United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued February 21, 1996 Decided July 16, 1996

No. 92-1485

UNITED DISTRIBUTION COMPANIES,
PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION,
RESPONDENT

WINDWARD ENERGY & MARKETING COMPANY, ET AL.,
INTERVENORS

Consolidated with
92-1495, 92-1496, 94-1171, 94-1173, 94-1174, 94-1175, 94-1176, 94-1177, 94-1178, 94-1179, 94-1180, 94-1181, 94-1183, 94-1184, 94-1185, 94-1187, 94-1188, 94-1189, 94-1190, 94-1193, 94-1194, 94-1196, 94-1197, 94-1198, 94-1200, 94-1201, 94-1206, 94-1207, 94-1209, 94-1213, 94-1215, 94-1217, 94-1218, 94-1222, 94-1223, 94-1226, 94-1228, 94-1229, 94-1231, 94-1232, 94-1233, 94-1234, 94-1236, 94-1237, 94-1238, 94-1239, 94-1240, 94-1241, 94-1242, 94-1243, 94-1246, 94-1247, 94-1248, 94-1249, 94-1252, 94-1256, 94-1257, 94-1258, 94-1259, 94-1263, 94-1264, 94-1265, 94-1267, & 94-1270

On Petitions for Review of Orders of the
Federal Energy Regulatory Commission

Frederick Moring, *Roy R. Robertson, Jr.*, *Michael W. Hall*, *O. Julia Weller*, *Roberta L. Halladay*, *Daniel F. Collins*, *Robert T. Hall, III*, *Harvey L. Reiter*, *Lee A. Alexander*, *Edward J. Grenier, Jr.*, *Charles F. Wheatley, Jr.*, *John P. Gregg*, *John T. Miller*, *David W. D'Alessandro*, *Denise C. Goulet* and *Philip M. Marston* argued the causes for petitioners, with whom *Dana C. Contratto*, *John E. Holtzinger, Jr.*, *Kevin M. Downey*, *Kenneth T. Maloney*, *William I. Harkaway*, *Donald K. Dankner*, *Frederick J. Killion*, *Jeffrey L. Futter*, *Stephen L. Huntoon*, *Douglas M. Canter*, *Mary E. Baluss*, *Kristine L. Delkus*, *Christopher J. Barr*, *John K. Keane, Jr.*, *Telemac N. Chryssikos, James K. Mitchell, Paul K. Sandness, Kevin J. Lipson, Scott Silverstein, Janice A. Alperin, Christine R. Pembroke, Kenneth M. Simon, Mitchell F. Hertz, Randolph Q. McManus, William L. Slover, Donald G. Avery, Andrew B. Kolesar, III, Laurence E. Skinner, William I. Harkaway, Michael W. Hall, William H. Penniman, Glen S. Howard, Sterling H. Smith, Gail S. Gilman, Thomas E. Hirsch, III, David K. Schumacher, Frederic G. Berner, Jr., Nancy Y. Gorman, Debra L. Raggio Bolton, Susan N. Kelly, William T. Miller, Elisabeth R. Myers-Kerbal, Glenn W. Letham, Steven M. Sherman, Don C. Uthus, Timothy P. Ingram, Richard A. Rapp, Jr., Jennifer N. Waters, Kelly A. Daly, Edward W. O'Neill, Harvey Y. Morris, Theresa V. Czarski, Paula M. Carmody, Diane Munns, Lawrence F. Barth, Veronica A. Smith, John F. Povilaitis, Harold L. Stoller, Jr., Penny G. Baker, Helene S. Wallenstein, Thomas B. Nicholson, Charles D. Gray, Robert S. Tongren, Margaret Ann Samuels, Jospeh P. Serio, Yvonne Ranft, Deborah Y. VanDervort, Robert J. Mussallem, Darrell S. Townsley, Ellen M. Averett, Richard A. Solomon, Robert K. Johnson, William H. Smith, Jr.* and *Kim M. Clark* were on the briefs. *Jack M. Wilhelm, Robin M. Nuschler, Douglas J. Law, Kathleen L. Mazure, Phillip G. Lookadoo, Toni M. Fine, John T. Stough, Jr., Robert I. White, Jacolyn A. Simmons, Kent D. Murphy, Marc Richter, Richard A. Rapp, Jr., Don S. Smith, Steven A. Weiler, Paul W. Fox, Kevin J. McIntyre, Scott S. Ives, Donald C. Shepler, Jr., James Howard, Robert S. Hall, Jr., James F. Bowe, Jr., Steven H. Lasher, Donald G. Avery, David C. Dickey, Robert F. Shapiro, Jack M. Irion, Philip B. Malter, Harold L. Talisman, Jeanne M. Bennett* and *Robert H. Benna* entered appearances.

Jerome M. Feit, Solicitor, Federal Energy Regulatory Commission, *Joseph S. Davies*, Deputy Solicitor and *Susan J. Court*, Special Counsel, argued the causes for respondent, with whom *Timm L. Abendroth, Eric L. Christensen, Randolph L. Elliott, Edward S. Geldermann* and *Janet K. Jones*, Attorneys, were on the brief. *Thomas J. Lane* and *Jill Hall*, Attorneys, entered appearances.

Henry S. May, Jr. argued the cause for intervenors, with whom *Judy M. Johnson, Clifton S. Rankin, Richard J. Kruse, Jeffrey D. Komarow, James W. McTarnaghan, Allan W. Anderson, Jr., David K. Schumacher, Frederick T. Kolb, Daniel F. Collins, Janice A. Alperin, Christine R. Pembroke, Michael W. Hall, Michael J. Manning, Kenneth R. Carretta, James P. White, William T. Miller, John P. Gregg, Elisabeth R. Myers-Kerbal, Emery J. Biro, III, Norma J. Rosner, David G. Stevenson, Bruce A. Connell, MaryJane Reynolds, Leslie J. Lawner, Jane E. Wilson, Joseph R. Hartsoe, R. Brent Harshman, Richard C. Green, Douglas W. Rasch, John H. Cheatham, III, Bud J. Becker, O. Julia Weller, Paul F. O'Konski, Marge O'Connor, Kenneth E. Randolph, Jeffrey G. DiSciullo, Edward J. Grenier, Jr., William H. Penniman, Glen S. Howard, Sterling H. Smith, Charles F. Wheatley, Jr., Don C. Uthus, Timothy P. Ingram, Paul Korman, Paul W. Mallory, Charles L. Pain, Kathleen T. Puckett, James J. Cleary, R. David Hendrickson, Patrick P. Pope, Ralph J. Pearson, Jr., Linda L. Geoghegan, Marilyn L. Doria, Blaine Yamagata* and *James Denvir* were on the brief. *Donald C. Shepler, Jr., James*

F. Bowe, Jr., Jean E. Sonneman, Kenneth T. Maloney, Gordon Gooch, J. Stephen Martin, Katherine B. Edwards, Mario M. Garza, Mark R. Haskell, J. Paul Douglas, Luke A. Mickum, Leslie J. Lawner, Deborah A. Macdonald, Sherrie N. Rutherford, Clifton D. Harris, Jr., Frederick W. Giroux, Mark D. Foss, Marge O'Connor, James K. Morse, Kevin M. Sweeney, James P. White, Michael J. Manning, Charles J. McClees, Michael A. Kelly, F. Nan Todd Wagoner, Janice H. Parker, Andrew N. Greene, Elisabeth Y. Pendley, Emmitt C. House, Georgetta J. Baker, Paul E. Goldstein, Frank X. Kelly, Maria K. Pavlou, Steve Stojic, Merlin E. Remmenga, David B. Ward, Robert Baker and *G. Mark Cook* entered appearances.

Appearances were also filed by *Carl M. Fink, Howard E. Shapiro, James C. Moffatt, Jennifer B. Corwin, Robert A. Nuernberg, Ronald D. Eastman, Oleta J. Harden, Barbara K. Heffernan, Cheryl L. Jones, Tom Rattray, Gearold L. Knowles, Margaret Ann Samuels, David C. Dickey, Thomas E. Hirsch, III, Britton White, Jr., James D. Senger, James J. Flood, Joel F. Zipp, Leja D. Courter, Ronald E. Christian, James C. Moffatt, Shippen Howe, John R. Staffier, Robert A. Nelson, Timothy C. Bladek, Andrew N. Greene, Edward B. Myers, Carolyn Y. Thompson, Kenneth D. Brown, Frank R. Lindh, Keith T. Sampson, Raymond N. Shibley, Cheryl J. Walker, Thomas J. Eastment, Michael L. Pate, Barbara S. Jost, Michael E. Small, Robin M. Nuschler, John C. Walley, Gary E. Guy, Stephen J. Small, Susan D. McAndrew, Timothy N. Black, David W. Anderson, David L. Huard, David J. Evans, George H. Rothschild, Jr., Charles H. Shoneman, Randall S. Rich, Joel L. Greene, Joseph M. Oliver, Jr., M. Lisanne Crowley, Mark C. Darrell, John B. Chapman, John K. McDonald, Richard E. Powers, Jr., Sylvia P. McCormack, Jeffrey M. Petrash, Phillip G. Lookadoo, J. Neises, S.D. Holbrook, James D. McKinney, Jr., John J. Wallbillich, Joshua L. Menter, Jack P. Grimaldi, J.D. Steelman, Jr., Nicholas W. Fels, Anthony J. Ivancovich, Rebecca S. Haney, John S. Grube, Stuart W. Conrad, Robert B. Langstaff, Michael J. Gianunzio, David W. Rubadue, Marilyn A. Specht, Paul W. Fox, Bruce F. Kiely, Mark K. Lewis, Jack M. Wilhelm, Michael R. Waller, Mark C. Moench, Paul M. Flynn, Frederick J. Killion, Michael Thompson, Wade H. Hargrove, Jr., Donald W. McCoy, Bruce Henderson, Kris L. Terry, Joseph M. Marcoux, Elizabeth A. Ward, Philip F. Cronin, Jr., Stephen L. Huntoon, Nancy J. Skancke, Timothy A. Beverick, Kenton L. Erwin, Scott P. Klurfeld, David B. Robinson, Anita T. Gallucci, Michael P. May, Daniel J. Guttman, Jr., William Bingham, James H. Holt, Don P. Garber, Floyd L. Norton, IV, Dennis D. Ahlers, David I. Bloom, Thomas M. Patrick, John M. Hopper, Jr., Mary A. Walker, Joseph E. Mixon, Nancy J. Skancke, Cecil W. Talley* and *Arthur L. Smith*.

Before: WALD, SENTELLE and ROGERS, *Circuit Judges*.

Opinion for the Court filed PER CURIAM.*

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*PARTS III AND V.A-B, E.3-4 AND F ARE BY JUDGE WALD; PARTS IV AND V.C-D AND E.1-2 ARE BY JUDGE SENTELLE; AND PARTS I AND II ARE BY JUDGE ROGERS.

TABLE OF CONTENTS

Per Curiam:

I. Introduction

In Order No. 636,[1] the Federal Energy Regulatory Commission

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[1] Order No. 636, Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,939, *order on reh'g,* Order No. 636-A, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,950, *order on reh'g,* Order No. 636-B, 61 F.E.R.C. ¶ 61,272 (1992), *reh'g denied,* 62 F.E.R.C. ¶ 61,007 (1993).

("Commission" or "FERC") took the latest step in its decade-long restructuring of the natural gas industry, in which the Commission has gradually withdrawn from direct regulation of certain industry sectors in favor of a policy of "light-handed regulation" when market forces make that possible. We review briefly the regulatory background for natural gas.

A. Background: Natural Gas Industry Structure

The natural gas industry is functionally separated into production, transportation, and distribution. Traditionally, before the move to open-access transportation, a producer extracted the gas and sold it at the wellhead to a pipeline company. The pipeline company then transported the gas through high-pressure pipelines and re-sold it to a local distribution company (LDC). The LDC in turn distributed the gas through its local mains to residential and industrial users. *See generally* EDWARD C. GALLICK, COMPETITION IN THE NATURAL GAS INDUSTRY 9-12 (1993).

The Natural Gas Act (NGA), ch. 556, 52 Stat. 821 (1938) (codified as amended at 15 U.S.C. §§ 717-717w (1994)), enacted in 1938, gave the Commission jurisdiction over sales for resale in interstate commerce and over the interstate transportation of gas, but left the regulation of local distribution to the states.[2] NGA § 1(b), 15 U.S.C. § 717(b). The NGA was intended to fill the regulatory gap left by a series of Supreme Court decisions that interpreted the dormant Commerce Clause to preclude state

[2] In 1954, Congress added the "Hinshaw exemption," which excludes from the Commission's jurisdiction gas that is received within a state (or at the state boundary) and is consumed within that state, provided that the gas is subject to state regulation. NGA § 1(c), 15 U.S.C. § 717(c).

regulation of interstate transportation and of wholesale gas sales. *See Arkansas Elec. Coop. Corp. v. Arkansas Pub. Serv. Comm'n*, 461 U.S. 375, 377-80 (1983). The overriding purpose of the NGA is " "to protect consumers against exploitation at the hands of natural gas companies.' " *FPC v. Louisiana Power & Light Co.*, 406 U.S. 621, 631 (1972) (quoting *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 610 (1944)). Federal regulation of the natural gas industry is thus designed to curb pipelines' potential monopoly power over gas transportation.[3] The enormous economies of scale involved in the construction of natural gas pipelines tend to make the transportation of gas a natural monopoly.[4] Indeed, even with the expansion of the national pipeline grid, or network, in recent decades, many "captive" customers[5] remain served by a single pipeline.[6] Order No. 436, ¶ 30,665, at 31,473.[7]

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[3] The seminal analysis of pipelines' market power over transportation can be found in the Federal Trade Commission (FTC) report that led to the enactment of the NGA. *See* SEN. DOC. NO. 92, pt. 84A, 70th Cong., 1st Sess. (1935).

[4] A natural monopoly occurs when, because of the high ratio of fixed costs to variable costs, a single firm has declining average costs at the level of demand in the industry, such that the single firm can supply the service more cheaply than two firms could. RICHARD A. POSNER, ECONOMIC ANALYSIS OF LAW § 12.1, at 343-45 (4th ed. 1992).

[5] We use the term "captive customer" to refer to customers "who must use gas and can only obtain it from one provider." *Mississippi Valley Gas Co. v. FERC*, 68 F.3d 503, 506 (D.C. Cir. 1995); *see also Wisconsin Gas Co. v. FERC*, 770 F.2d 1144, 1150, 1160 (D.C. Cir. 1985) ("[F]ull requirements [or "captive'] customers purchase their entire natural gas supply from one pipeline and, because of their geographical location, are unable to swing off the system to obtain cheaper supplies of gas.").

[6] As of 1985, 10% of gas deliveries were to LDCs served by four or more pipelines, 39.5% to LDCs served by three pipelines, 28% to LDCs served by two pipelines, and 22.5% to LDCs served by a single pipeline. STEPHEN F. WILLIAMS, THE NATURAL GAS REVOLUTION OF

Even though the market function potentially subject to monopoly power is the transportation of gas, for many years the Commission also regulated the price and terms of sales by producers to interstate pipelines. *See Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672, 677-84 (1954). Producer price regulation was widely regarded as a failure, introducing severe distortions into what otherwise would have been a well-functioning producer sales market. *See* STEPHEN G. BREYER & PAUL W. MACAVOY, ENERGY REGULATION BY THE FEDERAL POWER COMMISSION 56-88 (1974). When a severe gas shortage developed in the 1970s, Congress enacted the Natural Gas Policy Act of 1978 (NGPA), Pub. L. No. 95-621, 92 Stat. 3351 (codified as amended at 15 U.S.C. §§ 3301-3432 (1994)), which gradually phased out producer price regulation. Under the NGPA's partially regulated producer-price system, many pipelines entered into long-term contractual obligations, in what were known as "take-or-pay" provisions, to purchase minimum quantities of gas from producers at costs that proved to be well above current market prices of gas. *See* Richard J. Pierce, Jr., *Reconstituting the Natural Gas Industry from Wellhead to Burnertip*, 9 ENERGY L.J. 1, 11-16 (1988).

The problem of pipelines' take-or-pay settlement costs has

1985, at 4 (1985).

[7] Order No. 436, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,665, *order on reh'g*, Order No. 436-A, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,675 (1985), *order on reh'g*, Order No. 436-B, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,688, *order on reh'g*, Order No. 436-C, 34 F.E.R.C. ¶ 61,404, *order on reh'g*, Order No. 436-D, 34 F.E.R.C. ¶ 61,405, *order on reh'g*, Order No. 436-E, 34 F.E.R.C. ¶ 61,403 (1986), *vacated and remanded sub nom. Associated Gas Distributors v. FERC*, 824 F.2d 981 (D.C. Cir. 1987) (*AGD I*), *cert. denied*, 485 U.S. 1006 (1988).

plagued the industry and the Commission over the last fifteen years. The Commission's initial response to escalating pipeline take-or-pay liabilities was to authorize pipelines to offer less expensive sales of third-party (non-pipeline-owned) gas to non-captive customers while still offering only higher-priced pipeline gas to captive customers.[8] The court struck down these measures because the Commission "ha[d] not adequately attended to the agency's prime constituency," captive customers vulnerable to pipelines' market power. *Maryland People's Counsel v. FERC,* 761 F.2d 780, 781 (D.C. Cir. 1985) (*MPC II*); *see also Maryland People's Counsel v. FERC,* 761 F.2d 768, 776 (D.C. Cir. 1985) (*MPC I*). In response to the court's decisions in *MPC I* and *MPC II,* the Commission embarked on its landmark Order No. 436 rulemaking. *See* Order No. 436, ¶ 30,665, at 31,467.

B. <u>Order No. 436: Open-Access Transportation</u>

In Order No. 436, the Commission began the transition toward removing pipelines from the gas-sales business and confining them

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[8] First, the Commission approved special marketing programs, under which pipelines agreed to transport third-party gas to industrial end-users in exchange for the producer's agreement to credit the transported gas to the pipeline's take-or-pay liability. *See Columbia Gas Transmission Corp.,* 25 F.E.R.C. ¶ 61,220, *order on reh'g,* 25 F.E.R.C. ¶ 61,401 (1983), *order on reh'g,* 26 F.E.R.C. ¶ 61,031 (1984). Second, the Commission authorized selective transportation programs, under which a pipeline received a blanket certificate to transport third-party gas and was allowed to offer this service to its customers on a selective basis. *See* Order No. 234-B, Interstate Pipeline Blanket Certificates for Routine Transactions and Sales and Transportation by Interstate Pipelines and Distributors, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,476 (1983); Order No. 319, Sales and Transportation by Interstate Pipelines and Distributors, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,477, *order on reh'g,* Order No. 319-A, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,512 (1983).

to a more limited role as gas transporters. Under a new Part 284 of its regulations,[9] the Commission conditioned receipt of a blanket certificate for firm transportation of third-party gas on the pipeline's acceptance of non-discrimination requirements guaranteeing equal access for all customers to the new service.[10] Order No. 436, ¶ 30,665, at 31,497-518. In effect, the Commission for the first time imposed the duties of common carriers upon interstate pipelines. *See Associated Gas Distributors v. FERC,* 824 F.2d 981, 997 (D.C. Cir. 1987) (*AGD I*), *cert. denied,* 485 U.S. 1006 (1988). By recognizing that anti-competitive conditions in the industry arose from pipeline control over access to transportation capacity, the equal-access requirements of Order No. 436 regulated the natural-monopoly conditions directly. In addition, every open-access pipeline was required to allow its existing bundled firm-sales customers to convert to firm-transportation service and, at the customer's option, to reduce its firm-transportation entitlement (its "contract demand"). Order No. 436, ¶ 30,665, at 31,518-33. Moreover, the Commission established a flexible rate structure under which transportation charges were limited to the

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[9] Customers who receive service under a blanket certificate as authorized in Order No. 436 are known as Part 284 customers. Customers who receive individually certificated service, to which the open-access conditions do not apply, are known as Part 157 customers, or § 7(c) customers. Although the Commission's current policy is no longer to issue Part 157 certificates, *Blue Lake Gas Storage Co.*, 59 F.E.R.C. ¶ 61,118, *reh'g denied,* 61 F.E.R.C. ¶ 61,284 (1992), existing Part 157 certificates remain in effect.

[10] Pipelines generally offer two forms of transportation service: firm transportation, for which delivery is guaranteed, and interruptible transportation, for which delivery can be delayed if all the capacity on the pipeline is in use.

maximum approved rate (based on fully allocated costs) but pipelines could selectively discount down to the minimum approved rate (based on average variable cost). *Id.* at 31,533-49.

The court largely approved Order No. 436, but the principal stumbling-block was the unresolved problem of uneconomical pipeline-producer contracts in the transition to the unbundled environment. The Commission had decided not to provide pipelines with relief from their take-or-pay liabilities, even though the introduction of open-access transportation in Order No. 436 would likely exacerbate the problem by reducing pipeline sales.[11] *AGD I*, 824 F.2d at 1021-23. After the court remanded the case on the ground that the Commission's inaction on take-or-pay did not exhibit reasoned decision making in light of open access, *id.* at 1030, the Commission adopted various interim measures in Order No. 500.[12] First, it instituted a "crediting mechanism," under which a pipeline could apply any third-party gas that it transported

[11] The Commission limited itself to re-affirming a previous policy statement on take-or-pay liabilities that deferred the issue to individual rate-case filings. Order No. 436, ¶ 30,665, at 31,560-69; *see* Regulatory Treatment of Payments Made in Lieu of Take-or-Pay Obligations, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,637 (1985); 18 C.F.R. § 2.76.

[12] Order No. 500, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,761, *order on reh'g*, Order No. 500-A, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,770, *order on reh'g*, Order No. 500-B, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,772, *order on reh'g*, Order No. 500-C, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,786 (1987), *order on reh'g*, Order No. 500-D, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,800, *order on reh'g*, Order No. 500-E, 43 F.E.R.C. ¶ 61,234, *order on reh'g*, Order No. 500-F, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,841 (1988), *order on reh'g*, Order No. 500-G, 46 F.E.R.C. ¶ 61,148, *vacated and remanded sub nom. American Gas Ass'n v. FERC*, 888 F.2d 136 (D.C. Cir. 1989) (*AGA I*).

toward the pipeline's minimum-purchase obligation from that particular producer. Order No. 500, ¶ 30,761, at 30,779-84. Second, the Commission adopted two alternative cost-recovery mechanisms. As customary, a pipeline could recover all of its prudently incurred costs in its commodity (sales) charges, although that could prove difficult for pipelines with shrinking sales-customer bases. In the alternative, under the equitable-sharing approach, a pipeline offering open-access transportation could, if it voluntarily absorbed between twenty-five and fifty percent of the costs, recover an equal share of the costs through a "fixed charge" and recover the remaining amount (up to fifty percent) through a volumetric surcharge based on total throughput (and thus borne by both sales and transportation customers alike).[13] *Id.* at 30,784-92; 18 C.F.R. § 2.104. Third, the Commission authorized pipelines not recovering take-or-pay costs in any other manner to impose a "gas inventory charge" (GIC), a fixed charge for "standing ready" to deliver gas—the sales analogue to a reservation charge. Order No. 500, ¶ 30,761, at 30,792-94; 18 C.F.R. § 2.105.

The Commission's alternative solutions to the problem of take-or-pay settlement costs in Order No. 500 fared poorly on judicial review. First, the court remanded the crediting mechanism for an explanation of whether the Commission had the requisite

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[13] The remaining costs "may be recovered either through a commodity rate surcharge or a volumetric surcharge on total throughput." 18 C.F.R. § 2.104(a). In *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1299-1300 (D.C. Cir. 1992), the court upheld the Commission's reading of its regulation that a commodity rate surcharge must also be based on total throughput.

authority under § 7 of the NGA. *American Gas Ass'n v. FERC*, 888 F.2d 136, 148-49 (D.C. Cir. 1989) (*AGA I*). After the Commission explained its § 7 authority for the crediting mechanism in Order No. 500-H,[14] the court upheld the crediting mechanism.[15] *American Gas Ass'n v. FERC*, 912 F.2d 1496, 1509-13 (D.C. Cir. 1990) (*AGA II*). Second, the court struck down the equitable-sharing cost-recovery mechanism on the ground that the Commission's "purchase deficiency" method for calculating the "fixed charge," which assigned costs to each customer based on how much its purchases had declined over the relevant preceding period, violated the filed-rate doctrine. *Associated Gas Distributors v. FERC*, 893 F.2d 349, 354-57 (D.C. Cir. 1989) (*AGD II*), *reh'g en banc denied*, 898 F.2d 809 (D.C. Cir.), *cert. denied*, 498 U.S. 907 (1990). The Commission responded to the invalidation of the "purchase deficiency" method in *AGD II* by adopting Order No. 528,[16] which allowed pipelines, in the "fixed charge," to pass through a portion of costs to customers based on any of several measures of current (rather than past) demand or usage, with the intent of avoiding the filed-rate problem. Order No. 528, ¶ 61,163, at 61,597-98.

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[14] Order No. 500-H, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,867 (1989), *order on reh'g*, Order No. 500-I, [Regs. Preambles 1986-90] F.E.R.C. Stats. & Regs. ¶ 30,880, *remanded sub nom. American Gas Ass'n v. FERC*, 912 F.2d 1496 (D.C. Cir. 1990) (*AGA II*).

[15] The Commission terminated the crediting mechanism as of December 31, 1990. Order No. 500-K, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,917, *reh'g denied*, Order No. 500-L, 55 F.E.R.C. ¶ 61,489 (1991).

[16] Order No. 528, Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs, 53 F.E.R.C. ¶ 61,163 (1990), *order on reh'g*, Order No. 528-A, 54 F.E.R.C. ¶ 61,095, *reh'g denied*, Order No. 528-B, 55 F.E.R.C. ¶ 61,372 (1991).

Finally, the court struck down the Commission's approval of a GIC on a particular pipeline because it had given undue weight to the pipeline's customers' having agreed to the GIC and failed adequately to consider the interests of end-users. *Tejas Power Corp. v. FERC,* 908 F.2d 998, 1003-05 (D.C. Cir. 1990).

Congress completed the process of deregulating the producer sales market by enacting the Natural Gas Wellhead Decontrol Act of 1989, Pub. L. No. 101-60, 103 Stat. 157 (codified in scattered sections of 15 U.S.C.). As the House Committee on Energy and Commerce emphasized, the Commission's creation of open-access transportation was "essential" to Congress' decision completely to deregulate wellhead sales. H.R. REP. NO. 29, 101st Cong., 1st Sess. 6 (1989). The committee report declared also that "[b]oth the FERC and the courts are strongly urged to retain and improve this competitive structure in order to maximize the benefits of decontrol."[17] *Id.* The committee expected that, by ensuring that "[a]ll buyers [are] free to reach the lowest-selling producer," *id.,* open-access transportation would allow the more efficient producers to emerge, leading to lower prices for consumers, *id.* at 3, 7.

C. <u>Order No. 636: Mandatory Unbundling</u>

In Order No. 636, the Commission declared the open-access requirements of Order No. 436 a partial success. The Commission

[17] The committee added that "[t]his legislation does not deregulate gas pipelines, and the Committee will continue its oversight of the FERC to ensure that captive residential consumers are not disadvantaged, and that the current competitive "open access' pipeline system is maintained." H.R. REP. NO. 29, *supra,* at 4.

found that pipeline firm sales, which in 1984 had been over 90 percent of deliveries to market, had declined by 1990 to 21 percent. Order No. 636, ¶ 30,939, at 30,399 tbl. 1. On the other hand, only 28 percent of deliveries to market in 1990 were firm transportation, whereas 51 percent of deliveries used interruptible transportation. *Id.* at 30,399 & n.61. The Commission concluded that many customers had not taken advantage of Order No. 436's option to convert from firm-sales to firm-transportation service because the firm-transportation component of bundled firm-sales service was "superior in quality" to stand-alone firm-transportation service. *Id.* at 30,402. In particular, the Commission found that stand-alone firm-transportation service was often subject to daily scheduling and balancing requirements, as well as to penalties for variances from projected purchases in excess of ten percent. Moreover, pipelines usually did not offer storage capacity on a contractual basis to stand-alone firm-transportation shippers. *Id.* The result was that many of the non-converted customers used the pipelines' firm-sales service during times of peak demand but in non-peak periods bought third-party gas and transported it with interruptible transportation. The Commission found that "[i]t is often cheaper for pipeline sales customers to buy gas on the spot market, and pay the pipeline's demand charge plus the interruptible rate, than to purchase the pipeline's gas." *Id.* at 30,400. Because of the distortions in the sales market, these customers often paid twice for transportation services and still received an inferior form of transportation (interruptible rather than firm). *Id.* Because of the anti-competitive effect on the industry, the Commission found that pipelines' bundled firm-sales service violated §§ 4(b) and 5(a) of the NGA. *Id.* at 30,405.

The Commission's remedy for these anti-competitive conditions, and the principal innovation of Order No. 636, was mandatory unbundling of pipelines' sales and transportation services. By making the separation of the two functions mandatory, the Commission expects that pipelines' monopoly power over transportation will no longer distort the sales market. Order No. 636, ¶ 30,939, at 30,406-13; Order No. 636-A, ¶ 30,950, at 30,527-46; Order No. 636-B, ¶ 61,272, at 61,988-92. To replace the firm-transportation component of bundled firm-sales service, the Commission introduced the concept of "no-notice firm transportation," stand-alone firm transportation without penalties. Those customers who receive bundled firm-sales service have the right, during the restructuring process, to switch to no-notice firm-transportation service. Pipelines that did not offer bundled firm-sales service are not required to offer no-notice transportation; but if they do, they must offer no-notice transportation on a non-discriminatory basis. Order No. 636, ¶ 30,939, at 30,421-25; Order No. 636-A, ¶ 30,950, at 30,570-77; Order No. 636-B, ¶ 61,272, at 62,006-10; *see* 18 C.F.R. § 284.8(a)(4).

In contrast to the continued regulation of the transportation market, the Commission essentially deregulated the pipeline sales market. The Commission issued every Part 284 pipeline a blanket certificate authorizing gas sales. Although acknowledging that "only Congress can "deregulate,' " the Commission "institut[ed] light-handed regulation, relying upon market forces at the wellhead or in the field to constrain unbundled pipeline sale for resale gas prices within the NGA's "just and reasonable' standard." Order No. 636, ¶ 30,939, at 30,440. The Commission reasoned that open-access transportation, combined with its finding that "adequate divertible gas supplies exist in all pipeline markets," would ensure that the free market for gas sales would keep rates within the zone of reasonableness. *Id.* at 30,437-43; Order No. 636-A, ¶ 30,950, at 30,609-24; Order No. 636-B, ¶ 61,272, at 62,024-25; *see* 18 C.F.R. §§ 284.281-284.288.

The Commission also undertook several measures to ensure that the pipeline grid, or network, functions as a whole in a more competitive fashion. First, open-access pipelines may not inhibit the development of "market centers," which are pipeline intersections that allow customers to take advantage of many more transportation routes and choose between sellers from different natural gas production areas. Similarly, open-access pipelines may not interfere with the development of "pooling areas," which allow the aggregation of gas supplies at a production area. Order No. 636, ¶ 30,939, at 30,427-28; Order No. 636-A, ¶ 30,950, at 30,581-82; Order No. 636-B, ¶ 61,272, at 62,011-12; *see* 18 C.F.R. §§ 284.8(b)(6), 284.9(b)(5). Finally, as part of the move toward open-access transportation, the Commission required Part 284 pipelines to allow shippers to deliver gas at any delivery point without penalty and to allow customers to receive gas at any receipt point without penalty. Order No. 636, ¶ 30,939, at 30,428-

29; Order No. 636-A, ¶ 30,950, at 30,582-86; Order No. 636-B, ¶ 61,272, at 62,012-13; *see* 18 C.F.R. § 284.221(g)-(h).

Even though this is the court's first occasion to address Order No. 636, which was enacted in 1992, we do not write on a clean slate. Beginning with *MPC I* and *MPC II*, the court has consistently required the Commission to protect consumers against pipelines' monopoly power. No longer reluctantly engaged in the unbundling enterprise, the Commission has responded by initiating sweeping changes with Order No. 636. Accordingly, we review the Commission's exercise of its authority under the NGA in light of the principles that the court has already applied in this area.

D. Issues on Review and Conclusions

After two comprehensive rehearing orders, Orders No. 636-A and No. 636-B, the Commission denied further rehearing.[18] 62 F.E.R.C. ¶ 61,007 (1993). The Judicial Panel on Multidistrict Litigation consolidated all the petitions for review of the Order No. 636 series and transferred them to the Eleventh Circuit by random selection pursuant to 28 U.S.C. § 2112(a)(3). On February 15, 1994, the Eleventh Circuit transferred the petitions for review to

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[18] The Commission has modified its Part 284 regulations in two rulemakings since Order No. 636 that are not on review in this proceeding. First, the Commission adopted further standards for the electronic bulletin boards used for capacity release. Order No. 563, Standards for Electronic Bulletin Boards Required Under Part 284 of the Commission's Regulations, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,988 (1993) (amending 18 C.F.R. §§ 284.8(b)(4)-(5), 284.9(b)(4)), *order on reh'g*, Order No. 563-A, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,994, *reh'g denied*, 68 F.E.R.C. ¶ 61,002 (1994). Second, the Commission modified the short-term exception to the capacity-release rules. Order No. 577, Release of Firm Capacity on Interstate Natural Gas Pipelines, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 31,017 (amending 18 C.F.R. § 284.243(h)(1)), *order on reh'g*, Order No. 577-A, [Current] F.E.R.C. Stats. & Regs. ¶ 31,021 (1995).

this court. We consolidated with this case petitions for review of the Commission's decision to prohibit buy/sell agreements,[19] and of the Commission's decision to end capacity-brokering programs.[20] We ordered the petitioners to file briefs in consolidated industry groups: pipelines; local distribution companies (LDCs); small distributors and municipalities; industrial end-users; electric generators; and public utility commissions (PUCs).[21]

The petitioners do not challenge the mandatory unbundling remedy itself. At issue on review are numerous other aspects of Order No. 636 involving changes that the Commission undertook as part of its comprehensive restructuring of the natural gas industry. In Part II of our opinion, we discuss the challenges to the Commission's rules on Part 284 firm transportation. Part III addresses the challenges to the Commission's new capacity-release program. Part IV covers the requirement that pipelines use the straight fixed/variable rate-design methodology. Finally, in Part V we deal with challenges to the Commission's handling of transition costs.

As we discuss in Part II.A, the petitioners challenge four peripheral aspects of the Commission's unbundling remedy. We

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[19] *El Paso Natural Gas Co.*, 59 F.E.R.C. ¶ 61,031, *order on reh'g*, 60 F.E.R.C. ¶ 61,117 (1992).

[20] *Algonquin Gas Transmission Co.*, 59 F.E.R.C. ¶ 61,032, *reh'g denied*, 60 F.E.R.C. ¶ 61,113 (1992).

[21] The court also received separate petitioners' briefs from Carnegie Natural Gas Company, an interstate pipeline company; Elizabethtown Gas Company, a local distribution company; Hadson Gas Systems, Inc., a "marketer" that buys and re-sells pipeline transportation capacity; and Meridian Oil Inc., also a marketer.

uphold the Commission's rule that customers must retain contractual firm-transportation capacity for which the pipeline receives no other offer. *See* 18 C.F.R. § 284.14(e). Further, insofar as the Commission may have stated that a § 7(b) abandonment proceeding is never required for pipeline changes to contract-storage withdrawal and injection schedules, we grant relief, but we defer review of possible challenges to specific pipeline changes. The challenge to the Commission's rule that transportation-only pipelines may not acquire capacity on other pipelines has been rendered moot by virtue of an intervening Commission decision. We remand for further explanation the Commission's decision that only those customers who received bundled firm-sales service on May 18, 1992, are entitled to the new no-notice transportation service.

Part II.B concerns the Commission's award of pre-granted abandonment to long-term firm-transportation service, subject to the existing shipper's "right of first refusal" (ROFR). Under this provision of the rules, pipelines are no longer required to go through § 7 abandonment proceedings when a transportation contract expires. In return, the existing customer has the right to retain service if it matches the terms of a competing offer for that capacity. Such bids are capped at the maximum rate approved by the Commission for that service, and the contract length may not exceed twenty years. Order No. 636, ¶ 30,939, at 30,448-52; Order No. 636-A, ¶ 30,950, at 30,627-36; Order No. 636-B, ¶ 61,272, at 62,025-28; *see* 18 C.F.R. § 284.221(d). While we conclude that in its basic structure the right-of-first-refusal mechanism complies with § 7, we remand the right-of-first-refusal mechanism to the

Commission for further explanation of why it adopted a twenty-year term-matching cap. We uphold the Commission's decision not to require pipelines to discount rates in the right-of-first-refusal process.

The Commission also re-visited its policies for the curtailment of gas in times of a supply shortage or a capacity interruption. Gas can be curtailed on an end-use basis, meaning that high-priority users have priority in times of curtailment, or on a *pro rata* basis, meaning that each user's deliveries are curtailed proportionally. The Commission found that it was statutorily obligated to require pipelines to adopt an end-use curtailment plan for shortages in the supply of pipeline gas. On the other hand, the Commission declined to require pipelines to adopt end-use curtailment for capacity interruption. Order No. 636, ¶ 30,939, at 30,429-31; Order No. 636-A, ¶ 30,950, at 30,586-93. In Part II.C, we affirm the Commission's decision that title IV of the NGPA requires end-use supply curtailment and conclude that the issue of curtailment compensation is not ripe for review. We also deny the petitions for review of the Commission's capacity-curtailment policies, but we do not examine whether pure *pro rata* capacity curtailment is always appropriate because the Commission has examined that issue on a pipeline-specific basis in the restructuring proceedings. Finally, we uphold the Commission's policies for supply shortages of third-party gas.

Part III addresses the Commission's adoption of a uniform capacity-release program—a regulated market that allows capacity-holders to re-sell the rights to pipeline firm-transportation capacity. An existing shipper that finds itself with excess capacity may list that capacity on the pipeline's electronic bulletin board (EBB), which functions as a central clearinghouse for the secondary capacity market. Order No. 636, ¶ 30,939, at 30,416-21; Order No. 636-A, ¶ 30,950, at 30,550-65; Order No. 636-B, ¶ 61,272, at 61,994-62,003; *see* 18 C.F.R. § 284.243. We uphold the Commission's jurisdiction to regulate the re-sale of interstate-transportation rights in general, as well as specifically its jurisdiction over LDCs who broker capacity to local end-users and over municipal LDCs. We also uphold the Commission's decision that state-authorized "buy/sell arrangements"[22] are pre-empted by the Commission's capacity-release program. Finally, we uphold the Commission's decision to exclude Part 157 shippers and conclude that other challenges to the substance of the capacity-release program are not ripe for review.

Part IV deals with the Commission's requirement that pipelines adopt a new rate-design methodology known as straight fixed/variable (SFV).[23] Under SFV, pipelines must allocate fixed

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[22] A buy/sell arrangement is an agreement between an LDC and one of its local end-users under which (1) the end-user identifies (and sometimes purchases) gas held by a producer, (2) the LDC in turn purchases the identified gas and uses its firm-transportation capacity to transport the gas, and (3) the LDC sells the gas to the end-user.

[23] The Commission recently issued a policy statement approving the use of market-based rates for transportation services, analogous to the market-based rates for pipeline gas sales, *see supra* at 15-16, but only if the pipeline can demonstrate that it lacks significant market power over the transportation service. *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 F.E.R.C. ¶ 61,076, *reh'g denied,* 75 F.E.R.C. ¶ 61,024 (1996). This policy statement is not on review in this proceeding, and we

costs to the reservation charge, and variable costs to the usage charge.[24] The Commission mandated SFV so that fixed costs, which vary greatly between pipelines, would no longer affect the usage charge and thus distort the national gas-sales market that Order No. 636 fosters. Because the shift from the previous modified fixed/variable (MFV) rate design[25] would disadvantage low-load-factor customers,[26] the Commission adopted various SFV mitigation measures to protect those customers. Order No. 636, ¶ 30,939, at 30,431-37; Order No. 636-A, ¶ 30,950, at 30,593-609; Order No. 636-B, ¶ 61,272, at 62,013-24; *see* 18 C.F.R. § 284.8(d). We uphold the Commission's authority under § 5 to adopt SFV rate design and conclude that substantial evidence supports the Commission's findings that MFV rate design distorted the producer sales market and that SFV is an appropriate rate-design

review only the Commission's requirement that pipelines use SFV rate design.

[24] The reservation, or demand, charge is for reserving firm-transportation capacity; the usage, or commodity, charge is for the actual transportation of gas.

[25] Under the previously effective MFV rate design, pipelines assigned most fixed costs to the reservation charge, but return on equity and related taxes were assigned along with variable costs to the usage charge. According to one study, the practical result was that under MFV about 15% to 20% of fixed costs were assigned to the usage charge. GENERAL ACCOUNTING OFFICE, NATURAL GAS: COSTS, BENEFITS AND CONCERNS RELATED TO FERC'S ORDER 636, at 33 n.11 (Nov. 1993). In addition, under MFV rate design the reservation charge was divided into two equal components: the "D-1 charge" was based on a customer's daily contract demand, or entitlement, and the "D-2 charge" was based on a customer's actual annual usage.

[26] A customer's load factor is the ratio between its average usage and its peak usage. Customers with seasonal usage fluctuations, such as LDCs, have low load factors, whereas customers with constant usage throughout the year, such as industrial end-users, have high load factors.

methodology. Although we uphold the Commission's SFV mitigation measures against most challenges, we conclude that the Commission failed to explain why it ordered some mitigation measures on an individual-customer basis and others on a customer-class basis and why it did not require pipelines to offer small-customer discounts to former customers of downstream pipelines. Accordingly, we remand those issues to the Commission.

Finally, as we explain in Part V, the Commission addressed the transition costs involved with implementing Order No. 636. The Commission allowed pipelines, whose role as gas merchants was greatly reduced, to pass through to transportation customers all the costs of reducing contractual purchase obligations from producers, known as gas-supply realignment (GSR) costs. Unlike the Order No. 500 equitable-sharing cost-recovery mechanism for take-or-pay costs from pipeline-producer contracts, Order No. 636 imposes all the costs of realigning unneeded producer-pipeline contracts on pipeline customers. The Commission authorized pipelines to recover 90% of the GSR costs from current firm-transportation customers (including customers who converted from being bundled firm-sales customers under Order No. 436) and 10% of the GSR costs from interruptible- transportation customers. Order No. 636, ¶ 30,939, at 30,457-62; Order No. 636-A, ¶ 30,950, at 30,641-64; Order No. 636-B, ¶ 61,272, at 62,031-45. We uphold the Commission's decision to allow pipelines to recover GSR costs from customers who converted to open-access transportation before Order No. 636, but remand the decision that pipelines must allocate 10% of GSR costs to interruptible-transportation customers for further explanation. We also remand the decision that pipelines can pass through all their GSR costs to customers for further consideration by the Commission in light of the equitable-sharing procedures in Order No. 500 and the general cost-spreading principles of Order No. 636. We affirm the Commission's treatment of LDC by-pass, GSR costs for the Great Plains coal gasification project, and stranded costs.

The Commission resolved issues that it considered generic to all pipelines in the Order No. 636 rulemaking, but deferred many issues associated with the implementation of mandatory unbundling to restructuring proceedings. Every Part 284 pipeline is required to go through an individual pipeline restructuring proceeding, to conform its operations to the new regulations and to address pipeline-specific issues. 18 C.F.R. § 284.14; Order No. 636, ¶ 30,939, at 30,462-69; Order No. 636-A, ¶ 30,950, at 30,664-73. The Commission has by now completed the restructuring proceedings, and in the proceedings for some pipelines interested parties have petitioned for review.[27] In this decision, we review only the Order No. 636 rulemaking, although on some issues we have necessarily had to consider the interaction between the rulemaking and the subsequent restructuring proceedings.

II. Open-Access Firm Transportation

A. <u>Unbundling</u>

The petitioners challenge four aspects of the Commission's unbundling remedy: the rule that customers must retain contractual

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[27] The court has docketed the petitions for review of the restructuring proceedings in *UGI Utilities v. FERC,* No. 93-1291, and held them in abeyance until our decision.

firm-transportation capacity for which the pipeline receives no other offer; the Commission's policy on pipelines' ability to modify existing storage contracts without abandonment proceedings; the rule that transportation-only pipelines may not acquire capacity on other pipelines; and the eligibility date for no-notice transportation service.

1. Prohibition on unilateral customer release of transportation capacity

When the Commission concluded that the pipelines' bundled firm-sales service violated §§ 4(b) and 5(a) of the NGA, Order No. 636, ¶ 30,939, at 30,405, the Commission found also that "the continued enforcement of a pipeline sales customer's purchase obligations, agreed to before implementation of unbundling under this rule, is unjust and unreasonable, and unduly discriminatory." *Id.* at 30,453. Accordingly, all existing bundled firm-sales customers were given the option to reduce or terminate their contractual purchase obligations during the pipeline's restructuring proceedings. 18 C.F.R. § 284.14(d)(1). By contrast, those customers were not relieved of their contractual transportation obligations unless either an alternative, creditworthy shipper offered to assume the capacity at the same or a higher rate (up to the maximum approved rate), or the pipeline agreed to reduce or terminate the transportation obligation. *Id.* § 284.14(e)(2). If a customer wished to reduce or terminate its transportation obligation, and either a replacement shipper assumed the capacity or the pipeline agreed, then the pipeline was authorized to abandon the service under the prior contract. *Id.* § 284.14(e)(3). In effect, existing bundled firm-sales customers remained contractually bound to receive firm-transportation service on the pipeline.

On rehearing, Northern Indiana Public Service Company (NIPSCO) maintained that the Commission's actions entirely abrogated the existing pipeline-customer bundled firm-sales contracts, and that the Commission could not require the LDCs to enter into new transportation contracts. The Commission denied that it had abrogated the contracts: the pipelines remained contractually obligated to provide separate sales and transportation services. "[T]he fact that LDCs have an opportunity to revise their sales entitlements under existing contracts with their pipeline suppliers does not mean they should also have an unqualified right to terminate their obligations for the costs of transportation capacity under those contracts." Order No. 636-A, ¶ 30,950, at 30,638. The Commission also explained that if it released former bundled-sales customers from transportation obligations, "these capacity costs could be shifted from the customer who has contracted for the capacity to the pipeline or other customers that have no need for the capacity." *Id.* at 30,637.

NIPSCO, joined by other LDC petitioners,[28] contends that, by holding pipeline customers to the transportation component of bundled firm-sales contracts, the Commission essentially imposed a new contract upon the customers, which is beyond the Commission's § 5 authority. Section 5(a) provides that, whenever the Commission has found that an existing contract is "unjust, unreasonable,

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[28] The other LDC petitioners are the Atlanta Gas Light Company and the Chattanooga Gas Company.

unduly discriminatory, or preferential," it "shall determine the just and reasonable contract to be thereafter observed and in force, and shall fix the same by order." 15 U.S.C. § 717d(a). NIPSCO contests not the Commission's underlying finding that the bundled firm-sales contracts violated §§ 4(b) and 5(a), but only the remedy imposed under § 5. Our review is limited to whether the Commission's reading of § 5 to authorize it to hold LDCs to the remaining terms of a modified pipeline-customer contract is a reasonable construction of its statutory authority. *See AGD I*, 824 F.2d at 1001.

The bundled firm-sales contracts between pipelines and LDCs were subject to the Commission's § 5 authority. The regulatory structure of the Natural Gas Act is contract-based: it "permits the relations between the parties to be established initially by contract, the protection of the public interest being afforded by supervision of the individual contracts." *United Gas Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332, 339 (1956). Under § 5, "the Commission has plenary authority to limit or to proscribe contractual arrangements that contravene the relevant public interests." *Permian Basin Area Rate Cases*, 390 U.S. 747, 784 (1968). For example, in *Wisconsin Gas Co. v. FERC*, 770 F.2d 1144 (D.C. Cir. 1985), *cert. denied*, 476 U.S. 1114 (1986), the court affirmed the Commission's decision in Order No. 380 that "minimum bill" provisions in existing contracts were "unjust and unreasonable" under § 5.[29] The court upheld the Commission's

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[29]Minimum bills were clauses in pipeline-customer contracts that "require[d] a pipeline customer to pay for a minimum volume of gas, whether or not the customer purchase[d] that amount of

remedy, eliminating the minimum bill from the contracts, against the claim that such a remedy "unlawfully alter[ed] the terms of existing contracts," on the ground that "section 5 gives the Commission authority to alter terms of any existing contract found to be "unjust' or "unreasonable.' " *Id.* at 1153 n.9.

NIPSCO also maintains that the Commission has construed its § 5 authority to extend beyond the limits in § 1(b) on the Commission's jurisdiction. Regardless of the Commission's authority to impose modified contractual obligations on pipelines, NIPSCO contends that the Commission lacks such authority over LDCs because LDCs are "non-jurisdictional" entities. Under § 1(b), the Commission's jurisdiction over "the transportation of natural gas in interstate commerce" does not apply to "the local distribution of natural gas or to the facilities used for such distribution." 15 U.S.C. § 717(b). But the local-distribution exception applies only to the movement of gas within an LDC's local mains and not to the movement of gas in high-pressure interstate pipelines. *FPC v. East Ohio Gas Co.*, 338 U.S. 464, 470-71 (1950); *see also Louisiana*

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gas." *Wisconsin Gas Co.*, 770 F.2d at 1149. Thus, the minimum bills were analogous to the take-or-pay provisions in pipeline-producer contracts. *But cf. id.* at 1159-60. The Commission prohibited minimum bills because they allowed pipelines to collect substantial commodity charges for gas that was never delivered and because they "ha[d] become a major obstacle to the transmittal of clear market signals from the burner tip back to the well-head." Order No. 380, Elimination of Variable Costs From Certain Natural Gas Pipeline Minimum Commodity Bill Provisions, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,571, at 30,962, *order on reh'g,* Order No. 380-A, [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,584, *order on reh'g,* 29 F.E.R.C. ¶ 61,076, *order on reh'g,* [Regs. Preambles 1982-85] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,607, *order on reh'g,* 29 F.E.R.C. ¶ 61,332 (1984), *affirmed in part and remanded in part sub nom. Wisconsin Gas Co. v. FERC,* 770 F.2d 1144 (D.C. Cir. 1985).

Power & Light, 406 U.S. at 636 & n.13. Thus, for the same reasons that the Commission has jurisdiction over the re-sale of interstate capacity rights by LDCs to local end-users, *see infra* Part III.B.2, it also has jurisdiction over an LDC's ability to reduce or terminate its contractual interstate-transportation obligation. The pipeline-LDC contracts for transportation through interstate pipelines do not fall within the local-distribution exception to the Commission's jurisdiction.

The Commission cannot use the pipeline-LDC contracts as a jurisdictional hook for non-jurisdictional measures that do not relate to the Commission's § 5 remedial authority over the contracts.[30] As the court has held in a different context, the Commission may not assert its jurisdiction over a party merely because it is "involved in a contractual relationship with a jurisdictional pipeline." *ARCO Oil & Gas Co. v. FERC*, 932 F.2d 1501, 1503 (D.C. Cir. 1991). NIPSCO maintains that the Commission has done just that by replacing the agreed-upon contractual terms with entirely new terms of the Commission's own devising, when it would otherwise be without jurisdiction to compel the LDC to receive service in the first instance. But we do not agree that the Commission has overstepped the bounds of its § 5 authority in the first place. First, an LDC may maintain its original bargain by choosing not to exercise its unilateral right to terminate the purchase obligation. The resulting combination of sales service and no-notice firm-transportation service replicates its prior contractual entitlement. Thus, it is somewhat difficult to see the

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[30] *See also infra* at 74 n.67.

purported compulsion against LDCs in the Commission's decision not to grant them the right to terminate their transportation obligations. Second, the Commission's remedy was appropriately confined to the underlying violation. Because the Commission found the sales component of the bundled contracts to be unjust and unreasonable, Order No. 636, ¶ 30,939, at 30,453, it interfered with existing contracts only to the extent necessary to remedy the effects of pipelines' market power. The Commission has the authority under § 5 to adopt a remedy proportionate to the problem being addressed. *AGD I*, 824 F.2d at 1019. Finally, § 5 instructs that "the Commission shall determine the just and reasonable ... contract to be thereafter observed and in force, and shall fix the same by order." 15 U.S.C. § 717d(a). The limits of the Commission's authority to modify pipeline-LDC contracts under § 5 lie in the requirement that, given the original contract and the Commission's findings of unlawfulness, the resulting contract be "just and reasonable." NIPSCO does not contend that the result of unbundling the firm-sales contracts was unjust or unreasonable. We therefore uphold the Commission's § 5 authority to hold LDCs to the transportation component of the modified bundled firm-sales contracts.

NIPSCO contends in the alternative that, even if the Commission's action was within its § 5 authority, the Commission acted arbitrarily and capriciously. In NIPSCO's view, the limited nature of the remedy allows pipelines to continue to exercise market power over customers in the transportation contracts, in contravention of the overall goals of Order No. 636. We reject this challenge as well because the Commission has provided a reasonable basis for its decision not to allow customers unilaterally to reduce their contractual transportation obligations. *Cf. ARCO,* 932 F.2d at 1502.

The Commission found in Order No. 636 that "the amount of capacity reserved for pipeline firm sales still far exceeds the pipelines' actual sales so that capacity is not available for firm transportation and, as a result, interruptible transportation maintains a significant share of peak period transportation." Order No. 636, ¶ 30,939, at 30,406. In other words, because many firm-sales customers decided to purchase third-party gas and transport it using interruptible service, those customers ended up holding excess reserved capacity. NIPSCO asserts that the effect of the Commission's decision not to allow LDCs unilaterally to reduce their contractual transportation obligations is to perpetuate customers' excessive capacity holdings. NIPSCO is correct insofar as the effect of any contract is to lock in current conditions, and the existence of a long-term contract necessarily slows the transition of a market to a new equilibrium when some underlying condition changes. Moreover, the capacity-release mechanism is an imperfect solution for the LDCs because the existing pipeline customer is unlikely to receive full compensation for released capacity in an excess-capacity market situation. Yet the problem of capacity excess that the Commission identified was that customers held more capacity in bundled-sales contracts than they purchased gas from the pipeline, not that customers held more firm-transportation capacity than needed for their peak demand.

Contrary to NIPSCO's contention, there is no contradiction between the general goal in Order No. 636 of encouraging more efficient use of reserved capacity and the challenged rule that customers may not unilaterally release contractual transportation obligations: the Commission never found that the natural gas industry after mandatory unbundling would be characterized by excess reserved capacity.

Moreover, the Commission provided in Order No. 636-A a coherent rationale for its decision. Because a pipeline's rate structure is predicated upon levels of reserved capacity, providing customers with the unilateral option to reduce those levels would either reduce the pipeline's cost recovery or force the pipeline to increase rates for the remaining customers.[31] Order No. 636-A, ¶ 30,950, at 30,637. Because someone has to bear the costs of unfavorable contractual capacity obligations, the Commission reasoned that the customer who voluntarily assumed those obligations by entering into the contract should bear those costs rather than spreading them over all of the pipeline's customers.

The Commission decided to modify the set of contracts that forms the structure of the natural gas industry only as much as necessary to alleviate the anti-competitive sales component of the bundled contracts. The Commission is not required to exercise its § 5 authority beyond the limits of the problem it has identified,

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[31] The Commission also announced that the customer could negotiate an "exit fee" to induce the pipeline to release the customer from its contractual obligations. Order No. 636, ¶ 30,939, at 30,454. Whether the customer retains excess contractual capacity or negotiates a one-time exit fee, however, there is no reason why the cost to the customer should not be the same, discounted over time.

see AGD I, 824 F.2d at 1019, and its cost-shifting rationale was a well-reasoned justification for its decision not to go further. We therefore uphold this portion of the rules.

2. Pipeline modification of contract-storage rights

Because the Commission found that "pipelines' superior rights with respect to access and control provide them with several advantages over other gas merchants with no access to storage for their gas," it required pipelines to offer access to their storage capacity on an open-access basis. Order No. 636, ¶ 30,939, at 30,425-26. By defining "transportation" to include "storage," 18 C.F.R. § 284.1(a), the Commission made storage subject to the same non-discrimination requirements as capacity rights. *Id.* §§ 284.8(b), 284.9(b). Although pipelines were allowed to retain storage capacity for system management and in order to ensure the delivery of no-notice service, they were required to offer remaining storage capacity on an open-access contractual basis for customer-owned gas. Order No. 636, ¶ 30,939, at 30,426-27. The Commission granted former bundled firm-sales customers a priority right to that storage capacity. Order No. 636-A, ¶ 30,950, at 30,578.

In its request for rehearing of Order No. 636, CNG Transmission Corporation, a pipeline company, explained that the changes involving open-access storage would create difficulties for it in providing the contractual levels of service to its existing contract-storage customers. Because "current contract storage injection and withdrawal schedules, and other related operational protocols, are based upon current levels of contract storage service," CNG requested the ability to modify existing storage customers' contractual rights to inject or withdraw gas. The Commission responded that its

> intent was that current contract storage customers retain their full right to capacity as specified in their contracts. The Commission did not mean to infer [*sic*] that the terms and conditions associated with their rights could not be changed if they proved unreasonable in light of Order No. 636's requirements of no-notice transportation and open access contract storage. This, of course, is a pipeline specific matter and must be addressed in the restructuring proceeding.

Order No. 636-A, ¶ 30,950, at 30,579. Upon further rehearing, however, the Commission went further, stating that,

> while it has authorized pipelines to propose to change existing storage arrangements, if necessary, to provide no-notice transportation service, the pipeline must still show that the changes are necessary and reasonable. This includes an impact of a change on current contract storage customers. The Commission has not authorized any reduction in contract storage capacity. The Commission views changes to injection and withdrawal schedules as changes to terms and conditions, rather than to the level of certificated service. Hence, the Commission concludes that changes to existing contract storage terms and conditions will not need action under NGA section 7(b).

Order No. 636-B, ¶ 61,272, at 62,011.

A group of LDC petitioners[32] challenges the Commission's statement that changes to contract-storage withdrawal and injection schedules do not require a § 7(b) abandonment proceeding. We agree with the petitioners that it is difficult to discern exactly what the Commission's position is on this issue, and we grant the petitioners relief insofar as the Commission stated in Order No. 636-B that any change to injection and withdrawal schedules can be

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[32] The LDC petitioners are the Associated Gas Distributors, the Atlanta Gas Light Company, the Chattanooga Gas Company, the Brooklyn Union Gas Company, Elizabethtown Gas Company, and Long Island Lighting Company.

effected without a § 7(b) abandonment proceeding.

If the Commission has permitted the pipelines to "abandon" a "service rendered by means of ... facilities" certificated by the Commission, then it has failed to comply with § 7(b), which requires a "due hearing" and a Commission finding that "the present or future public convenience or necessity permit such abandonment." 15 U.S.C. § 717f(b). In general, the test for § 7 abandonment is whether the certificate-holder "permanently reduces a significant portion of a particular service." *Reynolds Metal Co. v. FPC*, 534 F.2d 379, 384 (D.C. Cir. 1976); *see also Kansas Power & Light Co. v. FERC*, 851 F.2d 1479, 1481 (D.C. Cir. 1988). By comparison, the withholding of gas delivery to an interruptible-transportation customer is not an "abandonment," because the customer has no right to guaranteed delivery under its contract or the certificate of service. *Cerro Wire & Cable Co. v. FERC*, 677 F.2d 124, 129-30 (D.C. Cir. 1982). Although the court has reserved the issue whether a § 7(b) abandonment occurs when only the identity of the customer changes, an abandonment does take place "when there is a reduction or alteration in overall service." *Tennessee Gas Pipeline Co. v. FERC*, 972 F.2d 376, 384 (D.C. Cir. 1992).

According to the submissions by the Associated Gas Distributors in the administrative record, a customer who contracts for storage is concerned with two elements: capacity (how much gas can be stored) and deliverability (how much gas can be withdrawn on a given day).[33] The AGD attached affidavits from six member LDCs

[33]The Commission has defined these terms as follows:

> [I]n contracting for storage, a customer reserves a

who stated that changes to injection and withdrawal schedules could reduce deliverability, with adverse consequences on their ability to meet residential customers' demands. Elizabethtown Gas Company, in its opposition to CNG's compliance filing in its restructuring proceeding, objected to CNG's specific proposals to reduce withdrawal amounts when contract-storage customers had low gas inventories in storage, to maintain elevated minimum inventory levels during the early winter months, to limit monthly withdrawal amounts to less than the total of the daily amounts, to reduce firm withdrawal rights to best-efforts rights, and to impose minimum inventory turnovers.

It is impossible, on the current record, to determine on a generic basis what changes to injection and withdrawal schedules would "permanently reduce[ ] a significant portion" of contract-storage service. *Reynolds Metal*, 534 F.2d at 384. Because contractual deliverability entitlements are an integral part of the customer's contract-storage rights, modifications that affect those rights could in some instances constitute a § 7 abandonment. On the other hand, under other circumstances an adjustment to an injection or withdrawal schedule could be sufficiently minor or temporary that no abandonment would occur.

> specific level of deliverability, capacity, and injection/withdrawal services. Deliverability reflects the right of the storage customer to call on the delivery capacity of the storage facilities every day for a specified level of daily contract deliverability. Injection/ withdrawal is the injection and withdrawal of gas from storage.

Consolidated Gas Transmission Corp., 47 F.E.R.C. ¶ 61,171, at 61,563, *order on reh'g*, 49 F.E.R.C. ¶ 61,041 (1989).

Whether an abandonment proceeding is necessary depends on the individual customer's storage contract and on the pipeline's proposed modifications, none of which are before us now.

To the extent that the Commission issued in Order No. 636-B a sweeping statement that no modifications to injection and withdrawal schedules for a contract-storage customer require an abandonment proceeding, such a statement is inconsistent with § 7. In its brief, however, the Commission denies that it has taken any such steps to degrade contract-storage rights. Instead, the Commission maintains that it has merely allowed pipelines to propose "necessary and reasonable" changes in the restructuring proceedings, Order No. 636-B, ¶ 61,272, at 62,011, for which the Commission has authority under § 5. In the restructuring proceedings, the Commission has followed this approach, approving proposed modifications to withdrawal and injection schedules if the pipeline can prove that the changes are "necessary and reasonable."[34]

The Commission's theory that it has the authority to proceed in the restructuring proceedings under § 5 rather than in abandonment proceedings under § 7(b) is explained nowhere in the Order No. 636 series. *See* Order No. 636-A, ¶ 30,950, at 30,579;

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[34] *See, e.g., Equitrans, Inc.*, 63 F.E.R.C. ¶ 61,009, at 61,064, *order on reh'g*, 64 F.E.R.C. ¶ 61,155, at 62,238, *order on reh'g*, 65 F.E.R.C. ¶ 61,132 (1993), *order on reh'g*, 66 F.E.R.C. ¶ 61,235 (1994), *petitions for review pending sub nom. UGI Utils. v. FERC*, No. 93-1291 (D.C. Cir.); *ANR Pipeline Co.*, 62 F.E.R.C. ¶ 61,079, at 61,527-28, *order on reh'g*, 64 F.E.R.C. ¶ 61,140, at 62,006, *order on reh'g*, 65 F.E.R.C. ¶ 61,162 (1993), *order on reh'g*, 66 F.E.R.C. ¶ 61,340, *order on reh'g*, 68 F.E.R.C. ¶ 61,009 (1994), *order on reh'g*, 71 F.E.R.C. ¶ 61,033 (1995), *petitions for review pending sub nom. UGI Utils. v. FERC*, No. 93-1291 (D.C. Cir.).

Order No. 636-B, ¶ 61,272, at 62,011. Under § 7(b), the Commission must hold a "due hearing" and must make a finding that "the present or future public convenience or necessity permit such abandonment." 15 U.S.C. § 717f(b). By contrast, under § 5 the Commission need hold only a "hearing" and must find that an existing contract is "unjust, unreasonable, unduly discriminatory, or preferential." *Id.* § 717d(a). We need not decide whether compliance with the procedures in § 5 could in certain circumstances satisfy the applicable statutory requirement in § 7(b). The Commission has assured us in its brief that its approach under § 5 will be "consistent" with the § 7 requirements. But without any explanation in the Order No. 636 decisions for why the Commission's procedures satisfy § 7(b), we cannot accept the Commission's suggestion that its exercise of its § 5 authority in the restructuring proceeding would obviate the need for abandonment hearings.

On the other hand, any claim that a particular pipeline's modification to contract-storage withdrawal and injection schedules requires a § 7(b) abandonment proceeding is premature and should be raised, if at all, in the review of individual restructuring proceedings.[35]

3. <u>Capacity retention by transportation-only pipelines</u>

A central part of the Commission's unbundling program is the requirement that all pipelines assign to their firm-transportation

[35] The LDC petitioners object that the Commission lacked substantial evidence to support the required showing under § 5 that existing contract-storage service was not "just and reasonable." We similarly defer any review of this claim until applied in a concrete situation in a restructuring proceeding.

customers the firm-transportation capacity that the pipelines held on upstream pipelines. 18 C.F.R. § 284.242. Now that customers can buy gas directly from the producers, they may bear the responsibility of reserving capacity both on "upstream" and "downstream" pipelines.[36] If the downstream pipeline were allowed to retain the capacity on the upstream pipeline, the Commission reasoned, it would inhibit the formation of a competitive gas-sales market by preventing downstream customers from gaining access to the new opportunity to purchase gas directly from the producers. Order No. 636, ¶ 30,939, at 30,417-18.

Two pipeline petitioners, ANR Pipeline Company and Colorado Interstate Pipeline Company, urge the Commission to carve out an exception for "transportation-only pipelines"—pipelines that do not offer any gas sales. For example, a downstream pipeline may wish to offer a customer a package of firm-transportation capacity on its pipeline as well as on a connecting upstream pipeline; the customer may well prefer not to have to contract separately with the upstream pipeline.

This petition for review has been rendered moot by an intervening declaratory order. In *Texas Eastern Transmission Corp.*, 74 F.E.R.C. ¶ 61,074, at 61,220 (1996), *reh'g pending*, Docket No. CP 95-218, the Commission declared that the successful completion of unbundling under Order No. 636, with the separation of pipelines' merchant and transportation functions, had alleviated the Commission's former concerns that pipelines would obstruct

[36] An "upstream" pipeline is located closer to the wellhead, or production area. A "downstream" pipeline is located closer to the burner-tip, or the end-user.

access to production areas to favor their merchant functions. Accordingly, the Commission announced that it would "decide whether to allow pipelines to acquire upstream or downstream capacity on a case-by-case basis." *Id.* The Commission's intervening action appears to have provided the pipeline petitioners with the relief that they had sought; any further relief is available in review of the declaratory-order proceeding.

4. <u>Eligibility date for no-notice transportation</u>

In its new regulation, the Commission requires interstate pipelines "that provided a firm sales service on May 18, 1992" to offer no-notice transportation service. 18 C.F.R. § 284.8(a)(4). In Order No. 636-A, the Commission clarified that "[t]he pipelines are required to offer no-notice transportation service only to customers that were entitled to receive a no-notice firm, city-gate, sales service on May 18, 1992." Order No. 636-A, ¶ 30,950, at 30,573. Although several commentators requested the Commission to require pipelines to extend no-notice transportation service to customers who had already converted from bundled firm-sales service under Order No. 436 and consequently no longer received such service on May 18, 1992, the Commission denied rehearing. The Commission offered three reasons: first, that it was prudent to begin the experiment with no-notice transportation on a limited basis; second, that customers who were not receiving bundled firm-sales service on May 18, 1992, "were not relying on that service"; and third, that such customers "could not reasonably expect to receive no-notice transportation in the future" because neither Order No. 436 nor the Notice of Proposed

Rulemaking for Order No. 636 had contemplated it. Order No. 636-B, ¶ 61,272, at 62,007.

The National Association of Gas Consumers (NAGC) contends that the ineligibility of former bundled firm-sales customers who converted to open-access transportation under Order No. 436 to receive no-notice transportation is unduly discriminatory.[37] NAGC relies on the Commission's own regulation, promulgated by Order No. 436, which requires an open-access pipeline to offer service "without undue discrimination." 18 C.F.R. § 284.8(b)(1). And as NAGC points out, the Commission found in Order No. 636 that the pipelines' open-access firm-transportation service under Order No. 436 was unlawfully discriminatory because it did not provide the same quality of transportation service as was available with bundled firm-sales service. Order No. 636, ¶ 30,939, at 30,402. Now, customers who converted under Order No. 436 remain limited to stand-alone firm-transportation service subject to scheduling and balancing requirements and other penalties. Thus, NAGC maintains that the Commission must extend eligibility for no-notice transportation service to customers who converted before Order No. 636 in reliance on the non-discrimination provisions.

We find the Commission's justifications in Order No. 636-B

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[37] NAGC frames its argument in terms of "small" customers and confuses in its brief the distinct issues of small-customer rates (one-part rates at an imputed load factor) and no-notice transportation service. In fact, the availability of no-notice transportation service does not depend on a customer's size. NAGC's argument about small-customer rates fails because eligibility for small-customer rates is determined by customer class, so any pipeline that offered small-customer rates on May 18, 1992, must continue to offer such rates "on the same basis" to all customers. Order No. 636-A, ¶ 30,950, at 30,600.

unconvincing. The Commission's desire to proceed cautiously with no-notice transportation, rather than require pipelines to offer it to all customers, cannot explain the disadvantaging of former bundled firm-sales customers who converted under Order No. 436. Although those customers had no right to expect to receive no-notice transportation service under Order No. 636, neither did customers who did receive bundled firm-sales service on May 18, 1992. Finally, the Commission has not provided substantial evidence to support its assumption that bundled firm-sales customers who retained bundled service relied more heavily on reliability of transportation service than did customers who switched to open-access transportation. We therefore remand this issue to the Commission for further explanation of which customers should be eligible for no-notice transportation service.

B. Right of First Refusal

Section 7(b) of the Natural Gas Act prohibits pipelines from abandoning certificated firm-transportation service until the Commission makes a finding that "the present or future public convenience or necessity permit such abandonment." 15 U.S.C. § 717f(d). In its original adoption of open-access transportation in Order No. 436, the Commission provided automatic "pre-granted abandonment"[38] for all firm-transportation service provided under a Part 284 blanket certificate. 18 C.F.R. § 284.221(d) (1989).

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[38] A natural gas company that receives "pre-granted abandonment" of a certificated service need not undergo the customary § 7 abandonment proceedings because the Commission has made *ex ante* generic findings of public convenience and necessity.

After the order was twice vacated on other grounds,[39] the Commission re-promulgated the automatic pre-granted abandonment rule in Order No. 500-H, ¶ 30,867, at 31,583-85. In its review of Order No. 500-H, the court remanded automatic pre-granted abandonment because "the Commission has not yet adequately explained how pregranted abandonment trumps another basic precept of natural gas regulation—protection of gas customers from pipeline exercise of monopoly power through refusal of service at the end of a contract period." *AGA II*, 912 F.2d at 1518. In *AGA II*, the court concluded that the Commission's reliance on various market alternatives available to LDCs—namely interruptible transportation, stand-by gas service and gas from alternative suppliers—provided inadequate protection for LDCs. *Id.* at 1517. The court similarly rejected the Commission's contention that it was furthering purposes other than the protection of existing customers because "the Commission's response seems to entail an enormous qualification of its basic purpose." *Id.* On remand from *AGA II*, the Commission decided to hold the issue of pre-granted abandonment in abeyance until Order No. 636. *See* Order No. 500-J, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 30,915 (1991).

In Order No. 636, the Commission responded to *AGA II* by amending its regulations to provide that an existing customer of long-term firm-transportation service could avoid pre-granted abandonment if it abided by a new right-of-first-refusal (ROFR) mechanism. 18 C.F.R. § 284.221(d). No petitioner challenges the

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[39] Order No. 436 was vacated by *AGD I* in 1987. Then Order No. 500 was vacated by *AGA I* in 1989. *See supra* Part I.B.

Commission's rule that interruptible transportation, and firm transportation with a contract term of less than one year, are subject to automatic pre-granted abandonment even without the right of first refusal. Order No. 636, ¶ 30,939, at 30,446; Order No. 636-A, ¶ 30,950, at 30,625-26. But the petitioners do challenge pre-granted abandonment for long-term firm transportation. In essence, the issue is whether the right-of-first-refusal mechanism provides the protection for pipeline customers that *AGA II* requires.

The right-of-first-refusal mechanism consists principally of two matching requirements: rate and contract term. *See* 18 C.F.R. § 284.221(d)(ii). Near the end of a long-term firm-transportation contract, the existing customer may notify the pipeline that it intends to exercise its right of first refusal. The pipeline must post the availability of that capacity on its electronic bulletin board and, in accordance with the criteria set forth in its tariff, identify the "best bid" offered by any competing shippers. Order No. 636, ¶ 30,939, at 30,451; Order No. 636-A, ¶ 30,950, at 30,634. The customer then has the right to match the competing bid's rate, up to the maximum "just and reasonable" rate that the Commission has approved for that service, and the competing bid's contract term. Competing shippers may choose to bid for only a portion of the capacity in the expiring contract. Order No. 636, ¶ 30,939, at 30,451-52; Order No. 636-A, ¶ 30,950, at 30,634-35. The Commission promised that it would scrutinize competing bids from pipelines' marketing affiliates to ensure that they did not collude to increase the bidding level.[40] Order No. 636, ¶ 30,939, at 30,451; Order No. 636-A, ¶ 30,950, at 30,634.

Originally, the Commission contemplated that competing bids could be for any contract length. According to the Commission, "[o]ther things being equal, the satisfaction of long-term transportation needs should have priority over the satisfaction of shorter-term needs." Order No. 636, ¶ 30,939, at 30,450. In Order No. 636-A, the Commission reconsidered that decision and found

> that capping the contract term that must be matched by a customer exercising its right of first refusal at a period of 20 years strikes an appropriate balance between the pipeline's need for stability, the customer's need for flexibility, and the Commission's overall goal in Order No. 636 to foster long-term, market driven arrangements in the gas industry. This cap, in the Commission's judgement, ensures that the customer obtaining the service values the service sufficiently to commit to using it for a reasonable period and provides the pipeline with a reasonable level of stability. Twenty years has been the traditional length of long-term contracts in the natural gas industry and a number of recent contracts for new capacity are for a twenty year term.

Order No. 636-A, ¶ 30,950, at 30,631. Commissioner Moler, dissenting in part, characterized the twenty-year period as "a blatantly anti-LDC rule," given that LDCs typically have existing contractual relationships jeopardized by pre-granted abandonment, and urged the adoption of a shorter contract-term cap. *Id.* at 30,678-79.

1. Pre-granted abandonment generally

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[40] The Commission exempted from pre-granted abandonment the firm-transportation capacity of any customer who converted from bundled firm-sales service between February 13, 1991 (the effective date of Order No. 500-J) and May 18, 1992 (the effective date of Order No. 636). 18 C.F.R. § 284.221(d)(3); *see* Order No. 636, ¶ 30,939, at 30,452; Order No. 636-A, ¶ 30,950, at 30,635-36.

Many of the petitioners[41] contend that the Commission's pre-granted abandonment of firm-transportation service violates § 7. The petitioners maintain that the right-of-first-refusal mechanism provides inadequate protection to existing pipeline customers from the pipelines' market power.

The Commission may satisfy its § 7 obligations by making generic findings of public convenience and necessity. In *Mobil Oil Exploration & Producing Southeast Inc. v. United Distribution Cos.*, 498 U.S. 211, 227 (1991), the Supreme Court upheld a pre-granted abandonment scheme under the Commission's Order No. 451, even though the Commission's "approval is not specific to any single abandonment but is instead general, prospective, and conditional." *See also FPC v. Moss,* 424 U.S. 494, 499-502 (1976). The Court approved the Commission's findings that, under its good-faith negotiation procedures for the pre-granted abandonment of producers' sale of "old gas" under the NGPA to pipelines, pipelines would be protected "by allowing them to buy at market rates elsewhere if contracting producers insisted on the new ceiling price." *Mobil Oil,* 498 U.S. at 227. In *AGA II,* by contrast, the court held that the Commission had not adequately explained why pre-granted abandonment of firm-transportation in Order No. 500-H would not "allow pipelines indirectly to extract monopoly profits

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[41] The petitioners on this issue include the Industrial End-User petitioners (the Process Gas Consumers Group, the American Iron and Steel Institute, the Georgia Industrial Group, the American Forest and Paper Association, Arcadian Fertilizer, and the Virginia Electric and Power Company), the American Public Gas Association, the National Association of Gas Consumers, and three LDC petitioners (Atlanta Gas Light Company, Chattanooga Gas Company, and NIPSCO).

from their customers." 912 F.2d at 1516. Most important, the Commission's proposed alternatives to existing firm-transportation service, such as interruptible transportation and stand-by service, failed to provide the existing customer with an adequate level of protection. *Id.* at 1517. From *Mobil Oil* and *AGA II*, we conclude that, for a finding of public convenience and necessity for pre-granted abandonment under § 7, the Commission must make appropriate findings that existing market conditions and regulatory structures protect customers from pipeline market power.

The Commission's initial protective measures—contractual "evergreen" or "roll-over" clauses—are by themselves inadequate. The Commission allows the pipeline and the customer to negotiate such a contractual provision allowing the parties to extend the contract before termination and thereby avoid the abandonment issue. Moreover, the Commission requires pipelines that offer evergreen or roll-over clauses to do so on a non-discriminatory basis. Order No. 636-A, ¶ 30,950, at 30,628. Yet the Commission declined to mandate the inclusion of contract-extension clauses. *Id.* As the petitioners note, the voluntary nature of evergreen and roll-over clauses means that those pipelines that do enjoy market power will likely refuse to offer such clauses to their customers. Thus, voluntary contract-extension clauses alone do not provide sufficient protection to existing pipeline customers.

The mandatory right-of-first-refusal mechanism, however, provides substantially more protection to existing customers.[42]

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[42] The Commission also provided that its complaint procedure is always available to remedy an

First, shippers bid against one another for capacity, which in the Commission's view will prevent the pipeline from using the right-of-first-refusal mechanism to push the rate above the competitive market price.[43] Second, under the right-of-first-refusal mechanism the competing bid is capped at the maximum "just and reasonable" rate, which protects the existing shipper from having to match a bid higher than the Commission-approved rate. If the existing customer is willing to pay the maximum approved rate, then the right-of-first-refusal mechanism ensures that the pipeline may not abandon the certificated service. In this way, even a captive customer served by a single pipeline can exercise its right of first refusal and retain its long-term firm-transportation service against rival

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> unjustified loss of service. A hearing is necessary, however, only when there are material facts in dispute. As the Commission has explained, the right of first refusal is an adequate protection for LDCs serving core customers.

Order No. 636-A, ¶ 30,950, at 30,633. Although the petitioners object that the complaint process, 18 C.F.R. § 385.206, provides inadequate protection, it is evident that the Commission intended the complaint process to serve only as a back-up to the right-of-first-refusal mechanism. We do not address the petitioners' contention, made for the first time at oral argument, that the Commission should have adopted a complaint procedure modeled after 18 C.F.R. § 157.106, which allows customers to contest the pre-granted abandonment of optional expedited certificates (an innovation of Order No. 436 in which the Commission presumes that an application for a "new service" meets the public convenience and necessity if the pipeline agrees to bear the full economic risk, *see AGD I,* 824 F.2d at 1030-31).

[43] The Commission decided not to specify on a generic basis the appropriate method for pipelines to use in determining the "best bid." *See* Order No. 636, ¶ 30,939, at 30,451; Order No. 636-A, ¶ 30,950, at 30,634. Rather, as the Commission stated, it can guard against such pipeline influence in its review of the individual restructuring proceedings and pipeline tariff filings.

bidders. Hence, the basic structure of the right-of-first-refusal mechanism provides the protections from pipeline market power required for pre-granted abandonment under § 7.

2. <u>The twenty-year contract term</u>

The petitioners also contend that the contract term-matching condition allows pipelines to exercise market power inconsonant with pre-granted abandonment. Thus, on capacity-constrained pipelines existing customers may be forced to match competing bids for twenty years' duration, which would not be the outcome in a competitive market without pipelines' natural monopoly. Competing bidders who come up against the rate ceiling for this scarce resource—capacity on constrained pipelines—may bid up the length of the contract term to try to win the auction. In effect, bidding for a longer contract term becomes a surrogate for bidding beyond the maximum rate level. Especially with the new capacity-release mechanism, a competing bidder could bid for a longer contract term than it would contract for in a competitive market, release the excess capacity at a discount, and absorb the loss just as though it had bid an above-maximum rate for a shorter term.

The Commission acknowledged the reality that contract duration is a measure of value when it declared that its policy was "for the capacity to go to the person who values it the most, as evidenced by its willingness to bid the highest price for the longest reasonable time." Order No. 636-A, ¶ 30,950, at 30,630. As a general matter, in a perfectly competitive market, a long-term contract incorporates a premium for stability, and a pipeline naturally values a longer-term transportation contract more highly, *ceteris paribus.* Order No. 636, ¶ 30,939, at 30,450. Thus, the contract term-matching condition is a rational means of emulating a competitive market for allocating firm-transportation capacity. There are obvious drawbacks—the industrial petitioners provide the example of a factory owner with a productive asset that has only a short useful life. Order No. 636-A, ¶ 30,950, at 30,629-30. But industrial end-users are also far more likely to have ready access to alternative fuels than do the residential consumers served by LDCs. *See AGD I,* 824 F.2d at 995.

For purposes of pre-granted abandonment, however, the issue is whether the Commission has shown that its choice of a twenty-year term-matching cap protects consumers against the exercise of pipeline market power. The petitioners note that longer-term contracts lock in customers and serve as a barrier to entry into the pipeline market by potential competitors. Rival pipelines will not build extensions to their system if the market for additional capacity has been foreclosed by long-term contracts with the existing pipeline. The Commission responds only that the pipeline plays no role in the competitive bidding process and thus cannot exercise market power. In the Commission's view, its choice of a twenty-year period reflects a reasonable weighing of the relative interests in preventing market constraint and encouraging market stability. None of these explanations, however, supports a finding that the twenty-year term-matching cap adequately protects against pipelines' pre-existing market power, which they enjoy by virtue of natural-monopoly conditions. The Commission has not explained why the twenty-year cap will prevent bidders on capacity-constrained pipelines from using long contract duration as a price surrogate to bid beyond the maximum approved rate, to the detriment of captive customers. If the maximum approved rate artificially limits a rival shipper's ability to outbid the existing shipper, the rival shipper may offer a higher-value contract by bidding up the contract duration instead.[44]

A further concern with the Commission's choice of a twenty-year cap is the Commission's reasoning in selecting twenty years. Most of the commentators before the agency had proposed much shorter contract-term caps, such as five years.[45] The Commission relied on the fact that twenty-year contracts have been "traditional" in the natural-gas industry. Order No. 636-A, ¶ 30,950, at 30,631 n.437. However, numerous commentators on rehearing of Order No. 636-A, as well as Commissioner Moler, *id.* at 30,679, pointed out that twenty-year contracts have been traditional only for contracts involving the construction of new facilities, where the pipeline requires a long-term contract to secure financing for the project, but not for contracts for the

[44] The LDC petitioners also contend that the Commission failed to consider that, following Order No. 636, LDCs are placed in a more vulnerable market situation, in which their traditional customers can purchase gas from marketers. The Commission reasonably responded that LDCs are no different from other industry participants in that they will have to evaluate future risks in determining how much capacity to reserve. Order No. 636-B, ¶ 61,272, at 62,026.

[45] The petitioners contend in part that the twenty-year cap cannot stand because the Commission failed to explain why it rejected the commentators' proposals for a shorter period. When, as here, the Commission must select some, necessarily somewhat arbitrary figure, we will defer to the Commission's expertise if it provides substantial evidence to support its choice and responds to substantial criticisms of that figure.

continuation of service after contract expiration. Indeed, both of the decisions that the Commission cited for the proposition that twenty-year contracts are customary were for new facilities.[46] Also, renewal contracts appear more similar to the situation in the right-of-first-refusal mechanism. The Commission in its brief responds that the term-matching cap was designed "not to determine the length of typical gas contracts, but to establish a reasonable outer boundary for contract length, within which the ROFR might reasonably function." The petitioners' claim, however, is that because the Commission looked to the wrong type of contract to determine the typical contract length it may have selected an outer boundary that is longer than it would have been if the Commission had examined the duration of renewal contracts. The Commission failed to respond to this objection in the Order No. 636 series.

Both of these reasons—the Commission's failure to explain why the twenty-year cap will protect against pipelines' market power, and the failure to explain why it looked at new-construction contracts in arriving at the twenty-year figure—persuade us to remand the length of the contract term-matching condition to the Commission for further consideration.[47] The right-of-first-refusal

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[46] *See Pacific Gas Transmission Co.*, 56 F.E.R.C. ¶ 61,192, at 61,727-28, *order on reh'g*, 57 F.E.R.C. ¶ 61,097 (1991), *order on reh'g*, 62 F.E.R.C. ¶ 61,243 (1993), *petitions for review pending sub nom. Altamont Gas Transmission Co. v. FERC*, No. 91-1369 (D.C. Cir. argued Nov. 14, 1995); *Iroquois Gas Transmission Sys., L.P.*, 53 F.E.R.C. ¶ 61,194, at 61,779-82 (1990), *order on reh'g*, 54 F.E.R.C. ¶ 61,103 (1991).

[47] The industrial petitioners also contend that the twenty-year cap is unduly discriminatory under § 5 of the NGA because industrial end-users are more likely to have shorter-term natural gas needs than other customers, such as LDCs who can count on still having residential customers twenty years in the

mechanism, incorporating the twin matching conditions of rate and contract term, is sufficiently justified. We remand only as to the Commission's reasons for adopting a twenty-year cap.

3. Requirement to discount

Petitioner Meridian Oil Inc., joined by the American Public Gas Association, challenges a different aspect of the right-of-first-refusal mechanism. The Commission declared that a pipeline need not accept a competing bid for a rate less than the maximum approved rate; in other words, "pipelines are not required to discount under the rule." Order No. 636-A, ¶ 30,950, at 30,629. The result is that a pipeline can choose between providing service to the highest bidder at a discounted rate and not providing service at all unless a shipper is willing to pay the maximum approved rate. In its comments to the Commission, Meridian urged that pipelines be required to accept the "best bid," which on pipelines on which capacity was not constrained would likely be less than the maximum approved rate. The Commission responded that it would

> not require pipelines to discount transportation rates. However, if a pipeline fails to attempt to maximize throughput, there is no guarantee that it will be able to recover all the costs of its underutilized capacity from its firm customers when it files its next rate case. Evidence that a pipeline refused to accept the highest valued bid for capacity below the maximum rate will be given significant weight during its next rate case.

Order No. 636-B, ¶ 61,272, at 62,028 (footnote omitted).

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future. The Commission responded that "[t]he requirement is not unduly discriminatory" because "[a]ll parties have an equal opportunity to bid for the capacity." Order No. 636-A, ¶ 30,950, at 30,632. Although the twenty-year cap may affect different classes of customers differently, under these circumstances it does not violate § 5.

Meridian contends first that the Commission violated § 7(b) by authorizing pre-granted abandonment without requiring the pipeline to discount. In Meridian's view, by forcing the existing customer to pay the maximum approved rate to ensure continuity of service, even if the competitive outcome as determined by the bidding process is a below-maximum rate, the Commission has failed to protect customers against pipelines' market power. *See Mobil Oil*, 498 U.S. at 227; *AGA II*, 912 F.2d at 1517. However, as we held above, the Commission has already protected against pipelines' market power by removing the pipeline's ability to influence the bidding and by limiting the maximum rate that the pipeline may charge. *See supra* at 43-44. The Commission first authorized selective discounting by pipelines providing transportation under a Part 284 blanket certificate in Order No. 436, ¶ 30,665, at 31,540-48. *See* 18 C.F.R. § 284.7(d)(5); *AGD I*, 824 F.2d at 1007-13; *see also Mississippi Valley Gas Co.*, 68 F.3d at 507. Given that the purpose of selective discounting is to increase throughput by allowing pipelines to engage in price discrimination in favor of demand-elastic customers, *AGD I*, 824 F.2d at 1011, Meridian's proposal that pipelines be required to discount in favor of demand-inelastic, captive customers would render meaningless pipelines' ability to charge up to the maximum approved rate. The § 7(b) abandonment provisions protect customers against loss of service only if the customer is willing to pay the maximum rate approved in a rate proceeding.

Meridian's second contention is that the Commission acted in an arbitrary and capricious manner by not responding to Meridian's comments that the lack of a requirement to discount would prevent the right-of-first-refusal mechanism from reflecting competitive market forces on pipelines with excess capacity. The Commission responded to Meridian's objection by assuring that a pipeline is not entitled to full cost recovery in its next rate proceeding when it forgoes the opportunity to recover some of its fixed costs from a bid rate between the minimum and maximum filed rates.[48] Order No. 636-B, ¶ 61,272, at 62,028. Meridian has offered no reason why the Commission's rate scrutiny will not provide sufficient incentives for pipelines to discount in appropriate circumstances. Accordingly, we affirm the Commission's decision not to require pipelines to discount in the right-of-first-refusal process.

C. <u>Curtailment</u>

When supply shortages arose in the natural gas industry during the 1970s, the Commission adopted end-use curtailment plans to protect high-priority customers from an interruption of supply. *See generally Consolidated Edison Co. v. FERC*, 676 F.2d 763, 765-67 (D.C. Cir. 1982); *North Carolina v. FERC*, 584 F.2d 1003, 1006-08 (D.C. Cir. 1978). In 1973, the Commission found itself " "impelled to direct curtailment on the basis of end use rather than on the basis of contract simply because contracts do not necessarily serve the public interest requirement of efficient allocation of this wasting resource.' " Order No. 467, 49 F.P.C. 85, 86 (quoting

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[48] Because we are satisfied by the Commission's assurance that it will examine pipelines' failure to discount in rate proceedings, we need not address the Commission's alternative contention in its brief that requiring pipelines to discount would violate the Commission's duty to ensure adequate capitalization to pipelines.

Arkansas Louisiana Gas Co., 49 F.P.C. 53, 66 (1973)), *order on reh'g*, 49 F.P.C. 217, *order on reh'g*, 49 F.P.C. 583 (1973), *petitions for review dismissed sub nom. Pacific Gas & Elec. Co. v. FPC*, 506 F.2d 33 (D.C. Cir. 1974). The Commission's end-use curtailment schemes were essentially enacted into law by title IV of the Natural Gas Policy Act of 1978 (NGPA),[49] which establishes the following priority system:

> Whenever there is an insufficient supply, under the Act first in line to receive gas are schools, small business, residences, hospitals, and all others for whom a curtailment of natural gas could endanger life, health, or the maintenance of physical property. After these "high-priority" users have been satisfied, next in line are those who will put the gas to "essential agricultural uses," followed by those who will use the gas for "essential industrial process or feedstock uses," followed by everyone else.

Process Gas Consumers Group v. United States Dep't of Agric., 657 F.2d 459, 460 (D.C. Cir. 1981) (*Process Gas I*); *see also* 18 C.F.R. §§ 281.201-281.215 (the Commission's regulations implementing NGPA § 401).

With the introduction of stand-alone firm-transportation service in Order No. 436, the Commission distinguished for the first time between supply curtailment and capacity curtailment.

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[49] Section 401(a) provides that:

> [T]he Secretary of Energy shall prescribe and make effective a rule, ... which provides that, ... to the maximum extent practicable, no curtailment plan of an interstate pipeline may provide for curtailment of deliveries of natural gas for any essential agricultural use, unless such curtailment ... (2) is necessary in order to meet the requirements of high priority users."

15 U.S.C. § 3391(a); *see also id.* § 401(f)(2), 15 U.S.C. § 3391(f)(2) (defining "high-priority user").

Transportation service can suffer from a capacity interruption (such as a *force majeure* loss of capacity due to pipeline system failure or a pipeline's overbooking of capacity), whereas sales service can suffer from a shortage in the supply of gas. *See* Order No. 436, ¶ 30,665, at 31,515; Order No. 436-A, ¶ 30,675, at 31,652. The Commission's subsequent approach was to allow pipelines to adopt *pro rata* capacity curtailment (allocation proportional to the amount reserved, without regard to end use), *see, e.g., Texas Eastern Transmission Corp.*, 37 F.E.R.C. ¶ 61,260, at 61,692-93 (1986), *order on reh'g*, 41 F.E.R.C. ¶ 61,015 (1987), *aff'd sub nom. Texaco, Inc. v. FERC*, 886 F.2d 749 (5th Cir. 1989), unless the parties agreed to end-use capacity curtailment on a particular pipeline, *see, e.g., Florida Gas Transmission Co.*, 51 F.E.R.C. ¶ 61,309, at 62,010-11, *order on reh'g*, 53 F.E.R.C. ¶ 61,396 (1990).

In *City of Mesa v. FERC*, 993 F.2d 888 (D.C. Cir. 1993), the court reviewed a proceeding in which the Commission had approved end-use curtailment for supply shortages but *pro rata* curtailment for capacity interruption. *El Paso Natural Gas Co.*, 54 F.E.R.C. ¶ 61,316, at 61,928-29, *order on reh'g*, 56 F.E.R.C. ¶ 61,290, at 62,153-54 (1991). First, the court upheld the Commission's interpretation of the word "deliveries" in § 401(a) of the NGPA to refer only to pipelines' sale of gas, so that the statutory end-use curtailment scheme in title IV applied only to supply curtailment. 993 F.2d at 892-94; *see also Atlanta Gas Light Co. v. FERC*, 756 F.2d 191, 196-97 (D.C. Cir. 1985). The court found that different treatment of supply and capacity curtailment was reasonable because high-priority users can "generally "fend for themselves' " to protect against capacity interruption:

> Supply shortages usually lead to prolonged periods in which there is simply too little gas to serve the needs of all users. In contrast, capacity constraints occur when there is enough gas in the market but an unexpected event has caused a brief interruption in the movement of the gas to consumers. Additionally, capacity constraints, unlike supply shortages, may only affect the movement of gas on *part* of a pipeline, thereby allowing customers to receive their quota of gas by using alternate routes that skirt the pipeline bottleneck. These differences mean that pipeline customers can more easily adopt self-help measures to protect their high-priority end-users against the harmful effects of capacity curtailments than supply shortages.

City of Mesa, 993 F.2d at 894-95.

Although *City of Mesa* upheld the limitation of title IV of the NGPA to supply shortages, the court acknowledged that the NGA provided protections for capacity shortages. The court stated that "implicit in th[e] consumer protection mandate [of NGA §§ 4 and 7(e)] is a duty to assure that consumers, especially high-priority consumers, have continuous access to needed supplies of natural gas." 993 F.2d at 895. This duty arises because " "[n]o single factor in the Commission's duty to protect the public can be more important to the public than the continuity of service provided.' " *Id.* (quoting *Sunray Mid-Continent Oil Co. v. FPC,* 239 F.2d 97, 101 (10th Cir. 1956), *rev'd on other grounds,* 353 U.S. 944 (1957)). The court emphasized that "since the NGA gives the FERC no specific guidance as to how to apply its broad mandates in a particular case, our review of the FERC's actions here is, again, quite limited." *Id.* In *City of Mesa,* the court concluded that the Commission had failed to engage in reasoned decision making when it approved a curtailment plan that protected "most" high-priority users rather than all such users. *Id.* at 896-97. The court noted that in Order No. 636-A the Commission had held that "self-help strategies were generally sufficient to assure protection of end-users and thus to meet NGA mandates" but did not further examine whether self-help measures were adequate to protect against capacity curtailment. *Id.* at 897.

In Order No. 636, which was issued before the court's decision in *City of Mesa,* the Commission continued without change its curtailment policies since Order No. 436. First, the Commission acknowledged that, as a policy matter, it chafed at the title IV end-use curtailment scheme for supply shortages but stated that it was bound by the statute. Order No. 636, ¶ 30,939, at 30,430; *see also Transcontinental Gas Pipe Line Corp.,* 57 F.E.R.C. ¶ 61,345, at 62,117 (1991). The Commission reiterated its reading of § 401(a) that limited its scope to pipelines' sale of gas. Order No. 636-A, ¶ 30,950, at 30,586-89. Second, the Commission maintained that self-help measures would allow the consumer-protection mandate of the NGA to be satisfied by *pro rata* capacity curtailment:

> The Commission believes that with deregulated wellhead sales and a growing menu of options for unbundled pipeline service, customers should rely on prudent planning, private contracts, and the marketplace to the maximum extent practicable to secure both their capacity and supply needs. In today's environment, LDC's [*sic*] and end-users no longer need to rely exclusively on their traditional pipeline supplier. Rather, to an ever-increasing degree they rely on private contracts with gas sellers, storage providers, and others; a more diverse portfolio of pipeline suppliers, where possible; local self-help measures (*e.g.,* local production, peak shaving and storage); and their own gas supply planning through choosing between an increasing array of unbundled service options.

Id. at 30,590.

The Commission's curtailment policies are challenged from both sides. Elizabethtown Gas Company contends that the Commission should have adopted *pro rata* curtailment for shortages in the supply of pipeline gas, and a group of small distributors contends that the Commission should have adopted end-use curtailment for capacity interruption and for shortages in the supply of third-party gas.

1. Supply curtailment of pipeline gas

Elizabethtown contends that because § 401(a) of the NGPA requires end-use curtailment only "to the maximum extent practicable," 15 U.S.C. § 3392(a), the declining role of pipelines as gas merchants renders end-use curtailment for shortages of pipeline gas no longer "practicable." The court recently rejected this argument, made by the same petitioner, in *Elizabethtown Gas Co. v. FERC,* 10 F.3d 866 (D.C. Cir. 1993) (*Elizabethtown III*):

> This argument makes no sense to us. Even if [the pipeline] supplies a smaller share of the gas bought by each of the LDCs, the gas it does deliver to them could still in times of shortage go first to "high-priority users." Accordingly, it seems entirely "practicable" to increase the level of protection for high priority users above that provided by the pro rata plan.

Id. at 874; *see also Process Gas Consumers Group v. United States*, 694 F.2d 778, 787-92 (D.C. Cir. 1982) (en banc) (*Process Gas II*) (holding that the phrase "to the maximum extent practicable" gives the Commission broad powers). Although Elizabethtown contends that the near-elimination of pipelines as gas merchants following Order No. 636 requires us to reconsider our holding in *Elizabethtown III*, this change in the industry does not affect our reasoning that end-use curtailment remains "practicable" no matter how small the pipelines' share of the gas-sales market. The Commission recognized that the limitation of title IV of the NGPA to pipelines' sale of gas means that pipelines are disadvantaged vis-à-vis other gas merchants, but explained that it remained bound by the statute. Order No. 636, ¶ 30,929, at 30,430. Because we have already decided this question in *Elizabethtown III*, we affirm the Commission's decision that title IV of the NGPA mandates end-use curtailment for shortages in the supply of pipeline gas.

Elizabethtown also maintains that the Commission acted arbitrarily in not requiring high-priority users to compensate pipeline customers who lose gas supply under end-use curtailment. In *Elizabethtown III*, the court "held that a compensation provision is not necessarily inconsistent with § 401(a)." 10 F.3d at 875. Indeed, this court has long held that the Commission retains the authority under title IV of the NGPA to adopt a compensation scheme. *See Consolidated Edison Co. v. FERC*, 676 F.2d 763, 767 (D.C. Cir. 1982); *cf. Elizabethtown Gas Co. v. FERC*, 575 F.2d 885, 887-89 (D.C. Cir. 1978) (*Elizabethtown I*) (holding that the Commission has authority under the NGA to adopt a curtailment compensation plan). In *Elizabethtown III*, the court remanded with instructions for the Commission to consider Elizabethtown's "request for a curtailment compensation scheme." *Id.* In the Order No. 636 series, decided before the court's decision in *Elizabethtown III*, the Commission stated that its

> position on curtailment compensation plans is that the parties in the individual restructuring proceedings must explore the development of such schemes ... in the context of developing their individual curtailment plans and in the development of voluntary emergency contractual arrangements between shippers. However, the Commission

> believes that it would be contrary to the concept of the restructuring proceeding process and the negotiation and development of individually tailored curtailment allocation procedures and emergency mechanisms for it to mandate a generic compensation scheme.

Order No. 636-A, ¶ 30,950, at 30,592; *see also* Order No. 636, ¶ 30,929, at 30,430. The comments by the Commission in the Order No. 636 series continue the Commission's pattern of avoiding the question of curtailment compensation and do not exhibit the reasoned consideration of curtailment compensation that the court subsequently requested in *Elizabethtown III.*

The Commission has reconsidered the issue of curtailment compensation, however, on remand from *Elizabethtown III. See Transcontinental Pipe Line Corp.,* 72 F.E.R.C. ¶ 61,037, *reh'g denied,* 73 F.E.R.C. ¶ 61,357 (1995). In those proceedings, the Commission

> conclude[d] that compensation is needed to render Transco's gas supply curtailment plan just and reasonable. The priority curtailment plan affects the contractual rights of Transco's customers by altering the *pro rata* allocation of curtailed supplies so that higher priority customers can obtain gas that would otherwise go to lower priority customers.

72 F.E.R.C. ¶ 61,037, at 61,235. The Commission rejected Elizabethtown's proposed compensation scheme, however, in favor of requiring the higher-priority customer to pay: (1) 150% of the spot market price for gas if the lower-priority customer was unable to cover (locate replacement gas on the spot market), or (2) the difference between the cover price and the original contract price if the lower-priority customer was able to cover. *Id.* at 61,237-38.

In light of the Commission's *Transcontinental* decision, the issue of curtailment compensation is not ripe for review. The Commission enjoys broad discretion whether to adopt a compensation scheme on a generic basis or in pipeline-specific proceedings. *See Mobil Oil,* 498 U.S. at 230. If Elizabethtown remains aggrieved by the Commission's decision to accept its general argument but fashion a different compensation mechanism, then it may seek relief in review of the *Transcontinental* decision. We therefore express no opinion on the appropriateness of any particular curtailment compensation plan.

2. Capacity curtailment

The small distributor petitioner group, on the other hand, contends that *pro rata* capacity curtailment violates the consumer-protection mandate of the NGA. We review the Commission's policy on *pro rata* curtailment to determine whether it is "just and reasonable" under § 4 and whether it serves the "present or future public convenience and necessity" under § 7(e). *See City of Mesa,* 993 F.2d at 895. The Commission decided that the consumer-protection mandate of the NGA did not require it to adopt end-use capacity curtailment across the board and promised to address the issue in each pipeline restructuring proceeding. Order No. 636-A, ¶ 30,950, at 30,591-92. Indeed, the Commission has broad latitude on whether to effectuate its policies in generic rulemakings or in individual-pipeline adjudications. *Mobil Oil,* 498 U.S. at 230. The issue presented to us, then, is whether the Commission's decision that the NGA does not require end-use curtailment in all circumstances is " "reasoned, principled, and based upon the record.' " *Great Lakes Gas Transmission Ltd.*

Partnership v. FERC, 984 F.2d 426, 432 (D.C. Cir. 1993) (quoting *Columbia Gas Transmission Corp. v. FERC*, 628 F.2d 578, 593 (D.C. Cir. 1979)).

The Commission explained that Order No. 636 had allowed the development of market structures that would enable customers to take independent, market-based steps to avoid the need for Commission-mandated end-use curtailment. Order No. 636-A, ¶ 30,950, at 30,590. Moreover, the Commission found that since the enactment of the NGPA in 1978 "the industry has not experienced shortages beyond isolated, short-lived dislocation," *id.* at 30,591, and "gas has always flowed according to the dictate of the market, *i.e.*, to the heat sensitive users who need it most and who are thus willing to pay the prevailing market price for it." *Id.* at 30,592. This experience with the industry provides substantial evidence for the Commission's conclusion that end-use curtailment is not required in all circumstances.

We are unpersuaded, particularly in light of the Commission's own actions in the restructuring proceedings, that *pro rata* capacity curtailment would adequately protect all high- priority customers on all pipelines. *Cf. City of Mesa*, 993 F.2d at 896-97. The Commission's market-based alternatives for customers to avoid curtailment fall into the following categories: (1) arrangements with other pipelines; (2) arrangements with other gas sellers; (3) arrangements for gas storage; (4) arrangements with other customers (including the capacity-release mechanism); and (5) "peak shaving."[50] First, arrangements with other pipelines are more widely available after Order No. 636, such as by using different pipelines that connect to one "market center," but a capacity constraint on a pipeline will still cut off delivery to any "captive customers," no matter how many transportation options some other customers may have. Second, arrangements with other gas sellers are by definition relevant only to supply curtailment, not to capacity curtailment. Third, arrangements for gas storage are unhelpful if the capacity interruption occurs at a point between the contract-storage area and the customer's receipt point. Fourth, obtaining gas from other customers, whether through the capacity-release mechanism or otherwise, depends upon the willingness of lower-priority customers to forgo deliveries. Fifth, practices such as "peak shaving" (letting a little gas go a longer way) can temporarily help to alleviate curtailment problems but cannot ensure continuous service if the interruption lasts too long. None of these market-based solutions, therefore, can guarantee continuous service to all high-priority customers in cases of capacity interruptions. Many of the market-based solutions fail to acknowledge that many customers have far less control over access to pipeline capacity than they do over gas supply. In addition, some of the self-help mechanisms will be more readily available to larger pipeline customers. *City of Mesa,* 993 F.2d at 897 n.7.

Yet the Commission has not applied Order No. 636 in the

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[50] Peak shaving is "the practice of adding propane air mixtures to augment supplies of natural gas during periods of peak demand." *Atlanta Gas Light,* 756 F.2d at 195 n.5.

restructuring proceedings to preclude the development of curtailment plans that provide more protection to higher-priority users. For example, on remand from *City of Mesa,* the Commission reiterated its general policy that "customers can, and should, avail themselves of self-help methods to obtain their needed supplies" but, in light of the decision in *City of Mesa,* ordered El Paso to "includ[e] provisions giving relief to any high priority shipper when that shipper has exercised all other self-help remedies in times of *bona fide* emergencies." *El Paso Natural Gas Co.,* 69 F.E.R.C. ¶ 61,164, at 61,624 (1994), *order on reh'g,* 72 F.E.R.C. ¶ 61,042, *reh'g denied,* 73 F.E.R.C. ¶ 61,074 (1995). In another restructuring proceeding, the Commission approved a settlement and found its curtailment plan consistent with *City of Mesa* because it "provides an exemption from *pro rata* curtailment whenever necessary to avoid irreparable injury to life or property." *Florida Gas Transmission Co.,* 70 F.E.R.C. ¶ 61,017, at 61,061 (1995). On occasions, the Commission has suggested that "there may be extraordinary circumstances when reasonable self-help efforts are insufficient, even for large customers," such that some emergency protections may always be required for certain *force majeure* capacity interruptions. *El Paso,* 69 F.E.R.C. ¶ 61,164, at 61,624; *see also United Gas Pipe Line Co.,* 65 F.E.R.C. ¶ 61,006, at 61,092, *reh'g denied sub nom. Koch Gateway Pipeline Co.,* 65 F.E.R.C. ¶ 61,338, at 62,630-31 (1993).

We need not reach the issue whether the adoption of a pure *pro rata* capacity-curtailment scheme on a generic basis would comply with the Commission's duty under the NGA to ensure that "high-priority consumers[ ] have continuous access to needed supplies of natural gas." *City of Mesa*, 993 F.2d at 895. All the Commission did in Order No. 636 was to decide not to require end-use capacity curtailment for all pipelines. Because the Commission expressly declared that it would re-examine the suitability of pure *pro rata* capacity curtailment for customers on each pipeline, Order No. 636-A, ¶ 30,950, at 30,591-92, we construe any indications that *pro rata* curtailment will be the default as unreviewable policy statements under § 4(b)(A) of the Administrative Procedure Act, 5 U.S.C. § 553(b)(A). *See Pacific Gas & Elec. Co. v. FPC*, 506 F.2d 33, 39 (D.C. Cir. 1974). The manner in which the Commission has applied its curtailment policy in the restructuring proceedings supports our conclusion that any preference for *pro rata* schemes is not suitable for review. *See Public Citizen, Inc. v. NRC*, 940 F.2d 679, 682-83 (D.C. Cir. 1991). Accordingly, the compliance of specific curtailment plans with the NGA's consumer-protection mandate remains open on review of the restructuring proceedings.

We uphold the Commission's decision not to require end-use curtailment on a generic basis for capacity curtailment but to proceed instead on a case-by-case basis.

3. <u>Supply curtailment of third-party gas</u>

Finally, the small distributor petitioners contend that the consumer-protection mandate of the NGA requires the Commission to adopt end-use curtailment for shortages in the supply of third-party gas. The petitioners concede that title IV of the NGPA applies only to pipelines' sale of gas, but urge that §§ 4 and 7(e) of the NGA require some form of end-use curtailment for the sale of gas by producers and other third parties. The Commission declined to "impos[e] ... the industry-wide, end-use supply curtailment scheme envisioned by the petitioners" because "the best protection against, and remedy for, supply shortages [i]s to allow the market to establish the price for gas." Order No. 636-A, ¶ 30,950, at 30,591.

As an initial matter, a group of intervenors in support of the Commission maintains that the Commission lacks jurisdiction under § 1(b) to enact a curtailment plan for third-party gas. But the Supreme Court has held expressly that "curtailment plans are aspects of [the Commission's] "transportation' and not its "sales' jurisdiction." *Louisiana Power & Light*, 406 U.S. at 641 (citing *Panhandle Eastern Pipe Line Co. v. Public Serv. Comm'n*, 332 U.S. 495, 523 (1947)). The intervenors rely on a Fifth Circuit case, *Sebring Utilities Commission v. FERC*, 591 F.2d 1003 (5th Cir.), *cert. denied*, 444 U.S. 879 (1979), in which the court indicated that the Commission would not have jurisdiction to order curtailment of gas not owned by a statutory "natural-gas company." *Id.* at 1016-19. However, the ownership of the gas is not relevant to the Commission's transportation jurisdiction because in adopting a curtailment scheme the Commission exercises its jurisdiction over the pipeline, which incorporates any curtailment plan into its tariff.[51] If we were to follow *Sebring*, then the Commission would

[51] Our reasons for holding that the Commission may apply a curtailment plan to shortages in the supply of gas owned by someone not a "natural-gas company" are the same as our reasons, for holding that the Commission may apply a capacity-release plan to capacity rights held by a municipal LDC, which is not a

also lack jurisdiction to regulate capacity curtailment of third-party gas—a proposition implicitly rejected by the *City of Mesa* court, which in remanding on the capacity-curtailment issue assumed that the Commission had jurisdiction over curtailment plans for third-party gas. 993 F.2d at 895-98. Moreover, *Sebring* was decided before the unbundling of sales from transportation, at a time when virtually all gas was pipeline-owned.[52] Under the principles of *Louisiana Power & Light,* the Commission's transportation jurisdiction extends to supply curtailment of third-party gas.

The Commission decided that an end-use supply curtailment plan for third-party gas was not required to ensure high-priority customers "continuous access to needed supplies of natural gas." *City of Mesa,* 993 F.2d at 895. As discussed with respect to capacity curtailment, *see supra* at 58-59, the Commission provided a list of market-based alternatives to secure the continuous supply of gas that is convincing in the context of supply curtailment. Although the petitioners posit a *force majeure* supply shortage that the market-based protections would not cover, namely a "freeze-off

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"natural-gas company." *See infra* Part III.B.3.

[52] The intervenors also rely on *American Public Gas Association v. FERC,* 587 F.2d 1089 (D.C. Cir. 1978) (per curiam), in which the court approved the Commission's policy at that time of excluding "direct sales" gas (gas sold directly from producers to LDCs or certain high-priority end-users) from pipelines' end-use curtailment plans, so as to alleviate the shortage of gas in the interstate market. *Id.* at 1097-98. Nothing in that opinion, however, limits the Commission's § 1(b) transportation jurisdiction to pipeline-owned gas or precludes the Commission from adopting a different policy for the curtailment of third-party gas, given the changed circumstances in the end of the gas shortage and the unbundling of sales and transportation. *See* Order No. 636-A, ¶ 30,950, at 30,589-90.

" of wells that would prevent all producers from producing sufficient quantities of gas during cold weather, the petitioners have provided no evidence that such an event has ever occurred or is likely to occur in the future. The Commission's decision that such an occurrence is unlikely "given foreseeable supply conditions" is reasonable. Order No. 636-A, ¶ 30,950, at 30,591. In addition, the Commission noted that title III of the NGPA, 15 U.S.C. §§ 3361-3364, authorizes the President to "declare a natural gas supply emergency" in the event of "a severe natural gas shortage, endangering the supply of natural gas for high-priority uses." *Id.* § 3361(a); *see* Order No. 636-A, ¶ 30,950, at 30,591.

Thus, the Commission has complied with the continuity-of-service guarantee of the NGA, as articulated in *City of Mesa*, with respect to supply shortages of third-party gas.

III. Capacity Release

In this part of the opinion, we address challenges to the voluntary capacity release provisions of Order No. 636, which permit holders of firm transportation rights on a gas pipeline to resell them. 18 C.F.R. § 284.243 (1995).[53] Petitioners challenge the Commission's jurisdiction to institute its capacity release program generally, as well as its jurisdiction over (1) LDCs' capacity sales to their local end-users; (2) capacity sales by municipal LDCs; and (3) state-regulated "buy/sell" transactions. Petitioners also challenge the exclusion of individually certificated shippers from the capacity release program, the

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[53] Our review is confined to the the capacity release provisions before they were amended by Order No. 577. *See supra* at 19 n.18.

standards that FERC promulgated for determining the prevailing bidder in the capacity release transaction, and the mechanism for crediting interruptible transportation revenues. We conclude that each of petitioners' claims is either incorrect on the merits or is not suited for review in these proceedings.

A. Introduction

Among the central goals of Order Nos. 436 and 636 has been the conversion of bundled sales arrangements into separate transportation and gas sales transactions. On the transportation side, the Commission recognized that while much of the nation's interstate pipeline capacity was reserved for firm transportation, those transportation rights ultimately were not being utilized. *See supra* Part I.C. FERC therefore sought to develop an active "secondary transportation market," with holders of unutilized firm capacity rights reselling them in competition with any capacity offered directly by the pipeline.[54] According to the Commission:

> Capacity reallocation will promote efficient load management by the pipeline and its customers and, therefore, efficient use of the pipeline capacity on a firm basis throughout the year. Because more buyers will be able to reach more sellers through firm transportation capacity, capacity reallocation comports with the goal of improving nondiscriminatory, open-access transportation to maximize the benefits of the decontrol of natural gas at the wellhead and in the field.

Order No. 636, ¶ 30,939, at 30,418. Understanding petitioners' challenges to the capacity release program requires a brief review of related policies that the Commission has employed in the past to

[54] In this sense, the Commission's description of capacity release as creating a *secondary* transportation market is somewhat misleading, given that both resales of firm capacity and initial sales by pipelines are in direct competition with each other, and unavailable in any other forum.

accomplish a similar end.

If a firm capacity holder does not ship gas under its transportation right, it pays the pipeline a "reservation fee," but does not pay a "usage fee." Historically, FERC prohibited such holders of unutilized firm capacity rights from transferring those rights to other shippers, and shippers were therefore able to purchase capacity rights only directly from pipelines. *See generally United Gas Pipe Line Co.*, 46 F.E.R.C. ¶ 61,060 (1989) (approving first experimental capacity brokering program). Beginning with the *Texas Eastern Transmission Corp.* proceedings, 48 F.E.R.C. ¶ 61,248, *order on reh'g*, 48 F.E.R.C. ¶ 61,378 (1989), *order on reh'g*, 51 F.E.R.C. ¶ 51,170, *order on reh'g*, 52 F.E.R.C. ¶ 61,273 (1990), however, the Commission authorized shippers on some pipelines to engage in nondiscriminatory "capacity brokering." Brokering arrangements allowed a holder of firm capacity rights (the "releasing shipper") to sell those rights to a "replacement shipper." The transaction took place directly between the two parties, and the replacement shipper essentially stepped into the shoes of the releasing shipper.

Three years later, in the Order No. 636 and companion *Algonquin Gas Transmission Corp.* proceedings, 59 F.E.R.C. ¶ 61,032 (1992), FERC concluded that it could not ensure that the extant capacity brokering programs were operating in a nondiscriminatory manner. When transactions occurred directly and privately between shippers, there was no way to verify that certain purchasers were not being favored unreasonably over others. "Simply put, there [were] too many potential assignors of capacity and too many different programs for the Commission to oversee capacity brokering...." Order No. 636, ¶ 30,939, at 30,416. In FERC's view, fairness could be secured only if capacity resale transactions were both centralized on each pipeline and subject to open bidding. Moreover, uniformity *among* the various pipelines was necessary to "prevent any pipeline or firm shipper from achieving an undue advantage, or incurring an undue disadvantage, compared to firm shippers on other pipelines." *Id.*

Accordingly, in Order No. 636, the Commission instituted a uniform national "capacity release" program, and exercised its power under NGA § 5 to conform pipelines' existing capacity brokering certificates to that program.[55] *Id.* While both capacity brokering and capacity release arrangements involve the releasing shipper's decision to sell excess capacity, capacity release requires the central involvement of the pipeline in the transaction. Specifically, under capacity release, each interstate pipeline is required to establish and administer an electronic bulletin board ("EBB"), which is a computer through which putative releasing and replacement shippers may communicate. *Id.* at 30,418. The EBB carries information about available and consummated capacity release transactions. For example, holders of excess firm capacity rights may "post" their available capacity on the EBB.

[55] Capacity brokering agreements already in effect on the date that the pipeline implemented its capacity release program were not substantially altered by Order No. 636. Order No. 636, ¶ 30,939, at 30,421. The Order required that the pipeline enter into a contract directly with the replacement shipper, as it would under capacity release, with terms that mirrored those in the capacity brokering agreement. *Algonquin Gas Trans. Co.*, 59 F.E.R.C. ¶ 61,032, at 61,096-97.

Further, they may establish nondiscriminatory conditions on the sale, including a minimum price and any terms under which the release may continue.[56] *Pipelines* are also required to post on the EBB any firm capacity that they have available for sale, where the capacity competes for buyers against capacity made available for resale by shippers. "Potential purchasers of capacity will then be able to choose from among the pipeline and the releasers the service that best suits their needs." *Id.* at 30,419. In addition, shippers that wish to acquire firm capacity rights may post offers to purchase capacity on the EBB. 18 C.F.R. § 284.243(d); Order No. 636-A, ¶ 30,950, at 30,565.

With two exceptions, the pipeline must sell the capacity to the highest bidder. First, "short-term transactions," *i.e.*, those for capacity releases of less than one month,[57] may be arranged between shippers without competitive bidding.[58] 18 C.F.R. § 284.243(h)(1); Order No. 636-A, ¶ 30,950, at 30,554. Second, a releasing shipper may identify a replacement shipper on its own and enter into a "pre-arranged" deal. 18 C.F.R. § 284.243(b); Order No. 636, ¶ 30,939, at 30,418. In such a transaction, the selected

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[56] For example, the releasing shipper may elect to release capacity only for so long as the temperature remains above a certain level. If the temperature were to drop, the firm capacity rights would revert to the releasing shipper. Order No. 636, ¶ 30,939, at 30,418.

[57] FERC has amended the short-term transactions provision specifically to encompass those capacity releases of no more than 31 days. *See supra* at 19 n.18. That amendment does not affect our review.

[58] The transaction must still be posted on the EBB. In addition, extensions and roll-overs of "short-term" transactions are prohibited. 18 C.F.R. § 284.243(h)(2); Order No. 636, ¶ 30,939, at 30,551.

replacement shipper need only match—rather than outbid—the highest offer made by any other shipper. 18 C.F.R. § 284.243(e). The net effect is that a shipper may ensure that it will receive certain capacity by entering into a pre-arranged deal that both conforms to the releasing shipper's conditions and matches the maximum allowable rate for the capacity. No matter what form the capacity release transaction takes, however, the purchase price for released capacity may not exceed the maximum rate set by FERC for the capacity. 18 C.F.R. § 284.243(e); Order No. 636, ¶ 30,939, at 30,420.

After the replacement shipper has been identified, the pipeline enters into a contract with it for firm capacity rights.[59] The pipeline then may elect to excuse completely the releasing shipper's obligation to pay the reservation fee and related costs. Order No. 636, ¶ 30,939, at 30,419. Otherwise, the releasing shipper is credited for those costs unless the replacement shipper defaults. 18 C.F.R. § 284.243(f); Order No. 636-A, ¶ 30,950, at 30,553. In no instance, however, is the releasing shipper liable for costs associated with the replacement shipper's *transportation* of gas.

We now turn to petitioners' varied challenges to the Commission's capacity release program.

B. Jurisdictional Challenges

Various petitioners challenge both FERC's jurisdiction to

[59] Order No. 636 pre-granted shippers a limited blanket certificate under NGA § 7 to release capacity in a nondiscriminatory manner. 18 C.F.R. § 284.243(g); Order No. 636, ¶ 30,939, at 30,421.

institute a uniform capacity release program and its jurisdiction over specific transactions and entities. We begin, then, by outlining the Commission's jurisdiction under § 1(b) of the Natural Gas Act of 1938. Ultimately, we conclude that FERC's capacity release program is a legitimate exercise of its jurisdiction over the interstate transportation of natural gas.

In the early part of this century, state regulatory agencies actively involved themselves in structuring the natural gas industry. The Supreme Court, however, severely cabined those efforts in a series of decisions that interpreted the dormant Commerce Clause to preclude state regulation of both the interstate transportation of natural gas and its ensuing sale in wholesale markets.[60] Congress enacted the Natural Gas Act of 1938 to fill the resulting regulatory gap. The Act, as provided in § 1(b), applies

> [1] to the transportation of natural gas in interstate commerce, [2] to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and [3] to natural-gas companies engaged in such transportation or sale, but [does] not apply [4] to any other transportation or sale of natural gas or [5] to the local distribution of natural gas or to the facilities used for such distribution or [6] to the production or gathering of natural gas.

15 U.S.C. § 717(b).

Petitioners' jurisdictional challenges require us to interpret the first and fifth provisions of § 1(b), which address the

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[60] For an overview of the history of the Act's inception, see generally *Arkansas Elec. Coop. v. Arkansas Pub. Serv. Comm'n,* 461 U.S. 375, 377-80 (1983); *Panhandle Pipe Line Co. v. Public Serv. Comm'n,* 332 U.S. 495, 514-21 (1947); *Illinois Gas Co. v. Central Ill. Pub. Serv. Co.,* 314 U.S. 498, 504-08 (1942); *National Ass'n of Regulatory Util. Comm'rs v. FERC,* 823 F.2d 1377, 1382-87 (D.C. Cir. 1987).

interstate transportation and "local distribution" of natural gas.[61] In truth, the two provisions are a unity. "It is well established that the ["local distribution"] proviso was added to the Act merely for clarification and was not intended to deprive [FERC] of any jurisdiction otherwise granted by § 1(b)." *Louisiana Power & Light*, 406 U.S. at 637 n.14; *see also East Ohio Gas*, 338 U.S. at 469-70 ("[W]hat Congress must have meant by "facilities' for "local distribution' was equipment for distributing gas among consumers within a particular local community, not the high-pressure pipe lines transporting the gas to the local mains."). As explained in the House Report on the Act:

> That part of the negative declaration that the act shall not apply to "the local distribution of natural gas" is surplusage by reason of the fact that distribution is made only to consumers in connection with sales, and since no jurisdiction is given to the Commission to regulate sales to consumers the Commission would have no authority over distribution, whether or not local in character.

H.R. REP. NO. 709, 75th Cong., 1st Sess. 3 (1937). And, as this circuit has concluded:

> Insofar as congressional committees spoke to the matter, therefore, they appear to have viewed distribution as confined to its parceling out function and (probably) even more narrowly, to parceling out *accompanied by* retail sales. As § 1(b) gave the Commission jurisdiction only over *sales for resale*, the states had unquestioned authority over retail sales anyway, making the reservation for distribution surplusage.

Public Utils. Comm'n v. FERC, 900 F.2d 269, 276 (D.C. Cir. 1990).

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[61] For an overview of the Commission's transportation jurisdiction, see generally *Louisiana Power & Light*, 406 U.S. at 636-40; *United Gas Pipe Line Co. v. FPC*, 385 U.S. 83, 89 (1966); *East Ohio Gas*, 338 U.S. at 467-74; *Cascade Natural Gas Corp. v. FERC*, 955 F.2d 1412, 1415-21 (10th Cir. 1992); *Michigan Consol. Gas Co. v. FERC*, 883 F.2d 117, 121-22 (D.C. Cir. 1989).

We now consider whether FERC has done more than its interstate transportation jurisdiction permits.

1. FERC's jurisdiction to regulate capacity release

Petitioners' first jurisdictional challenge is the claim of the LDCs that FERC lacks any authority whatsoever to regulate shippers' resale of firm capacity rights. "LDCs' capacity assignments," they maintain, "involve sales of LDCs' *rights to transportation service* but do not involve *interstate transportation* or sale for resale of gas itself." As we understand their position, the LDCs would limit FERC's regulatory authority over transportation to the *rendition* of interstate gas transportation services, as opposed to authority over the rights to *receive* those services. As their theory goes, the Commission has jurisdiction over the pipelines' initial sales of transportation capacity—given that it is the pipelines that render transportation services—but is without jurisdiction over *resales* of those same capacity rights by third parties—given that those third parties do not render transportation services.

Initially, we believe that the distinction drawn by the LDCs between the "rights to" and "rendition of " interstate transportation services is not a meaningful one. While the pipeline provides *transportation* only when a party utilizes capacity rights to transport gas, the pipeline provides *transportation services* throughout the capacity release process. Specifically, the pipeline operates the electronic bulletin board on which all prospective transactions are posted and consummated. The pipeline also selects the winning bidder in the transaction.

Moreover, unlike capacity brokering arrangements, which occur directly between releasing and replacement shippers, capacity release requires the pipeline to contract with the replacement shipper. "In effect, the pipeline is temporarily abandoning service to the releasing shipper and instituting service to the replacement shipper. Both of these activities are subject to the Commission's jurisdiction under NGA section[ ] 1(b)...." Order No. 636-A, ¶ 30,939, at 30,551. In sum, the capacity release regulations operate as a term or condition of pipeline service, with which its customers must comply.

As an entirely separate matter, the Commission's jurisdiction attaches to the subject of the capacity resale transaction: interstate transportation rights. "By controlling such capacity, the assignors are effectively determining by whom, and under what circumstances, gas will be transported and are using the pipeline's facilities as if they were the assignors' facilities." *Id.* (quotation marks, alteration, and citation omitted). In contrast, under the regulatory system envisioned by the LDCs, holders of capacity rights could engage in resales without regard to the principles of open access and nondiscrimination that are at the heart of the uniform capacity release system. Such a result is directly contrary to Congress' intent in enacting the Natural Gas Act. Responding to the Supreme Court's conclusion that the Constitution's dormant Commerce Clause *prohibited* state regulation of the interstate transportation of natural gas, *see supra* at 67, the federal government interceded to ensure stability and protect the interests of the consuming public. It thereby occupied the field, which necessarily includes both the sale and resale of interstate transportation rights.

2. <u>Jurisdiction over LDCs' capacity sales to their own end-users</u>

Several petitioners make more limited claims that specific classes of entities and transactions must be exempted from the Commission's control over capacity resales. First, the PUCs and LDCs together argue that FERC lacks jurisdiction over capacity sales by LDCs to their own end-users. Such transactions, they maintain, fall within the NGA's "local distribution" exemption. Specifically, according to petitioners, the Commission has always recognized that the states have jurisdiction to regulate *bundled* sales of natural gas by LDCs to their end-users, which necessarily involves some indirect influence over the interstate transportation element of the sale. State authority remains intact for LDCs' *rebundled* sales of gas and transportation even after the implementation of Order No. 636. They contend that there is no functional difference between that jurisdictional arrangement and state regulation of LDCs' sales of *unbundled* gas and—more relevant here—transportation to local end-users. In particular, petitioners contend that state regulatory commissions need the freedom to control LDCs' assignment of capacity so that local end-users will be ensured of access to pipeline service.

But, as we have already explained, petitioners' reading of NGA § 1(b)'s reference to "local distribution" is flawed; the proviso does not withdraw from FERC's jurisdiction any aspect of the interstate transportation of natural gas. In this regard, we find the Commission's explanation of the regulatory environment far more convincing. States have been—and are still—permitted to regulate LDCs' bundled sales of natural gas to end-users because those transactions include transportation over local mains and the retail sale of gas. In contrast, states have *never* regulated the terms and conditions of interstate pipeline transportation. When the gas sales element is severed—*i.e.*, unbundled—from the transaction, FERC retains jurisdiction over the *interstate transportation* component.[62]

3. Jurisdiction over municipal capacity release

We now turn to the claim of the municipally owned local distribution companies ("municipalities") that FERC does not have jurisdiction to require them to comply with its capacity release regulations. Petitioners parse the terms of the Natural Gas Act as follows:

> Municipalities are exempt from the Commission's jurisdiction under the NGA. The Commission's NGA jurisdiction extends only to "natural gas companies." A "natural gas company" is defined in NGA Section 2(6) as "a person engaged in the transportation of natural gas in interstate commerce, or the sale in interstate commerce of such gas for resale." NGA Section 2(1) defines a "person" as an "individual" or a "corporation." NGA Section 2(2) defines a "corporation" as *inter alia*, any corporation, partnership or association, but the definition expressly *excludes* "municipalities."

Small Distributors' and Municipalities' Br. at 11-12 (footnotes

[62] The LDCs briefly argue that NGA § 1(c), the so-called "Hinshaw exemption," deprives the Commission of jurisdiction over their capacity sales to their own end-users. In this regard, they refer us to Congress' determination in § 1(c) that certain pipelines are "matters primarily of local concern and subject to regulation by the several States." 15 U.S.C. § 717(c). Section 1(c), however, addresses a very specific type of natural gas pipeline, namely those "interstate pipelines that receive natural gas at their state boundary that is consumed within the state and subject to state commission regulation." *ANR Pipeline Co. v. FERC*, 71 F.3d 897, 898 n.2 (D.C. Cir. 1995). Accordingly, we reject the LDCs' claim, given that the LDCs do not suggest that they fall within that specific class of pipelines.

omitted).

Of course, as discussed above, *see supra* Part III.B.1, NGA § 1(b) extends the Commission's jurisdiction over not only "natural-gas companies" but also the interstate transportation of natural gas. FERC, however, has twice rejected the suggestion that it should invoke its transportation jurisdiction over municipalities.[63] *See Tennessee Gas Pipeline Co.*, 69 F.E.R.C. ¶ 61,239, at 61,906-07 (1994), *reh'g denied*, 70 F.E.R.C. ¶ 61,329 (1995); *Texas Eastern Transmission Corp.*, 51 F.E.R.C. ¶ 61,170, at 61,453-54 (1990). Accordingly, FERC wholly "agrees with [petitioners] that municipalities are beyond [its] jurisdiction." Order No. 636-A, ¶ 30,950, at 30,551.[64]

That notwithstanding, FERC may, consistent with the NGA, require municipalities to comply with its capacity release regulations. As we explained above, *see supra* Part III.B.1, FERC's transportation jurisdiction extends as a separate matter over capacity release given the involvement of interstate gas

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[63] Our opinion should not be read to either approve or disapprove the Commission's reading of the Natural Gas Act in this regard.

[64] *Accord Texas Eastern Transmission Corp.*, 51 F.E.R.C. ¶ 61,170 (1990) ("The Philadelphia Gas Works requests clarification that all the conditions imposed upon [capacity brokering] program participants do not apply to municipalities. Since municipalities are beyond the jurisdiction of this Commission, the Philadelphia Gas Works is correct."); *Northwest Alabama Gas District*, 42 F.E.R.C. ¶ 61,371, at 62,086 (1988) ("It is well settled that we cannot regulate a municipality under the NGA or the NGPA."); *Panhandle Eastern Pipe Line Co. v. City of Rolla*, 26 F.P.C. 736, 738 (1961) ("From [the plain language of the Natural Gas Act] it is clear that municipalities cannot be "natural-gas companies' as that term is used by the Act. We are not, therefore, vested with jurisdiction to regulate municipalities, even though they are engaged in the sale of natural gas to interstate pipeline companies.").

pipelines.[65] The pipelines' role in capacity release is absolutely central,[66] and the transaction itself controls access to interstate transportation capacity, entirely independent of the jurisdictional nature of the releasing and replacement shippers.[67]

The analogy drawn by the Commission, and the one we find most persuasive, is to the pipeline curtailment regime. As explained in Judge Rogers' opinion for the court, *see supra* Part II.C, pipelines at times must interrupt and redistribute their service based on shortages of both gas supply and pipeline capacity. The Supreme Court has expressly approved the Commission's authority to regulate such curtailments pursuant to its § 1(b) interstate transportation jurisdiction. *See Louisiana Power & Light Co.,* 406 U.S. at 640-41. The Commission's capacity release program is strikingly similar to its curtailment regulations, in that both involve the pipelines' allocation of transportation capacity among their shippers in compliance with federally mandated strictures. As the municipalities are subject to the curtailment regulations, so too

[65] Thus, in instituting the capacity release program, the Commission legitimately invoked its authority under NGA § 5 over "any rate, charge, or classification" or "any natural-gas company," 15 U.S.C. § 717d, given that pipelines are natural-gas companies under the Act.

[66] That factor distinguishes this case from the *Texas Eastern* proceedings, 51 F.E.R.C. ¶ 61,170 (1990), in which FERC concluded that it lacked jurisdiction to require municipal LDCs to comply with its capacity brokering standards.

[67] The municipalities contend that the pipelines' involvement in capacity release is too ministerial to establish the Commission's jurisdiction. While we ultimately disagree with that argument for the reasons set forth in the text, we recognize its relevance. This could well be a different case had FERC in fact merely manipulated its regulations to involve the pipelines in a minimal way only to thereby create a jurisdictional toehold over a nonjurisdictional entity.

must they comply with FERC's standards for capacity release.

We also find compelling the acknowledged jurisdictional arrangement *prior* to the implementation of either capacity brokering or capacity release. At that time, shippers acquired firm capacity rights directly from pipelines on a first-come, first-served basis. Resales of capacity by shippers, *including municipalities,* simply did not occur. We therefore conclude that the Commission has jurisdiction to require open, nondiscriminatory capacity release by municipalities.

4. Jurisdiction over "buy/sell" arrangements

The final jurisdictional challenge to the capacity release mechanism involves "buy/sell" transactions, which FERC professed to bar[68] in Order No. 636 and the companion *El Paso Natural Gas Co.* proceedings, 59 F.E.R.C. ¶ 61,031, *reh'g denied,* 60 F.E.R.C. ¶ 61,117 (1992). "Buy/sells" occur in three stages. First, an end-user of gas either purchases or identifies certain natural gas at the point of production. The LDC that services the end-user then purchases the gas and transports it first under its own transportation rights on an interstate pipeline and later across its local distribution facilities.[69] The end-user then receives the

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[68] "Buy/sell" agreements in place before the date that Order No. 636 went into effect were allowed to continue in force, but were required to be posted on the pipeline's electronic bulletin board for informational purposes. Order No. 636, ¶ 30,939, at 30,416-17.

[69] Hadson Gas Co. contends that FERC has yet to make clear the precise nature of the transactions that it has prohibited. But as the Orders under review explain, the bar to "buy/sells" "applies to all *firm* capacity that is subject to the Order No. 636 capacity release program." Thus, in the now-prohibited transactions, an LDC holds title to gas specifically purchased by the LDC for the customer while utilizing its firm capacity rights

gas from the LDC. The "buy/sells" reviewed by the Commission in the *El Paso* proceedings were conducted under the authority and oversight of the California Public Utility Commission.

FERC acknowledges that "buy/sell" transactions implicate legitimate state regulatory interests. *El Paso Natural Gas Co.*, 60 F.E.R.C. ¶ 61,117, at 61,383-84. That said, given the transactions' intermediate stage—in which the end-user expressly arranges for the interstate transportation of specifically identified gas—the Commission contends that it has authority to *preempt* such state regulation. We therefore begin by setting forth settled principles of federal preemption.

a. Introduction to federal preemption

The Constitution provides that the laws of the federal government "shall be the supreme Law of the Land; ... any Thing in the Constitution or Laws of any state to the Contrary notwithstanding." U.S. CONST. art. VII. That principle of supremacy is implemented through the doctrine of federal "preemption,"[70] under which state and local law may be stripped of its effect. Federal preemption may occur in a variety of circumstances:

> [1] It is well established that within constitutional limits Congress may pre-empt state

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to transport the designated gas over the interstate pipeline. *El Paso Natural Gas Co.*, 60 F.E.R.C. ¶ 61,117. It is not, of course, necessarily the identical gas that the end-user receives at the delivery point.

[70] *See generally New York St. Conf. v. Travelers Ins. Co.*, 115 S. Ct. 1671, 1676-77 (1995); *Cipillone v. Liggett Group*, 505 U.S. 504, 516 (1992); *Silkwood v. Kerr-McGee Corp.*, 464 U.S. 238, 248 (1984); *Florida Lime & Avocado Growers v. Paul*, 373 U.S. 132, 141-42 (1963).

> authority by so stating in express terms. [2] Absent explicit pre-emptive language, Congress' intent to supersede state law altogether may be found from a scheme of federal regulation so pervasive as to make reasonable the inference that Congress left no room for the States to supplement it, because [(a)] the Act of Congress may touch a field in which the federal interest is so dominant that the federal system will be assumed to preclude enforcement of state laws on the same subject, or [(b)] because the object sought to be obtained by the federal law and the character of obligations imposed by it may reveal the same purpose. [3] Even where Congress has not entirely displaced state regulation in a specific area, state law is pre-empted to the extent that it actually conflicts with federal law. Such a conflict arises when compliance with both federal and state regulations is [(a)] a physical impossibility, or [(b)] where state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress.

Pacific Gas & Elec. Co. v. State Energy Resources Conserv. & Devel. Comm'n, 461 U.S. 190, 203-04 (1983) (internal citations, quotation marks, and ellipses omitted).

Moreover, federal preemptive authority may be exercised not only through federal statutes but also regulations issued by administrative agencies.[71] When an agency announces its intent to pre-empt state authority in a particular area,

> the correct focus is on the federal agency that seeks to displace state law and on the proper bounds of its lawful authority to undertake such action. The statutorily authorized regulations of an agency will pre-empt any state or local law that conflicts with such regulations or frustrates the purposes thereof. Beyond that, however, in proper circumstances the agency may determine that its authority is exclusive and pre-empts any state efforts to regulate in the forbidden area. It has long been recognized that many of the responsibilities conferred on federal agencies involve a broad grant of authority to reconcile conflicting policies. Where this

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[71] *See generally Fidelity Fed. Sav. & Loan Ass'n v. De la Cuesta,* 458 U.S. 141, 152-52 (1982); *Lincoln Sav. & Loan Ass'n v. Federal Home Loan Bank Bd.,* 856 F.2d 1558, 1560-61 (D.C. Cir. 1988); *Conference of St. Bank Super. v. Conover,* 710 F.2d 878, 881-83 (D.C. Cir. 1983).

> is true, the Court has cautioned that even in the area of pre-emption, *if the agency's choice to pre-empt represents a reasonable accommodation of conflicting policies that were committed to the agency's care by the statute, we should not disturb it unless it appears from the statute or its legislative history that the accommodation is not one that Congress would have sanctioned.*

City of New York v. FCC, 486 U.S. 57, 64 (1988) (citations and quotation marks omitted) (emphasis added).

b. Analysis

We consider petitioners' arguments regarding "buy/sell" transactions under the branch of pre-emption doctrine that concerns "conflicts" between state and federal law, and particularly state law that "stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress," *Hines v. Davidowitz,* 312 U.S. 52, 67 (1941). The Commission's goal in preempting "buy/sell" transactions was to preserve the integrity of its uniform capacity release program. *See El Paso Natural Gas,* 60 F.E.R.C. ¶ 61,117, at 61,385. Specifically, the Commission concluded that "buy/sells" offer a ready means of circumventing the open, nondiscriminatory bidding process central to capacity release. Under Order No. 636, an end-user seeking firm interstate transportation for gas that it has identified or acquired at the point of production must attempt to purchase capacity by contracting on the open market. In a "buy/sell" transaction, in contrast, the end-user can contract with an LDC without being forced to compete with other shippers that value the capacity. FERC reasoned that because "buy/sells" occur without open bidding, and result in the tying-up of interstate pipeline capacity, they circumvent and distort the transportation market envisioned by

Order No. 636.[72]

The LDCs contend that preemption is inappropriate in this instance because the Commission's prohibition on "buy/sells" constitutes a regulation of the retail sale of natural gas, which Congress reserved to the jurisdiction of state regulatory bodies. While the Commission emphasizes the intermediate, transportation stage of the transaction, the LDCs focus on the terminal stage, describing "buy/sell" agreements as a classic instance of an LDC making a retail sale to a retail customer. *Cf. AGD I,* 824 F.2d at 995 ("LDCs purchase gas for resale to end users, large and small. Their services and prices are subject to state regulation but not to that of FERC."). As the LDCs characterize the transaction:

> A retail customer participating in a buy/sell arrangement with an LDC purchases the same product purchased by other retail gas customers: natural gas, delivered to the point of consumption, at a state-regulated price that includes the cost of (a) the gas; (b) the inter- and intrastate transportation required to move the gas from the market or production area to the point of consumption; and, (c) all other local distribution services, such as balancing and metering costs.

LDCs' Reply Br. at 8. Further, given the express terms of NGA § 1(b), the LDCs maintain that the Commission's jurisdiction cannot arise merely by means of some *effect* of "buy/sell" agreements on

[72] Hadson Gas Co. suggests that FERC "ignored relevant differences among shippers" in prohibiting *all* "buy/sell" arrangements, without regard to the market power of the particular shipper. In particular, Hadson contends that while LDCs may hold sufficiently substantial capacity rights to exercise market power, the same cannot be said of gas marketers. As FERC notes, however, when the capacity available for sale on a particular pipeline is limited, holders of even relatively small capacity allotments can exercise market power. Further, holders of smaller capacity shares are able to increase their market power by pooling their holdings and marketing them together. *See* Order No. 636-A, ¶ 30,950, at 30,558.

interstate transportation; such an interpretation of the Act would dramatically expand FERC's jurisdiction because almost all gas travels interstate and therefore almost all retail sales of gas affect interstate transportation. *See also Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 308 (1988) ("Of course, every state statute that has some indirect effect on rates and facilities of natural gas companies is not preempted."). Thus, conflict pre-emption analysis must be applied with particular care in those instances in which the Commission seeks to preempt state regulation merely because it has some *effect* on the interstate transportation of natural gas. *Northwest Central Pipeline v. State Corp. Comm'n*, 489 U.S. 493, 515-16 & n.12 (1989).

We believe that the LDCs have confused two separate issues. While the Commission's *rationale* in preempting "buy/sells" is the transactions' effect on interstate transportation—namely, that "buy/sells" facilitate circumvention of the capacity release program—the Commission's *authority* is grounded in the transaction itself.[73] In the intermediate stage of a "buy/sell" transaction, the LDC carries the gas identified by the end-user on its own firm capacity and under its own title on an interstate pipeline.

[73] Indeed, it is in truth the LDCs that would bootstrap jurisdictional implications to the *effects* of Order No. 636. According to the LDCs, "buy/sell" agreements allow them to distribute and utilize their capacity rights more efficiently. This has as a secondary effect "lowering the unit cost of gas to" end-users, which the LDCs characterize as a "traditional and legitimate state interest[ ]." That proposition sweeps far too broadly. Almost every element of the Commission's regulation of interstate transportation affects distributors' costs, which must be passed on to local end-users. Regulation of interstate transportation is not thereby converted into a ground for exclusive state jurisdiction.

Contrary to the LDCs' characterization, FERC's jurisdiction arises from the transportation itself; interstate transportation of gas selected by the end-user is *a central element of the parties' agreement.* As FERC states in its brief, "buy/sells" are "at bottom nothing more than agreements by which firm shippers allocate space on an interstate pipeline to customers who negotiate their own wellhead transactions." Transactions that do not include this transportation element *are not "buy/sells*" and are not preempted.

In a standard retail sale, by contrast, the end-user purchases gas from an LDC at the local delivery point without regard to aspects of gas transportation at points further upstream. *See id.* at 97 ("Traditional LDC retail sales consisted of sales of gas to local customers from generic system supply through local distribution facilities *after* the gas had completed its interstate journey."). Order No. 636 does not prohibit or condition such sales. Nor does the Order preempt state regulatory agencies from modifying an LDC's rate structure to accommodate differences in local conditions. Further still, LDCs remain free to *sell gas* to retail customers under the terms and conditions set by state regulators. Under Order No. 636, an end-user that would previously have engaged in a "buy/sell" transaction will still purchase the gas from the producer and still receive the gas at its delivery point. The crucial difference is that the end-user must purchase capacity rights from the LDC in the open market through the capacity release mechanism rather than by transferring title to the gas to the LDC and regaining title at the local delivery point.

Accordingly, we sustain the Commission's determination to ion to pre-empt state regulation of "buy/sell" transactions. FERC's effort to avoid circumvention of its capacity release regulations "represents a reasonable accommodation of conflicting policies that were committed to [its] care" under the Natural Gas Act. *City of New York,* 486 U.S. at 64. Further, given that the regulations do not impinge upon state control over retail gas sales, it appears that the Commission's accommodation is one that Congress would have sanctioned. *See id.*

C. Substantive Challenges

1. Exclusion of Part 157 shippers from capacity release

In Order No. 636-A, the Commission concluded that only "Part 284" blanket-certificated shippers would be permitted to engage in capacity release and utilize flexible receipt and delivery points. Order No. 636-A, ¶ 30,950, at 30,565. The Electric Generator Petitioners ("Electric Generators") contend that FERC's exclusion of Part 157 "individually certificated" shippers[74] was arbitrary and capricious. Their theory is that capacity release and flexible receipt and delivery points were intended to compensate for the greater costs of straight-fixed-variable rate design, which both Part 284 and Part 157 shippers are subject to; excluding Part 157 shippers from capacity release therefore allegedly deprives them of a necessary and equivalent means of cost mitigation. They also contend that subjecting Part 157 shippers to SFV rate design while

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[74] These shippers transport gas pursuant to individual certificates issued by the Commission under Part 157 of its regulations. The critical difference between Part 157 and Part 284 shippers is that Part 157 shippers have always been able to transport non-pipeline owned gas, while Part 284 shippers generally have had that capability only since the promulgation of Order No. 436. *See MPC I,* 761 F.2d at 782.

excluding them from capacity release is unduly discriminatory, given that both SFV rate design and capacity release were intended to develop a national natural gas market.

The Commission's decision to exclude Part 157 shippers from capacity release and flexible receipt and delivery points was not arbitrary and capricious. While capacity release does ameliorate the costs of SFV rate design, it was never intended as the central cost-mitigation measure, *see* Order No. 636-A, ¶ 30,950, at 30,594, 30,597-98, for there are specific mechanisms in place intended to address the particular costs associated with SFV, including alternative ratemaking techniques, phase-in measures, and the continued use of one-part rates for small customers. *See infra* Part IV.C.1. Moreover, allowing individually certificated shippers to utilize capacity release would in effect require Part 284 shippers to subsidize their Part 157 counterparts, given that Part 284 shippers pay *costs* that Part 157 shippers do not.[75] Specifically, Part 157 shippers are not required to pay the

[75] The Electric Generators maintain that their exclusion from capacity release represents a downgrade in their service because Order No. 636 also prohibited them from selling capacity under the Commission's predecessor "capacity brokering" program. They contend that because the Commission is eliminating a pre-existing program, it is obligated to offer a particularly persuasive rationale for its decision. *Cf. Williams Natural Gas Co. v. FERC,* 872 F.2d 438, 444 (D.C. Cir. 1989). But, as FERC notes, capacity brokering was authorized on only a few pipelines, so that widespread capacity release is in fact a major service upgrade. Moreover, the Commission's rationale in implementing capacity release applies equally to its decision to bar Part 157 customers from continuing to engage in capacity brokering, and is persuasive. Finally, as the Commission maintains, and the Electric Generators essentially concede in their reply brief, FERC's policy granting Part 157 shippers access to capacity brokering "was a settlement, was expressly limited to the facts in that proceeding, was adopted only on an interim basis, and was never intended to survive Order No. 636."

transition costs of Order No. 636, and their transportation arrangements are not subject to pre-granted abandonment. Further, the Commission prohibits Part 157 shippers, which do not operate under open-access provisions, from including unique terms and conditions in their contracts in order to avoid undue discrimination. For that very reason, the Commission prohibits Part 157 shippers from granting discounts, which itself presents a major obstacle to Part 157 shippers' participation in capacity release because competitive bidding presumes the ability to offer a lower price.

The Electric Generators reply that these factors have no connection to the cost-mitigation effects of the capacity release program. The more salient issue, however, is whether the factors identified by either the Commission or the Electric Generators have any intrinsic connection to SFV rate design; they do not. Fundamentally, the petitioners contend that they are entitled to release capacity as one way of making up for the costs of SFV. FERC replies, quite sensibly, that while capacity release would reduce the Electric Generators' costs, including costs associated with SFV, the Electric Generators are *already* receiving cost benefits not available to Part 284 customers, and are not entitled to further benefits.

Nor was the Commission's decision to exclude Part 157 shippers unduly discriminatory. The Commission applied SFV rate design to both Part 284 and Part 157 shippers because both generally have been subject to the same rate design. *See* Order No. 636-B, ¶ 61,272, at 61,992. Even if the goal of both SFV rate design and capacity release is the creation of a national gas market, that does not mean that FERC's decision to apply only one to Part 157 shippers constitutes undue discrimination. "[T]he competitive rationale for adopting SFV rate design as a means to promote the development of a national gas market applies equally to [Part 284 and] Part 157 rates." *Id.* While allowing Part 157 shippers to engage in capacity release might expand the national gas marketplace, as we have explained, it would also give them an unfair subsidy over Part 284 shippers. As FERC notes in its brief, "[g]iven the significant differences between these two forms of service under Order No. 636, it was not unreasonable to confine the capacity release program to Part 284 open access service." We see no reason to disturb the Commission's conclusion that those cost considerations outweighed any benefit to the national gas marketplace and disentitled Part 157 shippers from engaging in capacity release.

Moreover, as the Commission explains, the Electric Generators may receive access to capacity release and flexible receipt and delivery points by converting to Part 284 service. This does not mean, as petitioners contend, that the Commission is unlawfully attempting to leverage the Electric Generators' conversion. Here, we reject petitioners' reliance on *National Fuel Gas Supply Corp. v. FERC,* 909 F.2d 1519 (D.C. Cir. 1990). In *National Fuel,* this court turned back an effort by FERC to condition its certification of a Part 157 shipper's gas services on the shipper's obtaining a blanket Part 284 certificate as well. Our ruling there was based on the fact that the Commission had already determined that a Part

157 certificate was "required by the public convenience and necessity" when it nonetheless attempted to add the additional condition of acquiring a Part 284 certificate. Given the Commission's conclusion that the shipper was already entitled to a Part 157 certificate, "[i]t was thus clear at the outset that the Commission considered certification ... to be in the public interest regardless of whether the pipeline also accepted a blanket transportation certificate." *Id.* at 1522. FERC therefore lacked *authority* to deny the shipper a Part 157 certificate. In this case, in contrast, the Electric Generators do not contend that the Commission has determined that Part 157 shippers have the right to engage in a certain service, but is nonetheless denying them the right to engage in it. Moreover, even under the petitioners' far more expansive reading of *National Fuel,* this is not an instance in which FERC is attempting to coerce a conversion from Part 157 to Part 284 service; the Commission is simply pointing out that conversion offers the Electric Generators one means of cost-mitigation.

2. <u>The standard for determining the best bid</u>

The LDCs and Industrial End-Users raise three challenges to the methods selected by the Commission for determining the prevailing bidder and price in the capacity release transaction. In Order No. 636, FERC concluded that conditions set by LDCs on their release of capacity "must not prefer any shipper, such as an end-user, over other shippers, and cannot take into account the use of the LDC's own facilities." Order No. 636-B, ¶ 61,272, at 61,997. The LDCs maintain that, in a market sense, this rule prohibits them from selecting what is truly the "best" bid, *i.e.*, "one that reflects [the] greatest economic benefit to the releasing shipper." Specifically, the LDCs want the right to favor their own end-users in capacity sales, a practice that ultimately would reduce the LDCs' own costs. But that is not a right to which they are entitled under the Natural Gas Act. The LDCs' claim is at bottom nothing more than an objection to FERC's open-access, nondiscrimination policy. The goal of capacity release is to create a uniform national market for transportation, not to maximize the benefit to LDCs. Only by utilizing nondiscriminatory factors in determining the prevailing bid can FERC ensure that the shipper that places the highest value on capacity receives it.

The Industrial End-Users make the related argument that FERC acted arbitrarily in refusing to grant a bidding preference to LDCs' existing end-users. In particular, they note that FERC *did* grant existing end-users a preference in acquiring capacity released by upstream pipelines under the section 284.242 mandatory capacity release program. As with the immediately preceding claim, however, the standard set by FERC fundamentally is part of its nondiscrimination and open-access policy. Moreover, as FERC notes, an end-user can be sure of receiving capacity by entering into a pre-arranged deal with its LDC at the maximum allowable price.[76] The preference granted under the mandatory program, in contrast, is

[76] While an LDC could conceivably refuse to make such a deal, it would have no incentive to do so because no other transaction can provide it with a higher price. Further, as the Commission notes in its brief, claims that an LDC discriminated against its end-users in allocating capacity may be addressed through the NGA § 5 complaint procedure.

unrelated to the development of a transportation market through capacity release; it is specifically intended to ensure that when pipelines engage in *unbundling*, their end-users are not deprived of the transportation necessary to fulfill their pre-existing gas needs.

The Electric Generators finally contend that FERC should not uniformly have set the maximum allowable rate for resales of capacity at the originally determined maximum rate. They contend that this will in some instances result in discrimination against shippers who pay higher initial "incremental" rates.[77] The Commission responds that this issue is too complex and fact-bound to address in the overarching Order No. 636 proceedings, and that it should be deferred to the restructuring proceedings, where a better record can be developed. *See* Order No. 636-A, ¶ 30,950, at 30,561 ("[T]he parties in restructuring proceedings involving incremental rates should consider and propose methodologies to ensure that the capacity release mechanism operates efficiently and that all parties are treated fairly and equitably, without undue discrimination."). We agree. The Electric Generators' explication of their claim in these proceedings is far too sparse to allow for reasoned evaluation, primarily because the relevant factual record is not before us. Their claim may properly be evaluated by the Commission in individual restructuring proceedings where further facts can be developed.

[77] For a discussion of incremental rates, see generally *Transcanada Pipelines Ltd. v. FERC*, 24 F.3d 305, 308-11 (D.C. Cir. 1994); *Algonquin Gas Transmission Co. v. FERC*, 948 F.2d 1305, 1312-14 (D.C. Cir. 1994).

3. <u>Interruptible transportation revenue crediting</u>

After the implementation of capacity release under Order No. 636, the number of firm transportation sellers in the marketplace substantially increased. As a result, it became difficult for pipelines to determine how much demand there will be for interruptible transportation ("IT") service. In turn, it is difficult for the pipelines to determine what portion of their costs to recoup through billings to IT (as opposed to firm) service. In the Order No. 636 proceedings, FERC suggested that a pipeline

> might decide to attribute no revenue responsibility to interruptible transportation. Since the pipeline's firm shippers would be responsible for all pipeline costs, revenues from the sale of interruptible transportation would [later] be credited to the firm shippers.

Order No. 636-A, ¶ 30,950, at 30,563. Under true cost accounting, 100% of IT revenues would be credited to firm shippers, because firm customers are essentially being overcharged until the pipeline can figure out how much money it is recovering from IT service. The Commission suggested, however, that pipelines might adopt a 90/10 mechanism, under which only 90% of IT revenues would be credited to firm shippers. This 10% difference was thought by FERC to be a necessary incentive for pipelines to market interruptible transportation. Without it, pipelines would be assured of recovering their costs through firm sales charges, and therefore would have no reason to maximize IT throughput.

The Industrial End-Users, who utilize interruptible transportation, challenge the Commission's endorsement of a 90/10 IT revenue crediting mechanism on two grounds. First, they argue that the 10% gain creates an *insufficient incentive* for pipelines to market IT. The Industrial End-Users note that FERC rejected proposals for revenue crediting under Order No. 436, because they "give[ ] the pipeline little or no incentive to provide service under the rule." Order No. 436, ¶ 30,665, at 31,537. Second, they argue that the 90/10 mechanism reduces other shippers' incentive to release capacity; shippers know that if they do not put their firm capacity on the market, thereby forcing other companies to utilize IT service, they will receive some portion of the IT revenues through the crediting mechanism anyway.

We conclude that the Industrial End-Users' challenge to the IT revenue crediting mechanism is premature. Order No. 636-A expressly provides that pipelines "might" adopt this "potential approach," and that "parties to the restructuring proceedings also may consider whether other methods are needed." Order No. 636-A, ¶ 30,950, at 30,563; *see also* Order No. 636-B, ¶ 61,272, at 62,000 ("[T]he parties to the restructuring proceedings could consider a variety of approaches, such as agreeing on an appropriate level of throughput for interruptible transportation or some type of revenue crediting mechanism.").[78] Our concerns are magnified given that the Industrial End-Users maintain that the 10% pipeline credit does not provide pipelines with a sufficient incentive to market IT, but provide no data or explanation of why that is the case. The only way to evaluate their claim is in the light of the particular facts

[78] While the Industrial End-Users contend that the Commission has been applying the 90/10 mechanism as a rigid rule, they concede that it approved an 80/20 mechanism in *CNG Transmission Corp.*, 64 F.E.R.C. ¶ 61,082, at 61,776-66 (1993).

presented in individual pipelines' restructuring proceedings. *See id.* ("The petitioners requesting rehearing have not been aggrieved by the suggestion that the Commission would consider a revenue crediting approach proposed in a specific restructuring proceeding. In implementing its regulations, the Commission will not adopt rigid rate-making methodologies that fail to reflect the reality of the market or the intent of its regulations."). We therefore defer resolution of the Industrial End-Users' IT revenue crediting challenge to the individual pipeline restructuring proceedings.

D. Conclusion

We deny the petitions for review insofar as they dispute the Commission's jurisdiction over capacity release transactions. We further deny the petitions for review insofar as they challenge (1) the exclusion of Part 157 shippers from the capacity release program, (2) the mechanism chosen by the Commission for determining the best bid in capacity release transactions, and (3) the Commission's suggestion that a 90/10 mechanism is an appropriate means of crediting interruptible transportation revenues. We specifically defer to later proceedings consideration of the merits of both the revenue crediting mechanism and the Commission's treatment of incremental rates.

IV. Rate Design

Various petitioners raise three major challenges to the rate design portion of the Order No. 636 series. As noted above, FERC ordered a change from the preexisting modified fixed variable (MFV) to a straight fixed variable (SFV) rate design. First, petitioners question whether FERC has authority under the NGA to adopt SFV rate design. Second, they question whether FERC's decision to switch from MFV rate design to SFV rate design was a reasonable one. Third, they question whether the mitigation measures FERC employed to ease the shift to SFV rate design are within FERC's ratemaking discretion.

A. FERC's Authority to Adopt SFV Rate Design

1. MFV rate design's anticompetitive effects

FERC's authority over rate design in this case derives from NGA § 5, which requires it to replace any "unjust, unreasonable, unduly discriminatory, or preferential" rate, charge or classification charged "by any natural-gas company in connection with any transportation or sale of natural gas" with a "just and reasonable rate, charge, [or] classification." 15 U.S.C. § 717d. Under the preexisting MFV design, the pipelines incorporated into commodity charges to their sales customers and usage charges to their transportation customers fixed costs that varied greatly from pipeline to pipeline. Accordingly, the unit prices to gas customers did not accurately reflect the actual variable cost of supplying gas, because producers in different gas fields "compete for market share via different pipelines," so that their competitive positions in the market reflected the fixed costs in the pipelines' respective transportation usage charges and not simply "the producers' own costs and efficiencies in producing gas." Order No. 636, ¶ 30,939, at 30,434. The Commission concluded that a shift to the SFV rate design, under which the usage charges accurately reflect the actual variable costs of delivering gas, would remove this impediment to efficient competition.

The LDC petitioners[79] argue that FERC had no authority to take regulatory action on the basis of MFV rate design's anticompetitive effects on gas producers. They admit that FERC must consider the anticompetitive effects of rate design systems, but contend that FERC can only consider the anticompetitive effects of a system *on entities it regulates directly* (*i.e.*, pipelines themselves), not on unregulated industries such as gas producers, and they argue that MFV's anticompetitive effect on gas *suppliers* does not constitute an anticompetitive effect on *pipelines.* The LDCs cite in support of their position *Official Airline Guides, Inc. v. Federal Trade Comm'n,* 630 F.2d 920, 927-28 (2d Cir. 1980), *cert. denied,* 450 U.S. 917 (1981), in which the Second Circuit struck down a Federal Trade Commission ("FTC") ruling that a monopoly airline guide publisher's refusal to publish flight schedules for certain airlines impaired competition in the airline industry. The Second Circuit held that the FTC Act's power to proscribe anticompetitive conduct did not extend to the restraint of a business's practices solely because of the conduct's incidental effect on competition between third parties in another industry.

As the LDCs stress, antitrust policy "does not outlaw the practices of a party solely because those practices may indirectly affect competition between other entities with which it does not compete." Though the LDCs' premise is valid, it does not answer

[79] LDC petitioners presenting this argument include Atlanta Gas Light Co., Chattanooga Gas Co., Peoples Natural Gas Co., and Southwest Gas Co. Washington Gas Light Co. is a supporting intervenor.

the question of whether FERC has the authority to consider anticompetitive effects on unregulated segments of the gas industry in setting rates for the regulated pipelines. The Second Circuit's decision simply does not purport to answer that question. Rather, the *Official Airline Guides* court was extending the doctrine established in *United States v. Colgate & Co.*, 250 U.S. 300, 307 (1919) (as quoted in *Official Airline Guides*, 630 F.2d at 925), that, "[i]n the absence of any purpose to create or maintain a monopoly," antitrust policy "does not restrict the long recognized right of trader or manufacturer engaged in an entirely private business, freely to exercise his own independent discretion as to parties with whom he will deal." In fact, the *Official Airline Guides* court noted the dangers of departing from this principle of independent business judgment: "[W]e think enforcement of the FTC's order here would give the FTC too much power to substitute its own business judgment for that of the monopolist in any decision that arguably affects competition in another industry." *Official Airline Guides*, 630 F.2d at 927.

In contrast, FERC's decision in Order 636 represents not the rolling back of an independent business judgment because of its anticompetitive effect on an unrelated industry, but rather the substitution of one administratively imposed ratemaking regime for another based on the anticompetitive effect of the preexisting regime on unregulated entities dealing through regulated entities in a partially regulated segment of the economy—that is, the regulated pipeline segment of the partially regulated natural gas industry. The Commission's express duty under NGA § 5 to set aside rates and practices that it finds unjust, unreasonable, unduly discriminatory, or preferential is not limited to the remedies that the FTC may order in an unregulated market; nor is FERC's basis for the exercise of that authority necessarily as limited as the FTC's bases for enforcement decisionmaking. Antitrust policies governing the FTC in the unregulated market do not exhaust the public interest grounds on which the Commission may order a change in rates under NGA § 5. Here, given that we review the Commission's acts under the deferential "substantial evidence" standard, 15 U.S.C. § 717r(b); *Town of Norwood v. FERC*, 962 F.2d 20, 22 (D.C. Cir. 1992), we hold that the Commission adequately justified its exercise of its authority when it stated that its ratemaking authority "includes the establishing of just and reasonable transportation rates that maximize the benefits of decontrol to gas consumers," Order No. 636-A, ¶ 30,950, at 30,594-95, and that regulated transportation rates "should in no way inhibit the creation of a national gas market of efficient gas merchants as envisioned by Congress in enacting the Decontrol Act." Order No. 636, ¶ 30,939, at 30,433. Unlike the FTC in *Official Airline Guides*, FERC was not attempting to limit the options of a free business actor in order to promote competition in an adjacent industry, but only to prevent the regulatorily imposed price decisions of a regulated industry from creating anticompetitive factors in economically adjacent markets.

2. <u>SFV rate design and NGA § 5</u>

The PUCs argue that FERC's ordering of the switch to SFV rate design exceeds its statutory authority. Under the NGA, FERC draws its ratesetting authority from two sections: NGA § 4 (15 U.S.C. § 717c) authorizes FERC to accept or reject rates and rate adjustments filed by natural gas companies; and NGA § 5 (15 U.S.C. § 717d) authorizes FERC after a hearing and upon findings that an existing rate is "unjust, unreasonable, unduly discriminatory, or preferential" to fix "just and reasonable rate[s] ... by order." The PUCs contend, and FERC admits if we reach the merits, that the Commission draws its authority in the present restructuring from § 5, or not at all, as no natural gas company has filed the rate structure which FERC is imposing. The PUCs argue that FERC's order imposing the new rate structure exceeds its authority under § 5 because that section expressly provides "[t]hat the Commission shall have no power to order any increase in any rate contained in the currently effective schedule" then on file with the Commission. Because the new rate structure will result in an increase in charges to some customers, the PUCs argue that FERC's order violates this provision.

FERC first contends that this rate increase argument is not properly before the court "because none of these petitioners raised it before the Commission in their requests for rehearing of Order No. 636." As FERC rightly suggests, the party who raises an issue in a petition for review must have raised the same issue in its petition for rehearing before the agency. *ASARCO, Inc. v. FERC*, 777 F.2d 764, 773-75 (D.C. Cir. 1985). However, Atlanta Gas Light Company ("Atlanta") and Chattanooga Gas Company ("Chattanooga") specifically raised the rate increase argument in their petition for rehearing of Order No. 636. Request of Atlanta Gas Light

Company and Chattanooga Gas Company for Rehearing and Clarification at 14-16 (May 8, 1992). And in the LDCs' brief in this court, several LDCs (including Atlanta and Chattanooga) cross-reference the PUCs' presentation of the rate increase argument, thereby incorporating the argument into the LDC brief before us. Therefore, because Atlanta and Chattanooga raised the rate increase argument in their petition for rehearing before FERC and raise it again in the present proceeding, the argument is properly before us, and we must consider it on its merits.

In Order No. 636-A, FERC disposed of the rate increase argument by relying on *ANR Pipeline Co. v. FERC,* 863 F.2d 959 (D.C. Cir. 1988). In that case a pipeline filed a § 4 schedule to implement a rate *reduction.* Order No. 636-A, ¶ 30,950, at 30,666. FERC, using its § 5 authority, determined that the pipeline's rate design methodology was unjust and unreasonable (when a pipeline files a § 4 rate schedule, FERC can transform the proceedings into a § 5 action. *Western Resources, Inc. v. FERC,* 9 F.3d 1568, 1579 (D.C. Cir. 1993)), and ordered the company to implement MFV rate design and to eliminate its minimum billing practice. Under the minimum billing practice, certain customers "were obligated to pay ANR, in each contract year, an amount equal to the fixed-cost portion of the commodity rate times the greater of (1) the volume actually purchased by the customer, or (2) a "minimum bill quantity' (MBQ) specified by contract." *ANR Pipeline,* 863 F.2d at 960; *see also supra* at 27 n.29 (describing minimum billing practices). One of ANR's largest customers, Michigan Consolidated Gas Company ("MichCon"), was paying more than its allocatable share of fixed costs because of the minimum bill requirement. *ANR Pipeline*, 863 F.2d at 960. Once ANR eliminated the minimum bill in compliance with FERC's order, it recalculated the per-unit share of fixed costs based on the decreased number of total units over which to allocate fixed costs. (After eliminating the minimum bill, the projected number of units over which to allocate fixed costs necessarily decreased for MichCon, since MichCon had not purchased and was not expected to purchase the MBQ of gas.) As a result, the per-unit share of fixed costs incorporated in the commodity charge went up.

Although FERC initially rejected ANR's proposed "increase" in commodity rates as a violation of the filed rate doctrine, we reversed that decision, concluding that FERC "had not rationally explained why its requirement that ANR's minimum bill had to be removed would not authorize the removal of volumes attributable to the minimum bill for purposes of calculating the amount of the fixed-cost commodity charge." Order No. 636-A, ¶ 30,950, at 30,667. The Commission therefore reads *ANR Pipeline* as standing for the proposition that "when the Commission orders a pipeline to implement a different rate design method that requires reductions in one component of the pipeline's rates, it must permit the pipeline to implement offsetting increases in some other component simultaneously in order for the pipeline to recover its cost of service." *Id.*

FERC's argument based on *ANR Pipeline* is a powerful one. Our reasoning in *ANR* supports a small scale version of the large scale balanced restructuring with offsetting features that FERC has ordered in the present proceeding. *ANR* is not, however, totally dispositive. The issue in that case came to us at a later stage. In *ANR,* after the Commission had made its initial § 5 ruling, the pipeline had made a compliance filing. That filing incorporated the contested "increase." Reviewing FERC's rejection of the compliance filing, we could not conclude that the Commission had "rationally explained why that filing [did] not comport with" the earlier instruction to the submitting pipeline. *ANR Pipeline,* 863 F.2d at 964. We did not therefore purport to authoritatively decide the breadth of the limitation in § 5 providing "that the Commission shall have no power to order any increase ... unless such increase is in accordance with a new schedule filed by such natural gas company." 15 U.S.C. § 717d. That is, we did not determine how that section applies in the case of a Commission-initiated rate restructuring which, while reducing rates for some customers, necessarily offsets that reduction by an at least present increase in the share borne by others. Thus, *ANR* is at best persuasive rather than controlling authority in favor of the Commission's asserted power to order a restructuring that results in increasing some components to the detriment of some pipeline customers.

Also relevant to our determination of the issue is our decision in *Western Resources Inc. v. FERC,* 9 F.3d 1568 (D.C. Cir. 1993). In that case, the existing schedule included a "forward-haul rate" of approximately 20.05 cents per Mcf and a "backhaul rate" of one cent per Mcf. *Id.* at 1571. The pipeline filed a § 4 revised tariff sheet featuring increases in both the forward-haul and backhaul rates, making them equal to one another at a level above the former 20.05 cents per Mcf forward-haul rate. *Id.* FERC approved the forward-haul rate increase, but set the new backhaul rate at one-half the forward-haul rate. *Id.* at 1571-72. We remanded the case to FERC, however, holding that it had failed to sufficiently justify its decision as to the forward-haul rate and that it had improperly concluded that it could use its § 4 authority to grant half the requested backhaul increase. We determined that FERC's decision to increase the backhaul rate to only half the level requested was so far removed from the requested increase that it constituted an exercise of § 5 authority and not § 4. *See id.* at 1578-79. We remanded the backhaul increase on the grounds that FERC had not met the burden of proof imposed on it by § 5. *See id.* at 1580. Our opinion in *Western Resources* is susceptible of two interpretations. First, because we remanded for further consideration rather than vacating altogether a Commission order that amounted to a restructuring under § 5 including component increases, we implicitly concluded that FERC had the general authority to conduct such restructuring and only remanded for a determination as to FERC's use of that authority on the specific rate before it. In *Western Resources,* the turning point of our decision was that FERC had erroneously purported to use § 4 authority where it was unavailable. As § 5 authority was the only authority left, if FERC had acted properly at all, it must have been under § 5. Our *Western Resources* opinion is also subject to the interpretation that in that case we remanded to FERC for the possibility of a rate *decrease* under § 5, considering the relevant baseline to be the pipeline's § 4 submission, which proposed rates higher than those that the Commission was willing to approve. Under the first of these possible interpretations, our remand to the Commission to reconsider its action under § 5 may carry some implication that we deemed it to have the authority it purports to use now, but that implication is not a strong one, and again, our existing circuit law at most inclines us toward FERC's position but does not compel us to adopt it. Under the second possible interpretation of *Western Resources*, the case is simply not on point at all.

We therefore today for the first time authoritatively determine the issue of whether a § 5 rate restructuring that includes an increase in some rate components to the detriment of some customers amounts to a prohibited "rate increase" under § 5 itself. As FERC claims this authority under the Natural Gas Act, a statute committed to its administration, we review the Commission's decision under the deferential standard dictated in *Chevron U.S.A., Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837, 842-43 (1984). At the first step of that familiar two-step inquiry, we ask "whether Congress has directly spoken to the precise question at issue." *Id.* at 842. That is the point at which our inquiry ends "if we can come to the unmistakable conclusion that Congress had an intention on the precise question at issue," *Nuclear Information Resource Service v. NRC*, 969 F.2d 1169, 1173 (D.C. Cir. 1992) (in banc) (internal quotations and citations omitted). This is not such a case.

In reaching that conclusion we have examined first the plain language of the statute. The relevant text states: "[T]he Commission shall have no power to order any increase in any rate contained in the currently effective schedule of such natural gas company on file with the Commission, unless such increase is in accordance with a new schedule filed by such natural gas company." 15 U.S.C. § 717d(a). At first reading, it may be most natural to suppose that Congress included within the prohibition against "any increase in any rate" a preclusion of Commission orders for rate restructuring that would ultimately lead to rate increases for some pipeline customers. However, supposition and first reading are not the stuff of unambiguous expressions of intent, and the plain language does not convince us that Congress unambiguously intended the interpretation petitioners support. To further inform our inquiry into congressional intent, we examine the complete statutory scheme. *Davis v. Michigan Dep't of the Treasury*, 489 U.S. 803, 809 (1989) ("It is a fundamental canon of statutory construction that the words of a statute must be read in their context and with a view to their place in the overall statutory scheme."). The scheme considered under the NGA today contemplates that FERC must act consistently with the Natural Gas Wellhead Decontrol Act of 1989, Pub. L. No. 101-60, 103 Stat. 157 (1989), as well. That enactment contemplates a considerably changed natural gas world in which regulation plays a much reduced role and the free market operates at the wellhead. While a court construing congressional intent in one enactment should not be too greatly influenced by the enactments of a later Congress, we must necessarily consider the duties faced by an agency in examining its construction of its enabling acts. While this part of our analysis usually occurs at the second step of *Chevron*, it is not irrelevant to the first. A commission charged with the regulation of the rates of an industry may be expected to restructure its general mandates when its world changes. If the enabling act under which it operates can be construed so as to give it that authority, that construction should not be ruled out in the absence of a genuinely unambiguous expression of a congressional intent to the contrary. The general language prohibiting "rate increases" under § 5 is not so plainly directed at such a preclusion.

Insofar as legislative history is an appropriate guide to the unambiguous intent of Congress, the little available in the present instances argues against rather than for the claim of unambiguous congressional intent advanced by petitioners. At the time of the adoption of the NGA, Representative Clarence Lea, a principal sponsor of the NGA and chairman of the committee which reported it to the House, declared that "[t]he purpose of [the amendment creating the § 5 rate increase prohibition] was to prevent any company's rates being raised over their objection, with the idea of stifling competition with a competitor." 83 CONG. REC. 9101 (1938) (Statement of Rep. Lea). Under this interpretation, the prohibition was included not so much for the protection of gas consumers from rate increases, but to protect a pipeline disfavored by FERC from suffering under FERC-imposed rate increases that would harm the pipeline's ability to compete. While it is not of course impossible for a statute to have two purposes, the intent advanced by Lea supports the proposition that Congress did not unambiguously intend that § 5 would protect customers from restructured rate designs ultimately leading to increased charges. In short, § 5 is not unambiguous. The provision may easily be read to prohibit FERC from ordering increases in specific filed rates while leaving it free to order the restructuring of rates as it has attempted to do here.

As we have found that the statute is not unambiguous with respect to the specific issue before us, we proceed to the second step of the *Chevron* analysis. "At this stage, we defer to the agency's interpretation of the statute if it is reasonable and consistent with the statute's purpose." *Nuclear Information Resource Service,* 969 F.2d at 1173 (internal quotations and citation omitted). Having already observed in our step one analysis that the Commission's interpretation is consistent with the structure and purpose of the statute, we have no difficulty in finding that interpretation a reasonable one at step two. The petitioners' proffered interpretation is also a reasonable, indeed, perhaps a more natural interpretation of the statutory language. That, however, is not the standard. Even if we were convinced that the petitioners' interpretation were the better one, "we are not free to impose our own construction on the statute, as would be necessary in the absence of an administrative interpretation." *Id.* (internal quotations, brackets, and citation omitted). The only question is whether the agency's interpretation is reasonable and consistent with the statutory purpose. The answer to that question is yes. FERC undoubtedly has the authority to restructure pipeline rate calculation mechanisms, as long as it does so in an otherwise lawful manner and supports its actions with substantial evidence. Any restructuring, even if it does not alter a pipeline's revenues by one cent, will virtually always increase by some amount the charges that some individual customers pay and decrease the charges to some others. Reading § 5 in such a way that these increases for some customers constitute prohibited "rate increases" leads to the conclusion that FERC has no authority to restructure pipeline rates at all. FERC is not required to so interpret the statute.

B. SFV Rate Design and Substantial Evidence

1. MFV rate design's distortions of the natural gas market

For several decades, FERC's ratemaking regime has included some portion of a pipeline's fixed costs in the pipeline's commodity and usage charges. Over the years, it varied the specific percentage of fixed costs actually included in those charges, but it generally followed the principle that some portion of fixed costs should be recouped through quantity-dependent charges.[80] In 1986, the Seventh Circuit upheld FERC's 1983 adoption of the MFV rate design in use prior to the promulgation of Order No. 636. *See* Order No. 636, ¶ 30,939, at 30,432 (citing *Northern Indiana Pub. Serv. Co. v. FERC*, 782 F.2d 730 (7th Cir. 1986)). The PUCs argue that FERC cannot depart from this approved use of MFV rate design without giving a reasonable justification for doing so, and that FERC has failed to do so in the Order No. 636 series. They claim that FERC's determination that MFV distorts the gas

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[80] It does appear that the Commission has used a rate design method similar to SFV in the distant past of natural gas regulation. *See, e.g.*, *Mississippi River Fuel Corp. v. FPC*, 163 F.2d 433, 437-39 (D.C. Cir. 1947) (explaining the "demand-commodity formula").

market is inconsistent with prior FERC decisions and court rulings approving of MFV. Essentially, they maintain that if MFV was good in the past, it must still be good today. Additionally, the PUCs find plenty of evidence of competitive markets under MFV rate design, and they maintain that dropping MFV rate design is therefore improper. Finally, they stress that the full incorporation of fixed costs in variable charges seems to work well for the oil pipeline industry, so it should also work in the case of gas pipelines.

As the Supreme Court has noted, "[a]llocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts." *Colorado Interstate Gas Co. v. FPC,* 324 U.S. 581, 589 (1945). Although the relevant technology has changed since *Colorado Interstate Gas,* the point that "[r]ate-making is essentially a legislative function," *id.,* has not. Our task, then, is not to determine whether MFV rate design is superior to SFV rate design, but merely to determine whether FERC has "made a reasoned decision based upon substantial evidence in the record" in departing from MFV rate design. *Town of Norwood v. FERC,* 962 F.2d 20, 22 (D.C. Cir. 1992).

Initially, we note that the PUCs have mischaracterized FERC's decision to depart from MFV rate design. As FERC notes in its brief, "modifying pipeline rate design to promote competition is nothing new." The switch from MFV rate design to SFV rate design does not represent a reversal in ratemaking policy. FERC simply ordered a reallocation of fixed costs in pipeline rate design. The fact that the old system was labeled "MFV" and the new system "SFV" does not mean that the new system represents a radical departure from precedent. Rather, the change in Order No. 636 is simply one more adjustment, albeit a significant one, in a decades-long series of adjustments in rate design. *See, e.g., Canadian River Gas Co.*, 3 FPC 32 (1942), *aff'd, Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581 (1945); *Mississippi River Fuel Corp.*, 4 FPC 340 (1945), *aff'd in part and remanded, Mississippi River Fuel Corp. v. FPC*, 163 F.2d 433 (D.C. Cir. 1947); *Atlantic Seaboard Corp.*, 11 FPC 43 (1952); *State Corp. Comm'n v. FPC*, 206 F.2d 690 (8th Cir. 1953), *cert. denied*, 346 U.S. 922 (1954); *Fuels Research Council, Inc. v. FPC*, 374 F.2d 842 (7th Cir. 1967); *United Gas Pipeline Co.*, 50 FPC 1348 (1973), *reh'g denied*, 51 FPC 1014 (1974), *aff'd sub nom. Consolidated Gas Supply Corp. v. FPC*, 520 F.2d 1176 (D.C. Cir. 1975); *Columbia Gas Transmission Corp. v. FERC*, 628 F.2d 578 (D.C. Cir. 1979); *Northern Indiana Pub. Serv. Co. v. FERC*, 782 F.2d 730 (7th Cir. 1986) (*NIPSCO*).

Like past changes in rate design, FERC initiated the departure from MFV in response to changing market conditions. Specifically, the agency determined that continued adherence to MFV rate design would "inhibit the goal of the development of a competitive, national gas market and, therefore, ... [would] not comport with the goals set forth" in Order No. 636. Order No. 636, ¶ 30,939, at 30,433. For various reasons, pipelines prior to Order No. 636 had differing amounts of fixed costs in their commodity and usage charges. As FERC determined, "[t]his situation ... can hinder competition between gas sellers at the wellhead because competition is not based on the seller's costs and therefore on their ability to compete directly with each other." *Id.*; *see also supra* Part IV.A.1.

The PUCs' objection that FERC has used MFV pricing in the past does not come to terms with the fact that the natural gas industry is being reorganized at Congress' direction and that FERC is now attempting to structure the rate design system to favor the development of a nationwide, competitive natural gas marketplace. FERC reasonably determined that, "because in its current assessment of the prevalent economic and market circumstances it believes the goal of achieving an efficient, national gas market is the factor that should control the selection of the appropriate rate design method," Order No. 636-A, ¶ 30,950, at 30,605, its departure from the strict terms of MFV rate design as approved in 1986 was justified. Similarly, the PUCs' reliance on the practices in the oil pipeline industry is misplaced. The same goals, problems, and solutions may or may not apply to oil pipelines,[81] but there is no requirement that rate design function in the same manner across both industries. Finally, as FERC stresses, the Order No. 636 regime permits parties to seek approval of non-SFV rate design methods in individual rate proceedings. *See* Order No. 636, ¶ 30,939, at 30,434; Order No. 636-A, ¶ 30,950, at 30,605. For all these reasons, we hold that FERC has supported its determination to abandon MFV rate design with substantial evidence in the record.

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[81] For example, one crucial difference between rate design for oil pipelines and gas pipelines is that oil pipelines do not impose separate reservation and demand charges, thus occasioning no design problem analogous to the one the Commission confronted here. *See Association of Oil Pipe Lines v. FERC*, 83 F.3d 1424 (D.C. Cir. 1996).

2. FERC's choice of SFV rate design

Several petitioners raise challenges to FERC's determination that SFV is the appropriate rate design method for the natural gas market. The LDCs argue that the commodity and usage charges under SFV rate design will not reflect differences in transportation costs for different pipelines, thus sending improper price signals to gas purchasers. The PUCs argue that under SFV rate design, pipelines will recover all of their fixed costs through reservation and demand charges and will hence have no incentive to maximize pipeline throughput. The Electric Generators argue that FERC failed to consider adequately an alternative rate design method proposed by Arizona Electric. Finally, the Small Distributors argue that the switch to SFV will result in an increase in gas prices at the wellhead, and that FERC has failed to demonstrate that such an increase is necessary to assure an adequate supply of gas. As we noted in the previous section, our task is not to determine whether SFV is in fact the best rate design method available, but merely to determine whether FERC can support its choice with substantial evidence in the record.

a. LDCs' claim

The LDCs[82] claim that the switch to SFV rate design will undermine gas purchasers' ability to make economically efficient choices of gas suppliers because the per unit gas price they face from a supplier will not reflect the distance which the gas must travel over a pipeline to reach the customer. In consequence, a

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[82] LDCs presenting this argument include Atlanta Gas Light Co., Chattanooga Gas Co., Peoples Natural Gas Co., and Southwest Gas Co.

gas purchaser might choose to buy from supplier A, who transmits gas over pipeline AA for a distance of 1,000 miles, when the economically efficient outcome would have been for the purchaser to buy from supplier B, who transmits slightly more expensive gas over pipeline BB for a distance of only 500 miles. The LDCs' analysis, however, overlooks two important facts. First, as FERC points out, "the variable cost of transportation—basically the cost of fuel for pipeline compressors," will still be included in the commodity and usage charges. So gas purchasers will receive the proper signal regarding the actual differences among suppliers in variable transportation costs. *See* Order No. 636, ¶ 30,939, at 30,437. Furthermore, gas purchasers will still take differences in fixed transportation costs into account, because those cost components will be included in the reservation and demand charges. *Id.* As FERC notes, "[l]ocational advantages will continue to matter, because long-distance transportation generally will require more facilities, and thus will have higher fixed costs, than shorter-distance arrangements."

The LDCs argue citing *Catalano, Inc. v. Target Sales, Inc.*, 446 U.S. 643, 648 n.10 (1980) (per curiam) that FERC's removal of transportation costs from per unit charges at the supplier level amounts to "base point pricing," which, they argue, "would be [a] *per se* violation [ ] of the antitrust laws," if done by agreement among private parties to fix the price of transportation added to the price of products. While we have concluded that FERC's response to this argument is adequate, we further note that the base point pricing cases have involved private agreement in otherwise unregulated markets, and commodities such as cement, expensive to transport as contrasted with natural gas, a product which not only is the subject of pricing regulation but also is extraordinarily inexpensive to transport over pre-existing pipelines. *Cf. FTC v. Cement Institute,* 333 U.S. 683, 697 (1948). We accordingly reject the LDCs' challenge to FERC's decision to implement SFV rate design.

b. PUCs' claim

The PUCs argue that the switch to SFV rate design "will frustrate, rather than promote, the goals of maximizing efficiency and competition." Their complaint centers on the claim that because pipelines under SFV rate design will be able to collect all their fixed costs, including return on investment and taxes, in the demand charge, they will have no incentive to assure that gas actually flows through the pipeline under firm service arrangements. That is, because a pipeline will recover no fixed costs or return on investment through the commodity or usage charge, it will have no incentive to transport any gas.

FERC recognized this potential incentive problem in Order No. 636, but determined that "the pipelines will now have much less influence on the use of their systems because they are transporting gas to, rather than selling gas at, the city-gate." Order No. 636, ¶ 30,939, at 30,436. Accordingly, "[t]ransportation volumes will mainly be a function of the needs of gas purchasers and the prices offered by gas sellers in the production areas." *Id.* In any case, "the goals to be accomplished via SFV outweigh generally the goal of allocating fixed costs to annual throughput." Order No. 636-A,

¶ 30,950, at 30,606. We find these explanations sufficiently convincing to meet the substantial evidence standard for rate design in the face of the PUCs' incentive argument.

c. Electric Generators' claim[83]

The Electric Generators argue that FERC failed to consider adequately the demand-responsive volumetric charge system proposed by Arizona Electric Power Cooperative, Inc. (AEPCO), as an alternative to SFV rate design. They claim that AEPCO's proposed system does a better job of rationing scarce capacity during peak demand. However, FERC correctly counters that the fact that AEPCO may have proposed a reasonable alternative to SFV rate design is not compelling. The existence of a second reasonable course of action does not invalidate an agency's determination. *See Cities of Batavia v. FERC,* 672 F.2d 64, 84 (D.C. Cir. 1982) ("[T]he billing design need only be reasonable, not theoretically perfect."). Although an administrative agency must respond to "comments which, if true, ... would require a change in an agency's proposed rule," *American Mining Congress v. EPA,* 907 F.2d 1179, 1188 (D.C. Cir. 1990) (internal quotation marks and citations omitted), FERC has met that standard as to AEPCO's proposal. FERC noted the generator's concerns, but concluded that its own plan would better avoid the distorting influences on the gas market experienced during MFV ratemaking. Order No. 636-A, ¶ 30,950, at 30,606-07. Though AEPCO and FERC each briefly debate the merits of the two proposals, we see no basis for voiding FERC's ruling, which

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[83] Arizona Electric Power Cooperative, Inc., sponsors this argument.

appears based on substantial evidence in the record.

d. Small Distributors' and Municipalities' claim[84]

The Small Distributors and Municipalities argue that the effect of SFV rate design is to increase gas prices at the wellhead. They further claim that FERC failed to demonstrate that such an increase is necessary to assure adequate supply. FERC points out that this argument is not properly before the court because petitioners did not raise it in the administrative proceedings in their request for rehearing of Order No. 636. As we noted earlier, *see supra* Part IV.A.2, 15 U.S.C. § 717r(b) (NGA § 19(b)) clearly states that "[n]o objection to the order of the Commission shall be considered by the court unless such objection shall have been urged before the Commission in the application for rehearing unless there is reasonable ground for failure so to do." *See also ASARCO*, 777 F.2d at 773-75 (elaborating on the significance of the § 717r(b) requirement that the objection be raised before FERC). Finding no mention of this price increase objection in the petitioner's rehearing request, and hearing no explanation by the petitioner of a reasonable ground for this omission, we conclude that the price increase objection is not properly before the court and decline to reach it.

3. Regulatory Flexibility Act

The Regulatory Flexibility Act, 5 U.S.C. §§ 601-612 (RFA), requires that an agency conduct a regulatory flexibility analysis (or "small entity impact analysis") for any rule that will have a

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[84] The National Association of Gas Consumers supports this argument.

"significant economic impact on a substantial number of small entities." 5 U.S.C. § 605(b). The PUCs argue that the RFA required that FERC perform a small entity impact analysis for Order No. 636 because of its significant economic effect on LDCs. However, in *Mid-Tex Elec. Co-op, Inc. v. FERC*, 773 F.2d 327, 340-43 (D.C. Cir. 1985), we conducted an extensive analysis of the RFA provisions governing when a regulatory flexibility analysis is required and concluded that no analysis is necessary when an agency determines "that the rule will not have a significant economic impact on a substantial number of small entities *that are subject to the requirements of the rule*." *Id.* at 342 (emphasis added). FERC has no jurisdiction to regulate the local distribution of natural gas. 15 U.S.C. § 717(b) ("The provisions of this chapter ... shall not apply to ... the local distribution of natural gas or to the facilities used for such distribution."). Accordingly, the allegation that Order No. 636 may have a significant economic impact on LDCs (an assertion FERC disputes) is not sufficient to trigger the mandate of the RFA. FERC had no obligation to conduct a small entity impact analysis of effects on entities which it does not regulate.

C. <u>FERC's Discretion to Adopt Mitigation Measures</u>

1. <u>Background</u>

FERC recognized that the adoption of SFV rate design could result in cost shifting among pipeline customers because of their differing load factors. Order No. 636, ¶ 30,939, at 30,435; Order No. 636-A, ¶ 30,950, at 30,601-03; Order No. 636-B, ¶ 61,272, at 62,015-16. The adoption of SFV will, at least arguably, shift costs to low load factor customers in two ways: first by removing all fixed charges from the usage charge; and second by measuring usage solely based on peak demand, rather than annual usage. To elaborate, a low load factor customer transports most of its gas during the winter heating season; therefore, its average daily usage of its capacity entitlement is significantly below its usage on a peak day. As a result of this demand structure for low load factor customers, they usually pay proportionately more in reservation and demand fees than do high load factor customers. This result follows logically when reservation fees are constant throughout the year for a high and a low load factor customer who each have the same capacity entitlement. The low load factor customer purchases a lower annual volume of gas; hence, a larger proportion of its payments to the pipeline are made up of reservation fees. The existence of this phenomenon means that, once the pipeline has switched to SFV, the low load factor customers will pay a higher share of pipeline fixed costs than they did under MFV. Under MFV, low load factor customers could escape some of the fixed costs by not purchasing their full entitlement of gas because the per unit price of the gas contained some fixed costs. Additionally, under SFV, FERC has determined that the reservation and demand charges will no longer vary with annual usage, as they did under MFV. Order No. 636-A, ¶ 30,950, at 30,599.

To offset these cost shifts likely to result from Order No. 636, FERC adopted several mitigation measures. First, it required that pipelines "use some measure, such as seasonal contract quantities," in calculating reservation and demand fees when the switch to SFV rate design "causes significant cost shifts" to individual customers. Order No. 636-A, ¶ 30,950, at 30,599. If, even after the seasonal adjustments, the switch to SFV still resulted in a ten percent or greater rate increase under SFV for a particular customer class, FERC required that the pipeline phase in SFV rate design over four years for that customer class, allowing the customer class to avoid "rate shock." Order No. 636, ¶ 30,939, at 30,435-46; Order No. 636-A, ¶ 30,950, at 30,603-04. FERC also sought to retain the protection for small customers that the old regime offered by requiring all pipelines that offered service under a one-part volumetric rate at an imputed load factor on May 18, 1992, to offer transportation service under a similar rate structure to all customers who were eligible on that date for such an arrangement. Order No. 636-A, ¶ 30,950, at 30,600; Order No. 636-B, ¶ 61,272, at 62,018-22. We will label this mitigation measure the "small customer discount."

Petitioners bring several different challenges to the adoption of these mitigation measures and to various aspects of their implementation. We now consider each of these challenges.

2. Justifications for mitigation measures

The high load factor LDCs object to FERC's requirement of a small customer discount and to the use of seasonal adjustments for low load factor customers. They argue that the small customer discount results in high load factor customers having to pay higher unit charges than would be the case without the requirement. They also maintain that the use of seasonal adjustments for low load factor customers eliminates the incentive for these customers to flatten their demand over the course of the year. Seasonal adjustments also allegedly penalize high load factor customers for their foresight in using storage and other peak shaving tools in winter months to flatten their demand. The LDCs claim that the higher charges to high load factor customers resulting from these mitigation measures "unduly discriminate against residential customers of high load factor LDCs and give preferential treatment to customers" of low load factor LDCs in violation of NGA § 5(a).

FERC responds to the LDCs' claims by stressing that the effect of the mitigation measures is to preserve as much of the status quo as possible with respect to cost allocation. The intervenors point out that the LDCs' attack on the mitigation measures improperly assumes that SFV rate design is a baseline from which any mitigation measures should be judged. Both FERC and the intervenors are correct. The LDCs' claim of "discrimination" is based on the assertion that they, and ultimately their customers, will have to pay a larger share of fixed costs than they would pay without the mitigation measures. But the LDCs have no sustainable argument for why this should invalidate the measures. There is no "neutral" or inherently "fair" allocation of fixed costs, as the history of rate design amply demonstrates. The LDCs assume that allocating fixed costs according to a straight SFV methodology is the "fair" way of doing things, a curious position in light of the LDCs' opposition throughout these proceedings to the adoption of SFV rate design. But there is no "fair" baseline from which to judge a particular cost allocation scheme.

In any case, FERC correctly points out that it has long rejected the position that fixed costs should be allocated solely on the basis of peak day demand, as would apparently result under a straight SFV system with no mitigation measures. The courts have concurred in FERC's rejection of such a regime. *See NIPSCO*, 782 F.2d at 742 ("[T]he Commission long ago with judicial approval rejected the argument that fixed costs should only be allocated and recovered solely on the basis of peak day demands."). As for the LDCs' argument that the seasonal adjustments remove the incentive for low load factor customers to flatten their demand throughout the year, we note that this incentive is greatly magnified under a "pure" SFV system as compared to an MFV system. Under MFV, the low load factor customers could have avoided part of the fixed costs during periods of low demand because part of the per unit gas charge included fixed costs. "Reducing" the stronger incentive to flatten demand that would otherwise exist under SFV is not problematic because, as we have just explained, a pure SFV system is not a proper baseline from which to judge the appropriateness of mitigation measures.

The same reasoning applies to the LDCs' claim that the mitigation measures unfairly penalize those LDCs whose foresight led them to invest in peak-shaving facilities before Order No. 636. The mitigation measures only look like an unprecedented subsidy flowing from high load factor customers to low load factor customers when one compares the Order No. 636 regime to a straight SFV regime with no mitigation measures at all. Once again, a strict SFV regime is not the proper baseline. When one compares the Order No. 636 system with the pre-Order No. 636 system, in which low load factor customers escaped part of their share of fixed costs by reducing purchases in low demand periods, the mitigation measures make sense in light of FERC's goal of avoiding sudden and shocking departures from the status quo with respect to cost allocation. In short, low load factor customers avoided some fixed costs in low demand periods before Order No. 636, and they are still avoiding some fixed costs in low demand periods after Order No. 636. LDCs which adopted peak-shaving techniques are no worse off than they were before Order No. 636. It is therefore improper to say that FERC has "penalized" them.[85]

There being no neutral standard or baseline to guide the court in evaluating mitigation measures, the only relevant question is whether FERC has made a reasonable allocation of fixed costs supported by substantial evidence. Considering the Order No. 636 series as a whole and bearing in mind FERC's regulatory goals and history, we are convinced that FERC has supported its adoption of mitigation procedures with substantial evidence. We now turn to the various challenges raised by petitioners to specific aspects of the mitigation measures.

3. Non-permanence of mitigation measures

As we noted above, *see supra* Part IV.C.1, FERC ordered that under certain circumstances, pipelines must phase in SFV rate

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[85] The LDCs also argue that under the Order No. 636 regime, low load factor customers have several new means of adaptation at their disposal and are not in need of mitigation measures. However, as FERC points out, none of the LDCs raised this argument in their rehearing petitions before the Commission. They are accordingly barred from raising it in this court under 15 U.S.C. § 717r(b). *See supra* Part IV.A.2.

design over four years for a customer class, allowing the customer class to avoid "rate shock." Order No. 636, ¶ 30,939, at 30,435-46; Order No. 636-A, ¶ 30,950, at 30,603-04. The Small Distributors and Municipalities[86] contend that, rather than phasing in new rates, FERC should have adopted permanent mitigation of their rates. They argue that "[u]nreasonable rates do not become just and reasonable by phasing them in over a four-year period. Mitigation is no less vital four years later when the Commission's four-year "remedy' expires." But FERC responds that the purpose of the four-year phase in period was not to protect the customer class from cost shifting altogether, but merely to avoid the shock of allowing it to happen all at once. FERC's response is perfectly sensible, and we hold that the Commission has justified under the substantial evidence standard the four-year phase in period in the circumstances in which Order No. 636 requires it.

4. Impact on pipeline rate of return

The PUCs argue that FERC should have reduced the pipelines' rate of return because the pipelines will be able to recover all of their fixed costs and return on investment through demand and reservation charges instead of facing the uncertainty of recovering a portion of their fixed costs and return through gas sales throughout the year. *See supra* Part IV.B.2.b (describing reduced pipeline uncertainty under SFV rate design). Specifically, the PUCs contend that FERC should have followed its decision in *Transcontinental Gas Pipe Line Corp.*, 56 FERC ¶ 61,037, *modified in*

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[86] Distributors joining in this argument include the American Public Gas Association and the National Association of Gas Consumers.

part, 57 FERC ¶ 61,331 (1991), 62 FERC ¶ 61,221 (1993), 64 FERC ¶ 61,099 (1993), *rev'd in part on other grounds*, *Transcontinental Gas Pipe Line Corp. v. FERC*, 54 F.3d 893 (D.C. Cir. 1995), and imposed a 25 basis point reduction in pipelines' return on equity to reflect the lower risk under SFV rate design. However, FERC stresses that it deferred any such adjustments in rates of return to the individual restructuring proceedings in light of the fact that "pipeline risk is a matter for pipeline-specific analysis in light of all risks." Order No. 636, ¶ 30,939, at 30,437. As we have said before, setting a rate of return is "an intensely practical affair requiring the conversion of inexact data into exact rates or limits upon rates." *Matson Navigation Co. v. Federal Maritime Comm'n*, 959 F.2d 1039, 1043 (D.C. Cir. 1992) (citations and internal quotation marks omitted). Nothing in the law requires that FERC take a "shotgun" approach to the problem of decreased pipeline risk by ordering an across-the-board rate reduction, much less that the court do so. We note in this regard that *Transcontinental Gas*, the decision upon which petitioners rely, was itself an individual pipeline ratemaking decision. FERC easily meets its burden of supporting its decision to defer rate of return adjustments to individual restructuring proceedings.

5. Individual customer vs. customer class [87]

FERC required that pipelines use measures such as seasonal contract adjustments to avoid significant cost shifting for *individual customers*. If, after application of these mitigation

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[87] Williston Basin Pipeline Company seeks review of this issue.

measures, the use of SFV "still results in a 10 percent or greater increase in revenue responsibility for any *historic customer class*," then the pipelines are required to phase in the increase over four years. Order No. 636-B, ¶ 61,272, at 62,016 (emphasis added). The Pipeline Petitioners argue that the mitigation measures short of four-year phase in should also have been required on the basis of customer class rather than on the basis of SFV's effects on individual customers.

In deciding to base the initial mitigation measures on SFV rate design's effects on individual customers rather than customer class, FERC cited several recent decisions in individual pipeline restructuring proceedings. *Id.* at 62,016 n.140. However, these rulings simply implement Order No. 636 and order studies on the effect of SFV rate design on individual customers, anticipating the adoption of mitigation measures on a customer-by-customer basis. But relying on these orders as a justification for the customer-by-customer basis would be a classic case of bootstrapping, amounting to a conclusion that Order No. 636 properly requires the customer-by-customer approach since several decisions implementing Order No. 636 take that approach. Nothing in any of the decisions justifies the basic determination in favor of the individual customer approach. Significantly, FERC cites no other support for its decision in Order No. 636-B to favor the individual customer approach.

The Pipeline Petitioners also raise an important question about the danger of the individual customer approach with respect to pipeline cost recovery:

> [R]ates are determined on the basis of costs incurred and billing quantities during a specified test period. While it is reasonable to expect that the actual billing quantities of all customers in each class during the period the rates are in effect will approximate those experienced by the class during the test period, it is likely that individual customers may experience larger variances in billing quantities. The establishment of rates on a customer-by-customer basis therefore increases the risk that a pipeline will fail to collect its total costs during the period in which rates are in effect.

Pipeline Petitioners' Brief at 27. They also argue that FERC's order fails to take into account potential customer cost reductions under Order No. 636 that are not directly related to the switch to SFV rate design, and that the individual customer method "increases the likelihood for discrimination in rates to similarly situated customers in violation of Sections 4 and 5 of the Natural Gas Act."

FERC has provided, in response to our request at oral argument, several citations to Order Nos. 636-A and 636-B which supposedly explain FERC's decision to implement the initial mitigation measures on a customer-by-customer basis. However, after examination of these citations, we conclude that the discussions cited on this question are ambiguous at best and incomplete at worst. FERC has failed to address adequately, in either the Order No. 636 series or in its brief, the Pipeline Petitioners' objections which we have outlined above. Because, as previously noted, the Commission has failed to provide any reasoned justification for its decision on this issue, and because the petitioners' objections raise serious questions about the appropriateness of FERC's ruling, we conclude that the Commission has failed to support its decision on this issue with substantial evidence. We therefore remand to the Commission the question of whether the initial mitigation measures should be implemented on the basis of customer class for further examination.

6. Discounts for former customers of downstream pipelines

In requiring a continuation of the pre-Order No. 636 small customer discounts, FERC only mandated that downstream pipelines offer the discount to the class of customers eligible for it on May 18, 1992. But the Small Distributors[88] argue that FERC should have required upstream pipelines to provide the discounts to any customers of downstream pipelines who received the discounts on May 18, 1992. The downstream pipeline customers were indirect customers of the upstream pipelines under the old regime and now are direct customers of these upstream pipelines. The Small Distributors argue that these former downstream pipelines customers "are now indistinguishable from the upstream pipeline's other small customers, with whom they compete directly for markets." FERC's failure to account for this fact results in "undue discrimination between similarly-situated small customers on the same pipeline solely on the basis of whether they used to be served through a downstream pipeline prior to Order [No.] 636." Although FERC did indicate in Order No. 636-B that the former downstream pipeline customers' need for discounts should be examined in individual restructuring proceedings, the Small Distributors contend that it is unfair and unreasonable to make them demonstrate such a need in restructuring proceedings when that need has already been presumed for other small customers.

[88] The East Tennessee Group, the National Association of Gas Consumers, and the Tennessee Valley Municipal Gas Association support this argument.

The Small Distributors raise excellent points. FERC's failure to counter them with anything but its insistence that former downstream customers can raise their need for small customer discounts in upstream pipeline restructuring proceedings (perhaps they can, although the Small Distributors dispute the effectiveness of such a course of action), does not address the core of the Small Distributors' argument. FERC has made an arbitrary distinction between former indirect small customers of upstream pipelines (who are now direct small customers) and small customers who have always been direct customers of the same pipelines. Because FERC has not supported this distinction with substantial evidence in the record, we remand this issue to the Commission for further consideration of whether or not the small customer benefits should be made available to the former downstream small customers.

7. Triennial rate review

In Order No. 636-A, FERC abandoned the requirement of triennial rate review, which it had formerly imposed on many pipelines in exchange for granting the pipelines certain powers over their rates. FERC explained that the only reason it had formerly required triennial rate review was because of the power it had granted the pipelines. Specifically, under the purchased gas adjustment (PGA) regulatory scheme, participating pipelines had discretion to change the gas supply cost element of their rates. In exchange for this ability, "pipelines had to agree to a reexamination of all their costs and rates at three year intervals to assure that gas cost increases were not offset by decreases in other costs." Order No. 636-A, ¶ 30,950, at 30,671; *see also* 18

C.F.R. § 154.303(e) (laying out triennial rate review requirement). Under the Order No. 636 regime, pipelines have no special rate adjustment mechanism comparable to the PGA scheme, so FERC concluded that triennial rate review was unnecessary. In Order No. 636-B, FERC even raised the question of whether it had the discretion to order triennial rate review under the Order No. 636 regime, noting that "there are limits to the authority of the Commission to require pipelines to periodically justify their existing rate levels." Order No. 636-B, ¶ 61,272, at 62,044-45 (citing *Public Serv. Comm'n v. FERC,* 866 F.2d 487 (D.C. Cir. 1989) (*PSCNY*) (holding that requiring periodic filings under NGA § 4 is beyond FERC's statutory authority)).

The LDCs[89] argue that FERC should not have abandoned triennial rate review. First, they claim that FERC "ignored that the market-based sales rate authority granted pipelines under Order [No.] 636 *is* a "special rate adjustment mechanism' " justifying a periodic rate review. In any case, they argue that FERC certainly does have the authority to impose triennial rate review under the Order No. 636 regime. In their view, *PSCNY* simply means that "FERC cannot impose [a periodic filing] requirement except as a condition of some other benefit voluntarily accepted by the pipeline." Because Order No. 636 conferred several benefits on pipelines, the LDCs contend that FERC's failure to attach periodic rate review to at least one of those benefits was unjustified. FERC, however,

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[89] Associated Gas Distributors, Consolidated Edison Company of New York, Inc., Illinois Power Co., and Peoples Natural Gas Co. present this argument. Supporting intervenors are PECO Energy Co. and Washington Gas Light Co.

contends that the "benefits" to pipelines cited by the LDCs are not nearly so certain: "there is no reason to believe that by allowing a pipeline to sell gas at market-based rates, rather than regulated cost-based rates, Order No. 636 makes it more likely that rates for unbundled transportation service will become unjust and unreasonable."

The PUCs also argue in favor of retaining triennial rate review, restating the LDCs' argument that FERC has conferred a benefit on pipelines by instituting SFV rate design and can accordingly require periodic rate review. They also point out that, under SFV, as long as fixed costs continue to decline, pipelines will have no incentive to file NGA § 4 rate cases since they will be recovering all of their fixed costs through reservation and usage fees. Consumers will then be left with an NGA § 5 complaint as their only option for protecting themselves, but a § 5 complaint is less satisfactory than a § 4 rate case because under § 5 the burden is on the complainant to establish the unjustness or unreasonableness of the rate. Also, § 5 relief is prospective only; § 4 relief can encompass a refund order. FERC responds that "traditional ratemaking tools are available to take account of long-run declining costs, and a three-year review [is] unnecessary."

FERC's position that it lacks authority to impose triennial rate review is quite strong. The LDCs' claim that the market-based sales authority granted to pipelines is a "benefit" to which triennial rate review may be attached rings hollow in light of the fact that pipelines are leaving the gas sales business in favor of gas transportation under Order No. 636. Furthermore, whatever the benefits of SFV rate design to pipelines, they are not benefits voluntarily accepted by the pipelines and so cannot be the basis for the imposition of periodic rate review. *See PSCNY,* 866 F.2d at 492 (noting that FERC's authority to impose triennial rate review in the PGA context "obviously rests on pipeline consent" to triennial rate review in exchange for automatic PGA adjustment authority). In any case, in the presence of these serious doubts about FERC's authority to impose periodic rate review in the Order No. 636 context and in view of the alternative procedures available to the Commission for ensuring reasonable rates, we hold that petitioners have failed to show that FERC has not supported its decision to drop triennial rate review with substantial evidence.

V. Transition Costs

In this part of the opinion, we briefly review the history behind the transition cost issue and consider each of the petitioners' challenges to FERC's treatment of transition costs.

A. <u>Background to Transition Costs</u>

1. <u>Order No. 436 and its successors</u>

Order No. 436 began the natural gas pipeline industry's transition from its historic role as gas merchant to gas transporter. The Order authorized interstate gas pipelines to convert to blanket-certificated "open-access" transportation service. *See supra* Part I.B. In exchange, however, customers of those pipelines that did convert were permitted both (1) to convert their firm sales obligations into firm transportation contracts and also (2) to reduce their obligations to purchase gas from the pipelines. Pipeline customers in large numbers exercised their right under the Order to buy less gas from the pipelines, and secured gas supplies from less expensive sources. The pipelines themselves were then left with massive obligations to purchase high-priced gas at the wellhead:

> [T]he conditions under which the NGPA began to relax wellhead price controls—namely acute gas shortage and sharply rising prices for alternative fuels—tended to divert pipeline attention from the hazards of incurring long-term obligations to buy high-priced gas. Under pressure from the Commission, the pipelines had typically purchased gas under contracts for very long terms. Besides incorporating high prices (and provisions for escalation upward), *the contracts commonly included "take-or-pay" provisions, requiring the pipeline to pay for some specified percentage, say 75%, of the deliverable gas even if it took less.* While usually subject to recoupment later, and while a perfectly natural allocation of risk between producer and purchaser, *the take-or-pay provisions effectively committed the pipelines to high gas costs in what by 1982 proved to be a time of falling prices,* both for competing fuels and for substitute supplies of gas not covered by contract.

AGD I, 824 at 995-96 (citations omitted) (emphasis added).

Thus arose the "take-or-pay" liabilities addressed by the Commission in Order No. 436 and its successors, as well as by this court in a variety of opinions. *See supra* Part I.B. Specifically, because most customers could purchase gas more cheaply from other sources, pipelines essentially were unable to pass through the costs of their own supply obligations. With purchases sharply reduced, pipelines owed massive "take-or-pay" liabilities to gas producers, which they had to either "buydown"—*i.e.,* reduce—or "buyout"—*i.e.,* eliminate. In Order No. 436, the Commission refused to set a general policy on whether or how pipelines could attempt to recover these costs. We vacated and remanded the Order, concluding that, in this regard, it was not based on reasoned decisionmaking, primarily because it appeared to grossly underestimate the financial impact of take-or-pay liability on pipelines. *Id.* at 1021-30. Of great concern to the court was the likelihood that even higher gas prices would simply cause more customers to switch suppliers, thereby exacerbating the take-or-pay crisis. This cycle of ever increasing prices and ever shrinking customer base—a phenomenon that petitioners label the "death spiral"—made it very unlikely that the pipelines would in fact recoup their take-or-pay liabilities absent some mechanism for separately passing those costs through to their customers.

In subsequent proceedings, the Commission adopted and this court approved various measures designed to address that concern and allow pipelines to pass through some of their take-or-pay liabilities to a broader range of customers. *See supra* Part I.B. Most pertinent to our analysis here, under Commission policy, a pipeline could agree to absorb between 25% and 50% of its take-or-pay costs in exchange for the right to bill customers an equal share through a fixed charge, and recover the remaining amount through a volumetric surcharge based on total throughput. Customers, and in turn the consuming public, ultimately reimbursed pipelines for approximately $6.4 billion in take-or-pay costs, while the pipelines themselves absorbed $3.6 billion.

2. <u>Order No. 636 and petitioners' challenges</u>

After Order No. 436, all of the major interstate pipelines converted to open-access transportation. Not all customers on those pipelines, however, exercised their right to unbundle their sales agreements and reduce their gas purchase obligations. Several years later in Order No. 636, the Commission *mandated* unbundling and authorized sales customers to reduce their pipeline gas purchases. When customers exercised that right and secured gas supplies from other sources, the pipelines once again incurred substantial take-or-pay liabilities; though the Commission labeled these liabilities "gas supply realignment costs" in Order No. 636, they arose from the same type of producer-pipeline contract provisions as the "take-or-pay" costs considered in Order No. 436. *Cf.* Order No. 636-A, ¶ 30,950, at 30,649 n.466 ("Any costs that would qualify for recovery as GSR costs could be filed for recovery under [the successor to Order No. 436,] Order No. 528.").

In allocating recovery of GSR costs, however, the Commission adopted a policy more advantageous to the pipelines. Instead of refusing to establish a mechanism for pipelines to recover their take-or-pay costs, as it originally had in Order No. 436, FERC authorized pipelines to bill their customers separately for 100% of their GSR costs. This policy was, in fact, a substantial change from even Order No. 500, which permitted pipelines to surcharge their transportation customers for take-or-pay costs only if they agreed to absorb between 25 and 50% of those costs. The Commission set forth the mechanisms available to pipelines under Order No. 636 as follows:

> ... The Commission will permit pipelines full cost recovery of prudently incurred gas supply realignment costs deemed to be eligible under this rule. To recover those costs, a pipeline will be permitted to use either a negotiated exit fee, or a reservation fee surcharge recoverable from Part 284 firm transportation customers.
>
> Under this rule, a firm entitlement holder has

> options as to how to react to gas supply realignment costs: it may remain a sales customer of the pipeline; otherwise, it may take an assignment of the pipeline's existing contracts or pay an exit fee/reservation fee surcharge for costs approved by the Commission.

Order No. 636, ¶ 30,939, at 30,458. On rehearing, FERC modified this ruling somewhat, and required pipelines to bill 10% of their GSR costs to interruptible transportation customers. *See infra* Part V.E.3.b.2.

Pipelines also face three other types of significant transition costs under Order No. 636: (1) unrecovered gas costs or credits remaining in the purchased gas adjustment (PGA) account when a pipeline terminates its PGA mechanism; (2) costs of pipeline assets (such as storage facilities) currently used to provide bundled sales service which are not directly assignable to customers of the unbundled services ("stranded costs"); and (3) costs for equipment required to physically implement the rule ("new facility costs"). Order No. 636, ¶ 30,939, at 30,457. FERC determined in Order No. 636 that pipelines would generally be allowed to recover 100% of these costs. *Id.* at 30,457-60.

Petitioners raise several challenges to FERC's treatment of transition costs. First, they claim that FERC erred in allowing pipelines to recover 100% of their stranded costs, arguing that such recovery violates applicable legal standards. Second, they contend that FERC failed to adequately address the problem of "LDC bypass," which occurs when large industrial customers bypass LDCs, thereby avoiding transition costs properly attributable to them. Third, they oppose Order No. 636's passthrough of above-market prices paid by pipelines for synthetic natural gas from the Great

Plains Gasification Plant. Finally, they challenge in several respects FERC's treatment of GSR costs.

B. Stranded Costs and the "Used and Useful" Doctrine

A separate class of Order No. 636 transition costs are "stranded costs," which are those "incurred by pipelines in connection with their bundled sales services that cannot be directly allocated to customers of the unbundled services." Order No. 636, ¶ 30,939, at 30,460. To be denominated "stranded," an investment (1) must have been prudently made, Order No. 636-A, ¶ 30,950, at 30,662, but (2) must be no longer "used and useful" after Order No. 636, Order No. 636-B, ¶ 61,272, at 62,041. Examples include upstream pipeline capacity for which a downstream pipeline cannot find a buyer, and storage capacity that a pipeline no longer needs when the volume of its sales service shrinks. Order No. 636, ¶ 30,939, at 30,460. According to the Commission, pipelines can recover their stranded costs in NGA § 4 rate filings. *Id.*; *see also* Order No. 636-B, ¶ 30,950, at 62,042 ("The Commission will allow pipelines to make limited section 4 filings to recover ... the costs of stranded facilities that are currently incrementally priced.... However, pipelines must file to recover the costs of most, if not all other stranded facilities in general section 4 rate proceedings.").

The PUCs challenge the Commission's ruling, *see* Order No. 636-B, ¶ 61,272, at 62,041, that pipelines may recover 100% of their stranded costs. Their presentation is straightforward: items that are not currently "used and useful" may not be included in a utility's rates. In support, the PUCs invoke the Commission's statement in *New England Power Co.*, 42 F.E.R.C. ¶ 61,016, at 61,078 (1988), that "[i]n general, the used and useful standard provides that an asset may be included in a utility's rate base only when the item is used and useful in providing service." They also cite to this Court's statement in *Tennessee Gas Pipeline v. FERC*, 606 F.2d 1094, 1109 (D.C. Cir. 1979), that "the precept endures that an item may be included in a rate base only when it is "used and useful' in providing service."

In its brief, the Commission replies along two fronts. First, it contends that the PUCs' objection is premature, given that in Order No. 636, the Commission stated that, in subsequent restructuring proceedings, it would "consider arguments about whether particular facilities are used and useful, or whether the costs should be recoverable as transition costs" in § 4 rate proceedings. Order No. 636-A, ¶ 30,950, at 30,662. Second, the Commission contends that the "used and useful" principle invoked by the PUCs, while generally sound, does not apply to facilities that have been stranded only because of the Commission's own action. In other words, the pipelines should recover on their investments as they would have had Order No. 636 never been promulgated.

While we ultimately affirm the position taken by the Commission in the administrative proceedings, we believe that both the PUCs and the Commission itself may have overlooked a relevant distinction on appeal: the difference between a utility's *rates* and its *rate base*. "The rate allowed a utility is the sum of (1) its cost of service, and (2) its rate base multiplied by its rate of return." *Jersey Central Power & Light Co. v. FERC*, 810 F.2d

1168, 1172 (D.C. Cir. 1987) (en banc). "Generally, the rate base is comprised of total capital invested in facilities minus depreciation plus cash working capital. The rate of return, on the other hand, is a weighted average of different rates applied to debt, preferred stock and common stock." *Id.* at 1203 (Mikva, J., dissenting). "Calculation of rate base is a critical step in establishing maximum rates, since the product of rate base multiplied by allowed rate of return is the total sum of money the agency allows to investors in the firm." RICHARD J. PIERCE, JR. & ERNEST GELLHORN, REGULATED INDUSTRIES 102 (3d ed. 1994).

The cases cited by the PUCs, and not challenged by the Commission, stand for the proposition that the items in a utility's *rate base* generally should currently be used and useful to consumers. As a result, investors generally profit only from those investments that presently benefit consumers. However, that principle does not answer the question whether investments that are not used and useful may nonetheless be included in the utility's *rates, i.e.,* still treated as part of the utility's cost of service.[90]

Viewed in this light, the general statement in Order No. 636 that pipelines will recover 100% of their stranded costs still leaves the Commission with a number of options in the § 4 rate proceedings. For example, the Commission could decide that

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[90] Our opinion should not be read to *prohibit* the Commission from applying the "used and useful" principle to issues of recovery through cost of service. Instead, as we explain in our discussion, *infra* at 125, of *NEPCO Municipal Rate Committee v. FERC*, 668 F.2d 1327, 1333 (D.C. Cir. 1981), this Court has recognized that the Commission is not *required* to do so in all instances.

stranded costs should merely be included in the pipeline's cost of service, recoverable through amortization over time. In such an instance, "FERC has already moved somewhat in the direction of balancing competing interests by permitting recovery of the costs of building the plant in the cost of service. Investor interests have not, therefore, been entirely ignored." *Jersey Central*, 810 F.2d at 1192 (Starr, J., concurring). The Commission might also allow the pipeline to recover not only the amortization, but also interest, *i.e.*, the "cost" of the unamortized portion of the investment. The Commission could further decide to include stranded investments in the utility's rate base and thereby generate a profit for investors.

In the administrative proceedings, the Commission assiduously avoided announcing a general standard that would control the manner in which stranded costs may be recovered. Thus, Order No. 636, at 30,460 (emphasis added), states that while "most of the costs of *new facilities* would be includable in rate base, ... there is no way of anticipating the nature and amount of the *stranded costs*, and thus no way at this time of devising an appropriate billing mechanism on a generic basis." Similarly, in Order No. 636-B, ¶ 61,272, at 30,662, the Commission deferred until individual rate cases a party's objection that "costs associated with physical plant that is no longer used and useful ... should ... no longer be includable in the rate base."

The PUCs' objection therefore is ripe for review only to the extent that they contend that pipelines should not recover 100% of their Order No. 636 stranded costs *in any fashion.* We cannot at this point address the specific question of whether pipelines should be permitted to include stranded costs in their rate base, and thereby receive a profit on the investment, because Order No. 636 adopted no such rule. *Accord, e.g., Columbia Gas Trans. Corp.*, 64 F.E.R.C. ¶ 61,060 (1993) (deferring determination of rate base treatment of stranded cost recovery to § 4 proceeding); *National Fuel Gas Supply Corp.*, 63 F.E.R.C. ¶ 61,291 (1993) (same). In fact, in at least one NGA section 4 rate proceeding, the Commission expressly refused to permit such treatment of stranded costs, explaining:

> Included in [the pipeline's] claim for stranded cost treatment for the production facilities, is a pretax return allowance on the unamortized balance.... As discussed above, in order for [the pipeline] to receive stranded cost treatment for these facilities, they must no longer be used and useful. It is long standing Commission policy that when facilities are not used and useful, they do not qualify for rate base treatment. In addition, the recovery of stranded costs is designed to compensate pipelines for out-of-pocket costs that they have no other means of recovering. While the costs of facilities are out-of-pocket costs, equity return and related income taxes are not. Therefore, [the pipeline] should not be allowed a pretax return allowance on the unamortized balance. The Commission will limit [the pipeline's] recovery to interest on the unamortized amount....
>
> This is consistent with the way the Commission has treated other costs of a transitional nature that are being amortized over a period of years to reduce the rate impact on customers, *e.g.*, GSR cost amortizations or take-or-pay buyout and buydown cost amortizations. The interest treatment prescribed above adequately compensates the pipeline for the time value of the outstanding unamortized balance, but recognizes the nature of the costs being amortized.

Equitrans, Inc., 64 F.E.R.C. ¶ 61,374, at 63,601 (1993); *cf. National Fuel Gas Supply Corp.*, 71 F.E.R.C. ¶ 61,031, at 61,138 (1995) ("A rate of return on the amount of written down facilities would be inappropriate since this allows a return on facilities that are not economically viable, and may also result in a competitive advantage for the pipeline. The pipeline would, however, be allowed to recover interest on the unamortized portion of its written-down plant over a reasonable amortization period, as this will keep the pipeline whole for the direct cost of its investment in the facilities.").

We reject the PUCs' claim (now properly limited to the argument that the "used and useful" principle *per se* prohibits pipeline recovery of stranded costs even when merely amortized as part of the cost of service), because it was previously rejected in *NEPCO Municipal Rate Committee v. FERC,* 668 F.2d 1327, 1333 (D.C. Cir. 1981) (*NEPCO*). In *NEPCO,* we considered "whether FERC's refusal to include project expenditures in the rate base, while allowing their recovery as costs over time, is a valid approach to allocating the risks of project cancellation." We found such an approach acceptable because, in that case, the Commission's decision was based on substantial evidence and had adequately balanced the interests of investors and ratepayers. *Id.; see also Jersey Central,* 810 F.2d at 1183 (rejecting claim that *NEPCO* adopted *per se* bar to including in rate base items not currently "used and useful"). So long as the Commission's decisionmaking in the individual § 4 proceedings satisfies that standard, it will survive any subsequent challenge brought on "used and useful" grounds.

C. <u>LDC Bypasses</u>

Order No. 636 creates new opportunities for large retail customers to bypass LDCs and connect directly to pipelines. Problems of scale and efficiency preclude other customers from taking advantage of such options, however. State regulators and LDCs argued before FERC that it is unfair to force an LDC's remaining customers to pay the transition costs that they contend are fairly allocatable to the departed customers of the LDC. Order No. 636, ¶ 30,939, at 30,461; Order No. 636-A, ¶ 30,950, at 30,658-59. FERC, however, refused to adopt a generic rule to address this problem, determining instead that it would consider requests for relief on a case-by-case basis. The Commission believes that it is reasonable to require that "an LDC seeking relief in a bypass situation ... show that there is a direct nexus between the bypass and the pipeline, so that the costs it seeks to avoid should be reallocated to the bypassing customer." Order No. 636-A, ¶ 30,950, at 30,659.

The PUCs protest that the burden placed on LDCs of demonstrating the nexus between the bypass and the pipeline is "nearly impossible to meet" because of its specificity. They accordingly argue that the pipeline and the bypassing customer should have to explain why they shouldn't bear the bypassing customer's share of transition costs. FERC counters that it has "made no statement as to the ultimate burden of proof in such situations" but has left resolution of LDC bypass claims to individual proceedings. However, as noted above, FERC did find it "fair" to require an LDC seeking bypass relief to show a "direct nexus between the bypass and the pipeline." While arguably it may not constitute a "burden of proof" in a technical sense, it does constitute a hurdle of causation which LDCs seeking relief must clear in individual proceedings. Therefore, in contrast to the Intervenors' argument, FERC's "direct nexus" requirement is ripe for review.

We find the PUCs' arguments unpersuasive. First, we note that the "burden" LDCs face in these cases is not "impossible to meet." As FERC notes, it has already made it clear that at least one bypassing customer still must bear its fair share of GSR costs. *See Arcadian Corp. v. Southern Natural Gas Co.*, 67 FERC ¶ 61,176, at 61,538 (1994). Second, FERC reasonably determined that the factual circumstances surrounding LDC bypasses "differ sufficiently that the Commission cannot justify a generic rule [apart from the "direct nexus" requirement] that would be appropriate in all circumstances." Order No. 636-A, ¶ 30,950, at 30,659. We accordingly reject the PUCs' challenges on this issue.

D. <u>Above-Market Recovery for Great Plains Gas</u>

The Great Plains Gasification Plant was constructed to convert coal into synthetic natural gas (SNG). In Order No. 636-A, FERC noted that in *Transcontinental Gas Pipe Line Corp.*, 55 FERC ¶ 61,446, *reh'g denied*, 57 FERC ¶ 61,345 (1991) (*Transco*), it had "approved a settlement that provided for a volumetric surcharge on system throughput to recover the above-market gas costs and associated transportation costs related to Transco's obligations to purchase synthetic gas from Great Plains." Order No. 636-A, ¶ 30,950, at 30,657-58. Several petitioners complained that this arrangement was in substantial conflict with the competition-enhancing purposes of Order No. 636. FERC admitted as much in Order No. 636-A, but determined that the volumetric surcharge "is consistent with the Commission's goal of providing a smooth transition from the prior regulatory environment to the new market-oriented environment." *Id.* at 30,658. Furthermore, FERC followed its reasoning in *Transco,* concluding that "it is "reasonable for all [the pipeline's] customers to share in the above-market costs of the nation's first large-scale synthetic fuels plant, whose technological benefits would have redounded to all future gas users ... by increasing the supply of available gas.' " *Id.*

The PUCs challenge FERC's treatment of Great Plains gas, contending that it "conflicts with the goal which forms the heart of Order [No.] 636—providing consumer access to competitively priced supply." They also cite Commissioner Langdon's partial dissent in Order No. 636, in which he stated that "every comma, word, sentence and paragraph of the order is internally inconsistent" with respect to Great Plains gas. Order No. 636, ¶ 30,939, at 30,472 (Langdon, C., concurring in part and dissenting in part). "I fail to see how the [volumetric surcharge] will ultimately benefit the consumer, or transmit accurate pricing signals." *Id.* The PUCs also claim that FERC's decision requires gas consumers to subsidize Great Plains, an outcome the Commission has previously rejected with respect to failed SNG plants.

FERC responds to the PUCs' claims by arguing that *Elizabethtown III,* 10 F.3d at 873-74, has already settled this issue. *Elizabethtown III* reviewed FERC's orders approving restructuring agreements between Transco and its customers. The petitioners challenged Transco's passthrough of its above-market cost of SNG from Great Plains on the basis that "customers should pay rates based only upon the costs they cause the pipeline to incur." *Id.* at 873. We rejected that argument, however, concluding that the departure from cost-causation principles was justified because, "had the Great Plains plant succeeded in increasing the supply of natural gas, it would have contributed also to reducing the price of natural gas, to the benefit of all natural gas consumers." *Id.* at 874.

The PUCs argue that *Elizabethtown III* is inapposite because it did not consider the treatment of Great Plains gas in a restructuring proceeding *in light of the overall purposes of Order No. 636.* Although the PUCs are correct that *Elizabethtown III* does not address Great Plains gas in light of Order No. 636, we note that the case was both argued (February 23, 1993) and decided (December 17, 1993) after the issuance of Order No. 636 (April 16, 1992), Order No. 636-A (August 12, 1992), Order No. 636-B (November 27, 1992), and even Order No. 636-C (January 8, 1993). The *Elizabethtown III* court thus had ample opportunity to consider the consistency of the Great Plains volumetric surcharge with the overall policy objectives of the Order No. 636 regime. Petitioners point to no developments since the *Elizabethtown III* decision that effectively distinguish that case from the issue before us, and we are accordingly constrained by *Elizabethtown III* 's treatment of the Great Plains issue. We therefore reject petitioners' challenges to FERC's treatment of Great Plains gas.

E. <u>GSR Costs</u>

In this part of the opinion, we consider petitioners' challenges to the GSR costs that arose from the modification of producer-pipeline contracts. Order No. 636 both (1) required pipelines to unbundle their firm sales contracts into separate transportation and gas sales arrangements and (2) permitted customers to reduce or eliminate their obligations to buy gas from pipelines under the sales component. The pipelines, with fewer sales customers, were in turn forced by market pressures to buy their way out of many costly supply contracts with gas producers, thereby incurring some $1.7 billion in "gas supply realignment (GSR) costs." In Order No. 636, the Commission authorized pipelines to recover 100% of their prudently incurred GSR costs from their blanket-certificated *transportation* customers.[91]

Petitioners raise several objections to this recovery policy, all of which we conclude are ripe for review. First, they argue that FERC should have used its NGA § 5 authority to require gas producers to bear part of the GSR costs. We conclude that FERC reasonably declined to exercise the limited authority it possessed over producer-pipeline contracts. Second, petitioners contend that the Commission erred in its assignment of GSR costs to two classes of pipeline transportation customers. By and large, we conclude that the Commission's allocation of GSR costs among customers was an acceptable application of "cost spreading" and "value of

[91] In Order No. 636-B, ¶ 61,272, at 62,040-41, the Commission suggested that those pipelines that offered discounted transportation services might not be permitted 100% recovery, a statement that the pipelines challenged in this proceeding. The Commission has since withdrawn that suggestion, however, *Natural Gas Pipeline Co. of Am.*, 69 FERC ¶ 61,029, at 61,116-17 (1994), rendering the pipelines' claim moot.

service" principles. We do conclude, however, that the Commission has failed to explain adequately its decision in all instances to allocate 10% of GSR costs to the pipelines' interruptible transportation customers. Third, petitioners contend that the pipelines themselves should have been required to absorb some portion of their GSR costs. After carefully reviewing the issue, we conclude that the Commission did not engage in reasoned decisionmaking such that we can sustain its decision to exempt the pipelines altogether. We do not hold that the Commission was *required* to assign a particular portion of GSR costs to pipelines, however, but instead remand this question (along with the 10% interruptible transportation figure) for further consideration.

1. Ripeness of petitioners' challenges to FERC's treatment of GSR transition costs

"Settled principles of ripeness require that [a court] postpone review of administrative decisions where (1) delay would permit better review of the issues while (2) causing no significant hardship to the parties." *Northern Indiana Public Service Co. v. FERC*, 954 F.2d 736, 738 (D.C. Cir. 1992) (*NIPSCO*). FERC argues that none of the petitioners' challenges to its allocation of GSR costs are ripe for review. It notes that, under Order No. 636, "a pipeline may file ... to recover GSR costs *only after* it has restructured its system in full compliance with the rule" and argues that disputes over GSR cost recovery are therefore better left to individual restructuring proceedings. *See* Order No. 636, ¶ 30,939, at 30,460; Order No. 636-B, ¶ 61,272, at 62,042. Additionally, FERC noted in Order No. 636-B that the Order No. 636 series transition cost policies "are not incorporated in the regulations, but are policy statements." Order No. 636-B, ¶ 61,272, at 62,034-35. It further explained that it would "review specific proposals for recovering transition costs with reference to the particular circumstances of each pipeline system and the degree of support those proposals enjoy from the affected parties." *Id.; see also* Order No. 636-A, ¶ 30,950, at 30,648-49 ("Guidelines and policies will be developed ... in concrete cases" to address concerns about GSR cost recovery.). FERC thus compares this case to *AGA I*, 888 F.2d 136, which held unripe challenges to Order 500's equitable sharing policy in light of the strong norm against reviewing policy statements and other tentative agency positions where no hardship will result to the parties.

The problem with FERC's ripeness argument is that it fails to meet *NIPSCO*'s two criteria for declaring a case unripe. The Commission claims that it intended in the Order No. 636 series to merely announce a general policy approach to GSR costs and leave analysis of specific GSR cost disputes to individual pipeline restructuring proceedings. "Where the language and context of [an agency] statement are inconclusive, we have turned to the agency's actual applications." *Public Citizen, Inc. v. NRC*, 940 F.2d 679, 682 (D.C. Cir. 1991). In this case, FERC's treatment of the GSR cost issue in subsequent proceedings is inconsistent with a general policy approach. For example, in restructuring proceedings for Texas Eastern Transmission Corporation, petitioners challenged FERC's allocation of GSR costs, but FERC determined that "[b]ecause the Commission has addressed all of the Industrial Groups' arguments in Order No. 636 *et seq.*, the Industrial Groups' request for rehearing is denied." *Texas Eastern Transmission Corp.*, 63 FERC ¶ 61,100, at 61,512 (1993). In Texas Eastern's NGA § 4 filing for the recovery of GSR costs, FERC again refused to consider these arguments. *See Texas Eastern Transmission Corp.*, 63 FERC ¶ 61,254, at 63,245-46 (1993). In *Columbia Gas Transmission Corp.*, 64 FERC ¶ 61,365, at 63,588 (1993), FERC refused to consider certain GSR cost arguments because they were "essentially a request for rehearing of Order No. 636. There is no need to revisit these arguments again. We deny rehearing." In *ANR Pipeline Co.*, 64 FERC ¶ 61,140, at 62,083-84 (1993), FERC rejected arguments about GSR costs "for the same reasons stated in Order No. 636-B."

Unlike the situation in *Papago Tribal Utility Authority v. FERC*, 628 F.2d 235, 240 (D.C. Cir. 1980), where we found that FERC might "resolve the claims of the parties and obviate any injury to them if we allow it to complete its proceedings," FERC has demonstrated that it does not plan to offer any significant justifications for its treatment of GSR costs as outlined in the Order No. 636 series other than those presented in the Order No. 636 series itself. We therefore hold that FERC's treatment of GSR costs does not constitute an unreviewable general "policy statement" but rather a final determination ripe for judicial review. Because FERC continually relies on the Order No. 636 series' treatment of GSR costs, it is not reasonable to conclude that a delay in review would permit better review of the issue.

The second part of the *NIPSCO* test asks whether delay in review would cause significant hardship to the parties. Put another way, the petitioners must show "a direct and immediate effect on their primary conduct." *Tenneco Gas v. FERC,* 969 F.2d 1187, 1211 (D.C. Cir. 1992). FERC admits that Order No. 636 GSR costs as of February 7, 1996, totaled almost $1.7 billion without interest, hardly an insignificant amount. In any case, it is unlikely that FERC would have gone to such lengths to assure that pipelines recover 100% of GSR costs if those costs were unlikely to have an immediate effect on the conduct of the parties having to pay them. Furthermore, to the extent that pipelines and gas producers continue to renegotiate contracts, such negotiations will undoubtedly be affected by FERC's treatment of GSR costs in the Order No. 636 series (and in the individual restructuring proceedings). We accordingly conclude that FERC's treatment of GSR costs causes "a direct and immediate effect" on the petitioners' primary conduct, and that the petitioners' claims are ripe for review.

2. Gas producers' exemption from GSR costs

In the Order No. 636 series proceedings, petitioners presented several alternative solutions to the transition cost problems, some of which would have required that FERC abrogate existing contractual obligations between pipelines and gas producers. These alternative solutions would have forced gas producers to bear part of the transition costs. FERC declined to adopt these proposals on the grounds that, among other things, it lacked § 5 authority to abrogate producer-pipeline contracts. Order No. 636-A, ¶ 30,950, at 30,643. The Commission is correct that it lacks such authority. We have already said as much in *AGA II,* 912 F.2d at 1505, where we concluded that Congress unambiguously restricted FERC's § 5 powers to jurisdictional contracts. And FERC's jurisdiction over wellhead contracts began to decline as soon as Congress eliminated such jurisdiction over new wellhead contracts. *See* NGPA § 601(a)(1)(A), (B), 15 U.S.C. § 3431(a)(1)(A), (B); *Pennzoil Co. v. FERC*, 645 F.2d 360, 380 (5th Cir. 1981). The PUCs' claims that FERC's authority to regulate pipeline rates for the benefit of consumers gives it implicit authority over nonjurisdictional contracts crumble against the wall of the *AGA II* holding.

The PUCs also argue that, even if *AGA II* applies, FERC still retained jurisdiction over some "old" gas contracts when it issued Order No. 636 and that it should have used its § 5 authority to reform those contracts. (In *AGA II* we recognized that FERC still had jurisdiction over some wellhead contracts, noting that "[t]he proportion of wellhead sales that is subject to FERC jurisdiction steadily declines ... as old gas is exhausted." *AGA II*, 912 F.2d at 1505.) But exercising such jurisdiction would have conflicted with Congress' clear intent that FERC get out of the business of regulating wellhead gas prices, making such an approach a questionable vehicle for addressing the petitioners' concerns. Furthermore, as FERC noted in Order No. 636-A, its jurisdiction "over most producer/pipeline supply contracts has already been removed under the NGPA. As of January 1, 1993, there will be no remaining vestiges of such jurisdiction by virtue of the Decontrol Act." Order No. 636-A, ¶ 30,950, at 30,643 n.460. In light of these concerns, it would be unreasonable to conclude that FERC should have reformed any producer-pipeline contracts to force producers to bear part of the GSR costs. We accordingly decline to accept the petitioners' invitation to remand this issue to the Commission.

3. Allocation of GSR costs among customer classes

Order No. 636 authorizes pipelines to recover their GSR costs from all of their blanket-certificated transportation customers. Petitioners contend that the Commission erred in allocating costs to two specific classes of customers: customers that were not directly responsible for GSR costs under Order No. 636 (*i.e.*, those that did not reduce their pipeline gas purchases in response to mandatory unbundling); and interruptible transportation customers. FERC defends its allocation of GSR costs based on the principles of "cost spreading" and "value of service." It is there that we begin.

a. "Cost spreading" and "value of service"

Order No. 500, the immediate successor to Order No. 436, authorized pipelines to recover take-or-pay costs from both their customers that were blanket certificated under the Commission's open-access regime and customers that were individually certificated under NGA § 7(c). The § 7(c) shippers objected that they were merely *transportation* customers of pipelines, and were therefore not in any way responsible for the fact that the pipelines, in preparing to accommodate their anticipated *sales* obligations, had incurred take-or-pay liabilities. According to the § 7(c) shippers, the Commission's allocation of take-or-pay costs therefore violated accepted principles of "cost causation," under which "[p]roperly designed rates should produce revenues from each class of customers which match, as closely as practicable, the costs to serve each class or individual customer," *Alabama Electric Coop. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982) (citation and internal quotation marks omitted).

The Commission conceded that its take-or-pay allocation could not be sustained under a narrow view of cost causation. It argued, however, that "circumstances surrounding the take-or-pay crisis and the transformation of the pipeline industry necessitate and justify the crafting of new ratemaking principles." *K N Energy v. FERC*, 968 F.2d 1295, 1301 (D.C. Cir. 1992). Specifically, the Commission defended its policy on grounds of "cost spreading" and "value of service":

> Under this first notion, allocating take-or-pay costs to transportation customers who admittedly may not have directly caused them is acceptable because, in the Commission's judgment, the extraordinary nature of this problem requires the aid of the entire industry to solve it; there are no other alternatives that would allow a transition to a market-based pipeline industry to be effectuated. Closely related to this rationale is FERC's second: namely that all segments of the industry—including those who may not have caused take-or-pay problems—will nonetheless ultimately benefit from their resolution and the concomitant move toward an open access regime; consequently, all segments can rightly be assessed a portion of take-or-pay costs.

Id.

In *K N Energy*, we sustained the Commission's *invocation* of "cost spreading" and "value of service," *id.* at 1302, though we made clear that our approval of those principles was limited, *see id.* ("A more searching inquiry may well prove necessary ... if the Commission should attempt to adopt these ratemaking rationales outside the take-or-pay context."). We did not, however, approve of the Commission's conclusion that *application* of "cost spreading" and "value of service" justified billing take-or-pay costs to §

7(c) customers. While the Commission contended that § 7(c) customers benefitted from Order Nos. 436 and 500 through lower transportation rates, the data before the court suggested that those rates had in fact increased. *Id.* Moreover, the Commission's Orders allocated costs to pipelines' remaining sales customers inconsistently. *Id.* at 1303. We therefore remanded for further consideration of the manner in which take-or-pay liabilities should be applied to § 7(c) customers.[92]

In this case, the Commission contends that its assignment of GSR costs to all blanket-certificated shippers was an appropriate application of "cost spreading" and "value of service" principles.

b. Petitioners' challenges

1.) Limitation to bundled sales customers

The Industrial End-Users object to FERC's decision to allow recovery of transition costs from *all* blanket-certificated transportation customers, including those that were not pipeline sales customers at the time of the implementation of Order No. 636. The ground for their objection is straightforward: GSR costs arose from the contracts between the pipelines and those firm sales customers that they retained after Order No. 436, not from contracts with customers that had previously converted under Order No. 436. Specifically, Order No. 636 required firm sales customers to convert their sales entitlements into firm transportation entitlements. Some of those customers also exercised their option

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[92] On remand, the Commission concluded that the application of take-or-pay costs to § 7(c) customers was not justified. *Williston Basin Interstate Pipeline Co.*, 63 FERC ¶ 61,171, at 62,175 (1993).

to reduce their pipeline gas purchases, leaving the pipelines with excess sales capacity, purchase obligations, and related costs:

> Indeed, nearly 65 percent of pipeline capacity was committed to *sales* customers prior to Order 636 even though pipelines' sales accounted for less than 20% of deliveries by 1991. Transportation customers who had *earlier* converted under Order 436 and 500 from sales service to transportation service, or who had never been pipeline sales customers, had already negotiated their gas supply arrangements and had previously paid the cost of restructuring prior to Order 636. Significantly, *nothing in Order 636 permits* ***these*** *transportation customers to reform their supply or transportation arrangements (or to pass on to others the associated costs).*

Industrial End-Users' Br. at 18 (emphasis in original). The contracts of non-sales customers therefore did not directly give rise to Order No. 636 GSR costs.[93] The Industrial End-Users further note that even if customers that had previously converted to firm transportation service benefit from Order No. 636, the Commission made no attempt to correlate the degree of that benefit with its cost allocation decisions.[94]

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[93] The same is true of § 7(c) individually certificated shippers, which FERC exempted from paying GSR costs under Order No. 636. The Industrial End-Users maintain that exempting § 7(c) shippers but including *all* Part 284 shippers is arbitrary. As is discussed in Part III.C.1, *supra*, however, FERC excluded § 7(c) shippers both from the capacity release program and from paying transition costs in order to equitably spread both the costs and benefits of Order No. 636.

[94] The Small Distributors and Municipalities briefly make the separate argument that the Commission's allocation of GSR costs constitutes unlawful "retroactive ratemaking." They contend that "many small customers had converted to transportation prior to July 31, 1991 [the date of issuance for the Order No. 636 Notice of Proposed Rulemaking] and were therefore not on notice that they would be held responsible for such pipeline gas supply costs when taking transportation service prior to that date." Those customers, however, were on notice as of July 31, 1991 that if they continued to receive open-access transportation services, they would be responsible for paying GSR costs that arose after that date. *See* Notice of Proposed

FERC's approach in Order No. 636, however, is valid under the value-of-service and cost-spreading rationales approved by this court in the *K N Energy* decision. Even those customers not directly responsible for GSR costs benefit from the availability of lower priced transportation in the unbundled marketplace. Moreover, the Commission's options in spreading out costs to pre-Order No. 636 firm sales customers are substantially limited by the filed rate doctrine and the bar to retroactive ratemaking; FERC simply cannot reach backwards through time in a truly equitable manner. While the Industrial End-Users correctly note that to date we have approved the Commission's departure from traditional cost-causation principles in only limited circumstances, those circumstances are squarely presented in this case. GSR costs under Order No. 636 are the functional equivalent of take-or-pay costs under Order No. 436, and "the Commission has not betrayed its obligations to the NGA or precedent by employing these ratemaking principles in its attempt to bring closure to the take-or-pay drama," *K N Energy*, 968 F.2d at 1302.

2.) Interruptible transportation customers

The Industrial End-Users challenge the Commission's decision to allocate 10% of a pipeline's GSR costs to interruptible transportation customers.[95] They contend that unbundling confers

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Rulemaking, [Current] F.E.R.C. Stats. & Regs. (CCH) ¶ 32,480, at 32,560 (1991).

[95] While the Commission suggests that in the restructuring proceedings it may consider the *manner* in which the 10% is collected, it apparently does not consider the 10% figure itself open to negotiation. In three cases, the Commission has required the allocation of 10% of GSR costs to interruptible transportation cases based expressly on the ruling in Order No.

no real benefit on that class of customers, who therefore should not be responsible for paying GSR costs. They further contend that interruptible transportation customers in fact may receive *inferior* service after Order No. 636 because the higher volume of firm transportation expected to result under the Commission's capacity release program may displace interruptible transportation services. Moreover, given that less gas is transported by interruptible than firm transportation, the GSR surcharges applied to interruptible transportation in some cases may *exceed* those charges applied to firm transportation.

The Small Distributors and Municipalities concur that FERC should have better spread the costs of restructuring throughout the industry, but take the contrary position that *additional* costs should have been allocated to interruptible transportation. Invoking "benefit of service" principles,[96] the brunt of their claim is a relatively complex economic analysis of why interruptible transportation customers stand to gain a great deal under Order No. 636. In sum, their theory is that the customers who receive the most benefit under Order No. 636 are those with elastic demands, *i.e.*, those most likely to use interruptible transportation.

Our concerns here mirror those in our review of the application of take-or-pay costs to § 7(c) customers in *K N Energy*.

636-A. *See Texas Gas Transmission Corp.*, 68 F.E.R.C. ¶ 61,118, at 61,594 (1994); *Florida Gas Transmission Co.*, 63 F.E.R.C. ¶ 61,160, at 62,079 (1993); *Southern Natural Gas Co.*, 62 F.E.R.C. ¶ 61,136, at 61,946 (1993).

[96] The Small Distributors and Municipalities also contend that under the same principles GSR costs should be allocated to gas producers. This point is discussed above, *see supra* Part V.E.2.

The fact that interruptible transportation customers are part of the "natural gas industry" is not, standing alone, sufficient to assign them GSR costs; even the "cost spreading" and "value of service" principles that we have approved allow for the imposition of costs only upon those entities that either bear some responsibility for the costs or derive some benefit from the solution imposed. *See K N Energy*, 968 F.2d at 1302-04. We are quite sensitive to the Commission's expert conclusion that interruptible transportation customers do derive benefits from unbundling under Order No. 636; an active market for firm transportation would seem likely to drive down the cost of less desirable interruptible transportation, and while the additional use of firm transportation under Order No. 636 may crowd out some interruptible transportation, that results at least in part from customers converting from interruptible to firm service. Moreover, unlike our review of Order No. 500, we are not presented in this case with evidence that the Commission's prediction of reduced costs was wrong as a factual matter. Further still, interruptible transportation customers do clearly benefit from Order No. 636 through access to low cost transportation that is available through the Commission's capacity release mechanism.

More troubling, however, is the Commission's apparently stringent adherence to the 10% figure in all instances. FERC elected to allocate GSR costs to interruptible transportation (IT) in response to claims by some pipelines that they would not be able to recover all of their transition costs from firm customers alone. It completely failed, however, to explain why it chose 10% rather than 5% or 15%, and why that 10% figure should be applied to every pipeline; the Orders and FERC's brief simply do not attempt to defend that figure whatsoever. For example, we are presented with absolutely no explanation of why IT should contribute 10% of GSR costs even on those pipelines on which IT constitutes less than 10% of throughput. And, while the Commission correctly points out that courts have recognized the inherent ambiguities in ratemaking, that does not immunize an agency from engaging in *reasoned* decisionmaking that is susceptible of appellate review. As we explained in reviewing Order No. 500:

> While we owe the Commission substantial deference in matters predictive and economic, we cannot ignore the Commission's unwillingness to address an important challenge to its stated benefit rationale for charging transportation customers. It most emphatically remains the duty of this court to ensure that an agency engage the arguments raised before it—that it conduct a process of *reasoned* decisionmaking. The deference we owe FERC's expert judgment does not strip us of that responsibility. Indeed, ... we will uphold an agency's decision "if, but only if, we can discern a *reasoned path* from the facts and considerations before the [agency] to the decision it reached."

Id. at 1303 (citations omitted) (second emphasis added).

In this instance, we cannot discern the Commission's path from its view that interruptible transportation customers should bear *some* of the burden for GSR costs to the conclusion that the share should be 10%. *Cf.* WALT WHITMAN, LEAVES OF GRASS, *Darest Thou Now O Soul* ("Darest thou now O soul, Walk out with me toward the unknown region, Where neither ground is for the feet nor any path to follow?"). And, while we are sympathetic to the Commission's view that "[t]he task of determining fair allocations of transition costs is ultimately thankless, even though [it] bring[s] all [its] experience and best judgment to bear on it," Order No. 636-B, ¶ 61,272, at 62,034, the law requires more than simple guesswork.[97] We therefore remand the issue to the Commission for further consideration.

4. Pipelines' exemption from GSR costs

To this point, petitioners' objections to the distribution of GSR costs have involved the allocation of those costs among groups of pipeline transportation customers. As a separate matter, petitioners forcefully contend that the Commission erred in not requiring the *pipelines* themselves to absorb any GSR costs. They note the remarkable similarities between Order No. 636 GSR costs and Order No. 436 take-or-pay costs, and contend that the pipelines should absorb GSR costs just as they do take-or-pay costs. While we do not conclude that the Commission necessarily was *required* to assign the pipelines responsibility for some portion of their GSR costs, we do agree with petitioners that the Commission's stated reasons for exempting the pipelines do not rise to the level of "reasoned decisionmaking." We therefore remand the issue to the Commission for further consideration.

Initially, we agree with petitioners that the Commission's stated rationale for allocating take-or-pay costs to pipelines substantially applies in the context of GSR costs as well. As we explained above, *see supra* Part V.A, take-or-pay and GSR costs both arise from the same provisions in producer-pipeline contracts and

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[97] In point of fact, there may be unique circumstances in which it is simply impossible to attribute costs with anything resembling mathematical accuracy. In such instances, however, the Commission still must take the time to explain why that is the case.

result from pipelines' former firm sales customers reducing their gas purchases. We therefore find it instructive that in the take-or-pay context, the Commission itself concluded that pipelines should bear some of the burden, reasoning that

> allowing a pipeline to recover 100 percent of its settlement costs through a fixed charge would be inconsistent with the Commission's holding in Order No. 500 that all segments of the natural gas industry should share in the burden of resolving the take-or-pay problem, since no single segment of the industry was to blame for its take-or-pay problem.

Order No. 500-H, ¶ 30,867, at 31,575. In Order No. 636 as well, the Commission acknowledged that GSR costs had arisen at least in part due to the conduct of the pipelines, characterizing bundled sales arrangements, which arose in substantial part from pipelines' market power, as an unreasonable and unlawful restraint of trade. Order No. 636, ¶ 30,939, at 30,405. Moreover, according to the Commission, the pipelines *benefit* from Order No. 636, in that they "will presumably receive more favorable prices or other valuable consideration resulting from contract reformation." Order No. 636-A, ¶ 30,950, at 30,643; *cf. id.* at 30,642 ("[Petitioners] generally allege that since Order No. 636 will benefit all segments of the gas industry, all segments should bear the costs. The Commission believes that the benefits of Order No. 636 indeed will be widespread.").

The Commission nevertheless puts forward a wide variety of arguments for exempting pipelines from paying GSR costs, which we will address on the merits seriatim. We begin, however, by noting that, as a general matter, the Commission's arguments seem directed toward proving the wrong point. FERC allocated Order No. 636 GSR costs to *customers* based on the principles of "cost spreading" and "value of service" discussed above, *see supra* Part V.E.3.a. When it exempted the *pipelines* from those costs, however, the Commission reverted to traditional concepts of "cost causation," or to use its characterization, "returned to first principles holding that a utility is entitled to the opportunity to recover all of its prudently incurred costs in providing public service."[98] It is important to emphasize that these are competing models for allocating the industry's costs of service. "Cost causation" correlates costs with those customers for whom a service is rendered or a cost is incurred. For example, as we noted above, *see supra* Part V.E.3.b.1, the Industrial End-Users argue that under a cost causation model, the only customers who should be required to pay GSR costs are those that reduced their pipeline gas purchases in response to Order No. 636. "Cost spreading" and "value of service," in contrast, take a much wider view, assigning the costs of service to those classes of industry participants that either are at fault for the take-or-pay dilemma or benefit from its resolution. Applying these latter principles, we sustained the Commission's determination that GSR costs should be paid by all blanket-certificated transportation customers, even those that did not directly cause the pipelines to incur liabilities under their supply contracts. *See supra* Part V.E.3.b.1.

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[98] Of course, there may be a world of difference between what the Commission views as pipelines' *legal entitlement* to recover GSR costs by charging their remaining sales customers higher prices and the pipelines' *economic ability* to do so in the marketplace. *See supra* at 123 (discussing possibility of pipelines' "death spiral" of higher prices and smaller customer base).

If the Commission intends to assign GSR costs according to these "cost spreading" and "value of service" principles, it must do so consistently or explain the rationale for proceeding in another manner.[99] We approved the invocation of those principles in *K N Energy* because FERC had concluded that the take-or-pay crisis could be resolved only by spreading costs throughout the "*entire industry*," 968 F.2d at 1301 (emphasis added), and because we recognized that "*all segments of the industry* ... will benefit," *id.* (emphasis added), from restructuring. *Cf.* Order No. 636-A, ¶ 30,950, at 30,650 ("[I]n the Commission's judgment, [Order No. 636] continues the general goal of spreading the costs of industry restructuring.").[100] The Commission therefore cannot, without explanation, burden blanket-certificated transportation customers on the ground that they will benefit from Order No. 636, and then ignore that same factor as it relates to the pipelines. For example, the fact that *both* pipelines and customers will benefit from expanded open-access transportation is one argument in favor of applying GSR costs to both. On the other hand, it is not particularly relevant that GSR costs will total only approximately

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[99] For example, the Commission may conclude that responsibility for GSR costs would cause such harm to a particular segment of the industry as to raise substantial concerns about its economic health. In this case, FERC contended that it exempted pipelines from paying GSR costs because of the pipelines' precarious financial position. The Commission never articulated that rationale in the proceedings below, however, and we therefore do not consider it. *See Burlington Truck Lines v. United States*, 371 U.S. 156, 168-69 (1962). The issue remains open for further consideration on remand.

[100] This applies, of course, only to those entities over which the Commission may lawfully exercise jurisdiction. *See supra* Part III.B.

$1.7 billion, while take-or-pay costs were $10 billion, for that proves nothing about the *relative* responsibility of various segments of the industry for those costs. On the same footing is the Commission's recognition that pipelines have already paid $3.6 billion in take-or-pay costs; petitioners are quite right when they note that *consumers* have in the end paid nearly twice that amount. The relevant question is instead whether the $3.6 billion dollar figure should be even larger—recognizing that the figure for consumers is sure to grow—because the pipelines are in part responsible for GSR costs and will benefit from Order No. 636.

This is not to say, however, that it is impossible, or even improbable, that the Commission on remand can establish a convincing rationale for exempting the pipelines. For example, arguably, the pipelines' contribution to the costs of the industry's transition has already been so disproportionately large vis-a-vis consumers that they are entitled to be excused from further responsibility. It also may be that unbundling under Order No. 636 benefits consumers so much more than it does the pipelines that the pipelines should bear few or no GSR costs. Such issues, however, require a fuller airing in the administrative proceedings on remand than is evident from the record developed in the initial go-round.

Two final arguments raised by the Commission merit separate attention. First, it notes that unbundling under Order No. 436 was voluntary while under Order No. 636 it is mandatory. It is unclear in the Order No. 636 series, however, how the "voluntariness" of the reduction in pipeline gas purchases correlates with the pipelines' responsibility for the resulting costs. The fact that certain pipelines made an economic choice to convert to open-access transportation and thereby almost certainly incur take-or-pay costs under Order No. 436 does not make other pipelines less responsible for the same type of costs when the Commission ultimately decided that it had to force the final stages of industry restructuring. Moreover, we rejected that very distinction when we vacated Order No. 436:

> FERC also alludes to the "voluntary" character of pipeline provision of Order No. 436 transportation. There are two flaws in this. First, refusal of the option may spell bankruptcy: inability to provide blanket-certificate transportation for fuel-switchable users may in current market circumstances cause critical load loss....
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> Second, the argument obscures distinctions between pipelines in the aggregate and alone. To be sure, Order No. 436 gives pipelines an option, blanket-certificate transportation, which ... is not available outside of Order No. 436. But as soon as a single pipeline finds it attractive enough to accept, each competing pipeline will come under competitive pressure to match the first's flexibility.

AGD I, 824 F.2d at 1024.

The Commission also notes that under Order No. 500, but not Order No. 636, those pipelines that paid take-or-pay costs received a heightened presumption that those liabilities were prudently incurred.[101] As with "voluntariness," however, the Order No. 636

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[101] Order No. 636 subjects GSR charges to the same form of prudence review generally applied to pipeline billings. Thus, customers have the burden of proving any claim they might press that particular GSR charges were not prudently incurred. Order No. 636-B, ¶ 61,272, at 62,039. Petitioners challenge the Commission's conclusion that "the possibility of having to defend the incurrence of [GSR] costs, and suffer disallowance of recovery, should provide sufficient incentive for pipeline diligence in minimizing these costs," Order No. 636, ¶ 30,939, at 30,461. Prudence review, however, is a well-settled practice,

series does not explain how the presumption of prudence correlates with FERC's cost-spreading and value-of-service rationales. The Orders' differing treatment of prudence stems from the fact that Order No. 500 and its successors allowed pipelines to recover some, *but not all*, of their take-or-pay liabilities through a fixed charge on transportation *if and only if* they absorbed some of those costs themselves. The presumption of prudence created an incentive for the pipelines to engage in cost absorption in that it reduced expenses they might later incur in litigating the appropriateness of their take-or-pay liabilities. Order No. 636 needs no such incentive because pipelines can directly bill transportation customers for 100% of GSR costs, an option that was never available under Order No. 500. And, of course, were the Commission on remand to assign some proportion of GSR costs to pipelines, it could apply the same presumption of prudence that it used in the take-or-pay context.

In sum, we cannot conclude from the record now before us that the Commission's decision to exempt pipelines completely from

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and petitioners have offered no particular reason for disallowing its use in this context. In point of fact, petitioners' complaint in large part seems to be that the Commission's *application* of its prudence standards is too lax, not that the use of prudence review is *per se* unlawful. *See id.* at 26 (citing *Columbia Gas Trans. Corp.*, 26 F.E.R.C. ¶ 61,034, *on reh'g*, 26 F.E.R.C. ¶ 61,334 (1984); *Texas Gas Trans. Corp.*, 48 F.E.R.C. ¶ 61,266 (1986), as examples of inadequate prudence review). We do not foreclose such claims from being raised in any petition for review of a ruling by the Commission that a pipeline's GSR costs were prudently incurred. The same holds true for petitioners' claim that the Commission will fail to distinguish correctly between Order No. 636 GSR costs and charges that pipelines should properly recover as Order No. 436 take-or-pay costs. We may review the question when properly presented with a ruling by the Commission on particular GSR costs.

paying GSR costs was the product of reasoned decisionmaking. Order No. 636 is based on principles of cost spreading and value of service that are, in turn, premised on the notion that all aspects of the natural gas industry must contribute to the transition to an unbundled marketplace. In addressing pipelines' liability for GSR costs, however, the Commission at the very least undervalued those considerations. We leave it to the Commission on remand to consider whether the pipelines should nonetheless continue to be exempted from such costs in light of the factors we have identified.

F. Conclusion

With respect to stranded costs, we hold that FERC's interpretation of the used and useful doctrine is supported by substantial evidence. We reject petitioners' argument that FERC inadequately addressed the LDC bypass issue, and we also reject petitioners' challenges to the volumetric surcharge for above-market Great Plains gas.

Turning to GSR costs, we first conclude that petitioners' challenges are ripe for review. Next, we hold that FERC did not err by failing to exercise its NGA § 5 authority so as to force gas producers to bear part of the transition costs. Furthermore, we sustain the Commission's application of GSR costs to the full range of blanket-certificated transportation customers. We remand the case to the Commission, however, for further consideration of the appropriate share of those costs to be paid by interruptible transportation customers and the gas pipelines.

VI. Conclusion

In its broad contours and in most of its specifics, we uphold Order No. 636. However, we remand certain aspects of Order No. 636, which we now recount, to the Commission for further explanation. With regard to no-notice transportation service, we remand for the Commission to explain why it restricted entitlement to receive no-notice service to those customers who received bundled firm-sales service on May 18, 1992. We remand the right-of-first-refusal mechanism for the Commission to explain why it adopted a twenty-year term-matching cap. Two aspects of the SFV mitigation measures require further explanation: first, the decision to require initial mitigation measures, such as seasonal contract adjustments, on the basis of the effect of switching to SFV on individual customers, whereas the four-year phase-in mitigation measure is determined by the effect on customer classes; and second, the decision that former customers of downstream pipelines are ineligible for small-customer rates. Finally, with regard to the recovery of GSR costs, we remand for an explanation of why, in light of the equitable-sharing procedures in Order No. 500 and the general cost-spreading principles of Order No. 636, pipelines can pass through all their GSR costs to customers, and also for an explanation of why the Commission decided, in allocating costs among customers, that interruptible-transportation customers should bear 10% of GSR costs.

Until the Commission takes final action on remand, however, we leave these measures in place as currently formulated. *See A.L. Pharma, Inc. v. Shalala*, 62 F.3d 1484, 1492 (D.C. Cir. 1995); *Checkosky v. SEC*, 23 F.3d 452, 462-65 (D.C. Cir. 1994) (opinion of

Silberman, J.); *cf. AGA I*, 888 F.2d at 153 (stating that the Commission must promptly provide a reasoned explanation).

It is so ordered.