Scrubbers and Sludge Disposal)

Commercial Operation Dates
- Unit 1 1990
- Unit 2 1991
- Unit 3 1992

Nuclear-LWR
2-1150 MWe Units
(Cooling Towers)

Commercial Operation Dates
- Unit 1 1990
- Unit 2 1992

Legend: IDC = Interest During Construction
Esc = Escalation

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V. BREAK-EVEN FUEL COSTS

Break-even fuel costs for the nuclear and coal options are plotted in Exhibit 3. The fixed charge and operating and maintenance (O&M) cost components are first calculated. Then fuel costs are computed to yield equal bus bar generation costs for the fuel options being compared.

Fixed Charges

Fixed charges are calculated using an annual rate of 18 percent of the 1990 to 1992 capital costs and a 70 percent annual plant capacity factor. The component parts of the fixed charge rate are shown in Appendix 1. A value of 18 percent has been selected from Gibbs & Hill project experience with investor-owned utilities. Similarly, a 70 percent capacity factor has been selected as a reasonable industry average for baseload units.

Although it is recognized that variations in both the fixed charge rate and the capacity factor may exist for plants of this size in the time frame studied, the scope of the break-even fuel cost analysis has not been extended to cover such variations. Rather, a sensitivity analysis of both variables has been performed, with fixed charge rates varying from 10 to 20 percent and capacity factors from 50 to 80 percent. Results have been included in Section VII of this report as part of the analysis of bus bar generation costs.

Operating and Maintenance (O&M) Costs

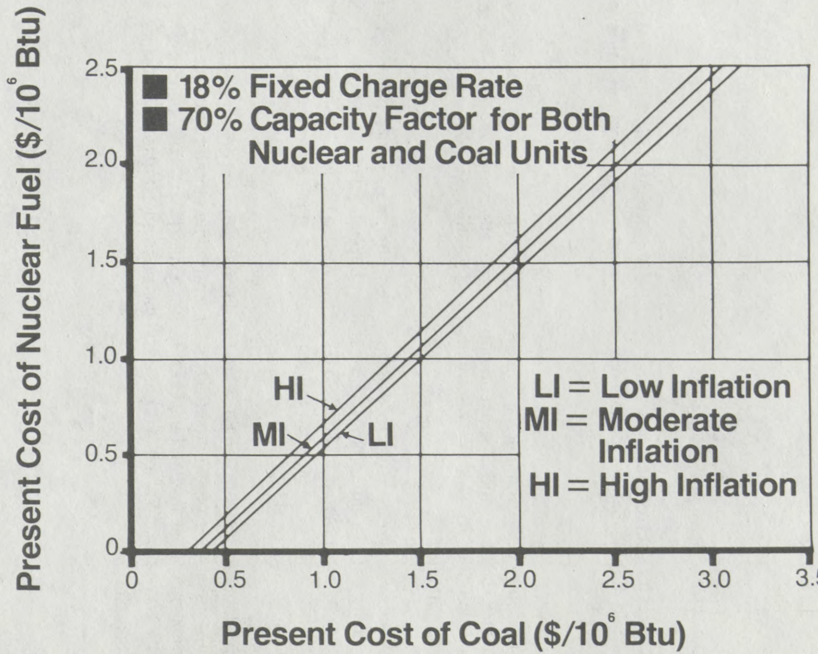
In developing the cost of material, supplies, and labor, plant staffing requirements and labor rates published by industry sources have been used; average values have been selected that are considered reasonable in the judgment of Gibbs & Hill Plant Betterment and Plant Testing and Startup Departments for the plant size and location. The estimated 1979 O&M costs are tabulated in Appendix 2. These are levelized over a 10-year period at the inflation rates described in Section III.

Total Operating Cost

Total operating costs are computed on a 10-year levelized basis by summing fixed charges, levelized O&M costs, and levelized fuel costs. To establish break-even costs, the fuel costs are calculated for each inflation case so that the total levelized operating cost of the nuclear power plant equals that of the coal plant. The levelized fuel costs are then converted to 1979 values using the appropriate inflation rates and interest rates for levelization. The resulting break-even fuel cost curves are shown in Exhibit 3.

To use these curves, enter the abscissa with a given value, e.g., the cost of coal expressed in dollars per million Btu. If a current value of $1.50 is selected for the moderate inflation case, find the intersection of $1.50 with the moderate inflation curve and read $1.08 on the ordinate. This means that the break-even cost of nuclear fuel is $1.08 per million Btu in the moderate inflation case when coal is valued at $1.50 per million Btu. Accordingly, if nuclear fuel is more than $1.08, coal is the choice at $1.50; conversely, nuclear fuel is the choice if its value is below $1.08. The break-even costs are based on 10-year levelized fuel and O&M costs. It should be noted that the results using 20-year levelized costs would vary by less than 5 percent.

Exhibit 3
Break-Even Fuel Costs—Nuclear vs. Coal



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VI. FUEL COSTS

In the second phase of this analysis, the fuel costs are estimated to develop bus bar generating costs for each of the fuel options. The 1979 fuel costs are summarized in Exhibit 4 for each of the fuel options.

Fuel costs for each of the inflation cases, computed for the period 1979 through 2012, are shown in Exhibit 5. The projections are based on the inflation rates presented in Section III.

The 10-year levelized fuel costs used in Exhibits 6 and 7 are computed for each 10-year period following the commercial operation date of each unit. The 20-year levelized costs used in Exhibits 8 and 9 are computed in an analogous manner. Interest rates for levelization of 9, 10, and 11 percent are used for the low-, moderate-, and high-inflation cases, respectively.

These curves can be used to determine the effects of future delivered fuel costs on generating costs from commercial operation through 2012. Generally, fuel cost ranges are shown to increase from $0.83 to $1.26 per million Btu in 1979 to $10.50 to $39.50 per million Btu in 2012. For each inflation case, the nuclear fuel cost is lower than the delivered cost of coal.

The nuclear fuel costs in Exhibit 4 are based on the federal government accepting title to spent nuclear fuel from electric utilities for a one-time storage fee. The D.O.E. estimated the maximum cost in October 1977 to be 1 mill/kWh.[5] The unit cost for spent fuel disposition shown in Exhibit 4 is based on this cost, adjusted to 1979 dollars.

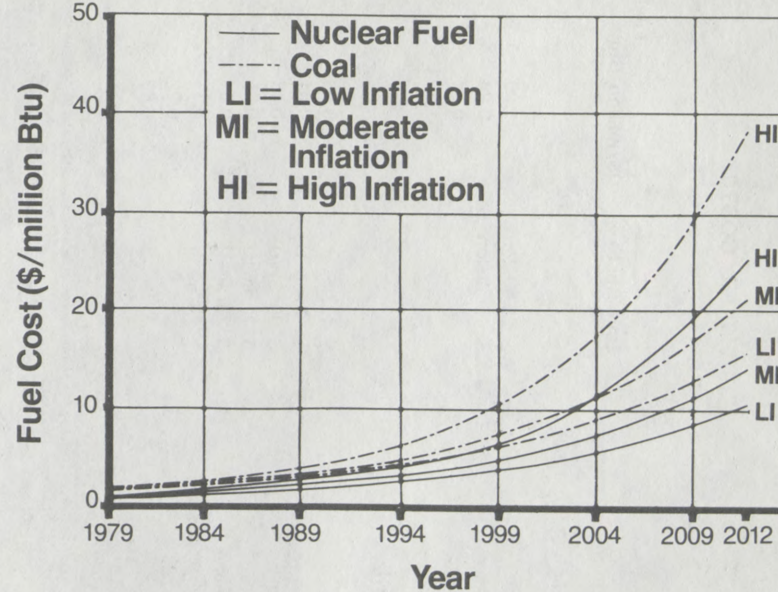
EXHIBIT 4

1979 FUEL COSTS

Fuel	Unit Cost	Fuel Cost ($/million Btu)	Fuel Cost (mills/kWh)
Eastern High-Sulfur Coal			
Raw coal	$ 25.00/ton	1.00	9.6
Transportation	$ 6.50/ton	0.26	2.5
Indirect costs(1)		0.04	0.4
Total		1.30	12.5
Nuclear Fuel			
Yellowcake	$ 43/lb	0.28	2.9
Conversion	$ 5/kg U	0.01	0.1
Enrichment(2)	$ 90/SWU	0.15	1.6
Fabrication	$130/kg U	0.05	0.6
Transportation	$ 25/kg U	0.01	0.1
Spent fuel disposition	$275/kg U	0.11	1.1
Indirect costs(3)		0.22	2.3
Total		0.83	8.7

NOTES:
(1) Carrying charges at 12 percent per annum for a 90 day coal pile and 70 percent capacity factor
(2) 0.25 percent tails assay
(3) Carrying charges at 15 percent per annum for annual reloading of a three-zone core and 70 percent capacity factor

Exhibit 5
Projected Fuel Costs (1979 to 2012)



Fuel Costs include Transportation

Gibbs & Hill, Inc.

VII. BUS BAR GENERATION COSTS

The 10- and 20-year levelized bus bar generation costs are computed for each fuel option for a range of capacity factors and fixed charge rates. For variations in capacity factor between 50 and 80 percent, bus bar costs are calculated at a fixed charge rate of 18 percent. In a similar manner, a capacity factor of 70 percent is used in the computation of bus bar costs for variations in the fixed charge rate between 10 and 20 percent. The fixed charges are combined with the escalated, levelized O&M costs and fuel costs. The results are shown in Exhibits 6, 7, 8, and 9.

Sensitivity to Capacity Factor

A comparison of the 10- and 20-year levelized generation costs for a range of capacity factors from 50 to 80 percent and a fixed charge rate of 18 percent demonstrates the following:

A. For 10-year levelized costs, nuclear generation is more economical than coal for capacity factors in excess of 65, 63 and 58 percent for the low, moderate, and high inflation cases, respectively.

B. For 20-year levelized costs, nuclear generation is more economical than coal for capacity factors in excess of 54 percent for the low inflation case and over the entire range of capacity factors studied for the moderate and high inflation cases.

It is evident from Exhibits 6 and 7 that low inflation puts coal-fired plants in a more favorable position because their bus bus generation costs are more fuel intensive. Conversely, high inflation favors nuclear.

It should be noted that for the capacity factors investigated, the maximum differential bus bar cost between coal and nuclear generation does not vary by more than 6 percent of the total bus bar generation cost for the 10-year levelized costs and 10 percent for the 20-year levelized costs. The apparent advantage of either generation option for a particular inflation case and capacity factor is actually within the limit of accuracy of the calculated values of the components of the bus bar generation costs. Consequently, these two exhibits are intended to demonstrate general trends rather than illustrate precise absolute values of the bus bar generation costs.

Exhibit 6
Ten-Year Levelized Bus Bar Generation Costs as a Function of Capacity Factor

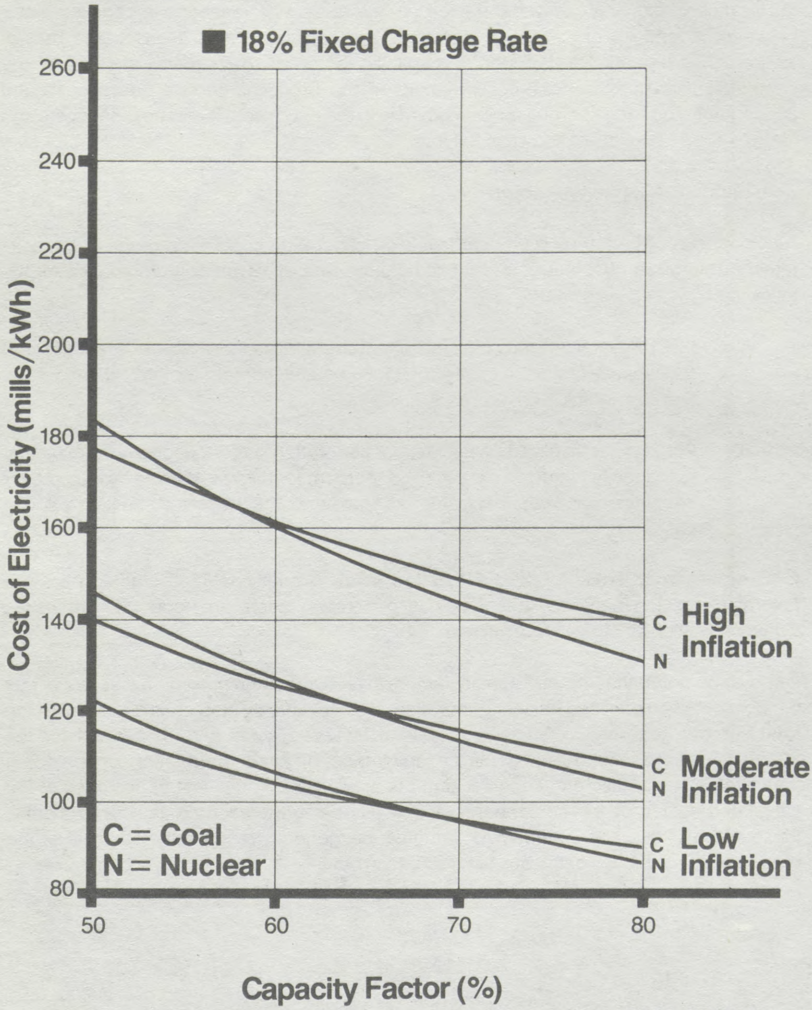


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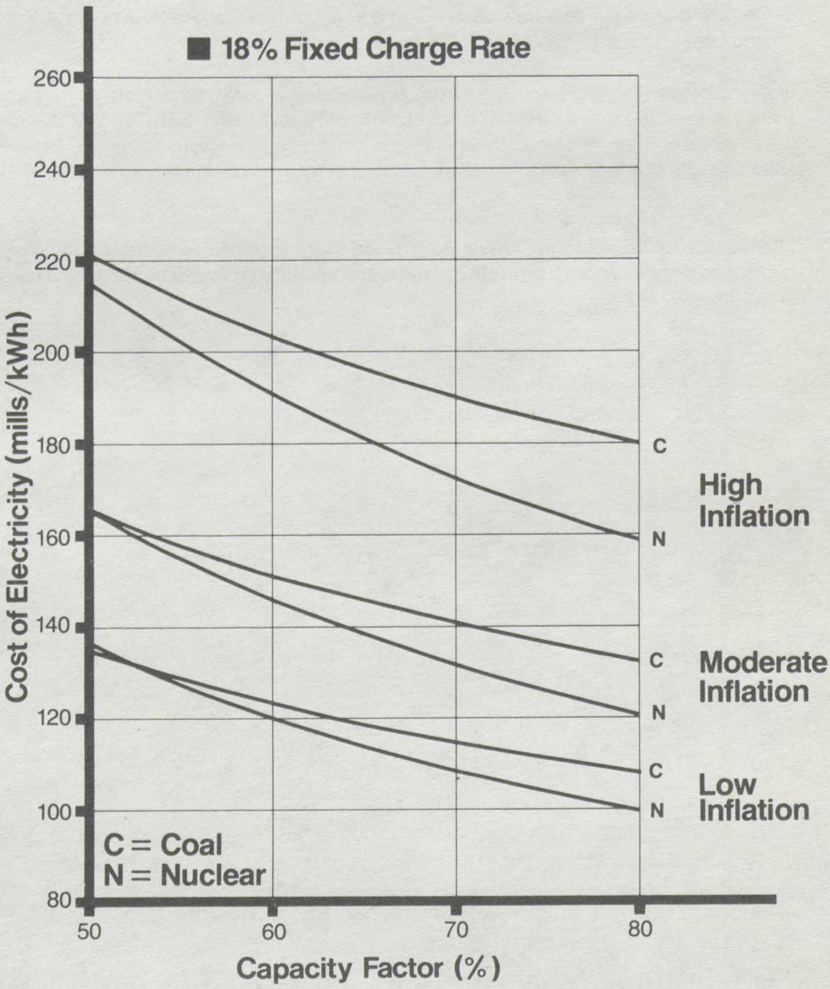
Exhibit 7
Twenty-Year Levelized Bus Bar Generation Costs as a Function of Capacity Factor



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Sensitivity to Fixed Charge Rate

A comparison of the 10- and 20-year levelized generation costs for a range of fixed charge rates from 10 to 20 percent and a capacity factor of 70 percent is shown in Exhibits 8 and 9. This range encompasses the domestic electric utility industry. The differential generation cost between coal and nuclear decreases with increasing fixed charge rate.

It is evident from Exhibits 8 and 9 that nuclear generation is consistently more economical than coal over the entire range of fixed charge rates studied for both 10– and 20-year levelized costs. There is an exception in the case of the 10-year levelized costs for the low inflation case where the advantage switches to coal for fixed charge rates in excess of 19 percent.

Interpolation of the values in Exhibits 6, 7, 8, and 9 allows one to compute bus bar costs for various combinations of fixed charge rates and capacity factors over the ranges used in this study.

Exhibit 8
Ten-Year Levelized Bus Bar Generation Costs as a Function of Fixed Charge Rate

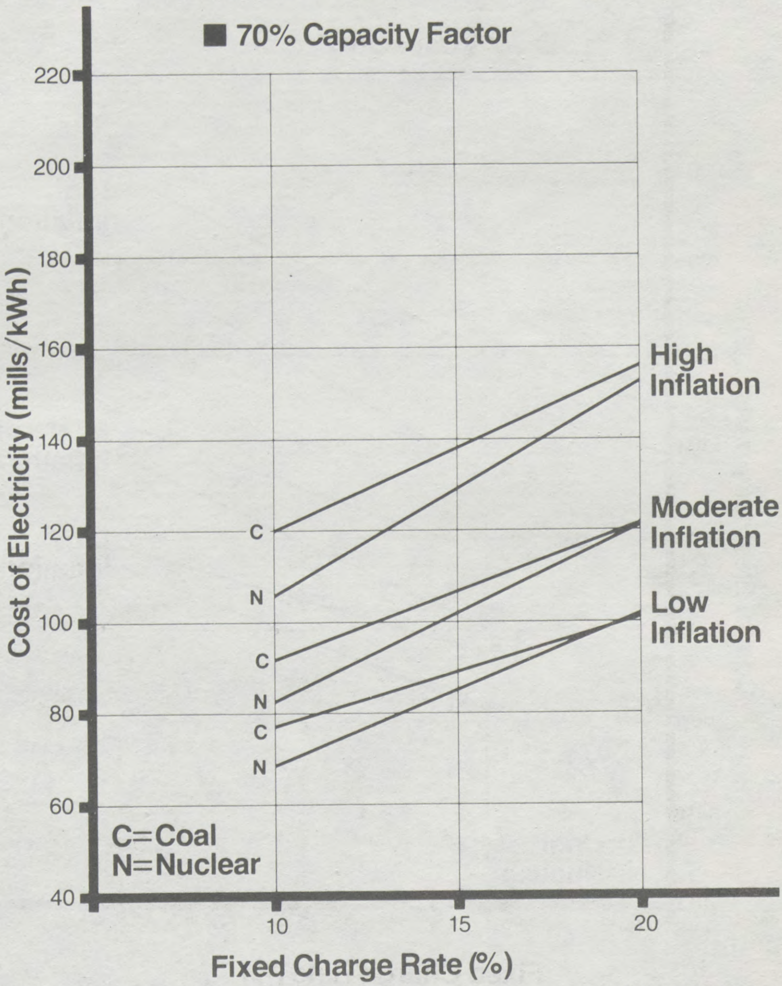

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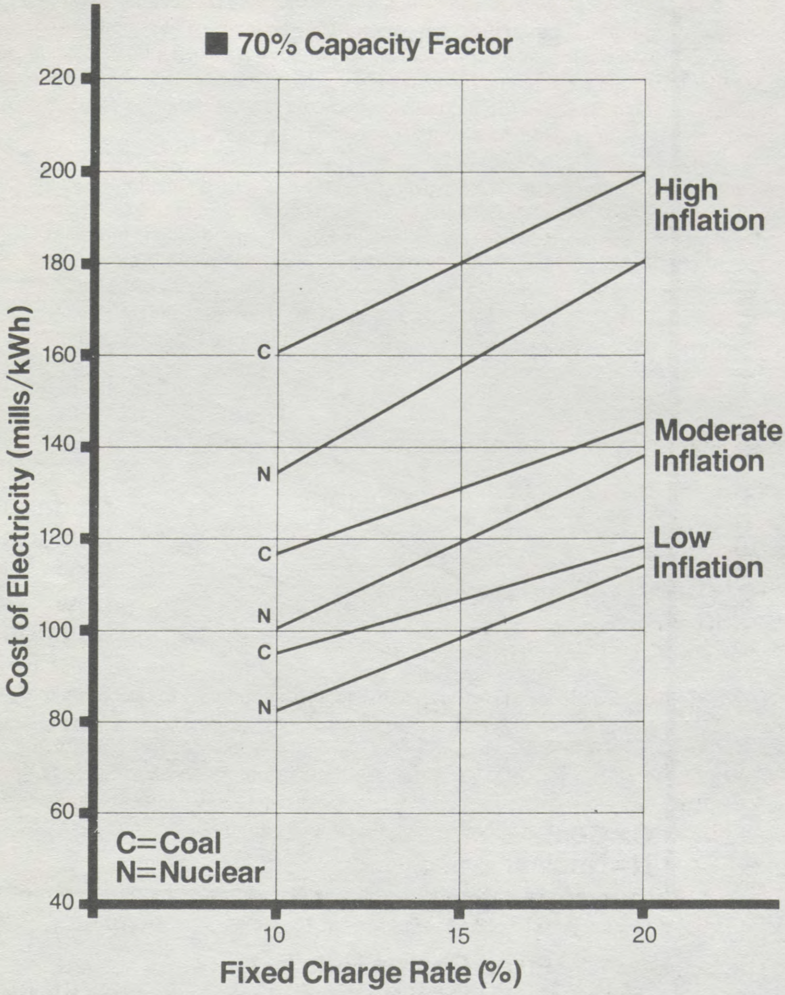
Exhibit 9
Twenty-Year Levelized Bus Bar Generation Costs as a Function of Capacity Factor



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The Effect of Nuclear Plant Decommissioning Costs

Up to this point, the analysis has not considered the impact of the cost of nuclear plant decommissioning on the bus bar generation cost. It is difficult to precisely estimate decommissioning costs for several reasons. First, there are several proposed methods of nuclear plant decommsissioning; they can be broadly classified as: mothballing, entombment, and prompt removal. Also, it is not certain whether a sinking fund employing bonds or other investment instruments to establish the fund required at the end of the plant's useful life would be subject to federal income taxes. The applicability of income taxes has a significant effect on the total cost of decommissioning.

A recent article [6] indicates that prompt removal of a nuclear plant is least affected by the method of financing and by future cost escalation. Adjusting the results of this article to compensate for inflation during the life of the plant, and assuming the sinking fund will be exempt from federal taxes, it is estimated that the uniform annual cost for nuclear plant decommissioning could vary between 0.6 and 3.5 mills/kWh, depending on the inflation case. These costs are based on a 70 percent capacity factor. The estimated nuclear plant decommissioning costs constitute less than 5 percent of the total bus par generation costs on either a 10-year or 20-year levelized basis.

VIII. CONCLUSIONS

The trends that seem most evident are the following:

For all three inflation economies, nuclear power generation emerges consistently as the lowest cost form of generation for capacity factors above 65 percent. This can be attributed to the fact that the lower cost of nuclear fuel in comparison to coal more than offsets differences in plant capital costs. This implies that exploration and supply of yellowcake keeps pace with demand and that reasonable solutions are found for the mounting problems of disposition of unreprocessed spent fuel and terminal storage of radioactive waste. Moreover, it is necessary that sociopolitical forces do not preclude the use of nuclear power as a safe, environmentally acceptable generation source.

For capacity factors below 65 percent, coal becomes more competitive with nuclear, particularly for the 10-year levelized costs.

IX. RECAPITULATION

The values and ranges for the variables used in this study are felt to be accurate and comprehensive enough to offer reasonable insight into the relative future costs of nuclear and coal electric power generation as they may be affected by changes in inflation. In addition, there is a need to keep abreast of changes in national policy, regulations, and economic conditions as they can have an impact on the cost trends and differentials presented in this study. These cost projections are not a substitute for the detailed studies that are required to deal with the specific conditions facing each electric utility.

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(3) U.S. Department of Commerce, Bureau of the Census, Statistical Abstracts of the United States, 1978.

(4) Nuclear Fuel, McGraw Hill, New York, Various Issues, June and July, 1979.

(5) Department of Energy Information, R-77-017, October 18, 1977.

(6) Ferguson, J.S., "A Case for Funding Nuclear Plant Decommissioning Cost", Power Engineering, December, 1978.

Appendix 1

COMPONENTS OF THE FIXED CHARGE RATE

The following values were used as typical of investor-owned utility financing:

Interest on debt portion	5.5%
Return on equity portion	5.6
Depreciation	3.3
Taxes and insurance	3.6
Fixed charge rate	18.0%

Appendix 2

ESTIMATED 1979 OPERATING AND MAINTENANCE COSTS

Capacity Factor (%)	Nuclear (mills/kWh)	Coal with FGD (mills/kWh)
50	3.85	4.85
60	3.21	4.32
70	2.75	3.95
80	2.45	3.67

COST COMPARISON OF CENTRAL ELECTRIC POWER GENERATION USING COAL AND NUCLEAR FUELS

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Presented Before

THERMAL REACTOR SAFETY
1980 ANS/ENS TOPICAL MEETING

April 11, 1980
Knoxville, Tennessee

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ABSTRACT

This paper addresses the current and expected future costs of generating electricity with the two available practical modes of power generation, coal and nuclear. It describes the procedures and inputs used to arrive at the conclusion that generation with nuclear fuels will be about 16% more economical than generation with the best coal alternative.

Recognizing the uncertainty in long range estimates of this type, various sensitivity checks are developed to determine how much the capital, fuel, and operating costs would have to change to force a change in the ranking of the alternatives. The results are current estimates of the costs of generating electricity in the future in the middle western area of the United States with large nuclear units, and with comparably sized and comparably loaded coal units firing high and low sulfur coals.

INTRODUCTION

Two fuels will almost certainly be the sources of electricity for the next several decades. This was the recently reported conclusion of a four-year Department of Energy (DOE) sponsored study made by the National Academy of Sciences (NAS). The NAS Committee on Nuclear and Alternative Energy Systems (CONAES) concluded that "as fluid fuels are phased out of use for energy generation, coal and nuclear power are the only economic alternatives for large scale application in the remainder of this century. A balanced mix of coal and nuclear generated electricity is preferable to the predominance of either."

Before describing how we derived the figures in this paper and reached our conclusions as to the relative future costs of these two alternatives, several caveats and a discussion of the uncertainties involved are in order. First, the method used is that of obtaining the lifetime levelized future generating cost of each alternative. A levelized cost is a constant annual cost that is equivalent to the actual time varying annual cost when consideration of the time-value of money is included. This procedure is selected as a measure of merit because it is relatively easy to understand and is commonly used by the electric utility industry. In a site-specific comparison of the economics of coal versus nuclear generation, recognition would have to be made of the particular utility's requirements, capabilities, and external conditions in existence at the time. Generation expansion models would be used for planning simulations, and total system costs and reliability factors would be considered in detail.

UNCERTAINTIES

Much has been said about the uncertainties surrounding cost estimates of nuclear power generation. There is about as much uncertainty, however, in the economics of coal as there is with nuclear generation:

- Coal project durations have been extended to achieve compliance with air and water pollution regulations and the requirements for flue gas desulfurization equipment.

- A recent EPA report shows cost variation ranges of 2½ times in capital costs and five times in operating costs for flue gas cleanup.

- Standardization of coal units is hampered by the non-uniformity of coal burned in power boilers.

• Since 1969, costs of coal at the mine have increased an average of 15%/Yr. and coal rail tariffs have increased an average of 10%/Yr. If railroads are deregulated as proposed, tariffs applied to unit train coal movements may increase at even greater rates.

It is also true, however, that nuclear units face many serious uncertainties. For example, safety features prompted by Three Mile Island will add to the investment cost of new units. For every $10 million increase (in 1980 dollars) that is added to an 1100 MW nuclear unit, the generating cost would increase about 0.6%. Should the price of yellowcake increase $10/lb from today's level of $40, the lifetime average nuclear generating cost would increase about 3%. The yellowcake price would have to nearly triple while coal costs stayed constant, however, before levelized coal generating costs would become the more favorable. The enrichment price could go from about $100 to $255 per separative work unit (in today's dollars) before nuclear generating costs become less favorable than coal. If nuclear spent fuel disposal costs, including storage in a federal repository, encapsulation, transportation, and security, were to triple from the value given in a 1978 DOE report, the increase in levelized generating costs would be less than 4 mills per kWh or about 2%.

Much has been said about the economic uncertainty of decommissioning nuclear units, but this too has a relatively minor impact on overall nuclear generating cost. In this analysis, we have added a 30% contingency to the present day estimated cost of decommissioning, arriving at about 51 million 1980 dollars. Escalating this cost and then spreading it over the nuclear unit lifetime yields an addition to the nuclear generating cost of about 1.2 mills per kWh and increases the levelized nuclear generating cost by less than 1%.

A major risk faced with both coal and nuclear units is that of delay in the date of commercial operation of the unit. This is particularly serious in the case of nuclear units where investment costs are higher. For example, if an unplanned delay of two years should occur immediately after design engineering commences, the cost of the nuclear unit might increase more than $200 million. This could vary with the length of the delay, when the delay occurs and the interest and inflation rates prevailing at the time. It does not include the additional costs of replacement power during the delay, penalty charges, and costs resulting from escalating regulatory requirements during the longer schedule. Large financial risks such as these influence utility system planners and could lead to the abandonment of the nuclear alternative. This possibility could have disastrous consequences for the country.

PROCEDURE

Total generating cost is the sum of fuel costs, operation and maintenance costs, and the cost of capital investment in new generating plant. To combine capital costs with annual production expenses, we apply a percentage, called a fixed charge rate, to the capital investment cost. This factor annualizes the investment and permits its addition to the annual fuel, operation and maintenance costs. Financial mathematics are used to adjust for differences in the timing of the cash flows among alternatives. This is necessary when comparisons are made of investment in plant today and operating costs or savings in future years.

CURRENT GENERATING COSTS

Each year the Atomic Industrial Forum surveys electric utilities having both fossil and nuclear capacity in their systems. Forty-three of 48 utilities responded to the most recent survey. Of those reporting total costs, the average nuclear production cost for a kilowatt hour of electricity was 1.54 cents in 1978, about the same as in 1977 and 1976. A base load coal-generated kilowatt hour in these utilities' systems cost 2.15 cents in 1978, up from 2.0 cents in 1977 and 1.6 cents in 1976. These costs include fixed charges on plant capital, fuel, and operating and maintenance costs and represent the total cost of producing power up to the point at which electricity leaves the generating station. Although the savings from nuclear generation are not now as great as was envisioned in the 1950's, the nuclear generating costs represent savings of millions of dollars each year for America's electric consumers, compared to higher-cost generation that would have occurred with fossil fuels.

FUTURE GENERATING COSTS

The National Energy Act of 1978 prohibits the use of oil or natural gas as a primary fuel in any new base load generating plant, with some exemptions. However, even before the 1978 Act, fuel economics had driven utilities away from the use of gas and oil to generate electricity. About 60% of the new boilers ordered in 1971 were designed to burn oil or gas. The last such unit was ordered in 1974.

We will deal here only with base load bulk power generation using coal and nuclear fuels. Despite certain disadvantages with each, we must realistically acknowledge that these are the fuels to be relied upon for almost all of our country's electric power at least through the end of this century.

More exotic sources of energy such as solar and windmills are too far over the horizon to allow realistic appraisals of their future costs, reliability, and availability. Other sources of large scale power supply, such as geothermal and hydroelectric, are severely limited by geography. Only coal and nuclear fuels are now sufficiently developed to allow realistic cost comparisons for large scale electric generation.

RESULTS

The average annual generating costs projected for midwestern coal-fired and nuclear power plants over 30 years of operation, starting operation about 1992, are shown in Figure 1. For the conditions assumed, the 1100 megawatt-electrical (MWe) nuclear unit is expected to generate at 161 mills per kilowatt-hour (kWh), an average of 16% lower than that of the next most economical alternative, a comparably sized unit fired with high-sulfur coal from central Illinois. During the 1992-2021 period, nuclear costs are thus forecasted to average about ten times higher than they are today, primarily due to inflation. The average cost for coal generation, however, will be even higher, primarily because coal generation is affected more severely by inflation.

Explained below is how the various components of generating costs shown in Figure 1 are derived.

CAPITAL INVESTMENT COSTS

The capital investment in a power plant is made up of four elements - direct costs, indirect costs, an Allowance for Funds Used During Construction (AFUDC), and escalation.

DIRECT COSTS are those costs which would be incurred by the utility if it could purchase all equipment and materials and construct the generating unit instantaneously at today's price levels.

INDIRECT COSTS include capital charges to the utility company that are beyond the direct costs of equipment, materials, and construction labor. They generally include charges for consulting engineering, construction management, quality assurance, permits, and other costs incurred during construction.

AFUDC is a cost added to the cost of the generating unit to compensate investors for the use of their money during the lengthy period between the time funds for building the unit are spent and the time the unit goes into operation. If construction work in progress is not included in the rate base, electricity rates are not increased sufficiently to recover these costs for money obtained from stock and bond investors during the construction period. Instead, over the life of the unit, the utility will recover from its customers through depreciation charges, compensation for financing the investment made prior to operation of the unit.

ESCALATION

Suppliers of power plant equipment, materials and services usually link their prices to various statistical indices issued by the government and others.

One such commonly used index is the Bureau of Labor Statistics Standard Industrial Code (SIC) 36. Since the 1973 oil embargo and the end of price controls, average hourly earnings in the electric industry increased between an average of 7% and 11% per year through 1979.

The materials indices to which many power plant equipment suppliers link their prices have increased at even greater rates. A commonly used Bureau of Labor Statistics material index for metals and metal products, Code 10, increased almost 28% during 1974, moderated somewhat shortly thereafter, and appears once more to be increasing at a high rate, averaging over 13% annually in 1978 and 1979.

Other power plant building, material, and equipment prices have increased markedly since mid-1973. Turbine prices, for instance, have increased at a rate of over 10% per year, exceeding the general inflation rate over the same period of time.

Figure 2 shows that total electric utility construction costs in the northern midwestern area of the United States have increased more rapidly than has the Consumer Price Index in the last ten years and since 1973.

Figure 3 shows Sargent & Lundy's most recent estimates for the investment costs of nuclear and high and low sulfur coal-fired units going into commercial operation in 1991-92. The operating dates shown were chosen because we believe it would take a minimum of eleven years to design, license, construct, and test a nuclear unit from the time engineering is authorized, assuming a site and unit size have been preselected. Coal units can possibly be put into commercial operation about six to seven years after the engineer is authorized to start design activities. All units are assumed to be located in the north central part of the country to normalize the costs of construction labor and coal transportation.

Investment cost escalation resulting from expected inflation in the economy has been determined using a rate of 9.5% per year through 1981 and 9% per year thereafter. Escalation in the cost estimates is assumed to take place from now to the payment dates for material, equipment, construction labor, and services.

The rate used to add AFUDC to the escalated cost of equipment, materials, construction labor, and services is 9.5% per year, compounded semi-annually. This is compatible with AFUDC rates allowed today by regulatory authorities in many jurisdictions. Sales and use taxes have been excluded from the capital cost estimates.

An important and relatively recent consideration in the estimates is the inclusion of flue gas desulfurization (FGD) equipment with both high and low sulfur coal units. The New Source Performance Standards recently issued by the Environmental Protection Agency require such equipment, even with the use of low sulfur coal that is abundant in the western United States. Such FGD equipment adds between 10% and 20% to the present-day direct investment cost of each coal unit, not including the cost of sludge storage ponds for FCD system waste disposal. Also included in plant investment costs are closed cycle turbine exhaust cooling systems using mechanical draft cooling towers. Very few, if any, new large power plants in the U.S.

will be allowed to use natural bodies of water for condenser cooling due to the increasingly stringent environmental regulations in effect now and expected to be in effect in the future.

The total estimated cost of the nuclear unit, including all directs and indirects, escalation, and AFUDC, slightly exceeds three billion dollars, or $2,765 per kilowatt in 1992. Of this, about $793 million is the present-day direct cost of equipment, materials, service, and construction labor. These costs do not include plant modifications which might result from the accident at Three Mile Island. The NRC has identified some of these as including technical and operational support centers, control room redesigns for better controls and instruments, emergency power supplies for certain valves and indicators, additional provisions for isolation of the containment, post-accident radiation controls and plant shielding, greater use of reactor simulators, and other capital equipment. A final determination of the extent of these additional facilities, or even whether they are needed, has not yet been made. What is known is that these items and their associated engineering and construction will not be inexpensive. A measure of the uncertainty in these costs is reflected in NUREG-0660, wherein the NRC estimates them to be about $25 million and involve about 73 man-years of effort per unit. The AIF believes the cost of implementation could range from $28 to $700 million and could involve 100 man-years of effort.

FIXED CHARGES ON INVESTMENT

Utility revenues are largely controlled by regulation; planning in regulated industries is done by minimizing revenue requirements. Certain revenue requirements can be expressed as percentages of the capital investment and must be paid each year, independent of production from the generating unit. These so-called fixed charges include interest on debt and return on equity, and represent compensation to bond and stockholders for use of their money. Fixed charges also include Federal income tax, insurance premiums to cover non-nuclear related losses, state and local taxes and depreciation expenses. Nuclear insurance expenses are included in nuclear operation and maintenance expenses, discussed below.

Levelized fixed charge rates of about 18% per year are applied against capital investment in this comparison of generating costs. Discounting is based on a 10% per year projected cost of debt and a 10.4% rate for preferred stock. The projected yield on common equity is assumed to be 15% per year. The capital structure is such as to result in a weighted average return and discount rate of 11.9%.

FUEL COSTS

Fuel costs have increased sharply in the past several years, as shown in Figure 4. Oil has increased in cost by nearly a factor of three since the oil embargo in late 1973. Gas has gone up by more than a factor of four since 1973, but remains less expensive than oil because of more rigid price controls. The cost of delivered coal has more than doubled since 1973, mainly due to inflation, declining labor productivity, and higher transportation costs. Nuclear fuel costs have remained relatively stable, but large recent increases in natural uranium and uranium enrichment costs are beginning to be felt.

Low sulfur coal is assumed to come from the Powder River Basin of Montana and northeastern Wyoming. An average sulfur content of 0.5% by weight and heating value of 8100 Btu/lb are assumed, typical of coal from this region. Discussions with coal suppliers and utilities and examination of prices reported in the trade press indicate a current price, FOB mine, of about $8 per ton for long term contracts, including local taxes.

Transportation of low sulfur coal is assumed to be in 100-car unit trains traveling on a single railroad's line to the Midwest. Examination of published tariffs and discussions with railroad executives and utility users suggest that about $16 per ton is a likely estimate of the tariff a railroad might require for this transportation. Total delivered coal cost thus is approximately $24 per ton, or about \$1.50 per million Btu (MBtu) as burned. Escalation of the delivered coal price is estimated at about 9.9% per year, based on examination of historical relationships between mining and transportation costs and general rates of price increases in the U.S. economy. This forecast conservatively assumes a 7% long range general inflation rate and therefore assumes the delivered price of western coal will rise in constant dollar (real) terms at a rate of almost 3% per year. Further evidence of the conservatism of the coal prices used in this study is the existence of coal bids for slightly better quality western coal with prices considerably in excess of \$2.00/MBtu, including transportation cost.

High sulfur coal is assumed to come from central Illinois, containing 3% sulfur by weight and 10500 Btu/lb. FOB mine cost for this coal is taken to be slightly under \$23 per ton, including local taxes, and unit train transportation is estimated at \$6.80 per ton, for a total delivered price of about \$29.80 per ton or \$1.40/MBtu. This delivered price is forecasted to escalate at approximately 9% per year, again assuming that general inflation will be 7% per year in the long range future. Midwestern coal is forecasted to escalate less rapidly than Western coal because the delivered price of Midwestern coal contains less transportation cost, which historic data suggests may rise more rapidly than mining costs.

In projecting future nuclear fuel costs we have assumed a current yellowcake price of \$40 per pound of U_3O_8, which appears to be slightly above the price at which uranium now is marketed. Cost of conversion to hexafluoride is \$2.50 per pound of uranium, approximately the current market price of this service.

Enrichment processing by the U.S. Department of Energy (DOE) is priced in terms of dollars per separative work unit (\$/SWU). DOE's price of \$98.95/SWU, effective at the beginning of 1980 for recent enrichment contracts, has been used in these cost comparisons.

Costs of fabricating nuclear fuel assemblies are based on recent proposals made by reactor suppliers.

Each of the foregoing components is presumed to escalate at rates derived by comparing historic cost behavior with general rates of price inflation. The composite rate of escalation for nuclear fuel is about 9% per year, equivalent to a rate of 2% per year in excess of the rate of increase in the general economy.

Perhaps the most controversial aspect of nuclear power today is treatment of spent fuel assemblies. Studies by many government and private organizations support the position that radioactive wastes from reprocessing can be disposed of safely. In addition reprocessing appears to be desirable because of the resource conservation afforded. Recycling the uranium and plutonium recovered from reprocessed fuel is equivalent in energy content to over 30% of the newly mined uranium and over 20% of the separative work present in fresh fuel. Permanent disposal of spent fuel instead of reprocessing would deprive the economy of these resources. Present government policy does not permit reprocessing, however, so we have based our nuclear fuel cost estimate on "throwaway" fuel management, in which spent fuel is encapsulated and disposed of at a Federal repository. The nuclear fuel cost estimates assume a total cost of \$165/ kilogram of uranium in 1980 dollars for spent fuel transportation and disposal, based on escalation of DOE estimates presented in a July 1978 report.

OPERATION AND MAINTENANCE COSTS AND DECOMMISSIONING

Annual operation and maintenance costs for the coal units include staff labor, operating and maintenance materials and supplies, and administrative costs but exclude fuel expenses.

These costs are based on units equipped with mechanical draft cooling towers and limestone throwaway-type flue gas desulfurization (FGD) systems. Inclusion of FGD systems can add about 70% to O&M expenses for coal units constructed without such systems, reflecting the cost of large quantities of limestone reactant and the expense of FGD system waste disposal.

O&M expenses for the nuclear unit include additional security personnel, shift technical advisors, nuclear insurance, decommissioning costs and NRC inspection fees. The inclusion of a shift technical advisor is the result of a recommendation made by the NRC's Three Mile Island "Lessons Learned" Task Force.

Annual nuclear insurance premiums provide property, liability, and outage coverage. Government indemnity is not included because government coverage is expected to expire before the 1992 commercial operation date assumed here. As a result of Three Mile Island, the electric utility industry is in the process of establishing an insurance company, Nuclear Electric Insurance Limited, whose purpose will be to insure utilities against costs of prolonged outages and expensive replacement fuel. The annual outage insurance premiums of $1.5 million included in this analysis are based on maximum coverage of $156 million.

Annual escalation of 8.9% per year is assumed for labor, limestone, and sludge disposal expenses; 8.5% per year for maintenance materials; and 7% per year for NRC inspection fees. These rates are based on historical relationships between O&M cost items and general rates of price inflation as measured by the GNPD.

Decommissioning costs for the 1100 MW nuclear unit are based on recent industry studies. The prompt removal/dismantling method of decommissioning has been selected for this cost estimate. A 30% contingency and a 9.0% annual escalation rate have been included in the estimate of decommissioning expenses, which amount to a levelized value of 1.2 mills per kWh, representing a cost in today's dollars of about $51 million.

CAPACITY FACTORS

Capacity factor, the ratio of actual to maximum possible annual energy generation, determines the total energy production over which the fixed charges on capital investments are spread. The capacity factor depends on system demands, including assignment by the utility of generating capacity to meet demand, and on forced and scheduled outages.

Capacity factors of presently operating coal and nuclear units are comparable. An Edison Electric Institute study using data for the ten year period 1968 to 1977 inclusive, shows a capacity factor for all nuclear units of 61.23% compared with 58.35% for fossil units in the 400-599 MW size range and 56.53% for fossil units in the 600-799 MW size range. In 1977, nuclear plants operated with a 66% capacity factor, compared with 57% for coal units and 50% for oil units. In 1978, nuclear looked even better, operating at a 68% capacity factor versus 55% for coal and about 51% for oil units. Figures for 1979 were not in hand as of the time this paper was prepared, but the nuclear results will probably be less favorable because of TMI, and problems with seismic calculations which forced several units off line.

The economic comparisons presented in this paper for future units assume an average 60% capacity factor for both coal and nuclear units over their assumed 30-year operating lives. Operation at lower capacity factors would hurt the nuclear units because of their relatively high fixed charges. Operation at higher capacity factors, on the other hand, would make the nuclear units look better economically, since the fixed charges would be spread over a larger number of energy units (kilowatt hours).

SENSITIVITIES

Sensitivity checks have been made to determine how much the capital investment and operating costs of the nuclear unit would have to be increased before the nuclear unit might be less economical than the best coal unit on a lifetime evaluated cost basis. Under the assumptions cited here, the direct investment cost of the nuclear unit would have to increase 31%, or $247 million in today's dollars to reverse our findings. Spent fuel disposal charges would have to increase by approximately a factor of sixteen in today's dollars before coal became more economic. Alternatively, nuclear operating and maintenance costs (excluding fuel) would have to increase more than 2.5 times or decommissioning costs would have to increase 26 times in today's dollars to reverse the ranking. The capacity factor at which the coal and nuclear units operate in the future would have to be less than 40% before the oal unit became the economic choice.

Fuel and operating costs--those which will be incurred over the assumed 30-year lifetime of the units--represent about 66% of the total cost of the coal unit and only 41% of the cost of the nuclear unit. Therefore, continuing cost inflation will impact the coal alternative more severely than it will impact the more capital intensive but less fuel intensive nuclear unit.

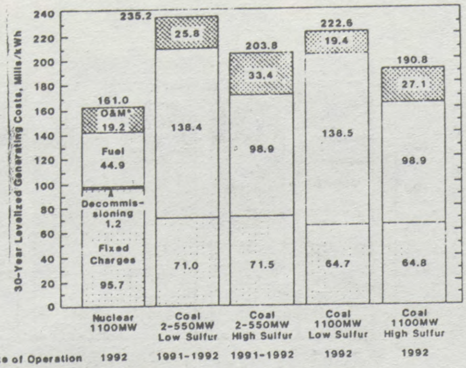
Actual data from operating plants demonstrates that nuclear generation is now more economic than coal generation. Our estimates lead us to believe that nuclear will continue to be more economic than coal in the future. Because of the distribution of investment and operating costs, nuclear power may also offer utilities greater long run protection against the effects of inflation.

CONCLUSIONS

Long development times are required for new forms of bulk power generation. It is neither prudent nor reasonable to believe that renewable energy sources such as solar power will be commerciallly available for bulk production of electric generation before the end of the century. That leaves only two practical and secure electricity generating alternatives for consideration for the near future -- coal and nuclear.

Today, nuclear power appears threatened. It has been beset by time-consuming and expensive regulation, uncertainties as to electricity demand, utility financial difficulties, and unusually rapid cost increases. Its public image has been damaged by a vocal and influential minority that has chosen nuclear power as a symbol of the establishment with which that minority is displeased. To this array of problems has been added perhaps the most serious of all: the accident at Three Mile Island. Should all of these concerns combine to make nuclear power infeasible, the American people will be the losers, for we will have reduced our practical and secure options for generating electric power from two - coal and nuclear, to one - coal alone. Coal may not be capable of bearing this load because of technical, environmental, legal and/or economic problems, thus forcing America to further increase its dangerous reliance on insecure foreign oil. If this happens, we will certainly see a serious decline in our standard of living as lights go out and factories shut down.

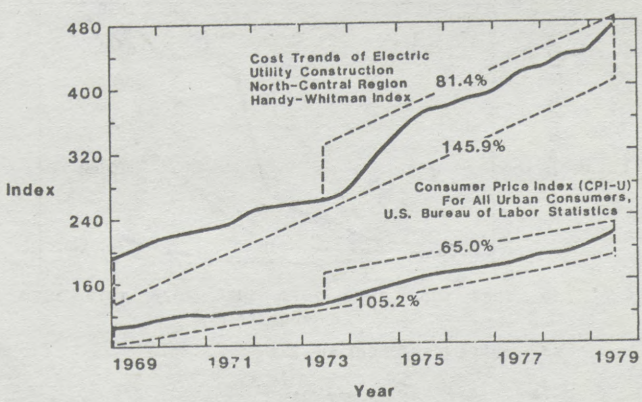
The United States is blessed with sufficient reserves and resources of both coal and nuclear fuels to carry us well through the period when the world's oil supplies are expected to run out. It defies all logic that we should be forced to depend upon unstable foreign governments, which can control our economic well being at their whim, for such a large share of our energy. We must ensure that circumstances will allow our nation to maintain a secure and adequate supply of electric energy. This can be achieved only if we base that supply on the two fuel resources, coal and nuclear, that are available <u>now</u>. We need <u>both</u> our coal and nuclear options to carry us through to the next century when yet-to-be-developed technologies might make meaningful contributions to our energy supply.



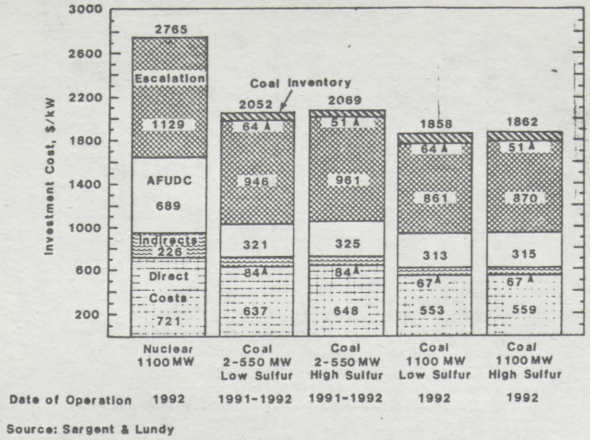
(60% Capacity Factor and Approximately 18% Fixed Charge Rate on Depreciating Capital and 21% on Fuel Inventory)

*Operation and Maintenance (Includes nuclear insurance for the nuclear case)

30 - Year Levelized Generating Cost From 1992
Nuclear vs. Coal
FIGURE 1

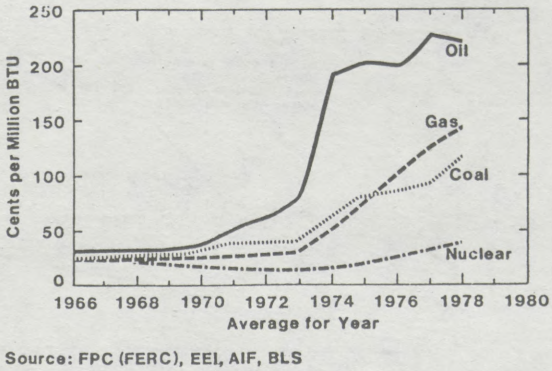


Electric Utility Construction Cost Trends
FIGURE 2



Projected Capital Investment Cost Nuclear vs. Coal

FIGURE 3



Fuel Costs of U.S. Electric Utilities (1966-1978)

FIGURE 4

THE ECONOMICS OF NUCLEAR POWER

DEVELOPED BY

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CONFERENCE
ON
NUCLEAR POWER AND THE PUBLIC

KANSAS CITY, MISSOURI

February 26, 1979

THE ECONOMICS OF NUCLEAR POWER

INTRODUCTION

This paper was written to provide those who are not utility executives with a general understanding not only of nuclear power costs but also of the system by which projects are planned and financed. It is not intended to provide new information to utility executives, but rather to present many aspects of the subject in a manner that will be useful to citizen's groups who advocate energy sufficiency, nuclear power and reduction of dependence on foreign fuels.

Despite the increased cost of material and labor, despite the costly impact of regulation and intervention, it is anticipated that electricity will continue to be generated in base load plants at less cost from nuclear energy than from any other energy source available in the foreseeable future. (Coal-fired plants will, of course, be the appropriate choice under certain circumstances and to avoid total dependence on a nuclear complex.)

Although price changes for labor and material seem subject only to a decreased rate of inflation rather than a reversal, a national commitment to restraint and common sense could do much to eliminate cost increases caused by delays attributable to capricious regulation and intervention. Such a commitment may follow belated recognition of the hazards of growing dependence on foreign oil and of our lack of any realistic option to greatly increased use of nuclear power.

Nuclear advocates should expect their critics to quote from "Nuclear Power Costs" (House Report 95-1090) issued in April 1978 and developed by the staff of the Committee on Government Operations chaired by the late Congressman Leo Ryan. The document is commonly referred to as "The Ryan Report." The dissenting views of several committee members, published with the report, makes clear that the document reflects the anti-nuclear bias of the staff, omitted much of the considerable volume of competent testimony that had been presented to the committee, and presents a distorted picture of costs. Responsible energy advocates should be thoroughly familiar with the refutations contained in these dissenting views. Despite the poor quality of the report itself, the testimony is a comprehensive source of information and a copy should be obtained through your Congressman.

INDUSTRIALIZATION, ENERGY, AND SOCIETY

The cost of nuclear power must be viewed in relation to availability and cost of energy from other sources - and in relation to the social cost of insufficient energy.

For nearly 5,000 years, until the industrial revolution, poverty and want were the lot of all but a priveleged few. A century of slow growth would be followed by a century of decline, because the food supply would be outstripped by the population growth. The world population did not exceed 1 billion until after the American Civil War. By 1930 it was 2 billion, by 1975 4 billion.

The benefits of agricultural feudalism and of mercantilism were enjoyed by a very few; the remainder had to endure it partly through lack of choice and partly because the privileged could employ power to enforce the system.

Industrialism, despite its crass and inhumane beginnings, brought the freedom to sell one's skills in the open market. Its productivity has brought the cornucopia of goods and services that have narrowed the gap between the lifestyles of the rich and the poor. The "dark, satanic mills" were really the road to freedom for millions who had suffered the misery of rural poverty and agricultural serfdom. They voted with their feet, and thronged to the cities.

Energy has freed man from the serfdom of a labor-intensive economy. Where once was a constant toil merely to exist, with no time, strength, or resources for intellectual development, almost all (in the industrial nations) now live long and fulfilling lives. High technology need not limit society to materialistic interest - rather it provides options for spiritual and cultural development which were available only to a fortunate few in the pre-industrial ages.

Our highly productive industrial society has given new opportunities to women. It is energy and industrialization that has been the liberator. Why so? Because our industrial society with its diet of energy has not only produced the labor saving devices in the home which give women time and energy to take part in the business world, in civic affairs, cultural pursuits, and recreation but has provided job opportunities. No longer are women (and men) simply providers of muscle power, now they provide the skills of mind and hand to control and direct the productive system which gets its energy from fossil and nuclear fuels instead of the muscles of people and animals.

The emerging nations are late entries to industrialization, but they want it for the same reason the now-industrialized nations seized on it. Not just for profit for the few but because it provides advantages to all that were previously and otherwise unobtainable.

Energy is, of course, the lifeblood of industrialization. Without it, the hopes of the emerging nations will not be realized; without it, the industrial nations must suffer disastrous attrition in food supply, goods, and eventually in population. Life for most will regress to a grinding struggle merely to exist, and, once again, only an elite and fortunate few will have leisure and the means for cultural and spiritual development, or even for elementary education. Insufficient energy and insufficient jobs, goods, and services are counter to the upward striving of the peoples of this earth and of this nation. Energy creates jobs, job create prosperity and hope for the future. What right has anyone to deny this hope to his fellow man? Are we to return to those dreary centuries where only the landowners, the princes of church and state, and a few merchants, were well fed and housed?

It is our highly productive industrial society that has produced such wealth that we share with less fortunate people. It should be noted that the industrial nations with a lower per capita energy usage than ours produce less food than they consume. The USA produces far more food than it consumes, partly because of fortuitous combination of climate and arable land, but also because energy has vastly increased the productivity of our agriculutural system. We are more than energy wastrels, we are able to be munificent with our energy-created wealth to a degree unknown in previous times and beyond the means of less productive nations.

Conservation to reduce needless waste is essential, but the conservation must not be perverted to mean denial of adequate energy and of a better life to those who have yet to achieve it, nor must it deny opportunity to our still growing population.

As historian Arnold Toynbee has pointed out, virtually every society in history failed when its ability to create sufficient wealth to pay the nation's bills was crippled by its rulers. These societies could not afford the reform and ambitions of the political leadership and its planners. If we are to afford the societal ambitions of this nation and our dream of eliminating want, we must ensure that our wealth-producing industrialization is not crippled by insufficient or too-costly energy.

It is a characteristic of some industrial nations with a very high standard of living that the productivity per industrial employee is so high that the nation can afford a large service sector. But the <u>average</u> productivity, when <u>all</u> workers are considered, may be less than that of another industrial nation with a lower standard of living-in that fewer services are available to its citizens. It is for this reason that the U.S. has an apparent low productivity relative to some other industrial nations.

Energy in electrical form has been an ever-increasing proportion of total energy consumed in the industrial nations. It is clean, convenient, and easy to control at point of end use. Electrical energy, by replacing the muscle power of man and animal, is very much responsible for our high productivity. Considering the cost of labor that is replaced, its price has been a bargain.

Electricity in all industrial nations is provided by some form of franchised utility.

THE FRANCHISED UTILITY CONCEPT

What is the advantage of electric utilities? Why is it not better for each individual of each community to have its own small utility? We enjoy electricity and other utilities at reasonable cost because many people have provided a pool of capital to construct and maintain these massive generating and distribution facilities. If the electrical age has begun with each person attempting to generate his own electricity, the supply, maintenance, and reliability problems would soon have caused them to invent the utility to take all those problems away and provide reliable and economical service from a skilled staff at a central generating station.

Wise men realized many years ago that competition between utilities was not in the best public interest, because of the nature of the service and the capital-intensive nature of the business. In the early days of the utility industry, it was not uncommon for competing utilities in the same service area to have their lines on the same streets. It soon became evident that the very capital intensive nature of the business made this impractical. An alternative system which retains the benefit of free enterprise could still be obtained by the regulated franchise concept. The concept predates the electric utility and telephone industries and was instituted in the West to correct abuses by owners of grain storage "elevators" at the railheads.

It was a natural development then, to provide a franchised and exclusive service area to one utility only. In return for being granted an exclusive "service area," the utility is required to increase and improve its system as required to satisfy the growing needs of the area and has its "rate" or "prices" determined by a State Public Utility Commission rather than by the competitive process as do most businesses.

There are essentially two types of utilities - investor owned and publicly owned. About 76 percent of the nations electricity is generated by investor-owned utilities. They operate in much the same way, and are subject to the same regulation; the principal differences are the manner in which finances are obtained and in taxation. In both cases, the utility is a mechanism by which capital is accumulated and put to intelligent use for public service. The investors are compensated with bond interest and/or dividends on shares.

In the investor-owned utility, the ratio of long-term debt to capital stock (equity) is typically about 65:35. The Securities Exchange Commission and the bond rating companies ensure that an appropriate debt/equity ratio is not exceeded.

The publicly owned utility, which is usually some sort of "authority" set up by a state or municipal government, is 100 percent funded by debt i.e., bonds backed by the credit of the state. The interest on the bonds is usually tax exempt, which means that bonds with a relatively low interest rate are saleable.

One of the characteristics of the investor-owned utility is that it pays not only ad valorem (property) taxes, but also corporate income tax. For each dollar of dividends, one dollar of federal income tax is generated. The publicly owned utility, all other things being equal, may sell its power more cheaply because no corporate income tax is incurred. It may also use tax free bonds, in which case the bonds can be sold with a lower interest rate than the bonds of an investor owned utility. The expenses of government go on, however, and the tax revenue must come from individual and business consumers in some other way.

An objective and enlightened Public Utility Commission must be concerned not only with the current price of electricity and the short-term interest of the public when considering an application for a rate increase, but must recognize that the long-term interest of the public requires that the utility be enabled to raise additional capital in the future for continued growth and modernization of its system; otherwise, the utility cannot implement its commitment to the public to forever supply the ever-growing demand. (It is in the long-term interest of the consumers ultimately to introduce nuclear plants and reduce generation from costly fossil fuels. In a broader sense, it is of course also in the public interest to reduce our dependence on foreign oil and avoid the environmental disadvantages of all fossil-fueled plants.)

The additional capital must be raised, as it is year after year, as the generating and distribution capacity of the system grows and changes with public needs, new technology, and changing fuel considerations. The capital is raised by sale of additional shares and by additional long-term interest bearing loans in the form of bonds and debentures, and in part by earnings set aside in so-called depreciation accounts.

An electric utility is allowed, because of the stability of its assests and the nature of its business, to have a rather high ratio of debt to total assets which in practice results in a ratio of debt to equity of about 65/35. The new issues of bonds and shares are sold through a group of investment bankers and brokers to the public and to "institutional" investors such as your company's employee pension and savings plans, your insurance company for investment of your premiums, and the bank-administered pooled trust fund on which many of our senior citizens rely to supplement their pensions or social security.

Will these prospective buyers purchase utility securities if the special interest group (and the politicians that respond) have forced the Public Utility Commission to reduce the utility's income such that the return on equity investment has been below that which could be obtained on some other securities? No, the public and institutional investors will put their money into shares in a fast food chain, or real estate, or some company manufacturing gas tank locks. Some investors will decide not to invest at all.

What is the result? Either the utility cannot raise the money to build the new plant to serve the public or it must pay ruinous bond interest to attract capital or sell shares at depressed prices. Interest is an expense which the utilities would have to include in the future rates to the public; but the utility is required to maintain about 35 percent of the capitalization from equity - and this is difficult if the protesters have their way and the value is depressed such that shareholders prefer to sell out and the public is hardly encouraged to buy more. In the end, the cost of financing is increased, and projects are delayed so as to suffer still more inflation, and the cost of power to the consumer is increased.

Internally generated funds from depreciation accounts of older plants can supply only a diminishing proportion of the vast sums of money needed today to build costly pollution-free plants, underground transmission, and all other things that the public thinks desireable, besides its still growing demand for electric power.

If this highly regulated version of the free enterprise system bogs down from the high cost of new capital (a serious problem is the industry today), obviously the utilities cannot be permitted to go out of business. Even if the investor-owned utilities are partially replaced or supplemented by publicly owned utilities (financed by 100 percent debt), these utilities must be allowed to set rates which service the debt, and these utilities would have the same considerations impelling them toward large central stations and nuclear power. In fact, commitment to nuclear power appears to be the common denominator of publicly owned utilities in this and other countries. This commitment is based on the obvious fact that neither investors nor consumers benefit from an uneconomic choice of generating plant, and that nuclear plants are selected when justified by expected economies over their lifetime relative to other means of generation, by consideration of the total costs of capital, fuel, and operating expenses.

An elementary understanding of the financing system gives the lie to the familiar allegation (by nuclear opponents) that capital intensive nuclear projects somehow make windfall profits for the investors.

The large capital intensive and highly efficient central station generating plants and interconnected transmission lines provide highly reliable and economical power to consumers, yet many mistakenly believe that decentralization and many small generating units should be the plan for the future.

A few simple statistics should dispel such notions.

Although the total investment in generating and transmission plant is many billions of dollars, the investment per customer in a typical utility is between $3,000 and $4,000.

High voltage transmission losses in a typical utility are small, between 1 and 2 percent.

Low voltage distribution losses, which would be common to decentralized and centralized systems, is about 6 percent.

The investment in transmission and distribution plant is about 13 percent in a typical utility; most of the remaining investment is in generation plant.

A 1,000 megawatt plant can be built for less than 60 percent of the cost of five 200 MW plants, would operate at a higher efficiency, perhaps on cheaper fuel, and would require about one fourth of the staff required for the five plants.

Although the reserve margin of generating capacity (to ensure reliable service when some plants are shut down) may need be greater in a utility with large units than in a utility with small units, the increased margin is vastly overshadowed by the economies of scale in the large units.

The economics of large central stations versus system decentralization is supported by numerous exhaustive analyses of alternate system expansion scenarios performed by utilities and their consultants. All evidence and cost experience is counter to the theories of the decentralization proponents.

The franchised utilities, with their combined managerial, financial, technical, and operating skills, are the device by which capital is gathered and put to intelligent use so that consumers are provided reliable and economic service through the central station concept.

DETERMINING THE NEED FOR NEW GENERATION

As the system load (demand) increases with time, the system generating capacity must be increased so that the total system capacity has always a reserve margin above the peak demand. A reserve of about 20 to 22 percent is usually required to ensure that outages can be accommodated without eroding system reliability.

The principle is illustrated in Figure 1. The vertical lines represent the addition of a new generation unit; solid lines are historical, the dotted lines are planned additions. The historical growth rate in electrical usage has been about 7 percent per year. The recession which followed the 1973 oil embargo and price increase was accompanied by a reduction in growth rate. The rate at which growth will continue in the long term is much debated and may certainly be higher than the 4.5 percent shown as an illustration on the chart. It should be noted that electrical usage has grown more than the total energy usage.

In practice, many different patterns of generation addition, extending 20 or more years into the future, may be evaluated before a decision is reached for location, size, and type of next unit. Such options as the purchase of electricity, or the share in the ownership of a generating plant built by a neighboring utility, may be included in the evaluation. The retirement of obsolete units, or of those that use fuels no longer available at reasonable cost, would be considered in the study. As the cost of oil increases, or the reliability of foreign supply is reduced, the early retirement of oil-fired plants to stand by status may become a significant factor in generation planning. Their capacity will have to be replaced, usually by coal or nuclear, perhaps supplemented by pumped storage.

A mixture of various types of generating capacity (baseload, cycling, and peaking) is required for optimum economics of year-round operation of the total utility system. Each new plant commitment must be made on the basis of its effect on overall system economics and on which of the three basic types of capacity needs to be added at a particular point in time. Despite the favorable economics of nuclear as a base load plant, coal may be a better choice for cycling and peaking. Also, of course, a mix of fuels provides some hedge against strikes, embargoes, monopolies, and weather influence on delivery.

FINANCING AN ADDITIONAL GENERATING PLANT; AFUDC, CWIP

A schedule of cash requirements (frequently called a forecast of expenditures) versus time is developed, covering the engineering, procurement, construction and start-up phases of the project, based on the anticipated schedule and a preliminary estimate. During the course of the project, the schedule, cost estimate, and forecast of expenditures will be updated as needed - and it has been needed too often in the past few years because of changes and delays because of intervention and regulation. The resulting schedule stretch-out is a primary reason for increased cost to the utility and of course, ultimately to the consumer.

A portion of the project funding is provided from internally generated capital - i.e., capital accumulated in depreciation accounts for previous plants as capital investment is recovered as a component of customer's billing. Because new construction of any type of plant is so much more expensive than in the past, capital provided from existing depreciation accounts is but a fraction of the total needed. The "depreciation account" is not a bank account. Generally, such funds are continuously reinvested in new construction; a temporary excess of such funds might be invested in certificates of deposit or other short-term commercial paper.

The remainder of the funding is raised by selling new issues of the utility's bonds and shares, as needed to match the forecast of expenditures. These are sold through investment bankers, who buy the bonds and shares at some agreed-upon price from the utility and sell them, usually through other investment bankers and stock brokers, to the investors. Usually several investment bankers or groups of bankers will bid for the securities and the highest bidder wins the contract with the utility.

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If the financial future of the utility looks clouded, perhaps because the state Public Utility Commission is perceived as unwilling to grant reasonable increases in rates (selling price of electricity), the bonds can be sold only if the interest rate is high, and/or if the utility gives a discount from face value to the investment banker. Similarly, the shares may be saleable only at a low price, so that the expected low dividends will be a reasonably high percentage of the price. From the investor's point of view, a sufficiently low price/earnings ratio must be expected to make it attractive compared with some other investment.

Obviously, to fund a project with discounted bonds at a high interest rate and with shares that are saleable at prices that may be below book value results in a high cost of financing. More bonds and shares must be issued. More bond interest, more dividends, and more corporate income tax before dividends are paid must be recovered through customer billing. Thus, the future consumers pay dearly for the "savings" obtained for current consumers when electric rates are held unreasonably low. The investors in utility bonds and shares do no better than they could do in other investments which had been competing for their investment capital. It is also of course, unfair to "dilute the equity" of current investors to sell new shares at less than book value.

In addition to the capital cost of the new plant (the sum of all engineering, procurement, construction, land, legal, and other costs related to the plant), large financing charges are accumulated until the plant is in operation and producing revenue. These financing charges, formerly called "Interest During Construction," but now called "Allowance for Funds Used During Construction" (AFUDC) are calculated from the time each payment is made (for engineering, for equipment, for craft labor payroll, etc.) until the date that the plant is placed in service (usually called the Commercial Operation date).

The AFUDC is more complex than simple interest, it is the cost of financing during the construction period, and is determined by the mixture of internally generated funds and of new securities. For the internally generated funds, the "cost" is the loss of interest had these funds been invested elsewhere. For the portion of funding obtained from new securities, the "cost" is the bond interest, dividends, and corporate income tax before dividends. Although the cost of financing may be considerably higher, the Federal Energy Regulatory Commission allows AFUDC to be "capitalized" at 9 percent, but has recently permitted the capitalized AFUDC to be calculated on the basis of semi-annual compounding. ("Capitalization" is discussed in the next section.)

The "capitalized" AFUDC has become a large component of the total plant cost, as schedules have become longer. For a large nuclear plant with a typically stretched-out schedule, the AFUDC may be one-third of the total cost, or over $300,000,000 for plants currently under construction, and even more in the future as "escalated costs" have to be financed.

A brief explanation of CWIP (Construction Work In Progress) is included here because it is so hotly debated. Essentially, it is a surcharge on the customer billing, and serves much the same purpose as if adequate rate relief had been granted by the state regulatory authority in the first place.

The surcharge is a means of paying some of the AFUDC as it is incurred, rather than increasing the borrowing in order to pay "interest" on money already borrowed to supplement the internally generated funds (funds displaced from depreciation accounts of earlier projects). Because of the escalating cost of new plant, which nevertheless must be built in time to meet projected customer needs, internally generated funds are not sufficient to finance new construction, nor sufficient even to pay the dividends and bond interest on new security issues. New funds from private investors cannot be conscripted, they must come voluntarily because potential investors perceive an adequate return in competition with other investments. Therefore, without CWIP to pay dividends and bond interest on new financing, the new financing may not be forthcoming and needed construction may be deferred.

If CWIP has been used, future billing to customers is less, because there is less additional capital to be raised for which bond interest and dividends (and corporate income tax before dividends) must be recovered later through customer billing.

The two popular arguments against CWIP are that current customers should not be burdened so as to give future customers a break, and that money will be worth less in the future anyway. A counter argument is that each extra dollar paid by current customers through the CWIP surcharge saves future customers (which may be today's customers just grown older) three to five dollars depending on future cost of financing. Future customers are penalized even more heavily if new financing simply cannot be obtained (through denial of CWIP or equivalent rate relief) so that the project is delayed and incurs additional escalation and AFUDC on funds already invested. If the delayed project is nuclear, the customers are still <u>further</u> penalized by the fuel adjustment charges for fossil fueled electric generation for a longer period than if the nuclear plant had remained on schedule. Ironically, the fuel adjustment charge may be greater than the CWIP surcharge!

The advantage of CWIP can be explained in an oversimplified manner by comparing it to the case where one has saved up most of the purchase price of an automobile so that only a small portion has to be financed. If one had not saved up, and a larger portion of the cost had to be financed, then the total cost to the owner over the long-term is far greater. It should be recognized also that, embodied in the cost of nearly all goods and services, is some component to assist the supplier to upgrade or maintain his future product or service.

It is evident therefore, that CWIP is not a device to increase profits to investors, it is rather a device to help attract new financing and to reduce overall cost of financing without excessive "discounts" on security pricing. Clearly, it benefits consumers over the long-term.

TYPES OF COST COMPARISON, LEVELIZING, CAPACITY FACTOR

The fundamental basis for economic choice should be the "Present-worth" of all future revenue requirements. ("Present-worth" is the discounted value of a series of future values, and is the opposite of calculating the future value of a present sum of money, or of a series of payments, after adding interest.) The annual revenue requirements of a project is the annual revenue necessary to meet all annual costs of that project, including fuel, operation and maintenance costs, insurance costs, taxes, recovery of capital for the depreciation account, and the minimum return that suppliers of bond and equity capital will accept. The calculation of "revenue requirements" is not dependent upon rate base considerations. It has to be assumed in economic comparisons that future rates will provide the revenue requirement. Admittedly, predictions of the future are subject to error, but the "present-worth" technique de-emphasizes their impact on the answer.

Although this "life cycle costing" is a sophisticated way of comparing one scheme with another, it is common to make comparisons on the basis of total generating cost at some point in time, using a "levelized" fixed charge rate and a "levelized" capacity factor (explained below). This method gives a good idea of the relative economic merits, but the true relative costs of two or more generating systems over their lifetimes for decision making is better illustrated by the present worth of revenue requirements for the total generating complex. This is particularly true if the capacity factors differ between the plants under consideration. For example, if a fossil plant is added to a system which has a number of nuclear plants, it probably will operate at a low capacity factor and will be used primarily for peaking or for "load following" as the system demand fluctuates over its daily cycle. However, it may be the most economic choice, from overal system considerations, if it is peaking or load following capacity that needs be added to the system.

The generating cost actually varies from year to year with changing capacity factors and annual fixed charge rates (see next section). Usually, however, costs are expressed and compared in cents per killowatt hour, using a "levelized" annual fixed charge rate and a "levelized" annual capacity factor.

Levelizing is a technique by which a series of unequal numbers occuring at annual intervals is expressed as a series of equal numbers occurring at annual intervals which would have the same total "present-worth", using standard interest tables (even though the numbers may not represent dollars).

Capacity factor is the ratio of kilowatt hours produced in a year to the kilowatt hours that would have been produced if operating at full power for a full year.

Nuclear generating costs presented in this paper are based on an annual capacity factor of 60 percent, but can be adjusted easily to any other capacity factor as desired. Much higher capacity factors may be achieved, as reliability is improved with experience, as availability becomes less inhibited by regulatory action, as the supply problems and high cost of fossil fuels increasingly favor assigning load to nuclear plants on the system.

A plant with rated net electric output of 1,250 Mw, operating at 60 percent capacity factor, would send out.

$$.60 \times 8760 \frac{\text{hrs}}{\text{yr}} \times 1250 \text{ Mw} \times 1{,}000 \frac{\text{kw}}{\text{Mw}}$$

$$= 6{,}570{,}000{,}000 \quad \text{kilowatt hours per year}$$

The generating cost, in cents per kilowatt hour =

$$\frac{\text{annual fixed charges + annual fuel cost + annual operating cost}}{\text{annual output in kilowatt hours}}$$

Generating cost may be expressed in mills per kilowatt hour. (ten mills = one cent).

The generating cost in cents per kilowatt hour is much dependent upon capacity factor; i.e., on actual kilowatt hours produced, because the annual dollar value of capital and operating costs is fixed and independent of load. The cost of <u>financing</u> (but not burnup) of the fuel cycle must be borne also, regardless of plant loading.

The capacity factor the nation's nuclear plants in 1977 was 66.2 percent vs 57.1 for base loaded coal- fired plants and 50.3 for base loaded oil fired plants. (The cumulative capacity factor of all New England nuclear plants from date of service averages 64.8, which is probably typical of national experience. If capacity factors are based on the years after the initial 2 or 3 year maturation period of each plant, somewhat higher "cumulative" capacity factors would be obtained.

The capacity factor for nuclear plants is high not only because of nuclear plant reliability, but because load dispatching in a utility system is intended to obtain least system fuel cost for any system load. Because nuclear plants have the lowest fuel cost of any existing type of plant (except hydro), they generally are heavily loaded. <u>Note that nuclear plants now generate over 12 percent of all the electricity in the U.S., with a nameplate capacity of about 9 percent</u>!

No plant operates at 100 percent capacity factor, of course, because of scheduled maintenance shutdowns, and forced outages. Nuclear plants must be shut down also for refueling, although this normally is performed concurrently with scheduled maintenance. During periods of low system demand (weekends or middle of the night), some nuclear plants may be backed off either because their total output would exceed the system load or because it is desired to keep some load on some fossil units rather than shut them down until system load grows a few hours later. In 1977, the combined availability of the nations nuclear plants was 76.5 percent, vs 76.8 percent and 78.9 percent, respectively, for coal and oil-fired base load plants.

CAPITALIZED COST - EXPLANATION AND METHOD OF DETERMINATION

The "capitalized cost" of a plant includes:

a. Cost of plant itself (sometimes called the construction cost) as discussed in more detail later.

b. Owner's engineering, legal, land, training, and other costs related to obtaining the plant and placing it in service.

c. Allowance for funds used during construction (AFUDC) - in effect, the cost of capital "tied up" during construction.

The "plant cost" (item "a") consists of:

a. "direct" costs for equipment, materials, and craft labor

b. "indirect" costs for engineering, clerical, accounting, planning, inspection, and other headquarters services, and for certain administrative services provided in the field

c. "distributable costs" such as construction supervision, labor fringe benefit costs, materials expended during construction, temporary construction facilities gasoline and lubricating oil, insurance during construction, etc.

(A contingency or "allowance for unknowns" would be included in the initial estimate. As the plant becomes more detailed and as actual procurement and construction costs become known, a more accurate estimate can be developed and the "allowance" reduced. When the plant is complete and all the costs are known, the "allowance" or "contingency" will of course be zero.)

The computer printout of a cost estimate may have as many as 12,000 line items, from major pieces of equipment to quantities of material and unit prices for material or installation. Supporting detail for each line item averages about six pieces of information or judgment. Large engineering - construction firms have computer programs not only to perform the routine arithmetic but to allow "sorts" by various categories of materials, labor, buildings, types of equipment, etc to be extracted for analysis and comparison with return costs on other projects, and with costs experienced to date on the project under study. Estimates are expanded into greater detail as the design develops and quantities of material and construction labor can be more exactly determined, and as orders are placed and equipment costs can be confirmed.

Labor costs are quite site specific, and the estimating process must include an assessment of productivity, craft labor rates, and fringe benefits.

Comprehensive management information systems are used to monitor progress and expenditures, provide information for corrective action, and provide input for continually upgrading the estimate to incorporate experienced costs. The data base capacity and speed of information processing provided by computer technology have vastly improved the "visibility" of cost trends, and have provided also the means by which changes in design, schedule, or construction sequence can be evaluated for overall effect on cost.

ANNUAL CHARGES ON CAPITALIZED COST (FIXED CHARGES)

Annual charges on capital include return on capital (interest on bonds, dividends on shares),corporate income tax paid before dividends, recovery of capital (or depreciation), and ad valorem taxes. These annual charges, as a percentage of the "capitalized cost" of the plant, are but commonly but somewhat improperly referred to as the "fixed charges". As capital is "recovered" from customer billing over the life of the plant, it is posted to a depreciation account. The depreciation account is insufficient to build a replacement plant; it is simply equal to the capitalized cost of the plant. Funds in the account called "internally generated capital" are used to help finance newer projects and the "charges on capital" in the depreciation account thus are no longer applicable to the original project. As the depreciation account grows and as the charges on capital in this account are borne by new projects, the fixed charge rate applicable to the original project declines each year with time. For approximate economic comparisons, it is common practice to use a "levelized" fixed charge rate.

Let us assume a "capitalized" cost of plant of \$1,000,000,000, that a negligible part has been financed by internally generated funds, that \$650 x 10^6 has been financed with bonds bearing interest at 12 percent, and \$350 x 10^6 represent new shares expected to pay dividends of 12 percent. Let us assume that annual ad valorem (property) tax is 14.7 million. Then, annual charge on capital (for the first year) is:

Bond interest (12% of \$650 million)	\$78 million
Dividends (12% of \$350 million)	42 million
Corporate income tax (approximately)	42 million
Ad valorem taxes (approximately)	14.7 million
Capital recovery (assuming 30 year life,	
$\frac{1}{30} \times 10^9$	33.3 million
	\$210 million

Or a first year fixed charge rate of

$$\frac{\$210 \times 10^6 \times 100}{\$1,000,000,000} = 21 \text{ percent}$$

For the second year, all items except ad valorem taxes are based on \$1,000 million - \$33 million; hence, the annual charges in dollars are reduced and the second year fixed charge rate, as a percentage of total capitalized cost, is reduced.

(The \$33 million in the depreciation account is undoubtedly put to work to help finance some other construction or renovation project in the utilities generation and transmission complex, and the "fixed charges" on the \$33 million are chargeable to the newer project, and no longer to the project postulated above.)

In the second year, the fixed charges would be applicable to \$1,000 million less \$66 million, and so on, so that the fixed charge rate, as adjusted to be a multiplier of the original \$1,000,000,000, declines each year.

The above is a simplified explanation; accelerated depreciation and various tax considerations introduce many complexities in determining or predicting the annual "fixed charge rates" for a specific project with a specific utility in a selected time span.

The "fixed charge rates" vary with the tax rules in each state, with the expected or realized dividend and bond interest rates, and similar factors. Assuming no difference in plant life (as allowed for accounting and tax purposes) between various types of generating plants, the levelized fixed charge rate for a specific utility in a specific state would be the same for all types of generating plants.

A levelized fixed charge rate of 20 percent is used in this paper, and is typical of that assumed by utilities for plants to be placed in service about 1990. It is probable that a 15 percent return on common equity will be required to attract the funds required, somewhat greater than shown in the example above.

Note that the "fixed charge rate" concept is a device for economic comparisons, but is not used in accounting practice.

Nuclear liability and property insurance usually is included under operating and maintenance costs.

As stated previously, levelizing is a technique by which a series of unequal numbers occurring at annual intervals is expressed as a series of equal numbers occurring at annual intervals which would have the same total "present worth."

The "Annual Capital Cost" is the capitalized cost times the levelized fixed charge rate. The "Capital Cost" in cents per kilowatt hour is obtained by dividing the "Annual Capital Cost" by the annual net electric sendout from the plant in kilowatt hours.

AVAILABILITY OF CAPITAL

Nuclear opponents often claim that there simply is not enough capital to fund the large nuclear generating plants. Although it is true that utilities can attract investment funds only with extremely high bond interest rates or discounts on selling price of bonds or shares, that does not mean either that capital is not in existence in sufficient quantities or that the nation can afford not to have the capital invested.

One must address the question by recognizing that the nation cannot afford not to invest funds in the basis for our industrial strength - the production of energy. If we cannot afford not to invest, then can we say that there is any way of achieving the result with a lesser investment? The answer is "No." The investment in coal-fired or oil-fired plants is nearly as great as nuclear in the first instance, and considerably greater in the "investment" for annual fuel. The capital investment is solar, wind, hydro, or similar "renewable resources" to generate the equivalent amounts of power are, of course, far greater than the capital investment required for nuclear.

The proponents of Amory Lovins' "soft path" and "soft technologies" should note the paper by Ian Forbes and J.C. Turnage "Exclusive Paths and Difficult Choices" (Energy Research Group - Framingham, MA). This paper points out that the soft path would require three times as much capital to produce the same amount of energy as large central station nuclear or coal-fired plants.

OVERALL CAPITAL REQUIREMENTS OF THE UTILITY INDUSTRY

An Edison Institute report "Economic Growth in the Future" issued in 1976, predicts the construction expenditures by utilities between 1974 and 1990 must be about 750 billion, assuming moderate growth, and that only 1/3 of this will come from internally generated funds. Therefore, at least 450 billion (or more if growth is more than moderate) must be raised in the competitive capital market, i.e., by competing for investor interest against fast food chains or whatever else promises an attractive rate of return at various points in time.

This investment capital required by utilities will represent about 25 percent of the funds raised annually for nongovernment uses in the competitive money markets or nearly 10 percent of total investment over the next 16 years. The problem is ability to attract investment funds, in competition with other attractive investment opportunities through investor perception of adequate return on equity (say 15 percent), rather than lack of funds in the money market.

CAPITAL COSTS-EXPERIENCE TO DATE

Everyone knows that the cost of stamps, automobiles, houses, food, clothing, and everything else has gone up - and so it should not be surprising that the capital cost of power plants has increased. Many of the reasons for cost escalation are the same - increasing wages, increasing cost of materials, even hidden taxes embodied in the cost of labor and material.

Power plants - particularly nuclear plants - have been hurt by two additional factors which have increased costs. These are:

A. Statutory and regulatory activity which has forced changes in design and in construction practices and tightened procedures for control and transmission of information related to design procurement, manufacturing, erection, and testing. These changes have added to direct cost (for example, the addition of cooling towers instead of once-through cooling systems as originally conceived). The changes have also directly increased the cost of engineering and supervision of labor and subtly slowed down the process of design, procurement and construction so that schedules are lengthened and craft labor productivity inhibited.

B. Regulatory confusion and intervention which has held up construction permits and further extended schedules, exacerbating the effect of the more rational regulatory activity.

Extended schedules increase the cost in several ways - chiefly:

1. Increased escalation. Labor and materials costs incurred years after originally intended invariably cost more.

2. Cost of storage and maintenance of partly completed plant is increased, as is the cost of "time dependent" staff such as security guards, key supervisors, etc.

3. Increased "interest during construction" or "Allowance for Funds Used During Construction" (AFUDC).

4. Increased cost of financing (because the "cost of money" has increased with the passage of time).

Generally, the difficulty of attracting new capital has increased in recent years. Higher bond interest has to be provided and/or greater discounts on bonds. The selling price of shares relative to their "book value" has been reduced.

Bond interest for Aaa utility bonds was three percent or less before 1957 and has climbed to as much as ten percent since then. Each one percent increase in bond yield has a cost impact of about $25 per kilowatt, or $25 million for a 1,000 MW plant.

The financing difficulties are compounded and final cost increased by the tendency of the state PUC's to hold down rate increases in response to public pressure. The public pressures are understandable, given the great increases in the electric bills since 1973. Unfortunately, inadequate rates have prevented utilities, in some cases, from being perceived by investors as being able to pay the dividends necessary to attract new capital. As a consequence, some utilities have had to defer issue of securities and stretch out project schedules through lack of funds. The stretched-out schedules, of course, result in even more escalation and still higher AFUDC. And so the vicious cost spiral continues, to no one's benefit, and certainly against the best interest of future consumers.

Because of regulatory changes, schedule extensions related to regulation and intervention, and escalation, the unit cost of some nuclear plants have increased (in constant dollars) from about $200 per kilowatt for plants completed at the end of 1969 to over $600 per kilowatt for plants completed at the end of 1977, although, of course, specific plants may be somewhat above or below these numbers. AFUDC adds about one-third to the capitalized cost, so that the total cost for a 1,250 MW plant now being completed , would be nearly $1,000,000,000.

FUTURE CAPITAL COSTS

What capital cost can we expect in the future? Many nuclear critics have improperly analyzed the reasons for cost increases experienced in the last few years and have extrapolated to predicted costs which seem far too high. The industry was not prepared, in estimates of a few years ago, for the plethora of regulations and quality assurance procedures which would dramatically alter the engineering, procurement, and construction processes, nor was it prepared for the schedule stretch outs which resulted from intervention and regulatory confusion. But the industry has learned much about coping with these, can now factor the effect into its estimates, and make intelligent allowance for some additional design or procedural requirements. Although additional requirements must be anticipated in preparing an estimate, it is unreasonable to expect that they will have anything like the impact that has been experienced.

It is believed that the rate of new regulatory guides and similar rulings has peaked - about 17 per year were issued in 1970, 1971, and 1972, about 60 per year for the following three years, and about twenty-seven per year since the beginning of 1976. It should be noted that the flurry of rules in the last eight years was to make up for past practice, in which few formal rules had been issued. In the past, each application for a license was examined and judged on its own merits by the Regulatory Staff. To some extent, the issuance of rules has merely standardized what had come to be judged as best practice; much of the increased cost has resulted from the procedures necessary to record and demonstrate compliance. As stated elsewhere, the industry has adjusted considerably to this modus operandi, and it is not reasonable to expect that costs attributable to regulatory changes will continue to increase at the rate experienced in the last few years.

The estimated cost in present day dollars, and of escalation and AFUDC, for a custom designed single unit 1,250 Mw (net electric sendout) nuclear plant, first on a site, scheduled for 1990 fuel loading, with once through cooling, and assuming moderate growth in regulatory requirements, is presented in Fig. 2.

What is the cost of a one year extension in schedule? It depends upon when the extension occurs. If inserted at the beginning of the project so that the entire project is deferred a year, then all costs are increased by one year of escalation - about $110 per kw for a project starting now, and there is a proportionate increase in AFUDC. If the delay occurs near the end of the project, when a large investment already has been made, the added cost is primarily the "interest," or AFUDC, on this investment for the additional year, and would be about $130 per kw for a plant being completed now. Most schedule extensions are a combination of the two cases, so there is no single answer to the cost of a one year schedule extension. When a nuclear plant is delayed, customers may incur additional cost through fuel adjustment charges for electricity generated by fossil fuels. In later 1978, generation by oil instead of nuclear could add about $50 million per plant per year in fuel adjustment charges.

The addition of hyperbolic cooling towers would add about $50 per kilowatt. A second nuclear unit on the same site could be built for about $150 per kilowatt less. Construction costs vary with location; the above costs are for a relatively high cost northeast U.S.A. location, and the costs would be less in the south and west.

Standardization will significantly reduce costs, especially if it advances the date on which a construction permit can be obtained and hence reduces escalation. The preengineering aspect of standard plants facilitates design for construction economies as well as quality of plant, and permits issuance of detailed drawings earlier in support of an orderly construction program. It is estimated that a standardized "preapproved" plant would reduce the capital cost in present-day dollars by about $200 per kilowatt. When escalation and interest during construction is considered, the saving would be increased to about $300 per kilowatt.

Although these costs are high compared to $200 per kilowatt (not including AFUDC) that we enjoyed with nuclear plants a decade ago, we must remember that the capital cost of fossil-fueled, hydroeelectric or any other type of plant has increased in a manner somewhat similar to that of nuclear. The cost of oil has of course increased more than has capital cost of generating plant and the cost of burning coal can be expected to increase because of transportation cost and environmental constraints on mining and stack effluents.

It should be noted that plant costs, as presented in various papers and government statistics, may be stated in "present day" dollars, or may include escalation anticipated during project life, and may or may not include AFUDC. The most meaningful statement includes both escalation and AFUDC. In any case, a cost for which the basis is not defined is of little use, and cost comparisons on differing bases are a frequent source of misunderstanding.

All types of generating plants (and indeed all construction and manufacturing) has been subject to unprecedented cost inflation in the last few years. Fossil-fueled plants are being subject also to licensing and intervention delays, with consequent increase in escalation and AFUDC.

It seems unreasonable to expect that other energy sources; e.g., the renewable resources, will not experience a similar discrepancy between realized costs and initially "hoped for costs," especially when there is little construction cost experience on which to estimate costs.

A capital cost comparison between nuclear and coal-fired plants is presented in Figure 2; a generating cost comparison is shown in Figure 3.

The coal fired plant is assumed to be a custom designed 800 Mw single unit station with once through cooling and scrubbers.

ESCALATION

Although escalation and inflation often are used interchangeably, escalation is the combination of inflation (change in the value of the dollar) and changes in cost (positive or negative) unrelated to the value of the dollar but brought about by changes in technology, regulatory requirements, labor productivity, etc.

The prediction of inflation and the evaluation of past effects has to be assessed for both material and labor. Wage rate statistics are available from the Department of Labor, and are useful in judging probable future change in rates. For material, a composite index based on the proportion of equipment and material found in power plants is developed, using prices obtained from the Engineering News-Record or similar sources.

It is beyond the scope of this paper to compare the various judgments of individuals and companies as to future inflation. For the costs predicted here, we have instead taken what appears to be a mean amongst varying judgments.

In practice, most cost estimates are upgraded periodically during the life of a project to incorporate increasingly detailed information, and cost experience to date. At the same time, the reference date for "present day dollars" may be adjusted to coincide with the date of the re-estimate. In that case, changes in design, anticipated labor productivity, etc. relative to a previous estimate are incorporated in the revised "present day dollars" estimate. The revised estimate of escalation (from the date of re-estimate to the date of Commercial Operation) is essentially a prediction of inflation only.

However, when final experienced costs are referred to the originial "present day dollar" estimate, what is identified as the escalation component may include not only inflationary effects, but also changes in cost unrelated to changing value of the dollar.

The "escalation" shown on Fig. 2 covers inflation only; the "present day" cost estimate for 1990 plants contains a modest allowance ($50/kw for both nuclear and coal) for future regulatory requirements.

NUCLEAR FUEL COST

Nuclear fuel costs include all materials and processes involved from the mining of the natural uranium to the ultimate disposal of the spent fuel and the cost of financing these activities. The various steps in the fuel cycle may be categorized by three phases, called front end, power production, and back end.

The front end of the fuel cycle consists of those activities required to produce fuel assemblies suitable for use in nuclear power plants. The front end activities include:

1. Mining and milling of natural uranium ore to obtain "yellow cake" (U_3O_8)
2. Conversion of the uranium mill product (U_3O_8) to uranium hexafluoride (UF_6)
3. Enrichment of the uranium in the form of UF_6 to increase the istopic ratio of U-235 to U-238 *from 0.7 percent to about 3.2 percent
4. Reconversion of the UF_6 to UO_2
5. Fabrication of Zircalloy tube fuel assemblies containing pellets of sintered UO_2

The power production step involves the insertion of the fuel assemblies into the reactor core and subsequent extraction of power from the fuel through the process of nuclear fission. Commercial power reactors typically replace between one-third and one-fourth of the core with fresh fuel annually. Each batch of assemblies thus produces power for three to four years. During the power production step, the percentage of fissile U-235* is reduced from about 3.2 percent to about 0.9 percent. The useful energy released, expressed as "burnup," is 720 million kilowatt hours of thermal energy per ton of UO_2.

*Natural uranium consists of 99.3 percent non-fissile U-238 and 0.7 percent of the fissile isotope U-235. Heat is produced from the fission of U-235. During the fission process, some of the U-238 is converted to plutonium, some of which may fission in the reactor. Current light water reactors typically obtain 65 percent of their power from isotopes of uranium and 35 percent from plutonium. The spent fuel contains additional plutonium which could be recovered (recycled) for additional power production.

When the reactor is shut down for refueling (usually about once a year), the "spent" or "depleted" fuel elements (usually about one third of the total) are removed and stored under water. Generally, the fuel in the central part of the reactor is most rapidly depleted, and it is fuel elements from this region which are removed, so that fuel elements from the outer regions can be moved toward the center and replaced with "new" fuel elements.

Spent fuel is stored under water for at least several months to allow radioactivity and decay heat production to decrease such that shipment in shielded casks is feasible.

The back end of the fuel cycle consists of those processes and activities required to dispose of the radioactive waste produced during the power production step and to reclaim the remaining uranium and plutonium from the discharged fuel so that they may be recycled and utilized as feed in the front end of the fuel cycle. Current government policy, however, does not allow reprocessing of spent fuel and, therefore, precludes recycle. Presently, the back end includes only fuel storage at the power station. Transportation of the spent fuel away from reactor storage facilities will be required once the power station storage pools are full. It is anticipated that the fuel would remain in storage and await future reprocessing and/or waste disposal.

Because the payment schedule over the entire fuel cycle of a particular batch of fuel spans many years, substantial carrying (interest) charges are also included in determining the fuel cycle cost. For example, a batch of fuel to be loaded into a reactor today would have required the uranium to have been purchased at least one year ago, but may not incur final charges for waste disposal until some time after the power production step.

In New England where approximately 32 percent of the electric power produced is generated by nuclear power plants, the average nuclear fuel cost over the years 1974-1977 has been 0.27 cents per kilowatt-hour.

Projections of future costs of nuclear fuel are higher as a result of higher interest rates and higher labor and material costs. The accuracy of such projections depends principally on the assumptions for escalation of the component costs and any comparison with alternate fuels should be performed on a consistent basis.

Table 1 gives projections of nuclear fuel costs, including all component costs for a 1,250 MWe plant with initial operation in 1990. The cost of uranium was assumed at $43 per pound U_3O_8 (yellowcake) in 1978 and escalated at 6.8 percent per year. The "no recycle" cost assumes continuation of the present situation for the back end of the fuel cycle; i.e., the spent fuel is ultimately disposed of without recycling to recover the remaining fissionable uranium and plutonium.

If the spent fuel could be reprocessed (a reversal of current government policy) so that the extracted uranium and plutonium is recycled, the fuel cycle cost would be reduced, as shown in Table 1. This includes the additional costs for reprocessing and the credits for the fissile plutonium and the reduced amount of feed uranium needed. The difference between the "no recycle" and "recycle" fuel cost depends heavily on the cost for uranium and assumed escalation; a lower uranium cost reduces this cost difference.

The cost of disposal of fuel cycle waste represents only 1.9 percent for "no recycle" and 4.0 percent for "recycle." This assumes a "one time D.O.E. charge" of $130 per kilogram of uranium metal (1978 dollars) for the cost of encapsulation of the wastes and permanent storage in a geologic repository. Doubling the cost of waste disposal would only raise the "no recycle" fuel cost by .04 cents per kilowatt-hour and raise the "recycle" fuel cost by .06 cents per kilowatt-hour to 1.56 cents per kilowatt-hour. (This is discussed further under "decommissioning and permanent waste disposal.")

Nuclear fuel costs projected for the future are much higher than experienced fuel costs because uranium "yellow cake" (U_3O_8) was purchased at perhaps $8.00 per pound versus a 1978 cost of about $45 per pound with additional escalation anticipated. Nevertheless, nuclear fuel costs in the future are expected to remain less than fossil fuel costs and believed less subject to escalation because the labor input per Btu content of fuel is much less.

Although development of the breeder reactor is temporarily inhibited in this country, the example of the rest of the world and belated recognition of our own energy costs and fuels availability undoubtedly will result in establishment of a comprehensive program of breeder construction. This would greatly extend our supply of fissionable material and inhibit cost increases for nuclear fuel. However, the timing of this effect would have little influence on the levelized fuel costs predicted for a plant placed in service in 1990.

An excellent paper "To Breed or not to Breed" by Stauffer, Wykoff, and Palmer was published in the February 1977 issue of "Mechanical Engineering" published by the ASME. This paper addresses the overall energy cost saving to the nation achieved by extending our supply of fissile material through breeding and the reduction in mining of low-grade uranium ore. The net benefit, after allowing for cost of breeder development, ranges from 48 billion to 122 billion, depending upon the assumptions of timing and of other factors. An additional benefit, which cannot be fully expressed in dollars, is that breeder development will further lessen our dependence on foreign fuels of any kind.

COST OF DECOMMISSIONING AND PERMANENT WASTE DISPOSAL

Nuclear generating costs frequently are criticized for failing to consider decommissioning and the cost of waste disposal. Neither have significant effect on fuel cost predictions, however.

Decommissioning, expressed in today's dollars, has been variously estimated between 30 and 75 million dollars. (The AIF estimated $40 million for decommissioning Oyster Creek; if escalated forward to about 2003 the cost would be about $100 million.) In order to demonstrate the minimal effect on generating costs, let us assume that decommissioning (dismantling) will cost 100 million dollars. By how much need electric rates be increased to have recovered 100 million dollars in 30 years? Let us assume a 1,250 MW plant operating at a levelized capacity factor of 60 percent over its lifetime:

Then the added cost of decommissioning =

$$\frac{\$100 \times 10^6 \times 100 \text{ cents per dollar}}{6.57 \times 10^9 \text{ kilowatt hours/year} \times 30 \text{ years}} = .05 \text{ cents per kw hr}$$

This is a highly simplistic calculation, of course, and neglects interest, but reveals how small the effect of decommissioning cost is. Another way to keep it in perspective is to remember that a 1,250 MW power plant produces the same amount of electricity as an oil-fired plant which would burn $150 million worth of oil per year at $12 per barrel. The cost of decommissioning, 30 years away, is not too significant relative to the fuel cost saving during that time. It is possible that the structures of future plants may be designed to be reused with a replacement nuclear system, this too will offset the cost of removal and storage of radioactive equipment. In any case, the cost of decommissioning will be a small portion of the cost of a replacement plant.

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Waste disposal is, of course, a political rather than a major technical problem. As long as we are not permitted to recover and reuse plutonium, the fuel cycle cost is not credited with the value of plutonium which is created in the fission process and which could be reused as fuel in the reactor. However, the value of this plutonium is greater than the cost of the reprocessing to recover it and of the cost of temporary storage of spent fuel until such time as we are permitted to reprocess and recover.

But what about the long-term storage of high-level waste and how are these included in the fuel cycle costs? In the fuel cycle cost discussion, we have used a "one time" charge (estimated by the Department of Energy) of $130 per kilogram of uranium metal for the cost of encapsulation of the wastes and of permanent storage, such as in some stable geologic formation. If the "estimated "one time" charge is low, then part of the cost of waste disposal would indeed appear in future taxes for government services, and is not completely factored into the cost of electricity.

In any case, the cost appears to be a negligible fraction of fuel cycle cost. The cost of placing the waste in a salt mine and guarding it for about 500 years (the length of time it takes for an average mixture to be reduced to the activity of naturally occurring uranium ore) is, of course, shared with the cost of guarding all the other material that will have been added during that time from previous and subsequent plants.

To get some rough idea of the magnitude, let us assume that the annual cost of maintenance and storage at a high level depository, including guards, is five million dollars per year. If we assume that this repository provides storage from approximately 100 reactors (actually it would be far more), the annual cost attributable to each reactor is about $50,000 per year. If this could be added directly to the price of electricity instead of paid for as a government service financed through taxes, $50,000 per year would increase the cost of power from a 1,250 MW reactor by about .0007 cents per kilowatt-hour. Whether one calculates that the 500 year cost should be spread over the 30-year life of a current reactor or charged against future reactors, the annual cost has a negligible effect on the cost of electricity per kilowatt-hour.

OPERATING AND MAINTENANCE COSTS

Operating and maintenance costs will increase in the future because of increased cost of labor and materials and perhaps increased security staff. The operating and maintenance cost of coal-fired plants is expected to increase far more than nuclear because of the pollution control apparatus which must be installed and maintained. (Nuclear plants have always been designed to contain pollutants and, in any case do not generate the vast quantities of pollutants characteristic of fossil fueled plants.)

Operating and maintenance costs are usually grouped into three components. For a 1,250 MW nuclear plant, to be placed in service in 1990, the annual values, in 1990 dollars, are estimated to be:

Operations	21,000,000
Nuclear liability and property insurance	3,200,000
Maintenance and consumable supplies	5,800,000
	$30,000,000

Operating at a capacity factor of 60 percent, this annual cost would contribute $0.5 cents per kilowatt hour to the generating cost from a 1,250 MW nuclear station.

Note that the operating and maintenance cost, averaged over the time period January 1974 to June 1978 was .26 cents per kilowatt-hour for nuclear plants in New England. During that time period, the operating and maintenance cost for New England oil-fueled plants averaged .17 cents per kilowatt-hour. It is anticipated that the differential would be reversed in the future, in those areas of the country in which coal rather than oil is burned and as the pollution control apparatus is placed in service.

SUBSIDIES AND HIDDEN COSTS

Nuclear critics mistakenly feel that there are massive subsidies and hidden costs in nuclear power. Let us address them one by one. Nuclear fuel is subsidized only in the same manner that all other fuels are subsidized - with a depletion allowance to the mine owners. Because the cost of yellow cake is only part of the cost of the entire nuclear fuels cycle, obviously this depletion allowance has a minor effect and, in any case, is common to other fuels.

The cost of enrichment is not subsidized; the charge by the government for enrichment service is intended to provide not only for the operating cost of the enrichment plants but for the return of the investment in the plant. When the new Portsmouth enrichment plant is placed in service, the enrichment charges again will be sufficient not only to pay for the operating cost but also for the return on, and return of, capital.

Nuclear indemmity is not a subsidy, it is a supplement to the insurance provided by private insurance companies. The government has never paid a claim and has collected about 25 million dollars from the utilities for this insurance. Rather than being a subsidy, it is one of the few profit making operations in the government. Actually, the private insurers provide about one third of the nuclear liability coverage ($540 million per site).

The United States has invested about 9 billion dollars in research and development of nuclear power, of which about one third has been applied to light water reactor development. The other two thirds has been spent on advanced nuclear concepts, including breeder reactors, and on radiation effects and similar research. The capital investment in the 64 nuclear units that were placed in service by end of 1977 was about 21 billion dollars, and the investment in plants now under construction is about 75 billion dollars. The value of oil equivalent to that of nuclear fuel used per year in nuclear plants is about 6 billion dollars. It is obvious that the 3 billion dollars research and development specific to light water reactors is a pretty small percentage of the total investment by the utility industry in nuclear power, and is one of the best bargains that the American people have had because it enables them to benefit from the savings in electrical costs from generation by nuclear power and helps reduce our balance of payments for foreign oil.

The government has provided in the past for storage and nuclear waste but has charged for providing this service at cost. At the present time, with the prohibition on reprocessing, the utilities are storing their own fuel and there is no government subsidy involved. Ultimately, when reprocessing is allowed and high level wastes placed in permanent storage, it can be anticipated that the Federal government (or private contractors if that is how the Federal government arranges it) will charge an amount which will provide funding for permanent care. At the present time, it would appear that less than one half a mill per kilowatt hour added to the generating cost would be more than adequate to pay for this. It should be remembered that nuclear wastes contain many valuable materials for which future uses may be found, and we should not look upon nuclear wastes as a liability but rather as a veritible mine of useful materials.

CAPITAL INTENSIVE PROJECTS AND "EXCESSIVE PROFIT"

Nuclear critics mistakenly believe that utilities profit somehow by embarking upon large capital intensive projects such as nuclear instead of building a number of small "low cost" units.

The opposite is, of course, true. Especially under current financing conditions, utilities do not have a financial incentive to invest needlessly. All new borrowing increases the average cost of the corporation's debt because interest costs are higher than they have ever been. Shares can now be sold usually only below the "book price" and usually below the price paid by the current investors. The days when increasing the rate base by construction of new plant could reduce a utility's overall generation cost are long gone. Utilities only construct new plant in response to their legal mandate - which is to ensure that the public will be provided with adequate electricity. The decision to construct must be made many years in advance of need, because of the many years it takes to license and construct the plant so that it is ready to meet the need.

What the public should be concerned about is that the utilities are almost forced by today's conditions to underbuild; the delays in investing in base load plants may well lead to lack of capacity some time in the 1980's, and certainly deny consumers the benefit of the savings from nuclear fuel relative to the costs of oil. From a national security and balance of payments point of view investment in additional nuclear plants would be in the public's interest.

It should be recognized that one of the reasons why fossil fueled plants are chosen today is not inherently economics, but rather that the uncertainties surrounding nuclear licensing and the need to build on a more assured schedule has led many utilities to choose fossil. No doubt in many cases, if a rational environment had existed in which business decisions could be made with certainty, the choice would have been nuclear. We can only hope that a rational environment in the future will allow business decisions which in the end benefit both investors and consumers. Unfortunately, at the present time, licensing and siting uncertainties are a growing problem with any type of plant.

The myth of decentralization has been discussed earlier, under "The Franchised Utility Concept."

CONCLUSIONS

The capital costs, the operating and maintenance costs, and the fuel costs are typical of those currently estimated by the industry, but may vary slightly from one company to another. The principal variation in thinking is in prediction of escalation and the numbers used are believed to be the mean of industry thinking, rather than representations of any one company.

The generating cost will vary slightly from the numbers given if one varies the capacity factor or the fixed charge rate. However, the relative difference between generating cost from nuclear and generating cost from coal, for the forseeable future, will be such as to favor nuclear. The use of oil in new generating plants is, of course, now forbidden under the national energy plan.

More important than the cost advantage of nuclear over coal is, however, the tremendous advantage of either nuclear or coal over other methods of electrical generation that are not yet commercially developed. Some cost estimates for various electric generating sources are shown in Figure 4.

There can be no good estimate for the cost of energy from the so-called renewable resources except, perhaps, for hydro. Although all other sources have been known for a long time, only hydro has been developed in practical commercially applicable sizes in sufficient quantity that valid cost information is available. Most cost estimates for alternate sources are probably too low, just as the grass on the other side of the fence is always greener. If nuclear power is not too cheap to meter, neither is solar power free.

The actual costs of nuclear plants have, of course, been far greater than originally estimated, much to the glee of the nuclear opponents, but clearly a significant portion of the cost increase can be attributed to irresponsible intervention and to the influence of these people on regulatory action and inaction. These people hope, of course, to continue the process to the extent that nuclear is no longer a viable option. The joy of the nuclear critics is akin to that of peasants dancing around a grain field they have burned to spite the management, uncaring that food will be costlier and scarcer in the coming winter.

There seems good reason to believe that the nation will not stand for such continued arrogance and energy suicide; the fact that we are here today at this meeting is some evidence of that change in mood.

Projected Nuclear Fuel Cycle Cost
for 1,250 Mw Plant Placed In Service 1990

	No recycle	Recycle
Fuel cycle cost, cents/kwhr		
levelized for first five years	1.3	1.1
levelized over 30 years	2.0	1.5
Components (based on 30 years)		
Uranium	68.0%	58.0%
Conversion	1.6	1.4
Enrichment	22.0	21.0
Fabrication	5.9	9.4
Transportation	0.6	1.2
Reprocessing	-	5.0
Waste	1.9	4.0

NOTE: Financing of fuel cycle is included in above. Costs are expressed in 1990 dollars.

Recycle is believed more appropriate than non-recycle for fuel cost predictions in 1990, and is used in Fig. 3 for prediction of generating cost.

TABLE I

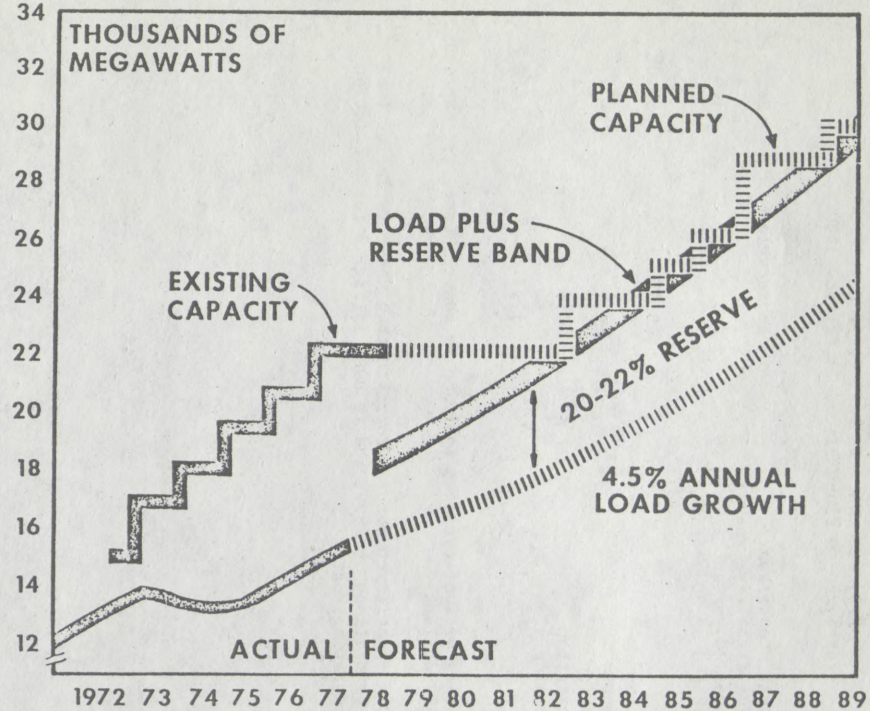
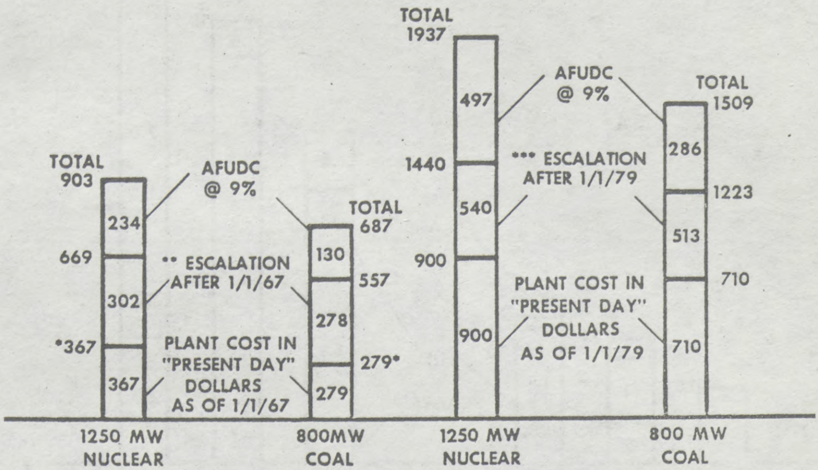


FIG. 1

GENERATING CAPACITY VS PEAK DEMAND

(NEW ENGLAND)

All costs are in $/kw net electric sendout based on custom design, first unit on site, once-through cooling, scrubbers on coal plant, designed to regulations and standards applicable as of 1/1/79 except that $50/kw has been added to 1990 plants for possible future regulatory requirements.



PLANTS PLACED IN SERVICE 1/1/79

** Based on experienced escalation

PLANTS PLACED IN SERVICE 1/1/90

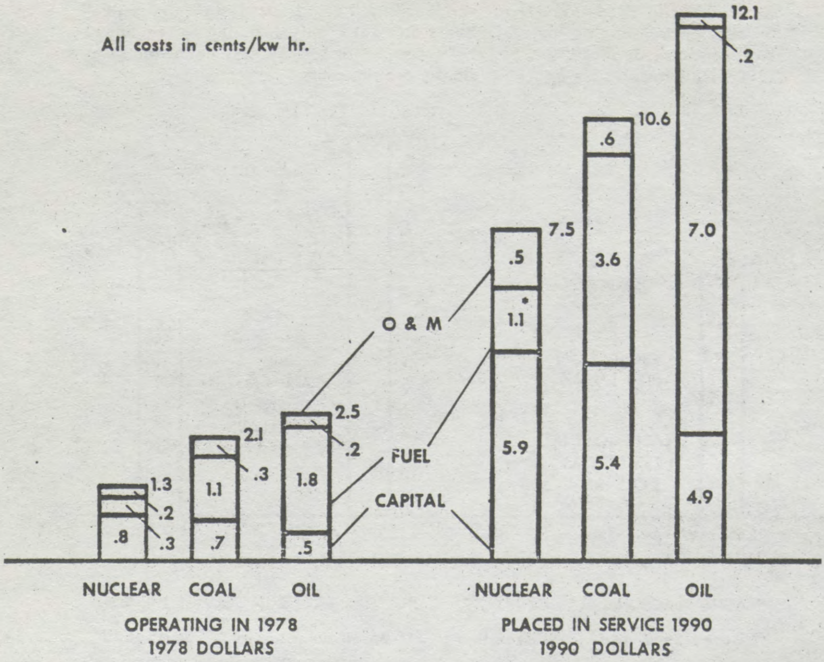
*** Based on assumed 6% compound escalation rate to point of each expenditure

Coal escalation is nearly as high as nuclear, even though it has a shorter schedule, because construction starts later to meet same in-service date.

Estimates are based on plant design as of 1/1/79, not as it would have been in 1967. Numbers marked * are, therefore, higher than would have been estimated in 1967 when regulatory requirements and effects on schedule could not have been anticipated. Estimate assumes 115 months from authorization for detail design and 79 months from construction start to commercial operation date for nuclear; 78 months and 48 months, respectively, for coal.

A standard preapproved nuclear plant would reduce cost by about $300 per kw.

ALLOCATION OF CAPITAL COSTS
FIG. 2



FOR APPROXIMATE COMPARISON OF 1990 DOLLARS WITH 1978 DOLLARS
MULTIPLY 1990 DOLLARS BY ASSUMED DEFLATOR OF .5.

Generating costs for 1990 plants based on 1990 capitalized cost times levelized fixed charge rate of 20% plus average fuel and operating costs for first five years of operation; capacity factor 60%.

Generating costs for 1978 plants are typical of costs experienced on large modern plants and do not represent any specific location.

* Assumes recycle

COMPARISON OF GENERATING COSTS

FIG. 3

APPROXIMATE ELECTRIC GENERATION COSTS FROM ENERGY SOURCES NOT YET COMMERCIALLY DEVELOPED CENTS/kw HOUR (1978 DOLLARS)

SOURCE	CAPITAL	FUEL	O&M	TOTAL
BREEDER	4.0	0.4	0.2	4.6
FUSION	4.5	0	0.5	5.0
SOLAR STEAM	10.0	0	0.5	10.5
SOLAR CELLS	80.0	0	0.5	80.5
WIND	9.0	0	0.2	9.2

The above costs are illustrative of costs developed in various studies, but are not supported by cost experience available from commercially developed sources such as nuclear, oil and coal and should be used only to assess the approximate relationship to costs from developed sources.

FIG. 4

INFO Atomic Industrial Forum, Inc.
Public Affairs and
Information Program

SUMMARY OF COMPARATIVE CAPITAL AND
GENERATING COSTS OF NUCLEAR AND COAL

1. Department of Energy, September/October 1980

Page 45
Nuclear capital costs:

Average costs for U.S. nuclear plants scheduled to be:

Operational	1980	$703/kwe
	1985	$1,353/kwe
	1989	$1,553/kwe

2. Department of Energy, July/August 1980, page 73 (for 1979); May/June 1980, page 59 (for 1978); June 1978, page 34 (for 1977); and July 1977, page 50 (for 1976).

National average generating costs for nuclear and coal:

	Nuclear	Coal
1979	2.067 ¢/kwh	2.235 ¢/kwh
1978	1.670	NA
1977	1.446	1.726
1976	1.46	1.59

3. Ebasco Services Incorporated, October 1979

Page 1 & 2, Chart 1

Nuclear and coal capital costs, 1978 estimates:

2 - 1200 mwe nuclear units, operational 1988 and 1990,$1,648/kwe

3 - 800 mwe coal units, operational 1988, 1989 and 1990,$1,266/kwe

Page 3, Chart 9
Nuclear and coal capital costs,1979 estimate, by midwestern and eastern sites:

Midwestern site

2 - 1200 mwe nuclear units, operational 6/90 & 6/92,$1,804/kwe

3 - 800 mwe coal units, operational 6/90, 6/91 & 6/92, $1,445/kwe

Eastern site

2 - 1200 mwe nuclear units, operational 6/90 & 6/92, $1,670/kwe

3 - 800 mwe coal units, operational 6/90, 6/91 & 6/92, $1,231/kwe

4. <u>Gibbs Hill, January 1980</u>

Pages 8 & 9
Nuclear and coal capital costs:

2 - 1150 mwe nuclear units, operational 1990 & 1992, moderate inflation, $2,368/kwe

3 - 750 mwe coal units, operational 1990, 1991 & 1992, moderate inflation, $1,791/kwe

5. <u>Sargent & Lundy, April 1980</u>

Figures 1 & 3
Nuclear and coal capital and generating costs:

1100 mwe nuclear unit, operational 1992
$2,765/kwe 16.10 ¢/kwh

2 - 550 mwe coal units, operational 1991 & 1992, low sulfur
$2,052/kwe 23.52 ¢/kwh

2 - 550 mwe coal units, operational 1991 & 1992, high sulfur
$2,069/kwe 20.38 ¢/kwh

1100 mwe coal unit, operational 1992, low sulfur
$1,858/kwe 22.26 ¢/kwh

1100 mwe coal unit, operational 1992, high sulfur
$1,862/kwe 19.08 ¢/kwh

6. <u>Stone & Webster, Feburary 1979</u>

Figures 2 & 3
Nuclear and coal capital and generating costs:

1250 mwe nuclear unit, operational 1/1/79
$903/kwe 1.3 ¢/kwh in 1978

800 mwe coal unit, operational 1/1/79
$687/kwe 2.1 ¢/kwh in 1978

1250 mwe nuclear unit, operational 1/1/90
$1,937/kwe 7.5 ¢/kwh in 1990

800 mwe coal unit, operational 1/1/90
$1,509/kwe 10.6 ¢/kwh in 1990

Mr. Lent?

Mr. LENT. Thank you.

I want to respectfully dissent a little bit from what the chairman has said, that we should not debate the economics of these various energy sources as we are discussing them. I think the economics of the situation are key. Ultimately the ratepayers are going to be picking up the tab for the decisions that are made by the utility companies and by the Government through their regulatory actions as to whether plants are going to go coal or they are going to be nuclear.

Just reaching back to this discussion that Dr. Komanoff has brought back, and I know can place you, I know your mother. She is the supervisor of the city of Long Beach, a well-known Democrat. Now it all comes to me. I think you have indicated, Dr. Walske, that the cost of constructing a nuclear plant, while it is greater than the cost of constructing a coal-fired plant initially, that the real savings in nuclear versus coal comes later on over the lifetime of that plant because the cost of the nuclear fuel is so much less than the cost of the coal.

Now, it would seem to me that would be particularly true in the Northeast where the transportation cost of the coal is so high. I understand that the cost of coal delivered to a plant, let's say in the New York City environs, can be almost double the cost of coal per ton at the mouth of the mine and that with the deregulation of the rails that this increase in the cost of coal is going to be aggravated even further.

Is that basically so?

Mr. WALSKE. I am sorry, I don't know details about individual coal costs, but I would like to be on the record here as being in favor of coal-fired electricity. I thought I was in my statement.

Mr. LENT. You were.

Mr. WALSKE. We really need both. It is folly to say nuclear versus coal. They are very close in cost. I think nuclear has a small edge over coal but the small edge is quite irrelevant to the point that we need both.

In our electrical generation in this country, about 50 percent came from coal this past year. It is getting pretty high. As we move forward and worry about things that might even cut off our domestic coal supply—and I don't need to detail those, it has happened before—it is a little foolish to put all your eggs in one basket.

The report I submitted for the record by Dr. Starr of EPRI analyzes how much coal production can be increased in the future. Opinions will differ about that. But in there you will find the problems that coal faces are increasing and the increases in production scheduled for coal are tremendous.

Some of them you referred to, the difficulty of transportation in the Northeast. The rail system, as I understand it, into New England, would be quite limited as far as bringing in quantities of coal to New England. So there are plenty of problems for coal.

The net result of it is that the only way we can do this job is to use them both.

Mr. LENT. I have been told that if all fuel costs were to double, nuclear costs, oil costs, and the coal costs over the next decade, that the nuclear electrical generating costs would rise only slightly whereas the fossil fuel fired plants would rise much more dramatically. This is because the cost of uranium fuel is but a very small percentage of the cost of the total electric generating costs.

Mr. WALSKE. Today in the final cost of electricity produced from coal and nuclear, about 20 percent of the cost of nuclear is from fuel and about 60 percent or a little less of the cost of coal-fired electricity is from fuel.

So if you are talking about a doubling of fuel costs, it obviously would affect coal more than it would affect nuclear. To an extent that is one of the things that utilities like about nuclear power—those who are heavily committed to it. They feel that once they finish their construction which is a great difficulty, of course—in these times when they are so pressed financially—they have sort of locked in their cost if they have heavily depended on nuclear power and they are less subject to the escalation that may come from the coal fuel costs.

Mr. LENT. The Long Island people tell me all the fuel necessary for the operation of a Shoreham plant can be brought to the site of the plant in one boxcar on a railroad in a year; whereas, the cost of firing an equivalent Btu or megawatt plant fired by coal involving thousands and thousands of carloads of coal and taking the waste out, that the difference in transportation costs would be astronomical.

Mr. WALSKE. I think the transportation costs were included in the fuel costs when I talked about the coal fuel costs. But transportation is certainly an area where nuclear has an advantage over coal.

Mr. LENT. I have one last question for Dr. Weil. Doctor, you are quoted in the National Journal, August 23, 1980, as saying:

> The obvious conclusion from current data is that if you do want nuclear plants to displace imported oil, then the place you should build them is in New England but, because of the high population density, New England is probably the worst place to build them.

I understand your apprehension about nuclear plants in New England. We have some apprehension in New york as well. But looking at the entire Northeast, I wonder if coal is really an alternative either.

I say this because of a number of points. One, we were just addressing the cost variation and the fact that coal is so much more expensive over the long haul than is a nuclear plant.

Second, the EPA requirements in the Northeast are such that the nearby eastern coal requires very expensive scrubbers or chemical factories to be installed due to the high sulfur content.

I also understand that the sludge produced by these scrubbers is highly toxic and very difficult to dispose of. So that low sulfur western coal is realy not an alternative either because it is so far away and we have the problem of the cost of getting it to the East.

Both types of coal, both the eastern and the western, are subject to the rapidly increasing railroad coal rates occasioned by the 4-R Act and the new deregulation just passed by the Congress.

So focusing in on the Northeast, if you would just for a moment, wouldn't you have to conclude that nuclear plants make more sense than coal plants?

Mr. WEIL. Congressman Lent, I think that is the conclusion you would arrive at because we have nuclear. I think the question also is one that has been discussed quite thoroughly here and which I don't think has arrived at any conclusion, which is cheaper coal or nuclear. At least I am not convinced.

Now it is very possible, accepting the costs transportation charges and scrubbers and so on, that you might prefer to have coal plants in the Northeast rather than nuclear plants.

One reason might be reliability, which I think is an important question, that has not been considered in these hearings, as far as the future is concerned.

Now we are sitting here today and many of the reports that have been presented today are essentially inspired by the fact that we have come so close to a moratorium on nuclear plant licensing. The reason for that, of course, is that we did experience a rather serious accident to a nuclear plant in 1979. I think it would be unrealistic to believe that we are not going to experience another serious accident, maybe more, maybe less. But serious enough that it is going to at least affect the reliability, as measured by plant factor of nuclear plants, if not the shutdown of nuclear plants as some of them were following Three Mile Island.

If it were a really serious accident, it might shut down all nuclear plants in this country. I am not trying to be an alarmist, believe me, but I think it should be seriously considered in discussing a nuclear future whether it be in the Northeast, the Middle West or the West, or the country as a whole.

Mr. LENT. Well, when we talk about reliability, of course we know that there have been shutdowns of various nuclear plants by reason of problems that they have had in their operation.

I understand your report indicates that there is a 56.7-percent cumulative capacity factor that you use for all commercial nuclear plants. So there is the fact that the industry has constantly complained of shutdowns of nuclear plants occasioned by Government rules and regulations which are not always entirely safety related.

But on the issue of reliability, what about the problem that is cited by the nuclear people, the pronuclear people, that coal is far less reliable than nuclear power is that you get into all of the problems of transporting coal, you get into the labor problems, the United Mine Workers, the strikes that seem to take place on a regular basis at the mines, the supply difficulties.

I think a case could be made that coal and nuclear supplies are equally subject to forces that make them, at least at some point or another, unreliable.

Mr. WEIL. I would not disagree with the fact that we certainly have gone through some difficult times with fossil fuel, coal-fired plants as well as oil-fired plants.

I think the real focus should be on, if you have a plant, say, in Pennsylvania or in any area, which has been shut down because of lack of coal, even though they may have 6 months supply which takes up a lot of acres, it is not quite the same thing. It doesn't shut down all of the coal-fired plants and they wheel in electricity from other areas which may not be affected by that particular strike.

This is not true of nuclear. We have what is called generic interaction. In other words, we know that after the Three Mile Island accident all plants designed by the same manufacturer were shut down to make inspections of the equipment that failed at Three Mile Island. Fortunately, it was not long before they discovered what the equipment was and how it could be fixed. But it did shut down something like 6 or 10, I forget the exact number, of plants for a considerable period of time.

It is true that the plant factor during 1979 was somewhat low. The average may be 60 or 62 percent, or possibly above that. Mine was 57.2 percent.

We are talking about 40 percent of our oil from Venezuela, Mexico, and the Caribbean, et cetera. So I think it should be clearly distinguished at this hearing that we are not dependent for our electricity on the Middle East.

I think I have said what I wanted to say. I just wanted to be sure that I emphasized the right point.

Mr. LENT. I will follow by adding one thing I heard today, that the cost of Long Island Lighting Co.'s Venezuelan oil is going to double in price in the very near future. I believe they are going to make an announcement of this in the not too distant future, the Long Island Lighting people are going to disclose this.

Certainly this is going to have a tremendous impact on the cost of electricity in the New York area.

Mr. WEIL. Well, I think, again, it is the cost of electricity versus the cost of something else that might happen. I don't think cheap electric energy is the greatest thing that we need. I think it is reliable, safe electric energy.

Mr. LENT. I have no further questions at this time, Mr. Chairman.

Mr. MARKEY. Thank you.

In conclusion, if we could just have each one of the panelists answer the question with which we started off the hearing. That is, how much difference will nuclear power make in reducing our dependence upon imported oil by the year 1990?

Dr. Weil?

Mr. WEIL. I think, Mr. Chairman, I have just made my comment to Mr. Lent. I will just add that the nuclear power is not going to have a very great impact on oil, particularly imported oil, whether it is from the Middle East or from Mexico, that most of the powerplants have other fossil fuels, particularly coal, available.

I think people have learned that nuclear power is perhaps not the best way to invest money. Without financing, I don't think we are going to have very many nuclear powerplants built in the future.

Mr. MARKEY. Thank you.

Dr. Taylor?

Mr. VINCE TAYLOR. It is also my conclusion that whether or not the nuclear power construction program goes forward or not is going to make a very small amount of difference in the amount of oil we import.

The basic foundation upon which this conclusion rests seems to me unarguable. The utility sector as a whole today is only using 7 percent of all the oil in this country. The trend has been strongly downward because of the very powerful economic incentives to move away from oil.

Now, if the nuclear option is available to utilities and it is not tied up with controversy, the utilities would choose to build nuclear plants. If they are denied that ability for whatever reason, whether there is too much uncertainty about nuclear safety to warrant making the decision or whether it is prohibited, they will turn to other alternatives.

When you are talking about economics there is a very small difference between coal and nuclear economics relative to the savings that you get from getting off oil.

So if the nuclear option is not available to utilities, they will move off from oil in any event and they will do it by a variety of methods, including converting existing plants from oil to coal where it is possible, and if it is required of them to make enough investment in air pollution controls to make it acceptable to their localities, it will still pay them to do that. They will build increased transmission networks.

Down in New York State you people are planning to increase the importation of hydroelectric power from Canada as another alternative. More of that will be done in other areas as well.

But the important thing to undertand is that we are talking about 7 percent of our oil. It has dropped now 30 percent in the last couple of years. It is going to keep going down. By 1990, we are talking about a couple of percent of our total oil consumption.

There is no way, I think, that you can argue that whether or not nuclear power goes forward is going to very much affect this equation. It is just there. It is small.

We have a lot of problems with oil. We ought to put our attention where it really counts.

Mr. MARKEY. Thank you.

Dr. Walske?

Mr. WALSKE. Vincent Taylor persists in the story that the only oil you can save with new electrical generation from coal and nuclear is the oil that is burned under boilers to make electricity.

I am saying this now for the third time, I think, today that that is simply not so. It is very misleading to ignore the natural gas you can save and then use to replace oil in other places.

It is wrong to ignore the fact that coal- and nuclear-fired electricity can save oil in the homes, in the factories, and, ultimately, in transportation through mass transit and even the electric car.

As far as how much they can save, it is very difficult for me to be specific but the fact is that we are going to about triple our nuclear capacity in the next decade. Today it is worth to us in energy equivalent—and I don't mean to be misunderstood, it is not all replacing oil—but in energy equivalent it is like 1.3 billion barrels of oil per day. When we triple it, it will be that much more in the picture.

Since three-fourths of energy comes from oil and natural gas it is not too hard to figure out you can make a dent in our total energy picture by using electricity from coal and nuclear.

Mr. MARKEY. Thank you.

Mr. Taylor.

Mr. John Taylor. I have a lot more respect for 7 percent than Vincent Taylor because that makes all the difference between making and losing money in our company today.

Furthermore, gas substitution adds another 7 percent. As Mr. Walske said, there is also potential for substitution of electricity for oil.

I have a very strong conviction, that in the 1990's, if we set our minds to it, we can make a major electric substitution for the things we use today with oil and gas, such as space and water heating.

Assuming half of the potential for electric generation and for heating that we see can be accomplished by 1990, 10 percent of the potential for industrial uses of electric substitution against the 75 percent that is technically feasible according to DOE, and no use of electricity to serve the transportation sector, there would result the substitution of 3½ million barrels of oil per day. Nuclear must contribute to that because coal cannot do it alone.

Mr. Markey. Thank you.

Mr. Weiner?

Mr. Weiner. I want to point out that both nuclear and coal are the options for the decade of the 1980's. Without pursuing both of these options to supply our electric needs in the near term we would be unable to offset consumption by the electric utilities. As indicated by attachment A to table VI, at least 237,000 barrels of oil per day could be displaced by nuclear powerplants by the mid-eighties. Electric utility consumption of oil cannot go to zero in this period of time.

I am talking in terms of a continuing downward trend but you must realize that a bottom will be reached. There are many reasons for this that I will not get into at this time.

For the past few years, the electric utility industry has undergone, and it will continue to undergo, the most severe trauma it has ever experienced. The utility companies are unable to acquire rates sufficient to cover their expenses. They are unable to invest in the market; they are unable to comply with the environmental concerns laid upon them. They are unable to find their way through the regulatory morass to bring new plants on line, both coal and nuclear.

The decade of the eighties does give us concern for production and consumption. I do not want to lose focus on the need to bring about supply efficiencies in our industry.

Mr. Markey. Dr. Komanoff?

Mr. Komanoff. I sympathize with the members of the panel who must be perplexed as to how we can all be looking at the same situation and come up with very different viewpoints on it. But I do feel that Vince Taylor's approach is the one that most captures the reality of the situation.

Let me amplify it by positing, what if we were to embark on an accelerated electrification strategy, heat pumps, electric cars, electrification in industry, and ignore the fact that they would take a long time to happen.

What if we did that and at the same time decided to phase out nuclear power? Would we be able to do this electrification strategy?

The answer is yes, because we have enough coal under American soil to last for hundreds of years, 400 or 500 years at present consumption rates; several hundred years at accelerated consumption rates.

If we were to do this accelerated electrification and build no more nuclear plants, we would build coal-fired plants to take their place. That is true whether you believe my view of nuclear power economics or Mr. Walske's side of the economics of nuclear power.

The only way this could not be true is if we had huge energy growth rates which would make it impossible for coal to supply the increased energy and also backout oil and gas. But we are not going to have the increased growth rates.

The people telling you about high energy growth have been saying that since 1973. There is now a 7-year record to prove that they are incorrect. Some of them still insist that to have zero or low energy growth requires major lifestyle changes. One member of the panel implied this today. That is nonsense.

I live in an apartment building in New York. Last summer we put in double-glazed energy windows which keeps the heat in and the cold out. That is a positive lifestyle change because now I can't hear the noise from outside.

We are going to have relatively low energy growth rates which means we can rely on coal to back out oil and gas and displace nuclear if we choose to do that and to also supply economic growth.

Mr. MARKEY. Mr. Lent?

Mr. LENT. I have no further questions.

Mr. MARKEY. For the record, we would also like to have a statement from the EEI and the American Nuclear Energy Council be submitted. We are going to hold the record open to receive.

Mr. Walske?

Mr. WALSKE. May I suggest that you also invite the National Rural Electric Cooperative Association and the American Public Power Association who have a complimentary membership to the Edison Electric Institute to submit statements?

Mr. MARKEY. We could do that and I don't think that would be inconsistent with the tenor and the theme of this hearing and our goal to achieve a record that will make it possible for us to make informed decisions in the future.

I and the ranking minority member here, each have our own biases and inclinations, both of which are probably very well known.

I think that just having this hearing today has been very helpful because I think it has helped to give other people who don't ordinarily have the opportunity of listening to both sides discuss the issue with each other to combat the arguments that are most often presented by either side to make their points in a forum of this nature.

I would hope that as the next year or so goes by that we can make this a more frequent occurrence because I think it is one of the most important issues we have to face in our society. The degree and level of commitment we make to the nuclear option in order to make our society energy independent is extremely important. We are going to need to make decisions that allow us to make the energy transition into renewable and other energy resources.

So I thank you all for participating here today. I think it has been very helpful for us. I hope that it can become a part of a continuing dialogue that we have here so that we can come to some resolution of these questions.

Thank you all very much for participating. The hearing is adjourned.

[The following statement was received for the record:]

POTENTIAL DISPLACEMENT OF OIL BY NUCLEAR AND COAL GENERATION IN THE ELECTRIC UTILITY INDUSTRY

Comments by Edison Electric Institute submitted to the Subcommittee on Oversight and Investigations, Committee on Interstate and Foreign Commerce, December 15, 1980.

Edison Electric Institute welcomes this opportunity to comment on the subject of oil substitution by electric utility nuclear and coal generation. Edison Electric Institute (EEI) is the national association of investor-owned electric utilities. Member companies of EEI serve 99 percent of all ultimate customers served by the investor-owned electric utility industry.

Introduction

Two interlocking strategies underlie efforts to displace oil imports through the electric utilities. One controls imports by oil-to-coal conversions of existing power plants and by completing on schedule coal and nuclear units under construction. Unfortunately, because of financial and regulatory constraints, both of these alternatives are proving difficult to implement.

A second strategy, involving increased electrification to replace oil at end-use, reduces oil import dependence and expands the domestic energy base of our economy. Of course, economic growth will dictate overall energy needs and as such set the pace for implementing this strategy.

Inextricably linked to both strategies is the role of nuclear power--first, because when completed, nuclear power plants presently under construction can limit significantly utility oil use. And second, because practical constraints on the rates of growth of extraction, transportation, and environmental acceptance of coal are likely to make dependence on coal alone for expansion of base load generation an impossibility. Moreover, by the end of the century, coal will also have become a major feedstock for synthetic fuel production.

Utility Oil Displacement - The Next Ten Years

Edison Electric Institute, in cooperation with Dr. Martin Baughman of the University of Texas, used the Baughman/Joskow Regionalized Electricity Model (REM) to examine the effects of restrictive nuclear policies and alternative demand projections on electric utility oil requirements for the 1980s. The analysis was based on the National Electric Reliability Council (NERC See Figure I) regional projections which average to a national annual load growth of 4.3 percent. The NERC projections assume adverse hydro conditions and a scheduled completion of 228,600 MWe of new capacity. Approximately 87,900 MWe or 40 percent of this scheduled total is to be nuclear. In addition, load growth rates of 2.0 percent and 3.0 percent per year were analyzed along with the required changes in scheduled capacity additions. For each load growth scenario, a case eliminating nuclear after 1980 was considered.

As Table I shows, the results are quite dramatic. For all three demand growth cases and no nuclear generation after 1980, oil requirements grow significantly from the present rate of oil consumption. For the 4.3 percent demand growth with no nuclear generation after 1980, oil requirements by 1990 are approximately three times the value projected without nuclear constraints.

Even in the 2 percent growth case, if no nuclear is permitted to operate, oil requirements by 1990 increase to almost 2-1/2 times the unconstrained nuclear case. These results suggest that nuclear capacity already on line and scheduled to be completed in the eighties can be expected to displace from 630 million to 870 million barrels of oil per year (1.7 to 2.4 million barrels/day). Unlike simple analyses which account for displaced nuclear generation through a one-to-one trade-off with oil generation, our analysis allows for displacement by all generating types. Table I shows the percentage displacement of nuclear by other generation and unserved energy. As Table I shows, coal would be expected to make up close to 30% of the displacement in all cases. Oil (steam) initially would account for about 50% of the displacement and thereafter account for 40%.

Significantly, the nuclear constraints would result in deficiencies in electricity supply capability. As Table II shows by 1990, with no nuclear capacity used after 1980, seven of the nine NERC regions would experience shortages. MAAC, MAIN, and SERC would suffer capacity shortages of over 5% in the 4.3% growth case, and even with 2% load growth MAIN and SERC would suffer capacity shortages of over 5%.

Closer to the consumers, the nuclear constraints affect utility operating and fuel costs substantially. Increased oil use represents a multiple burden for U.S. consumers. First, the customers of the system directly affected by the nuclear shutdown must pay a much higher energy charge, regardless of whether all or only a portion of the replacement power is produced from oil.

Second, the increased demand for alternative generation fuels will drive up the price for those fuels, causing customers of all power systems using those fuels to bear increased costs. Table III shows, for all demand growth cases without nuclear, utility fuel and operating expenses rise sharply. Under high and low growth assumptions the cost increase is over 30%. In the 3% demand growth case the cost increase is almost 40%. And these increases do not include the capital charges associated with shutdown nuclear capacity and customer outage costs due to unserved energy.

A third burden, the portion of increased alternative fuel which is imported will force all U.S. consumers to bear the costs associated with a deteriorating balance of payments (e.g., depreciated value of the dollar, greater inflation) and the risks of greater foreign fuel dependency. For example, the increased oil use in all demand growth cases would probably be imported oil. For the 3% growth case, the 1990 oil import bill (computed in 1980 dollars starting at $32 per barrel and increasing at 2% real per year) associated with a nuclear shut-off could amount to 31 billion dollars. If expressed as a percentage of total oil imports, the increased imports associated with a nuclear shutdown become even more alarming. The potential increase of over 2 million barrels per day represents about 30% of current petroleum imports and would be equivalent to nearly half of the Carter Administration's 1990 import target of 4.5 million barrels/day.

Oil Displacement - Electricity's Long-Term Role

Most contemporary economic/energy studies that project to 2000 and beyond find that electricity's share of primary and end-use energy will rise substantially. These studies by reputable groups such as CONAES, Ford Foundation, Resources for the Future, and the Electric Power Research Institute all point to the inevitable need for nuclear power as conventional exhaustible supplies dwindle and as the level of utility coal consumption begins to reach practical limits.

Typical of these studies' results are the findings of EEI's Economic Growth in the Future-II (EGIF-II) done in cooperation with the Electric Power Research Institute. As Table IV implies, for annual GNP growth rates of 2.4 percent and 3.1 percent to the year 2000, primary energy increases by 34 percent and 50 percent, respectively. Most of the increase is due to coal and nuclear generation. Electricity's role at end-use increases from 9.6 percent in 1978 to as high as 24 percent in 2000, and in terms of incremental end-use energy supply, electricity accounts for over 65 percent of this increase. According to the EEI study, economic policies favorable to capital formation can halve oil import dependence from 1978 levels. For the utility industry, combined oil and gas use reduces by about 50 percent from 1978 levels. Base load power plants account for close to 90 percent of total generation with coal providing 50-55 percent and nuclear 33-38 percent.

As indicated under Table IV's energy intensity entry, EGIF-II estimates that conservation will contribute over 13 quads of energy by 2000 -- a contribution larger than the utility industry's current KHW output and much larger than future nuclear contribution. Residential and commercial heat pumps, more efficient air conditioners, load management, better appliances, tighter insulation and prices all play major roles. EGIF-II like its contemporaries also recognizes the full potential of solar and renewable sources. Looking past the year 2000, most analysts see nuclear's role (using breeder technology) becoming even more significant to our nation's energy future.

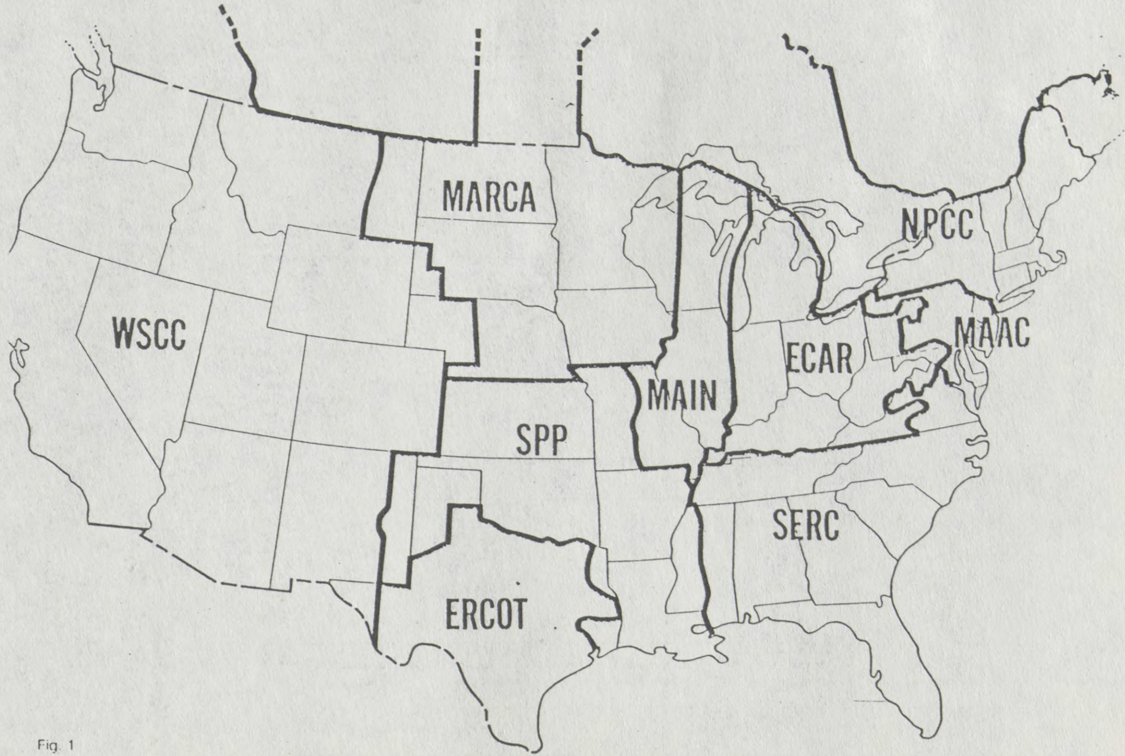


Fig. 1

Regional Reliability Councils of the National Electric Reliability Council

TABLE I EFFECTS OF NUCLEAR CONSTRAINTS ON OIL REQUIREMENTS

Total U.S. Oil Consumption by Electric Utilities
(in millions of barrels per year)

Year	For 4.3% Annual Demand Growth: No Nuclear Constraints	For 4.3% Annual Demand Growth: No Nuclear Generation After 1980	For 3.0% Annual Demand Growth: No Nuclear Constraints	For 3.0% Annual Demand Growth: No Nuclear Generation After 1980	For 2.0% Annual Demand Growth: No Nuclear Constraints	For 2.0% Annual Demand Growth: No Nuclear Generation After 1980
1979*	525.4	525.4	525.4	525.4	525.4	525.4
1981	523.8	996.0	492.0	961.9	468.2	934.9
1985	476.7	1,213.0	441.1	1,101.6	426.7	1,033.3
1990	566.3	1,437.8	395.2	1,194.2	498.7	1,130.7

*Actual

NUCLEAR REPLACEMENT BY ALTERNATIVE GENERATION TYPE* (%)

Year	Type	4.3%	3.0%	2.0%
1981	Coal	28.2	29.2	30.0
	Oil (Steam)	48.9	49.8	50.4
	Gas (Steam)	3.7	3.8	3.8
	Combustion Turbine	12.8	11.8	11.0
	Other	.9	.9	.9
	Unserved Energy	5.5	4.5	3.7
1985	Coal	24.5	28.3	29.3
	Oil (Steam)	42.9	45.4	48.1
	Gas (Steam)	5.2	5.3	4.6
	Combustion Turbine	14.3	12.0	11.1
	Other	.9	1.0	1.0
	Unserved Energy	12.2	8.0	5.8
1990	Coal	24.3	26.4	26.5
	Oil (Steam)	32.8	41.7	42.5
	Gas (Steam)	4.2	5.0	4.8
	Combustion Turbine	14.4	12.7	13.0
	Other	.7	.9	.9
	Unserved Energy	23.4	13.1	12.3

*Supply shortages also present.
Percent numbers may not add up due to rounding

TABLE II
REGIONS EXPERIENCING SUPPLY SHORTAGES AS A RESULT OF NUCLEAR GENERATION CONSTRAINTS

	For 4.3% Annual Demand Growth			For 3.0% Annual Demand Growth			For 2.0% Annual Demand Growth		
	Regions with Electrical Energy Shortage			Regions with Electrical Energy Shortage			Regions with Electrical Energy Shortage		
Year	less than 1%	1%-5%	greater than 5%	less than 1%	1%-5%	greater than 5%	less than 1%	1%-5%	greater than 5%
1981	ECAR, MACC, MARCA	MAIN, SERC		ECAR, MAAC	MAIN, SERC		ECAR, MAAC	MAIN, SERC	
1985	NPCC, WSCC	ECAR, MAAC, MARCA	MAIN, SERC	MAAC, MARCA	ECAR, MAIN	SERC	ECAR, MAAC, MARCA	MAIN, SERC	
1990		ECAR, MARCA, NPCC, WSCC	MAAC, MAIN, SERC	NPCC	ECAR, MAAC, MARCA, WSCC	MAIN, SERC	MAAC, WSCC	ECAR, MARCA	MAIN, SEPC

TABLE III

TOTAL ELECTRIC UTILITY OPERATING AND FUEL EXPENSES FOR NUCLEAR CONSTRAINTS
(in billions of constant 1980 dollars for the total U.S.)

	For 4.3% Annual Demand Growth		For 3.0% Annual Demand Growth		For 2.0% Annual Demand Growth	
Year	No Nuclear Constraints	No Nuclear Generation After 1980	No Nuclear Constraints	No Nuclear Generation After 1980	No Nuclear Constraints	No Nuclear Generation After 1980
1981	62.2	75.3	61.0	74.0	60.0	73.0
1985	73.9	97.4	70.4	91.6	68.1	87.5
1990	95.4	125.7	82.2	114.3	82.1	107.3

Supply shortages also present.

TABLE IV

ECONOMIC GROWTH AND ENERGY SUPPLIES IN THE YEAR 2000

	SCENARIOS				
	High	Independence	Preferred	Continuation	Low
Real GNP	3.8	3.7	3.1	2.4	1.7

	1978	SCENARIOS High	Independence	Preferred	Continuation	Low
PRIMARY ENERGY USE						
Quads	78	147.0	136.5	117.2	104.2	77.3
Percent per Year		2.9	2.6	1.9	1.3	0.0
PRIMARY ENERGY INTENSITY						
1000 BTU's per 1972 $	55	47	45	43	45	39
Percent per Year		−0.7	−0.9	−1.1	−0.9	−1.6

PRIMARY ENERGY SUPPLY IN THE YEAR 2000 (QUADS)

	1978	High	Independence	Preferred	Continuation	Low
PETROLEUM SUPPLY						
Domestic	19.6	19.7	22.0	21.6	19.6	15.9
Imports	18.1	27.9	12.3	6.8	13.2	—
Shale		0.2	1.0	1.0	0.1	1.0
NATURAL GAS SUPPLY						
Domestic	19.2	16.5	16.0	16.9	17.5	11.5
Imports	1.0	10.2	4.7	—	4.4	—
COAL SUPPLY						
For Electricity	10.1	39.7	31.3	29.1	17.2	11.1
Other	4.0	8.2	10.8	9.4	9.2	7.6
For Synthetics		1.2	6.0	6.0	0.6	6.0
NUCLEAR	2.9	18.0	24.0	18.0	18.0	15.8
HYDRO & OTHER	3.1	3.4	3.4	3.4	3.4	3.4
SOLAR	—	2.0	5.0	5.0	1.0	5.0

ELECTRICITY GENERATION IN THE YEAR 2000

	1978	High	Independence	Preferred	Continuation	Low
ENERGY INPUTS: (Quadrillion BTU)						
Coal	10.1	39.7	31.3	29.1	17.2	11.1
Petroleum and Gas	6.6	3.1	3.7	3.6	4.8	3.0
Nuclear	2.9	18.0	24.0	18.0	18.0	15.8
Hydro and Other	3.1	3.4	3.4	3.4	3.4	3.4
TOTAL	22.7	64.2	62.4	54.1	43.4	33.3
% Coal	44.5	61.8	50.2	53.8	39.6	33.3
% Nuclear	12.8	28.0	38.5	33.3	41.5	47.4

[Whereupon, at 12:40 p.m., the hearing adjourned.]

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