following results: (i) The demand price to jurisdictional end users will increase (decrease), (ii) the current vintage price to producers of current vintage gas will decrease (increase), (iii) the incentive price to producers of current vintage gas will decrease (increase), and (iv) the quantity of gas produced and sold will decrease (increase).

For an exogenous change in a:

$dP/da > o$, $dC/da > o$, $dV/da > o$, and $dq/da > o$

Translating these results into words gives the following: If the price of current vintage gas is not constrained *and* the supply curve remains fixed *and* desired levels of inventories remain fixed *and* market participants act to keep actual inventories at the desired level *and* the demand for gas increases (decreases), i.e., the quantity demanded at each price increases (decreases), the market will induce the following results: (i) the demand price to jurisdictional end users will increase (decrease), (ii) the current vintage price to producers of current vintage gas will decrease (increase), (iii) the incentive price to producers of current vintage gas will decrease (increase) and (iv) the quantity of gas produced and sold will increase (decrease).

For exogenous changes in b:

$dP/db < o$, $dC/db < o$, $dV/db < o$ and $dq/db > o$

Translating these results into words gives the following: If the price of new gas is not constraining *and* the demand curve remains fixed *and* the desired level of inventories remain fixed *and* market participants act to keep actual inventories at the desired level *and* supply increases (decreases), i.e., the quantity of gas supplied at each price increases (decreases), the market will induce the following results: (i) the demand price to jurisdictional end users will *decrease* (increase), (ii) the current vintage price to producers of current vintage gas will *decrease* (increase), (iii) the incentive price to producers of current vintage gas will *decrease* (increase) and (iv) the quantity of gas bought and sold will increase (decrease).

For an exogenous change in r:

$dP/dr > o$, $dC/dr > o$, $dV/dr < o$, and $dq/dr < o$

Translating these results into words gives the following: If the price of new gas is not constrained *and* the demand curve remains fixed *and* the supply curve remains fixed *and* desired levels of inventories remains fixed *and* market participants act to keep their actual inventory levels equal to the desired levels *and* the interest rate increases (decreases), the market will induce the following results: (i) The demand price will increase (decrease), (ii) the current vintage price will increase (decrease), (iii) the incentive price to producers of current vintage gas will decrease (increase), and (iv) the quantity of gas bought and sold will decrease (increase).

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Friday
October 18, 1985

Part VIII

Department of Energy

Federal Energy Regulatory Commission

18 CFR Parts 2, 157, 250, 284, 375, and 381

Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol; Final Rule and Statement of Policy

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 2, 157, 250, 284, 375, and 381

[Docket No. RM85-1-000 (Parts A-D); Order No. 436]

Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol

Issued: October 9, 1985.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule and statement of policy.

SUMMARY: The Commission is amending its regulations in three specific areas.

Part A—Transportation

A simplified transportation program is adopted, including blanket certificates under section 7 of the Natural Gas Act (NGA), and transportation under section 311 of the Natural Gas Policy Act of 1978 (NGPA), conditioned to require non-discriminatory access to such transportation. Tariffs for such service are required to be volumetric, downwardly flexible, cost-of-service rates, differentiated by time-of-use, and consistent with sections 4 and 5 of the NGA.

A conditional opportunity is provided for customers of pipelines to modify their existing service agreements in order to reduce their contract demands for firm sales service. This customer option is only available if the pipeline held itself out as a transporter of gas for others. Pre-granted abandonment is available to the pipeline to the extent of any customer's reduction. This enables such customers to choose more freely among a portfolio of service options offered by pipelines. This also entails an adjustment in the pipeline's sales obligation under its existing service agreement and certificates, and revision of, among other things, any demand charges, minimum bills, that may be required under the firm sales tariff for the sales service being adjusted.

Traditional sales and transportation options remain available to pipelines and their customers under the Commission's existing certificate authority.

Part B—Take-or-Pay

The Commission is reaffirming its earlier policy statement regarding buy-outs of take-or-pay contracts. This flexible approach is contained in the April 10, 1985, Policy Statement in Docket No. PL85-1-000. In addition, the Commission is providing for expedited processing of producer abandonment applications under current substantive criteria.

Part C—Optional Expedited Certificates

A pipeline that assumes the risk of undertaking a venture for new services, facilities, and operations may apply for a new optional expedited certificate under section 7 of the NGA so long as the pipeline agrees to specific conditions governing the proposed services.

Appropriate abandonment is conditionally pre-granted to the pipeline to be effective at the expiration of the underlying contracts. If the customer has an alternate provider of service, the pipeline may discontinue service at the expiration of the applicable private contract. Because pipelines assumes the risk of their ventures, competing certificates may be granted. Traditional certification proceedings are still available to pipelines seeking to impose some of the risk of their venture on other parties, in order to ensure that the risk imposed involuntarily on others is required by the public convenience and necessity.

EFFECTIVE DATE: The amendments to Part 2 are effective October 9, 1985. The amendments to Part 284 are effective November 1, 1985. The amendments to Parts 157, 250, 375, and 381 are effective November 18, 1985.

ADDRESS: The environmental assessment, the exhibits, and the three maps referenced in the preamble are not being printed in the **Federal Register.** These documents are available for review in the Commission's Public Reference Section, Room 1000, 825 North Capitol Street, NE., Washington, DC 20426, (202) 357-8118.

FOR FURTHER INFORMATION CONTACT:

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For policy matters: Charles E. Teclaw, Federal Energy Regulatory Commission, Office of Regulatory Analysis, 825 North Capitol Street, NE., Washington, DC 20426, (202) 357-8100

SUPPLEMENTARY INFORMATION:

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Before Commissioners: Raymond J. O'Connor, Chairman; A. G. Sousa and Charles G. Stalon.

In the matter of Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Docket No. Rm. 85-1-000, (Parts A–D) order No. 436.

Final rule

Issued: October 9, 1985.

I. Introduction

A. The Proposed Rule

On May 30, 1985, the Federal Energy Regulatory Commission (Commission) proposed changes to its regulation of natural gas pipelines after partial wellhead decontrol of gas on January 1, 1985.[1] The May 30 Notice of Proposed Rulemaking (NOPR) was the outcome of a five month notice of inquiry begun in this docket on December 24, 1984.[2] The Commission is issuing its final rule in order to comply with the Natural Gas Act (NGA),[3] the Natural Gas Policy Act of 1978 (NGPA),[4] and the mandate of the court in *Maryland People's Counsel* v. *FERC*, Nos. 84-1019, 84-1029 and 84-1090 (D.C. Cir. 1985).

The NOPR proposed significant changes to our regulation of natural gas pipeline companies in light of the many changes in the natural gas industry over the years. These changes have included the NGPA which immediately removed market entry and exit restrictions over "first sales" of all new supplies of natural gas (NGPA section 601(a)(1)) and which removed wellhead price controls on the majority of gas supplies on January 1, 1985, pursuant to the Congressionally-mandated schedule (NGPA section 121).

The May 30th NOPR proposed a package of four interrelated parts.

Part A—Transportation

• A simplified transportation program was proposed, including blanket certificates under section 7 of the NGA and transportation under section 311 of the NGPA, conditioned to require non-discriminatory to such transportation.

• Tariffs for such service were required to be volumetric, downwardly flexible, cost-of-service rates, differentiated by time-of-use, and consistent with sections 4 and 5 of the NGA.

• A conditional opportunity was proposed for customers of pipelines to modify their existing service agreements in order to reduce their contract demands for firm sales service. This customer option would only be available if the pipeline held itself out as a transporter of gas for others. Pre-granted abandonment would be available to the pipeline to the extent of any customer's reduction. This would enable such customers to choose more freely among a portfolio of service options offered by pipelines. This would entail an adjustment in the pipeline's sales obligation under its existing service agreement and certificates, and revision of any demand charges, minimum bills, etc., that may be required under the firm sales tariff for the sales service being adjusted.

• Traditional sales and transportation options would remain available to pipelines and their customers under the Commission's existing certificate authority.

Part B—Take-or-Pay

• During a limited transition period, a rebuttable presumption of prudence would have been established for certain limited and circumscribed payments made by pipelines to extinguish all future minimum payment or purchase obligations in certain contracts.

• This presumption would have been available only to pipelines willing to offer non-discriminatory access to transportation service; this in turn would have given rise to an option for firm sales customers to reduce their contract demands.

Part C—Optional, Expedited Certificates

• Optional expedited certification procedures under section 7 of the NGA for new services, facilities and operations were proposed to be made available by choice to pipelines willing to assume the risk of these ventures by agreeing to specified conditions governing the proposed services.

• Appropriate abandonment would be conditionally pre-granted to the pipeline to be effective at the expiration of the underlying contracts. In those instances where the customer has an alternative provider of service, the pipeline would be able to discontinue service at the expiration of the applicable private contract.

• Because pipelines would knowingly assume the risk of their ventures, competing certificates would be granted.

• Traditional certification proceedings would remain available to pipelines seeking to impose some of the risk of their venture on other parties, in order to ensure that the risk imposed involuntarily on others is required by the public convenience and necessity.

Part D—Billing Mechanism for Old Gas Supplies

• A three-part gas rate was proposed for pipeline gas sales, to preserve the benefits of "old" gas for existing firm sales customers and to mitigate competitive distortions resulting from the lingering effects of existing wellhead price controls.

• The first block would contain "old gas" under sections 104, 106(a) and 109 of the NGPA and would be available first to all existing firm sales customers of the pipeline; the second block would contain all other gas. All non-gas costs associated with purchasing gas were to be billed as a third charge to be allocated between the two blocks.

• When a pipeline has permitted its firm sales customers to reduce 100 percent of their contract demands and offers those customers non-discriminatory self-implementing transportation, then, subject to a transition period, the sales price established by the pipeline for natural gas assigned to the second block was proposed to be presumed to be just and reasonable.

B. The Final Rule

Comments on the proposal were received from several hundred persons. The full Commission heard two very full days of oral argument from over one hundred commenters at the public hearing held on August 1–2, 1985. A list of those commenting and making oral presentations is attached as Exhibit A.

The comments, written and oral, have been extremely helpful. Major changes have been made in the proposal as a result. These changes include:

Part A—Transportation

• Allowing imposition of a reservation charge for firm transportation service.

• Allowing firm sales customers of a transporting pipeline a transitional option to convert from firm sales to firm transportation upon payment of a reservation fee.

• Express recognition of a pipeline's ability to impose reasonable operational conditions on requests for service and a requirement that such conditions be filed as part of the tariff.

• Providing for interim transportation rates effective November 1, 1985.

• Clarifying that projected levels of service for self-implementing transportation may be changed in rate cases.

• Providing for the "grandfathering" of certain transportation transactions and providing a smooth transition for certain other types of transportation.

• Exempting of intrastate pipelines from the rate conditions for self-implementing transportation and from the requirement to offer firm service.

• Providing for environmental review of new construction.

Part B—Take-or-Pay

• Deleting the proposed safe harbor rules for take-or-pay buy-outs and providing for review of such buy-outs under the more flexible approach contained in the April 10, 1985 Policy Statement in Docket No. PL85-1-000.

• Providing for expedited processing of producer abandonment applications under current substantive criteria.

Part C—Optional, Expedited Procedure

• Adding a requirement that an applicant seeking a certificate to provide transportation service must obtain a blanket transportation certificate under § 284.221.

• Including express rules prohibiting cost shifting.

• Clarifying the use of abbreviated procedures of section 157.7.

With regard to the billing procedure proposed in Part D, the Commission is not promulgating a final rule at this time. As detailed below, the Commission is, by separate notice issued today, requesting additional comments on a revised proposed rule which is designed to be phased-in beginning July 1, 1986. The proposed effective date is designed to be consistent with the other rate aspects of the final rule relating to transportation. The revised proposal for Part D is as follows:

Part D—Block Billing

• Eliminating "Part 3" with revisions to clarify that the "as-billed" principle continues to apply to fixed costs.

• Phasing-in the implementation of block billing beginning in the summer of 1986.

• Extending the base period to include the period between December 1, 1978 to December 31, 1984.

• Including interruptible purchases for purposes of determining block 1 allocation factors.

• Providing for case-by-case review and determination of allocation between blocks 1 and 2 of certain enumerated gas supplies.

• Clarifying that the presumption of justness and reasonableness for block 2 gas under specified conditions is subject to rebuttal and will only apply to rates that are "reasonably related" to block 2 acquisition costs.

• Various clarifications regarding implementation.

C. Statement of Commission Purposes

As will be detailed in this Preamble, the natural gas industry has changed significantly since Congress adopted the NGA in 1938 and indeed since adoption in 1978 of the NGPA.

Among the statutory responsibilities granted by Congress to the Commission is section 4(a) of the NGA which requires that all natural gas rates and practices subject to the jurisdiction of the Commission shall be just and reasonable, and any such rate or charge that is not just and reasonable is declared to be unlawful.[5] Section 5(a) of the NGA gives the Commission the power, after hearing, to determine the just and reasonable rate or practice and to fix the rate by order.[6]

Section 7(e) of the NGA authorizes the Commission to condition certificates for services and facilities in such manner as the public convenience and necessity may require.[7] Section 7(e) grants the Commission broad power because such certificate and conditioning authority is the means by which the Commission effectuates the purpose of the NGA to underwrite just and reasonable rates to the consumers of natural gas.[8]

However, what Congress has given, Congress can take away. In 1978, Congress did just that when it enacted the NGPA. The NGPA expressly removed the Commission's NGA jurisdiction to establish just and reasonable rates *at the wellhead* for new gas supplies not committed or dedicated to interstate commerce prior to enactment.[9] The NGPA also severely limited the Commission's jurisdiction to review the purchase costs of such new gas by pipelines at the city-gate.[10] The NPGA, however, did not remove or restrict the Commission's remaining NGA jurisdiction and the responsibility to establish just and reasonable rates for the transportation of all categories of gas in interstate commerce, or for the sale of natural gas committed dedicated to interstate commerce prior to enactment.[11]

In essence, sections 601 and 121 of the NPGA effected a phased partial reversal of the Supreme Court's 1954 decision in the *Phillips* case [12] (holding that independent producers are "natural-gas companies" when they make field sales of natural gas to interstate pipelines for resale). Section 601 removed all NGA jurisdiction over "new" gas, effective December 1, 1978, while section 121 removed NPGA price controls over specified gas supplies, effective November of 1979, January 1, 1985 and July 1, 1987.

These statutory changes reflect a Congressional determination that producers of natural gas do not have "natural" monopoly power.[13] In other words, the statute reflects the workably competitive nature of the production industry.

Moreover, as a result of physical and technological changes that have taken place as the industry has grown and matured over the last fifty years, a given supply of the natural gas commodity can now be transported—by front haul, back haul, exchange or displacement—to points throughout the continental United States. As a result, as a technical matter, producers of natural gas can market their supplies in an essentially national market while individual customers or resellers of gas (such as the local gas utilities) can obtain supplies from a variety of sources.

These legal and technical changes have already begun to restructure the industry.

The Commission's overriding goal in this docket is to adapt our regulations to these fundamental legal and technical changes so that we may continue to fulfill our statutory mandates under the NGA and the NPGA. Thus, the final rule adjusts, within the scope of the authority delegated by the Congress, those aspects of our current regulations that now appear to hinder the development of competition in those areas where competition will better protect the public interest than will traditional public utility regulatory rules. The final rule retains the traditional regulatory approach in areas where it is needed to protect the public from market dominance by natural gas companies.

The purpose of the final rule is to assure that commodity and transmission prices for natural gas between the wellhead and burner-tip are clear and accurate and consistent with the requirement of the NGA that rates and practices be just and reasonable and not unduly discriminatory, or preferential. The final rule also secures to consumers the benefits of competition in natural gas markets consistent with both the NGA and the NPGA. The final rule achieves these goals by establishing a framework for setting just and reasonable rates and practices for the sale and transportation of natural gas in interstate commerce, and by reasonably conditioning self-implementing interstate transportation services under the NGA and the NPGA.

Accordingly, in light of the record of comment and experience detailed herein and pursuant to sections 4, 5, 7 and 16 of the NGA, sections 311 and 501 of the NPGA and sections 402 and 403 of the DOE Organization Act,[14] the Commission is issuing the present final rule.

D. Effective Dates and Implementation Schedule in Final Rule

Because of the need to place all transportation programs on a sound and even footing prior to the expiration of certain programs on November 1, 1985, the Commission has determined for good cause that Part A of the final rule—Transportation—will generally be effective November 1, 1985. As a Statement of Commission Policy, Part B—Take-or-Pay Buy-Outs and Expedited Producer Abandonment—is effective immediately. Part C—Optional Expedited Certificates—will be effective 30 days from issuance. Part D—Block Billing—is proposed to take effect beginning June 1, 1986.

The Commission has considered whether to fix just and reasonable rates and practices by rule or on a case-by-case basis, and concluded that fairness to all natural gas consumers requires that these rates and practices be established by rule. To do otherwise would risk lengthy and time-consuming proceedings which may raise issues of undue discrimination against some consumers in later cases in favor of others whose rates and practices are fixed in earlier cases.

However, the Commission has also considered the hardships that might accrue to parties in individual circumstances during a transition period following issuance of the rule. For this reason, the Commission has determined that the final rule should provide a suitable transition period for fundamental choices in the industry, such as what services to offer, how to structure basic contractual arrangements, and how to allocate the risks and fixed costs of engaging in a particular business.

Although the transportation program in Part A is effective November 1, 1985, the Commission is providing a transition period for the various aspects of that program, such as the "grand-fathering" of existing transportation arrangements, the applications for new self-implementing transportation authority, the setting of transportation rates for new transportation service under the rate conditions, and the exercise by firm sales customers of their conditional opportunity to reduce or convert their firm sales entitlements.

The schedule for implementing the transportation program is as follows:

1. *Effective Date of Part A—Transportation.* Effective November 1, 1985 unless specifically indicated otherwise.

2. *"Grandfathering" of Ongoing NGPA Section 311 Transportation.* Sections 284.105 (for interstate pipelines) and 284.125 (for intrastate pipelines) provide that self-implementing transportation service authorized under NGPA section 311 prior to November 1, 1985 may be continued after that date, without additional filings, until the earlier of (1) the expiration of the original term of the transportation agreement as it was in effect on the date of issuance of the final rule, or (2) October 31, 1987. The rate conditions of § 284.7 (including the provision for interm rates) will apply to previously authorized transactions by interstates. The new reporting requirements will apply effective November 1, 1985.

The final rule does not affect any transportation arrangement authorized under §§ 284.107 or 284.127, again except with regards to the rate conditions (for interstate pipelines) and the reporting conditions (for both interstate and intrastate pipelines).

3. *"Grandfathering" of Order No. 319—Blanket Certificate Transportation on Behalf of High-Priority End-Users.* Section 284.223(g)(1) provides that transportation on behalf of high-priority end-users that commenced under existing § 157.209(a) prior to November 1, 1985 is deemed to be authorized in the full term originally certificated. The rate conditions of section 284.7 (including the provisions for interim rates) will apply November 1, 1985 consistent with the general rule above (since no other date is specifically provided).

4. *"Grandfathering" of Order No. 234 Series—Blanket Certificate Transportation on Behalf of Other End-Users.* Paragraphs (g)(2) and (g)(3) of § 284.223 provide a *brief* transitional arrangement for ongoing transportation under the Order No. 234–B program which must otherwise halt on October 31, 1985. The section provides that the transportation may continue after November 1, 1985 if several conditions are met. Most important is the condition that the transporting pipeline must file, prior to November 1, 1985, a statement that it will, effective November 1, 1985, comply with the express non-discriminatory access condition spelled out in §§ 284.8(b) and 284.9(b) and with the rate conditions in § 284.7. Paragraph (g)(3)(ii) makes it clear that transportation under the transitional rule is subject to the non-discrimination and rate conditions of the final rule. The remaining provisions allow for continuous authorization so long as the notice and protest procedure has been followed or where the transaction is within a 120-day automatic authorization period that has not expired.

The authorization under § 284.223(g)(2) ends on December 15, 1985 unless the pipeline has filed for a new blanket certificate prior to that date.

5. *Pipeline Choice to Participate in New Transportation Program.* There is no deadline for this, except to the extent a pipeline wishes to continue existing transportation.

Any pipeline may file for a new transportation certificate at any time.

6. *Interim Rates for Transportation.* Effective until the date of the new rates become effective.

"Grandfathered" transportation arrangements and new transportation services provided under the final rule may be provided by pipelines under comparable transportation rates already effective and on file at the Commission. See new § 284.7(b)(1). Such interim rates may be effective until the pipeline files and places in effect new rates which conform to new § 284.7 and which are filed to be effective no later than July 1, 1986. See new § 284.7(b)(2).

7. *New Rates for Self-Implementing Transportation.* New rates under § 284.7 must be filed to become effective no later than July 1, 1986.

8. *Exercise of Conditional Opportunity for Firm Sales Customers to Reduce or Convert Firm Sales Entitlements.* a. First notice of any reductions are due February 1, 1986. If a pipeline accepts a new blanket transportation certificate under new § 284.221 or begins a new NGPA section 311 self-implementing transportation arrangement under new Part 284, any of its firm sales customers may give it notice of an intent to exercise their conditional option to reduce firm sales entitlements up to 25 percent in the first year on February 1, 1986. Such "CD" reduction may not be effective before September 1, 1986. See new § 284.10(c).

After the initial reductions, "CD" reduction rights may be exercised only once a year, at a time specified by the pipeline and only with 150 days prior notice. See § 284.10(c)(2).

b. Notice of conversion after February 1, 1986. If a pipeline accepts a new blanket transportation certificate or begins a new section 311 transportation arrangement, any of its firm sales customers may give it notice no earlier than February 1, 1986, of intent to exercise their conditional option to convert up to 25 percent of firm sales entitlements in the first year to transportation service under new § 284.10(d). Such "CD" conversion may not be effective before 60 days following such notice. See new § 284.10(d). "CD" conversion options may be exercised at any time by a customer, subject to 60 days notice to the pipeline. See new § 284.10(d)(2).

II. Background and Discussion

A. Changes in the Industry and the "Unbundling" of Natural Gas as a Commodity

1. *The change in a nutshell and the Commission's overriding goal.* The natural gas industry has changed in fundamental ways over the nearly 50 years since the Natural Gas Act was adopted in 1938. The changes have been accelerated over the last seven years by the phased removal of wellhead price controls under the Congressionally mandated schedule set out in the Natural Gas Policy Act of 1978.

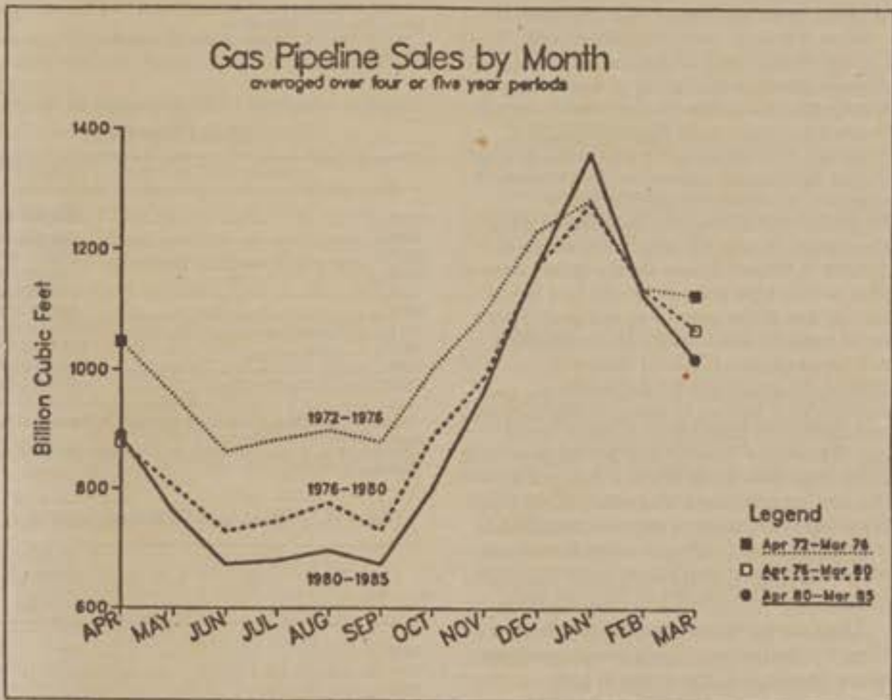
In a nutshell, the single most important economic change has been that natural gas has become a separate and distinct economic *commodity*: distinct from oil, distinct from transportation, and distinct from storage and various load balancing services. Around the commodity has evolved a highly competitive and rapidly growing spot market, with a thriving infrastructure of brokers and marketers, electronic information exchange services, and trade publications tracking price and market movements. Moreover, the Congressional decision in the NGPA to remove both price (NGPA section 121) and non-price (NGPA section 601(a)(1)) regulation over "first sales" of most natural gas—whether in interstate or intrastate commerce—has meant that these supplies of gas can now generally be sold by producers or marketers without the need for prior regulatory approval of market entry, market exit or price.

With regard to the availability of interstate pipeline *transportation*, the situation has also changed in significant ways. There are some geographic areas where there is but a single pipeline supplier, as was the case for the vast majority of markets in 1938. But in many other markets, there are two or more pipeline suppliers capable of serving a customer. The presence of pipeline-to-pipeline competition in these markets has radically altered the role of the Commission as well as the ability of utility-type regulation to tightly control regulated price levels.

Moreover, the maturing of the pipeline industry in recent decades has meant that there is now an interconnected nationwide pipeline grid. This enables increasingly efficient transportation transactions through backhauls, displacement and exchanges, enabling the "transportation" of a particular supply to a particular purchaser who is far removed from the supply and indeed may not even be directly physically connected with the field supply source. Thus, even where a pipeline is the only supplier to a given customer, that customer—given non-discriminatory access to the transportation service and proper rate treatment for all pipelines—has access to supplies of the *commodity* located in virtually any producing area in the Nation. Conversely, a producer of gas can now—given the same non-discriminatory access to the *transportation* grid—seek markets for his gas virtually anywhere in the Nation. As is demonstrated later, this is not economic theory but bustling commercial reality.

Finally, there is the question of capacity. While it is true that pipelines generally continue to be fairly fully utilized during peak period operations, total deliveries through their systems have fallen sharply from the 1972–1973 period. This is illustrated in Chart 1 below.

Chart I



Source: FERC Form 11's.

This phenomenon has been reflected in lower annual load factors for interstate pipelines and higher *unit* costs of providing service. It has also meant a significant increase in the amount of capacity available for transportation outside of the periods of peak demand. The chart further indicates that pipeline utilization for sales during the peak winter period has remained high and indeed has even increased. This indicates that firm capacity is generally being utilized on peak by those customers who have contracted for (or "booked") such service.

In short, the Commission is confronted with:

(1) A generally competitive market in the *commodity* of natural gas, most of which has been removed by Congress from all federal regulation as to market entry, exit and price, although such regulation has been retained by Congress over substantial amounts of gas; and

(2) A highly integrated *transportation* network, highly monopolistic in some markets, fairly competitive in others; over which Congress has generally determined to retain utility-type regulation over market entry, exit and price; but for which Congress has also allowed an alternative approach (under NGPA § 311) in which there may be no restrictions as to market entry and exit, but for which Congress expressly retained regulation as to rates.

Thus, in the words of one recent court decision:[1]

> In its oversight of the natural gas market, FERC confronts baffling problems.

But these problems are not unique to the natural gas industry.[2] Nor are they insurmountable. What is required is to adapt our regulatory framework to the changed circumstances in order to implement our statutory responsibilities in ways that further Congressional goals of the lowest reasonable rate for natural gas customers consistent with reliable, long-term service.

Accordingly, our overriding goal in this docket is to adjust our regulatory framework for natural gas in ways which:

(1) Retain and revise utility-type regulation over the interstate *transportation* function—that function which the Congress has deemed sufficiently uncompetitive so as to require such regulation in the public interest—yet

(2) Allow the *commodity* market for natural gas to continue to develop in a competitive fashion.

In this way, regulation will allow competitive forces to operate in those areas where Congress has determined they will better protect the public interest than traditional utility-type regulation, while retaining the traditional-type regulation in those areas where competitive forces have been found inadequate by the Congress.

To do this, the final rules generally seek to provide additional market options for suppliers, pipelines and customers. Thus, where a pipeline offers *transportation* as an "unbundled" service, the customer will be able to purchase *gas* in what Congress has determined (and which experience increasingly demonstrates) to be a workably competitive market. The terms and conditions of that transportation service remain fully subject to regulations under the NGA.

Moreover, where an interstate pipeline offers a "bundled" service in which the gas commodity is offered only as part of a package of services which includes a transportation component, the Commission presently concludes that the potential for market dominance by the pipeline is so great that more traditional utility-type regulation is required to satisfy the Congressional mandate set out in the NGA.

The various components of the final rule are designed to implement these general goals. In promulgating this rule, we are mindful of our obligation "to take into account what is known as to past experience and what is reasonably predictable about the future."[3] Accordingly, the remainder of the preamble sets forth in some detail the factual, logical and legal bases for the above conclusions and explains how the final rule will operate to advance these goals.

2. *Natural gas is a separate commodity from oil.* At the time of enactment of the NGA, natural gas was primarily a by-product of oil production. According to the Federal Trade Commission Report of 1935, approximately 60 to 70 percent of all natural gas (including both associated and non-associated natural gas) was found as a result of exploration for oil.[4]

Over the years, advanced exploratory knowledge and techniques gradually have made it possible for producers to explore for gas separately from crude oil.[5] Prior to the development of such techniques, the natural gas resource base which supported the rapid expansion of gas use in the 1950's and 1960's had been developed for the most part as a result of drilling for oil rather than gas and the role of gas prices as an incentive for developing new gas reserves had been secondary.[6] The advanced exploratory techniques sharply increased the importance of price as an incentive for further drilling of natural gas and helped establish gas as a separate economic commodity.[7] Indeed this economic fact played a major role in the Commission's decision in 1965 to adopt two separate "vintages" of "old" and "new" gas, each subject to a separate ceiling price.[8]

The key conclusion which flows from this fact is that *price* signals for natural gas play the same role in stimulating or dampening supply as they play in other commodity markets. Accurate, responsive price signals are thus not a matter for mere academic concern but a matter of commercial life and death for the production industry.

3. *Development of the transmission grid.* The interstate natural gas transmission industry has matured over the last 50 years, developing from a series of essentially individual, separated systems into an extensive integrated transportation grid.

In 1935, when the Federal Trade Commission completed its exhaustive study of the industry, interstate natural gas pipeline companies were largely separate systems, dependent on a few fairly well localized sources of supply. This is well illustrated by the attached 1934 map of the industry and by the FTC's detailed discussion of each of the industrial systems.[9]

The industry of the time was succinctly described by the FTC Report:[10]

> The function of transmission or transportation of natural gas in bulk over the long distances commonly required to market any considerable volume of gas is, on the other hand, one of the least competitive situations to be found involving commodities or public utility service. There is no known method by which gas in large quantities can be transported except by pipe lines. Oil may be moved in pipe lines, tank cars, trucks, and water-floated barges or "tankers" and packaged in barrels and other small containers for transport by various means. Most, if not all, commodities can be moved from points of origin to points of destination with a choice of routes, containers, and volumes to be handled at any one time.
>
> Most, if not all, commodities, except electric power, may be accumulated in storage previous to, during, or following transportation and drawn from such storage to meet intermittent or variable quantity demands. Except for some incidental storage in pipe lines under considerable pressure, commercial storage of natural gas is inconsequential after it is withdrawn from the ground. Again the large investment of $20,000 to $35,000 a mile for the larger sizes of pipe in long pipe lines generally laid below the surface of the ground as contrasted with overhead wire circuits ($1,000 to $15,000 a mile) and various physical means of transportation of other commodities constitutes a barrier to direct competition in transportation through the installation of competing pipe lines by any but large-volume purveyors, which has led to a demand from the smaller producers that existing gas pipe lines be made common carriers obligated to transport gas of producers other than those affiliated with, or making satisfactory terms for sale with the owners of the pipe line.

Thus, even where opportunities for direct pipeline-to-pipeline competition were presented, the natural gas companies in the 1920's and 1930's generally preferred to enter a new market by way of joint ventures.[11]

Over the decades the system has changed immensely. Even superficially the development of a farm more integrated system is readily apparent as illustrated by the attached 1982 map.

Moreover, the integration of the system is vividly illustrated by the increase in the amount of gas which interstate pipelines transport or exchange for each other (Table I below) and by the increase in costs incurred by pipelines in purchasing transportation services from other pipelines (Table II below).

The storage situation has also changed completely. Whereas the FTC in 1935 found commercial storage to be "inconsequential," storage now plays an integral role in the industry. As indicated by Table III below, the amount of storage capacity has continued to increase over the years.

TABLE I.—DELIVERIES OF INTERSTATF PIPELINE GAS FOR TRANSPORTATION OR COMPRESSION BY OTHERS

[MMcf]*

Year	
1975	1,677,260
1976	1,888,642
1977	2,285,530
1978	2,909,314
1979	4,065,743
1980	5,057,677
1981	5,850,408
1982	5,742,003
1983	4,885,770
1984	5,094,581

* Major Class A and B companies.

Sources: *Statistics of Interstate Natural Gas Pipeline Companies* (for 1975–1983 data).

FERC Form 2 (Annual report of interstate pipelines (for 1984 data)).

TABLE II.—ACCOUNT 858 BALANCES OF MAJOR INTERSTATE PIPELINES

Year	Dollars
1975	$228,308,000
1976	283,951,000
1977	358,990,000
1978	454,263,000
1979	671,687,000
1980	790,160,000
1981	1,038,717,000
1982	1,354,935,000
1983	1,709,063,000
1984	1,640,551,000

Sources: *Statistics of Interstate Natural Gas Pipeline Companies* (for 1975–1983 data).

FERC Form 2 (Annual report of interstate pipelines (for 1984 data)).

TABLE III.—TOTAL U.S. STORAGE CAPACITY

Year	Storage capacity
	Bcf
1935	38
1940	232
1945	416
1950	770
1955	2,084
1960	2,854
1965	4,086
1970	5,178
1975	6,644
1980	7,488
1981	7,581
1982	7,728
1983	7,986
1984	8,043

Sources: 1960–1982 American Gas Association. 1983–1984 Energy Information Administration.

The availability of this storage capacity means that gas does not have to be produced and consumed at identical rates (with resulting reliance either on shutting in of production in field or in "dump" sales of gas in markets). Rather, delivery of volumes can be taken in many instances even where there is no immediate use for the gas.[12] Operational constraints remain a limitation, of course. But operational flexibility has increased enormously.[13]

This is also reflected in changes in corporate structure. Thus, we note that the recent mergers and acquisitions [14] have given the companies involved much greater operational flexibility. These mergers have allowed companies access to new markets,[15] to new sources of supply,[16] as well as to storage capabilities.[17]

TABLE IV.—MERGERS AND ACQUISITONS INVOLVING FERC-REGULATED PIPELINES FROM 1982 TO PRESENT

Parent company	Acquired pipeline	Date	Acquired markets by State
Acquisitions by Non-pipelines			
Burlington Northern	El Paso Natural Gas Co	1982-1983	AZ, CO, NM, OK, TX, UT.
Goodyear Tire & Rubber Co	Celeron Corp. (included Mid Louisiana Gas Co., Louisiana Intrastate Gas Corp., & Tuscaloosa Pipeline Co.).	1983	LA.
CSX Corp	Texas Gas Transmission	1983	AR, CO, IL, IN, KY, LA, MS, OH, OK, TN, TX.
Williams Cos	Northwest Energy Co	1983	CO, ID, MN, OR, UT, WA, WY.
Acquisitions by Pipelines			
Northwest Energy Co. (Northwest Pipeline Corp.)	Cities Service Gas (now Northwest Central Pipeline Corp.)	1982	CO, KS, MO, NE, OK, TX, WY.
MidCon Corp. (Natural Gas Pipeline Co. of America)	Mississippi River Transmission Corp	1983	AR, IL, LA, MO, OK, TX.
Houston Natural Gas Corp. (Houston Pipe Line Co.)	(1) Transwestern Pipeline Co	1984	AZ, KS, NM, OK, TX.
	(2) Florida Gas Transmission Co	1984	AL, FL, LA, MS, TX.
MidCon Corp. (Natural Gas Pipe Line Co. of America) & Texas Oil & Gas Corp.	Tatham Corp. pipelines including Sugar Bowl Gas Corp. (renamed Acadian Gas Pipeline System), Pelican Interstate Gas Corp., Bayou Interstate Pipeline Corp., West lake Arthur Corp. and Tidal Transmission Co.	1984	LA, TX.
MidCon Corp. (Natural Gas Pipe Line Co. of America), in conjunction with Transok, Inc., and Houston Pipeline Co.	Conversion of 457 mile crude oil pipeline (formerly Texoma Pipeline Co.) to naltural gas service 40 mile "interstate segment" owned by Natural Gas Pipe Line Co. of America).	1984	TX.
Coastal Corp. (Colorado Interstate Gas Co.)	American Natural Resources (ANR Pipeline Co., Great Lakes Gas Transmission Co. (50%)).	1985	IL, IN, IA, KS, LA, MI, MO, OH, TN, WI, WY.
InterNorth, Inc. (Northern Natural Gas Co.)	Houston Natural Gas Corp. (Houston Pipeline Co.)	1985	TX, NM.
MidCon Corp. (Natural Gas Pipeline Co. of America)	United Gas Pipe Line Co	[1]1985	AL, FL, LA, MS, TX.
Tenneco Corp. (Tennessee Gas Pipeline Co)	Mid-Louisiana Gas Co, Louisiana Intrastate Gas Corp., Tuscaloosa Pipeline Co. (from Goodyear Corp.).	1,985	LA.
Phillips Gas Pipeline Co	Conversion of 500 mile crude oil pipeline (formerly Seaway System) to natural gas service.	1984	TX.

[1] Not yet consummated proposed, August 1985.

4. *The effects of rolled-in pricing of gas supply.* The Commission has generally adopted rolled-in pricing for natural gas supplies. Since this document proposes a variant of full rolled-in pricing, some background may be appropriate.

a. *What is rolled-in pricing*

"Rolled-in" pricing of natural gas simply means that a pipeline sells its gas supply at the weighted average cost of gas (or "WACOG") even though it may purchase gas at a variety of differing prices. In effect what it means is that a pipeline can pay $7.00 for a unit for gas, resell it at $3.00 because it pays lower prices for other supplies—and still make a profit transporting the $7.00 gas to the $3.00 purchaser.

Rolled-in pricing of *gas* purchases should be distinguished from rolled-in ratemaking treatment for new *facilities.* The Commission has generally followed rolled-in treatment for new facilities except where the costs of the new facilities are more appropriately assigned to a particular customer or group of customers. Thus, new pipeline construction or looping of some portion of a mainline transmission system in order to provide increased services to some particular customer downstream has been granted rolled-in treatment on the grounds that the new looping will also benefit all system customers through greater reliability of service.[18]

On the other hand, where the facilities were sufficiently segregated according to particular markets, costs have generally been assigned to the particular customers involved.[19]

Obviously, some filings present circumstances where large amounts of judgment are required and where reasonable minds may differ. The courts have generally recognized the need for deference to the Commission's balancing of the principles of cost responsibility, fairness and the need for administrative simplicity in this area.[20]

b. *Adoption of "vintaging"*

With regard to rolled-in pricing of gas, the situation has been somewhat different. Prior to 1954, when wellhead purchases were unregulated, the fact that individual purchases of gas were made under contract at differing levels was not particularly troublesome.[21] But after the *Phillips* decision and the adoption by the FPC of "vintaging" of gas in the Permian Basin Area Rate Proceedings,[22] the situation changed. Under vintaging, separate prices were set for "old" gas and "new" gas with the price of the "new" gas designed, at least in theory, to be high enough to reflect current costs of new supply.

But all the gas was sold at the lower, rolled-in average price.

Under this regulatory approach, purchasers were encouraged to demand gas at a different price than producers were being encouraged to supply it.

Under the area and national rate approach to producer price regulation, the price of the new gas was set on a modified cost-of-service approach based primarily on adjusted historical costs. These costs were generally below both replacement costs and market value. The result was a continuing increase in demand, a decline in supply, and a resulting shortfall which was rationed among customers through curtailment plans.[23]

The adoption by Congress in the NGPA of rapidly increasing price ceiling for some new gas, deregulation of 1979 of deep gas—and the Commission's retention of full rolled-in pricing—ended the shortage, but not the distortions.

c. *Effects on alternative gas supply projects*

As a result in part of full rolled-in pricing, consumers were investing too little in conservation and too much in purchasing gas. Producers were investing too much in high-cost gas prospects and in a variety of supplemental supply alternatives.

There were quite literally billions of dollars committed to alternative gas supply projects including:

- Liquefied natural gas from Algeria with regasification plants constructed in Elba Island, Georgia (service terminated in April 1980); Lake Charles, Louisiana (service terminated in December 1983); Cove Point, Maryland (service terminated in April 1980); and Everett, Massachusetts (sponsor filed for Chapter 11 on September 30, 1985); and
- synthetic or manufactured gas derived from coal with a facility constructed in North Dakota by the Great Plains consortium of pipelines (sponsors withdrew from project in August 1985).[24]

In each of these projects, the question had been debated as to whether the new supply source should be billed to customers on a rolled-in or separate basis. On a number of occasions the FPC initially required separate billing of the supplemental source.[25] In each of these instances the sponsors objected and asserted that the project could not be financed without rolled-in pricing of the gas. In each instance the Commission ultimately allowed the project to go forward on a rolled-in basis.[26]

In nearly every one of these instances where rolled-in pricing was used, the project ultimately failed the economic test—but only after several billion dollars had been expended. In 1984 *alone*, minimum bills imposed over $100 million of the costs of these projects on pipeline customers.[27]

d. *Effects on deep gas drilling*

A similar phenomenon took place with drilling for deep gas. Under the NGPA, this category of gas was deregulated in 1979. Prices rose sharply, passing the $10.00 per MMBtu level by 1981. Many millions of dollars were spent on exploring for gas that the market seemed to be saying could be sold for as much as $10.00 per MMBtu. In fact, it was being sold for between $3.00 to $4.00 per MMBtu.

Now, the extent of the distortion of rolled-in pricing tends to be inversely proportional to the deregulated volumes.

Suppose for example a pipeline whose market will absorb 100 units of gas at an average price of $3.00. Assume that there are only two categories of gas, one regulated at a price of $2.22 and the other unregulated. Assume further that the pipeline has 90 units of regulated gas and needs to purchase 10 additional units of deregulated gas. The pipeline will be able to pay up to $10.00 per unit of deregulated gas.[28]

Assume now that demand begins to fall as a result of an economic recession, warm weather and the customers' reaction to the high prices. Assume that the pipeline must lower the rolled-in price by 20¢ to maintain the same level of sales. Assume the pipeline cuts back its higher priced gas supply first. Under those circumstances, a 20¢ reduction in the resale value of gas will require a decrease in the marginal unit that is 10 times greater (since the volumes of deregulated gas make up only one-tenth of the total). Thus, the 20¢ decrease in the market value of gas requires a $2.00 decrease in the price paid for deregulated gas.

Similarly, if demand picks up and the resale value rises, then the pipeline would be able to pay 10 times more to the deregulated producer.

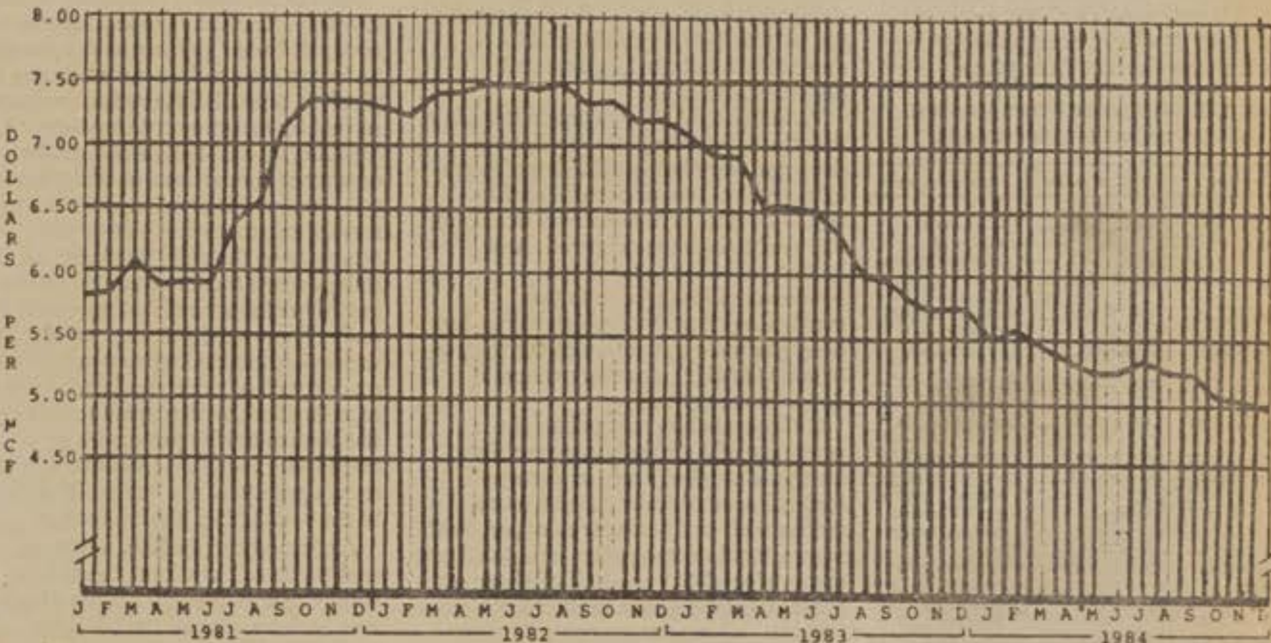
The real world under the NGPA is of course considerably more complicated than the simplified example. And the fact that a pipeline is theoretically able to pay a higher price is no indication that it will in fact pay the theoretical maximum. But the basic price relationships illustrated in the examples clearly reflect much of the experience of the last seven years.

The average price of "old" gas in November of 1978 was around $0.90 [29] rising to about $1.56 by July of 1985. The average price of "new" gas rose from about $2.03 in December of 1978 [30] to $3.77 in December of 1984.[31]

But the average price of NGPA section 107 gas follows a different path. It rose sharply from December 1979 to the summer of 1981 and then hit a plateau, as shown in Chart II below. As pipelines began to exercise market out clauses in the summer of 1982, the price of section 107 gas began to fall, first slowly, then more rapidly.

Chart II

Average Price of Total Section 107 Gas for Twenty Interstate Natural Gas Pipelines 1981 - 1984



Source: Based on Foster Associates' *Bulletin on Deregulated Natural Gas*, 1981—1984 issues.

Notwithstanding the price decline, the total amount of revenue received by sellers of section 107 gas still increased in 1982 and 1983 as increased volumes more than made up for decreased prices. But by 1984 the amount of revenue received by these producers had fallen by over $1.3 billion, as shown in Table V. The first six months of 1985 indicate an acceleration of this trend, with the annual rate running some $2 billion below the 1983 level.

TABLE V.—TOTAL REVENUES RECEIVED FROM SALES OF SECTION 107 GAS

	Average price (per Mcf)	Quantities (Bcf)	Total revenues (millions)
1981	$6.58	382	$2,514
1982	7.31	709	5,183
1983	6.25	942	5,888
1984	5.39	838	4,516
1985 (six month)	4.98	386	1,924

Source: EIA Natural Gas Monthly, Table 5 (July 1985) (published September 1985).

Table VI indicates that revenues lost by the high cost producers have been received instead by producers of other "new" gas supplies. The total amount of revenue received by producers as a group has remained basically unchanged.

For example, as shown below, while total amounts paid to producers for all gas by the major pipelines in 1984 *rose* by $370 million over the prior year, payments to high cost producers *fell* by more than $1.2 billion. Revenues of producers selling other new gas supplies rose by about $1.5 billion. When 1984 is compared to 1982, the disparity is even more pronounced.

TABLE VI.—PRODUCER REVENUE FROM SALES TO MAJOR INTERSTATE PIPELINES (1981–1985)

[In billions of dollars]

	Old Gas	New Gas	Section 107	Total
1981	$6.77	$8.70	$2.51	$17.98
1982	7.56	12.13	5.18	24.88
1983	6.23	12.94	5.88	25.14
1984	6.29	14.26	4.62	25.51
1985*	6.25	15.18	3.85	25.28

*Based on annualizing first six months of 1985.

Source: EIA Natural Gas Monthly, Table 5 (July 1985) (published September 1985).

In other words, while total wellhead revenues from major pipelines have gone up marginally over the last three years, revenues of high cost producers have plummeted while revenues of other new gas producers have been up strongly.

The legacy of distortions from rolled-in pricing of deep gas can still be seen. A great deal of the deep gas drilling was in the Anadarko Basin in Oklahoma. When the "bust" hit in 1982, dozens of producers in that area were forced into bankruptcy.[32]

Banks that had loaned money, particularly in the Anadarko Basin, based on the artifically high prices prevailing during the boom also suffered as debtors were unable to repay the loans. Some banks collapsed (at times taking larger downstream banks with them) while other banks survived, but with substantial losses.[33]

e. Effects on pipelines and producers

But while the inequities and inefficiencies may have been starkest in the case of deep gas, coal gas and LNG, the problems affected the entire industry. The interstate pipeline industry has estimated that the bill for natural gas that was contracted for but not taken is something on the order of $7 billion.[34]

These amounts are not being currently paid, however. Most major pipelines are reported to have invoked *force majeure* or similar contract defenses regarding their gas purchase contracts from both producers as well as pipeline suppliers. Table VII below lists at least some of the actions that have been publicly reported over the last three years.

TABLE VII.—REPORTED FORCE MAJEURE ACTIONS BY INTERSTATE PIPELINES

Company	Date of action	Against whom
United Gas Pipe Line.	July 9, 1985	Pan Alberta & Northwest Alaskan Pipeline.
Do	July 2, 1985	Domestic Producer Suppliers.
Do	Feb. 2, 1983	Northwest Alaskan Pipeline.
Columbia Gas Trans.	April 1983	3,000 producers.
Do	Aug. 8, 1982	Five pipeline companies.
Natural Gas Pipe Line.	July 8, 1985	Certain producers.
Do	Mar. 4, 1983	GHR Energy.
Northern Natural Gas.	March 1983	Consolidated Oil & Gas for Canadian gas transported by TransCanada
Do	June 1983	Texaco.
Tennessee Gass Pipeline.	May 31, 1983	Producers via the "Energy Gas Purchasing Program."
Consolidated Natural.	April 4,1983	Pipeline suppliers.
Panhandle Eastern	March/April 1983.	Pan Alberta.
Transwestern	November 1984	Producers.
Do	July 1985	Producers.
Trunkline Gas	December 1983	Trunkline LNG & Sonatrach.
Northwest Alaskan Pipeline.	Feb. 1983	Pan Alberta Gas.
ANR Pipeline	June 27, 1985	Producers.
Texas Gas Transmission.	May 31, 1985	Amoco Production.
Colorado Interstate Gas.	Spring 1984	Northwest Pipeline.
Transcontinental Gas Pipe Line.	July 25, 1985	1,400 producers.

Source: Exhibit Q.

The producers tell a similar story. One study conducted about a year ago indicates that over 70 percent of the independent producers sampled reported that they were not receiving their full contract price for new gas.[35] Producers testifying at the public hearing in August similarly indicated that they were not receiving full contract price for full contract quantities.[36]

f. Effects on gas supply

As detailed in section IV.D. of the Comment Analysis in this docket, full rolled-in pricing has contributed to establishing an exaggerated "boom and bust" cycle for the natural gas production industry. These distortions have led to serious problems in the industry and extensive debate among all segments of the industry as to the appropriate national policy to be followed to mitigate or remove these distortions.

With removal of price controls over most new gas on January 1, 1985 (and with the fact that the regulated ceiling prices on still other categories are considerably above what the market will bear) the extreme volatility on deregulated prices that characterized the 1979 to 1984 period should be diminished. But the fundamental distortions remain.

With the light of experience it is plain that the supra-competitive prices for deep gas were being subsidized by the infra-competitive prices allowed for regulated gas. Without rolled-in pricing this could not have occurred. And indeed, virtually none of the commenters disagree with the conclusions that (1) the high prices for deep gas were a function of the rolling-in policy and (2) massive economic distortions resulted.

5. *Congress has recognized the existence of a workably competitive wellhead market, and has removed Federal controls over market entry, market exit and price for new gas.* With regard to all new supplies of natural gas, comprising about one-half of al gas at present, the Congress in the NGPA removed all regulatory controls over market entry (NGA section 7(c) certification) market exit (NGA section 7(b) abandonment) and price (NGPA sections 102–109 and section 504).[37] See NGPA section 121 and section 601(a). Indeed, in NGPA section 601(c) Congress removed from the Commission any power to prevent interstate pipelines from "flowing through" to their customers the costs of purchasing the gas commodity absent "fraud and abuse or similar grounds."

Thus, in the words of one court:[38]

> The NGPA is a fundamental change in regulatory outlook. Contrary to the Supreme Court's assumption in *Phillips Petroleum Co. v. Wisconsin*, 357 U.S. 672, 74 S.Ct. 672, 98 L.Ed. 1035 (1954), which subjected gas producers to utility-type regulation under the NGA, Congress apparently decided that gas producers do not have "natural" monopoly power; that is, the industry does not possess the inherent technical characteristics that prevent its efficient and economical operation unless operated as a monopoly.[36] Therefore, the theory that a regulatory agency is necessary to represent consumers when they bargain on rates with a natural monopolist like a utility no longer applies to gas production. *See generally* Goldberg, Regulation and Administered Contracts, 7 Bell J. Econ. 426 (1976).
>
> [36] *See*, J. Bonbright, Principles of Public Utility Rates 10–13 (1961). The congressional assumption concerning lack of producer natural monopoly power is evidenced in the phased deregulation of wellhead prices and the elimination of FERC regulatory control under the NGPA over gas eligible for § 601(a)(1). The continuation of price controls on older, cheap gas reflects only a concern about preventing financial windfalls to sellers with very low-cost gas properties, and not a concern about natural monopoly power.

As a direct result of the NGPA, for example, a natural gas producer can now sell "new" gas to any purchaser—an intrastate pipeline, an interstate pipeline, a local distribution company served by an intra- or interstate pipeline, an end-user, a non-profit consumer cooperative or what have you—without federal restrictions as to market entry, market exit or price attaching to the sale. Similarly, an independent marketer can acquire a portfolio of gas purchase agreements and sell gas supply to any person, again without coming under any market entry, market exit or price regulation over the sale. In short, with respect to sales of the commodity by producers or marketers, Congress removed controls in recognition of the competitive nature of the commodity market for gas.

An interstate pipeline, however, seeking to sell gas from its system supply (a commingled stream of gas that was at the wellhead both NGA-jurisdictional and NGA-non-jurisdictional) is subject to the full panoply of statutory regulation governing market entry, market exit and price. As a result, *even for already certificated sales to existing customers*, it may change its rates only upon 30 days advance notice. It must supply extensive documentation detailing each and every source of natural gas supply, including an identification of the seller, the location, and the price. If it seeks to provide a new service to an existing customer, it must file for and obtain a section 7(c) certificate authorizing the new service. Any party opposing the new market entry has a right to explore genuine issues of material fact in a contested, trial-type hearing.

The rationale for maintaining utility-type market entry, exit, and price regulation over the sales for resale of interstate pipelines while removing that regulation for similar sales by other market entities is only implicit in the NGPA but appears plain enough: While Congress concluded that gas production was sufficiently competitive to remove regulation, the control which interstate pipelines exercised over transportation still conferred on them the same kind of market power over their customers as had existed at the time of enactment of the NGA.[39]

If customers had access to transportation for gas which they purchase directly in the competitive, commodity market, the pipeline would find itself at a serious competitive disadvantage in marketing gas in competition with producers and other entities because the regulatory rules as to market entry, exit and price would deprive it of the flexibility to meet the competition. We have *already* seen a good deal of that with the development of the spot market, the resulting decline in pipeline sales and increased use of transportation. And with the advent of repeated out-of-cycle PGA filings, we have seen what may be the beginnings of a virtual "posted price" approach to gas at the resale end where pipelines compete against other pipelines.[40]

Yet a pipeline that accepts the open access condition tendered in the final rule will have agreed to provide its customers with that access, thereby accelerating the process. This would thus require those pipelines that wish to remain merchants to seek greatly increased pricing flexibility.

6. *Evolution of the spot market.* Traditionally, natural gas in the interstate market has been bought and sold at the wellhead on the basis of long term contracts, typically for ten or twenty years.[41] This "contract market" was essentially the only way of transacting business. In part, this approach may have reflected the business needs of the parties. But regulation of market entry—and especially market exit—exerted a powerful constraint. Under a series of cases implementing the Supreme Court's *Phillips* decision, the Federal Power Commission, with the affirmance of the courts, took a progressively broader view of the scope of section 7(b) of the NGA as it applied to producers. Thus, the Commission held that the dedication of gas to the interstate purchasers survived the expiration of the wellhead contract,[42] and indeed the expiration of the underlying mineral lease.[43] Even where a producer willing to continue to sell gas in the interstate market wanted to contract, upon expiration of an earlier contract, with a different interstate pipeline purchaser, the law held that this could only be authorized after a comparative hearing in which the Commission weighed the comparative costs and benefits of the proposed change.[44]

Under these circumstances, development of an interstate spot market was precluded for essentially regulatory reasons.

In the 1970's, the situation began to change. With the onset of curtailments, parties sought supplemental sources of supply that were not subject to curtailment.[45] In the Order No. 533 series,[46] the Commission adopted a policy of granting *transportation* certificates to interstate pipelines that proposed to carry natural gas purchased from producers directly by certain end-users. As these direct sales for use were not subject to NGA rate regulation, the end users could pay a price sufficiently high to induce the producer to sell to an interstate purchaser instead of in one of the intrastate markets where gas by this time was selling for prices far higher than the regulated price. The Commission limited its transportation certificates under Order No. 533 to two years.

As a result of this step,[47] a small [48] "spot" market came into existence. But this market was essentially the result of customers seeking to avoid curtailment in a world where *all* interstate sales of gas for resale were subject to NGA certificates, abandonment and price regulation.

Accordingly, as curtailments eased in the late 1970's, the attraction of this program waned.

Enactment of the NGPA in 1978 and FERC implementation of section 311 brought a major change, however. In essence, section 311, as implemented by the FERC in 1978 and 1979,[49] created an alternative marketing scheme which was outside the Commission's NGA jurisdiction and utility-type regulation.

Nonetheless, as late as January of 1983, the president of a major pipeline company could declare flatly to the Congress that "There is no spot market for natural gas."[50]

But the situation had already begun to change.

Under the section 311 regulations, promulgated shortly after enactment of the NGPA, pipelines began increasingly transporting gas for local distribution companies for these utilities to use as part of their own "system supply."

By 1983, the volumes were increasing at an extraordinary rate as local distribution companies began increasingly to purchase gas from alternative merchants. As noted below, volumes transported "on behalf of" local gas utilities have continued to increase over the last two years. See Exhibit D.

In August of 1983, the Commission instituted Phase II Blanket Certificate rules allowing all categories of end-users to be eligible to receive blanket transportation. Immediately, substantial volumes of gas began to flow. By the end of calendar year 1984, after barely 16 full months of experience, volumes transported for end-users under the blanket certificate regulations amounted to just under four percent of *total* sales for resale of the major companies.[51] While actual data for 1985 are not available, of course, the estimates submitted with the filings indicate that the volumes are continuing to grow dramatically.

Finally, the Commission initiated its experiment with Special Marketing Programs beginning in the spring of 1983.[52] Initially, the programs were sought by pipelines or by a producer affiliated with a pipeline. The Commission encouraged producer programs, however, and by the summer of 1985 there were literally dozens of companies—most of them producers and marketers—that had filed for or received authorizations. See Exhibit E.

Thus, by the summer of 1985, the spot market was accounting for a substantial percentage of the total market. As shown by Exhibits D (summarizing experience under programs from January 1, 1985 to June 30, 1985), J (list of local gas utilities and intrastate pipelines receiving gas under section 311), and K (list of end-users receiving gas under blanket certificates), transactions under both section 311 and the blanket transportation certificates include virtually every major pipeline, hundreds of local gas utilities and hundreds of individual end-users. Customers in the great majority of the states are now benefiting from access to the national market for the gas commodity under one program or the other. The extent that these programs have been used in different regions of the country is illustrated in Map III which shows recent transactions for end-users under blanket certificates.

Estimates of the exact size of the spot market vary. A study submitted in this docket by DOE has estimated that by January of 1985, the total spot market (including intrastate transactions) has increased to between 2 to 2.5 Tcf per year (compared to total gas consumption of about 17–18 Tcf), having *tripled* in size in the space of one year.[53] Moreover, the great bulk of this growth has taken place in the interstate market. And of the total spot trading, the SMPs make up only about 15 percent.[54]

In addition, the DOE study documented several significant trends that are evident in the filings made with the Commission:

(1) The average size of the spot transaction is continuing to decrease, indicating a "broadening of the array of buyers and sellers in the market." [55]

(2) Local gas distribution utilities are increasingly involved [56] as "nearly all states have approved, or are in the process of considering gas

transportation rates" for the local utilities.

This systematic evidence of the growth of the spot market is confirmed by statements at the public hearing in which all of the marketers underlined the explosive growth in just a few short years.[57]

Further evidence of the viability and maturity of the spot market is the development of a non-profit gas marketer that has been able through spot market transactions to generate over $10 million worth of gas cost savings for low-income and elderly persons and an additional $2 million in other benefits provided to these consumers.[58]

Finally, we note that the market has over the last two years developed an infrastructure that includes trade publications following prices and market developments [59] as well as at least one electronic buy-sell exchange to which members of the public are free to subscribe.[60]

In short, the breadth and variety of this market leads us to conclude that it is not a transitory phenomenon. Rather, the development of this market is an indication of the radical change which the natural gas industry has undergone and is continuing to experience as a result of the development of distinct markets for the gas commodity and for unbundled transportation service.

7. *Legislation and regulation of carriage at the state level.* Since the NGPA was enacted in 1978, an increasing number of state legislatures and state public utility commissions have taken action that either encourages or requires public utilities to carry gas for a shipper other than themselves.

In 1983, New York enacted legislation permitting the State Public Service Commission to "order any gas corporation to transport . . . gas . . . owned by [a] consumer." [61] Similarly, in 1983 the West Virginia Legislature passed legislation stating that the state commission could "require the transportation of natural gas . . . by intrastate pipelines, by interstate pipelines with unused or excess capacity . . . or by local distribution companies for any person . . . ." [62] In 1985, the New Mexico Legislature enacted a provision authorizing the public Service Commission to "require the nondiscriminatory transportation of natural gas . . . for a seller or purchaser of natural gas to the extent of available capacity . . . ." [63] In July 1984 the Kentucky Legislature enacted a statute granting the State Commission the authority to direct intrastate utilities with excess or unused capacity to transport customer-owned gas.[64]

The Pennsylvania Public Utility Commission in 1984 stated that it was "directing that [Peoples Natural Gas Co.] provide a gas and transportation service to its industrial and commercial customers who acquire their own source of gas supply." [65] Also in 1984, the California Public Utilities Commission has instituted a proceeding to investigate "whether contract or common carriage of natural gas can be ordered . . . ." [66] No decision has been reached in the California proceedings, however.

The effect of these developments at the state level is again that purchasers of natural gas have increased flexibility and a real ability to purchase competitive gas supplies where interstate transportation is available.

B. The Problem in a Nutshell

The NGPA certainly accomplished its primary goal of increasing competition and gas supplies at the wellhead.[67] But the NGPA also aggravated price distortions between the city-gate and the wellhead. These price distortions have intensified competitive pressures on pipelines for new and lower-priced services. In turn, these competitive pressures require changes in the Commission's regulations if we are to fulfill statutory regulatory obligations over interstate pipelines in turbulent and fast-changing gas commodity markets.[68]

The problems created by the NGPA are inextricably intertwined with the Commission's administration of its remaining jurisdiction under the NGPA.

To the extent the NGPA removed the Commission's NGA jurisdiction over certain wellhead gas markets, the Commission is powerless to "turn back the clock" and restore that jurisdiction, no matter what problems and "disorders" have arisen in those markets since the NGPA.

To the extent the Commission exercises its remaining NGA jurisdiction so as to thwart the competitive commodity market for gas contemplated by the NGPA, the Commission may be negating one of the primary Congressional mandates of the NGPA.[69]

The Commission has no choice in the matter; we are required to live within the letter and spirit of both the NGA and NGPA as Congress has directed, and we must reconcile the two in changing circumstances—in terms of surplus as well as times of shortage.[70]

The NOPR summarized the current problems. The comments received in response generally support the Commission's analysis of the problem (if not necessarily all of the proposed solutions).

1. Prior to January 1, 1985, many interstate pipelines contracted for more gas supply than they could market at the prices set forth in those contracts, and do not intend to resume contracting for less expensive new gas reserves until their existing high-cost contracts are terminated or renegotiated to marketable levels.[71]

2. Producers of gas, responding to very high prices and high "take-or-pay" terms bid by pipelines for small supplies of gas deregulated following enactment of the NGPA in 1978, have developed new supply sources of gas. But gas demand has fallen off since 1981 due to recession and lower oil prices, and the market today cannot absorb these supplies at prevailing prices, even if "rolled-in" with cheaper "old" price-controlled gas.[72] A surplus of gas deliverability has been created, resulting in many wells of all vintages being shut-in.[73] In response, producers—particularly independent producers—are seeking equal and open access to pipeline transportation as an alternative to pipeline sales for marketing their gas.[74]

3. Interstate pipelines, particularly those with larger quantities of "old" price-controlled gas to "roll-in" with more expensive "new gas" supplies[75]—as well as intrastate pipelines under their limited interstate transportation and sales authority granted by section 311 of the NGPA[76]—are seeking new markets and lower prices for both surplus gas supplies and surplus pipeline capacity. Pipelines are especially seeking new sales to new or existing fuel-switchable or pipeline-switchable customers, such as industrial boiler fuel users or partial-requirements customers.[77]

But the existing interstate and intrastate customers of the pipelines are concerned that so-called "off-system" sales and "special marketing programs" will effectively transfer to the new customers a portion of the economic rent associated with the price of old, price-controlled gas when it is "rolled-in" with other, higher-priced supplies.[78] Reflecting these same concerns, the Commission generally has allowed these alternative sales and marketing programs only under somewhat restrictive conditions or on an experimental basis.[79]

In the case of the experimental "special marketing" programs" [80] and the "blanket certificate" [81] transportation programs for fuel-switchable end-users, pipeline customers have successfully challenged and overtruned the programs on judicial review on the ground they arbitrarily exclude other customers without consideration of the impacts on competition.[82]

On the other hand, the Commission has promulgated a final rule which prohibits pipelines from recovering, in minimum commodity bills, the variable costs for gas not purchased by its customers.[83] The rule has been sustained on judicial review on the grounds it permits partial requirements customers to "shop around" for gas supplies from other pipelines on a competitive basis.[84]

4. Purchasers of natural gas, seeing the availability of supplies in the field at prices below the rolled-in average cost of all gas,[85] are seeking to purchase gas directly in the field and have it transported to the city-gate or burner-tip in competiton with the system supplies which the pipeline retains under certain uneconomic long-term contracts.[86] In so doing, purchasers of gas are seeking the same opportunities to "swing" back and forth among a balanced "portfolio" of natural gas supplies [86] that "partial-requirements" customers currently enjoy, after implementation of the minimum bill rule, in "swinging" back and forth among competing pipeline suppliers.[87]

5. The pipelines have generally expressed a reluctance to provide these transportation services on a non-discriminatory basis to their existing sales customers [88] or to customers without immediate fuel-switching capability, such as residential and commercial consumers.[89]

a. With respect to incremental volumes (*i.e.*, gas that would not displace a sale by the pipeline itself from its own contracted-for supply), pipelines generally do not have adequate incentives to provide this service as long as the pipeline's rate structure requires the crediting to the pipeline's sales customers of essentially all revenues received from the transportation. The regulations allowed the pipeline to elect an option pursuant to which costs would be allocated to the transportation service (allowing retention of the revenues), but until fairly recently most major pipelines had not elected that option.[90] Moreover, the pipelines have been under no legal obligation to elect the revenue retention option. Once pipelines began to design their rates to allocate costs to the transportation service, thereby obtaining the right to retain revenue, the ratemaking rationale for declining to transport incremental volumes has diminished.

b. With regard to volumes of gas that would displace a sale by the pipeline from its own contracted-for supply, the situation has been somewhat more complex.

(i) Where the pipeline's take-or-pay exposure was so great that it believed that prepaid gas would never be able to be "made up," the pipeline faced the possibility of forfeiting the entire principal amount of the prepayment. Under these economic circumstances, even where the pipeline was able to retain the revenues received from providing transportation, the pipeline would still lose money were it to transport gas that would displace a unit of contracted-for gas. The more gas it transported, the more money it would lose. Under these circumstances the pipeline's reluctance to transport was at its height. Accordingly, it is important to provide flexibility for pipelines and producers to renegotiate these contracts, to review "buy-outs," "buy-downs" and to provide for expedited treatment of limited term and permanent producer abandonment and certificate requests.

(ii) Where the pipeline's take-or-pay exposure was *not* so great as to confront it with the prospect of forfeiting prepayments, the question was more one of fixed cost allocation. If the pipeline had to finance the prepayments, who should bear the burden of the carrying charges, the fixed costs associated with the prepayment: the sales customers, the transportation customers, the producer (by not being paid in accordance with the contract), or the pipeline's share-holders?

6. As a result of the pattern of contractual arrangements developed by the industry during previous eras of pipeline expansion [91] and supply curtailment,[92] such as take-or-pay and minimum bill provisions,[93] customers of pipelines have been allocated a large part of the risk that gas supplies deregulated by the NGPA might prove unmarketable over the life of contracts signed by producers and pipelines.

In turn, the Commission's administration of its ratemaking and certificate obligations under the NGA [94] has impeded the ability of natural gas consumers to secure the rewards of competition in natural gas markets commensurate with the risks that have been allocated to them by pipelines and producers.

In particular, the Commission's policy of full rolled-in pricing of price-controlled and deregulated gas supplies has frustrated the transmission of clear and accurate price signals between the city-gate and the wellhead,[95] and has premitted pipelines to bid up new gas prices above market-clearing levels.[96]

The Commission's policy of discouraging the flexible entry and exit of new pipeline services from natural gas markets is thwarting the expansion of the interstate pipeline system in order to provide for changing end-uses of gas [97] and changing locations of new gas fields.[98]

7. As a result, average delivered prices of gas are not adjusting downwards in line with the decline in field prices,[99] and this failure is causing unnecessarily high energy costs to consumers and a very large loss to the American economy in jobs, production, and net economic efficiency.[100]

Accordingly, the Commission has determined to make the changes set out in today's rule. We turn now to a detailed analysis of the comments filed in this docket.

III. Response to General Comments and Review of Alternatives

Although the majority of commenters addressed the specifics of Parts A–D of the NOPR, many commenters also responded in more general terms or with comments that do not fall neatly under any specific part of the rule. These general comments also included requests that the Commission consider various alternatives to the proposed rule including the alternative of issuing no final rule at all.

A. Whether To Issue Any Final Rule

Comments. The majority of commenters commended the Commission for moving forward to address the problems of the industry on a generic and expedited basis.[1] Many of these commenters echoed their comments filed in the earlier Notices of Inquiry phase as well as in earlier petitions, complaints, judicial decisions, and Congressional directions before the Commission.[2] These commenters also generally urged the Commission to act with dispatch to issue a final rule in this docket during the current conditions in gas markets.[3]

However, several commenters urged the Commission to consider issuing no final rule,[4] or else to issue a final rule governing transportation and the optional certificates while delaying a final rule on other parts of the proposed rule, such as the billing procedure.[5] Several requests were received urging the Commission to provide for further public comment on the billing procedure.

For example, some commenters pointed to the fact that delivered gas prices have remained flat for several months and suggested that gas markets were adequately adjusting to partial wellhead deregulation after January 1, 1985; therefore, the Commission's proposed rule was unnecessary except where required in response to court remand.[6] Other commenters suggested that the Commission address its regulatory obligations on a case-by-case basis rather than by rule,[7] or suggested that in any case the Commission's proposal was administratively unworkable.[8]

Commission Reponse. The Commission initiated the proceedings in this docket over nine months ago. As a practical matter, however, these proceedings also owe their origin to nearly seven years of Commission and industry experience in attempting to reconcile the NGA and the NGPA in rapidly changing gas markets which have been described as "disordered" [9] and "chaotic." [10] In response to our notices, we have received close to 200 comments in the NOI phase of the proceeding and 300 comments on the proposed rule, aggregating a record of over 10,000 pages. Some one hundred and fifty parties participated in four days of public conferences on the NOI and in two days of hearings in response to the NOPR.

In considering the alternative of taking no substantial action, the Commission has reviewed those comments and the actual experience under the present regulatory framework as detailed in Section II above. That record of comment and experience demonstrates conclusively that the natural gas industry has undergone radical changes in its structure and markets and that the regulatory framework must also be changed. Issues relating to gas-on-gas competition, access to transportation, pipeline and local distribution company "by-pass," prudency of pipeline "high-cost" gas purchases, persistence of "take-or-pay" problem contracts, shut-in of gas supplies, restrictions on entry and exit from the gas business, and allocation of fixed costs are arising with increasing frequency in filings before the Commission. (See Exhibit B showing out-of-cycle PGA filings). For reasons of administrative economy and predictability alone, the Commission could determine to deal with these issues by rule.

However, a much more compelling reason exists for the Commission's rejecting the alternative of issuing no final rule today: we have no choice under the NGA.

Section 5(a) of the NGA is mandatory, not discretionary. Once the Commission finds that an existing rate or charge or practice is unjust, unreasonable, or unduly discriminatory, it must prescribe the remedy for that situation.[11] Moreover, the Commission also has an obligation under the NGA to weigh and consider the competitive effects of our decisions,[12] especially where, as here, the Commission's regulations relating to the transportation of natural gas have been held to deviate from fundamental protections intended by the NGA.[13]

As detailed here, the Commission has found that certain aspects of the present regulatory framework are allowing rates, charges, and practices which are unjust, unreasonable, and unduly discriminatory under section 5 of the NGA. In addition, the Commission has considered the competitive effects of certain of its regulations and is adjusting those regulations in order to assure that the benefits of new competitive pressures in natural gas markets are secured to all customers consistent with the NGA.[14]

The continued persistence of a large "bubble" of surplus gas deliverability (Exhibit L) during a period of sustained recovery in the general economy demonstrates vividly the distortions created under the present regulatory framework. Moreover, the depressed state of the domestic drilling industry, now into its fourth year (Exhibits M and N), reflects the surplus of current supply but also may raise some concern as to how quickly drilling may accelerate as the surplus is dissipated. If producers are to increase drilling at the appropriate time and in efficient amounts, they *must* have more accurate price information than has been the case in the past.

One key to those more accurate prices is equal and open access to burner-tip markets. In turn, this access can only be realized if the ratemaking and certificate standards for interstate transportation are structured appropriately. This is what we have endeavored to do in Parts A and C.

B. Whether To Sever Out Parts A and C

Comments. As noted above, a number of commenters have requested the Commission to delay action on (or terminate) Parts B and D of the NOPR. They generally assert that these aspects of the NOPR (and especially Part D) have received insufficient study, will produce undesirable results and in any event should be considered separately, perhaps following a revised NOPR.

Commission Response. The Commission has considered whether to adopt such a "piecemeal" approach and issue only the transportation components of the rule. The issue in this regard is whether the identified problems and the proposed solutions (or rather mitigating measures) "are so inextricably related . . . that simultaneous resolution of the issues is required." [15] In this regard, we are well aware of the fact that a major criticism of the minimum bill rule was that the Commission had engaged in irrational "piecemeal reform" [16] by acting at the downstream nexus rather than upstream at the wellhead.

We understand the surface appeal of dealing with transportation issues alone:

- The strong mandate of the court decisions on SMPs and especially blanket transportation certificates, calling for a non-discrminatory approach to implementing interstate transportation; and
- The concern over the expiration of these programs effective November 1, 1985.

But we have concluded that many of the residual problems in the industry to a large degree *are* "inextricably related."

(1) Increased access to transportation on a non-discriminatory basis will place a pipeline in the position of competing as transporter with itself as merchant. An increase in transportation volumes inevitably exposes the pipeline to the risk of a decrease in its sales. Hence, we need to address such issues as the circumstances under which a pipeline can buy out of its wellhead contracts and the questions of how a producer that remains subject to NGA jurisdiction can obtain *regulatory* approvals to market gas which the pipeline is willing *contractually* to release. The new transportation rules are thus tied to the April 10, 1985 Policy Statement and the provision for expedited review of producer abandonment filings.

(2) Moreover, how does a pipeline customer make an informed judgement as to whether to buy gas from the pipeline or to convert to some amount of reserved transportation and buy gas from an alternative merchant *unless* the pipeline's sales price for gas reflects more accurately the cost to the customer of alternative purchases? Thus, the ultimate efficacity of the transportation rules is linked in part to the whatever final resolution is adopted to address the distortions of rolled-in pricing.

(3) How can a sole-supplied customer gain access to the competitive *commodity* market unless he can gain access to firm transmission capacity, *e.g.*, through the "unbooking" of already contracted for capacity via the CD reduction option and through the conversion option? Thus, the viability of the transmission rules (as well as the presumption of justness and reasonableness proposed in the revised Part D) is tied into the CD adjustment options of section 284.10.

(4) If the commodity market is to *remain* competitive even after the present excess of gas inventory is

"worked off," (and even if the current move towards corporate consolidation continues), then the regulatory framework must be structured in such a way that unbundled transportation will continue to be available. Thus, pipelines must bear more of the risk of underutilization of their transmission facilities than is the case when all costs are recovered from sales customers and with transportation revenues being credited to other customers rather than retained by the pipeline. Only in this way will the regulatory framework provides adequate linkage between the allocation of economic risk among industry participants and business control over those risks.

(5) "Conscious parallelism" is easiest to pursue in a market with a very small number of participants. While such activity may not run counter to the antitrust laws,[17] it certainly is not to be encouraged. A good way to help police against such behavior in a regulated market is to make sure that current market participants cannot use the regulatory structure to exclude new competitors. Thus, the viability of the transportation rules is tied into the easier market entry contemplated by the optional expedited certificates.

In short, the Commission has concluded that changes are required in several different areas concurrently. This does not mean, however, that the present rule is expected to be a panacea, or that further action in other areas is necessarily foreclosed. Rather, the three components issued today, together with the revised proposal regarding Part D, reflect a first step—albeit a major one—towards adapting our regulations to the post-NGPA world.

Accordingly, in light of the inter-relationship of the parts and the significant changes made to respond to many of the problems identified by the comments, the Commission has determined to proceed with the broader approach reflected in the final rule, while at the same time calling for further comment on a revised proposal for block billing.

C. Discussion of Other Alternatives

Since 1982, the Commission has considered a number of alternative approaches for dealing with the changes that have been be coming increasingly apparent in the industry. For example, we have considered:

- Setting new, just and reasonable rates for old gas;
- Establishing pipeline supply "cut-back" plans;
- Eliminating minimum commodity bills;
- Modifying the PGA regulations; and
- Encouraging broader access to pipeline transportation for others.

The first two options focus on the wellhead. Under the first, the Commission would raise the price of old gas under NGPA sections 104, 106(a) and 109 to "just and reasonable" levels. All aspects of this approach were aired in a Notice of Inquiry commenced in April of 1982 in Docket No. RM82-26.[18] The advantages of such an approach are that it would provide increased incentives for development of lower cost gas resources and would mitigate the distortions created by full rolled-in pricing in combination with the "cushion" of "old gas." It would put increased downward pressure on spot prices, however, and on the price of all above-average priced gas supplies. It could also involve the Commission in a most intimate way in determining the "proper" supply mix as between old and new gas. In effect the exercise of such power involves the concomitant responsibility of setting rates for the commodity that are neither too high nor too low.

The experience of 1954 to 1978 speaks eloquently to the difficulties faced by an independent economic regulatory commission in attempting to discharge that responsibility. It is the Commission's tentative judgement that Congress, through its decisions to ultimately decontrol all natural gas supplies (as old gas is depleted), determined that the workably competitive wellhead market would do a better job of setting such rates for the commodity than would a utility regulatory body.

Much of the discussion in the comments on Part D of the May 30th NOPR repeats the comment and argument received in response to the 1982 NOI in Docket No. RM82-26. For example, the Indicated Producers stressed the importance of continuing rolled-in pricing and called for action to raise the price for old gas. Similarly, their 1982 comments asserted that shortages could be expected in the not too distant future unless action was taken expeditiously to raise old gas prices.[19] The California Public Utilities Commission, on the other hand, in their 1982 comments, called for an end to full rolled-in pricing and the institution of a form of separate pricing of all old and new gas.[20] We anticipate that there will be a more refined analysis of these issues in response to our request for supplemental comments on the revised Part D.

With regard to the second basic approach, beginning in 1983, a number of interstate pipelines, distributors and state commissions of major downstream gas consuming states began urging the Commission to establish gas "cut-back" plans for interstate pipelines. In essense, they proposed for the Commission to order the pipelines as to which gas supplies should be taken and in which order. A list of these filings is attached as Exhibit R.

In many respects this option represents the "flip side" of the old gas proposal. Like it, the "cut-back" plan approach would involve the Commission ultimately in many aspects of natural gas production decisions. It would substitute the Commission's judgement for that of the commercial parties on such issues as which supplies of gas should be taken by a pipeline in managing its portfolio of gas purchase agreements.

But unlike the old gas proposal, the cut-back approach would lay the predicate for pipelines to assert to producers that supervening governmental action relieved the purchaser of all liability for breach of contracts that would otherwise exist. It would thus also raise extremely serious questions regarding the ability of private parties in the gas production industry to rely on private parties in the gas production industry to rely on private contracts as a tool for structuring basic economic relationships.

The potential effect of the Commission pursuing this option thus could well have been, by essentially a stroke of the pen, to void thousands of gas purchase agreements nationwide and to declare worthless some $7 billion worth of contract damage claims which producers might otherwise pursue against interstate purchasers. Neither the legal nor the factual basis for potentially voiding billions of dollars in freely negotiated contracts was made clear in the filings made with the Commission. In addition, a determination that effectively abrogated non NGA-jurisdictional wellhead contracts would run directly counter to the Congressional directives in the NGPA that progressively removed federal regulation of producer-pipeline transactions, and which expressly allowed the free operation of those contracts where below any applicable maximum lawful prices prescribed by statute. See NGPA section 101(b)(9). See also NGPA section 601(c). Accordingly, the Commission has declined to pursue this path.

Moreover, the Commission has sought to make it crystal clear that *nowhere* in the final rules, including in the bilateral CD reduction and conversion options, has the Commission abrogated any contracts nor created a regulatory framework predicated on any unilateral contract abrogation. In short, while the Commission has the power to abrogate NGA jurisdictional contracts where required by public interest considerations, we have not invoked that power in these rules and revised proposed rules.

A third option considered over the last two years was to shift the regulatory focus "downstream," away from the wellhead, and to the nexus between the regulated pipelines and their customers. Here the Commission found minimum commodity bills and minimum take provisions—fully regulated contract provisions that impeded competition for the natural gas commodity and allowed for receipt of revenues by the regulated pipelines in excess of their costs.

The Commission determined in May of 1984 to limit the operation of these NGA-jurisdictional provisions. Through the summer and fall of 1984 appropriate proceedings were conducted and rules were promulgated to that effect. Those rules have since been affirmed in court.

During this same time period in 1984, the question of increased access to unbundled transportation was reviewed. The Commission heard oral argument in a case which illustrated vividly the conflicting interests involved in the issue and the interaction of the existing rate structure, certificate authority and the take-or-pay provisions which limited a pipeline's flexibility in dealing with requests for transportation that would displace its own sales.[21]

In view of the inter-related nature of the problems raised, and the overhanging uncertainty raised by the approach of wellhead decontrol on January 1, 1985, no further action on the access question was taken at that time. Action on minimum bills, however, appeared sufficiently well defined so as to permit Commission action. This, of course, was the path the Commission chose. Experience since the August 1, 1984 effective date of the minimum bill rule has confirmed the powerful effects of competition among pipelines for sales to partial requirements customers. But as recognized by the Commission at the time, a major concern was with the potential for harm to customers that purchased all their gas supply from a single pipeline.

A fourth alternative course was to take action regarding pipeline PGA clauses. With the increase in competition, it seemed likely that PGA regulation might heed to be adapted to the impending arrival of partial wellhead decontrol on January 1, 1985. To review this option, the Commission issued a Notice of Inquiry in Docket No. RM84-12 (issued April 27, 1984).[22] The general thrust of the comments received, however, was that no major changes were required in the PGA regulations, at least at that time. Accordingly, no rule changes have been proposed to date.

A fifth approach was to take action to encourage broader access to the competitive, wellhead market. As noted above, in 1984 the full Commission heard oral argument on a case that raised these issues. As it was apparent that further analysis of these complex issues was required, no action was taken to allow time for further analysis and for developments in the industry to ripen. By the end of 1984, uncertainty over the likely immediate effects of partial wellhead decontrol were dissipating. On the other hand, a number of Sherman Act cases had been filed regarding access to transportation. Finally, experience under section 311 and the Order No. 234-B market certificate programs was indicating in a most concrete way the practical ability of the industry to adapt commercial practices to achieve the economic benefits of more open transportation. In short, events appeared to have progressed to where public comment on the issues was appropriate. Accordingly, the Commission commenced its Notice of Inquiry in the present docket in December of 1984 and issued the NOPR in May. This, then, in conjunction with the minimum commodity bill rule already implemented, constitutes the thrust of the Commission's policies in this area of our jurisdiction.

D. Format of Comment Analysis

Due to the very large number of comments received in response to the NOPR, the Commission's analysis of the comments has been organized under separate headings entitled "Comments" and "Commission Response." This approach is intended to help focus the response as much as possible; it does not preclude the Commission from relying on the entire record in this proceeding in responding to the many interrelated concerns raised by the commenters.

IV. Comment Analysis

A. Transportation

1. *Summary of final rule.*

a. Prohibition of undue discrimination in access to transportation.

Non-discriminatory access to self-implementing transportation services under section 7 of the NGA and section 311 of the NGPA is a cornerstone of the Commission's final rule.

Pipelines that provide transportation services on a non-discriminatory basis are assuring that the benefits of competitively priced gas supplies and transmission services are being made available to the broadest number of consumers. In addition, opening up transmission capacity on an across-the-board basis helps to achieve a traditional utility ratemaking goal of maximizing throughput in order to spread fixed costs over the greatest number of customers.[1]

On the other hand, permitting pipelines to unduly discriminate or to exclude certain consumers from transportation services is inconsistent with the fundamental goals of consumer protection and competition in the Natural Gas Act and the Natural Gas Policy Act. This is especially true where the Commission is authorizing pipelines to provide self-implementing transportation services to customers under section 7 "blanket" certificates or under section 311 authority.[2]

The self-implementing nature of such services require the Commission to more carefully scrutinize and condition the certificates and agreements which underlie the services to assure that consumers are fully protected against discriminatory or unreasonable practices associated with the individual transportation arrangements that are being authorized prospectively without further Commission review.

The final rule adopts two complementary approaches in dealing with the question of non-discriminatory access.

(i) *Rate structures.* The rule modifies the ratemaking standards governing transportation for non-owner shippers. By requiring that costs be allocated to self-implementing transportation (§ 284.7(c)(4)) and that rates to recover those costs be based on projected units of services (§ 284.7(c)(2)), the final rule establishes a ratemaking framework within which the regulated company recovers its costs (including its allowed rate of return) by providing the regulated transportation service. Moreover, the rule provides for the use of reservation charges only for firm service (§ 284.8(d)) and forbids all other provisions that have the effect of guaranteeing revenue irrespective of the level of service actually provided § 284.8(c)(1), § 284.8(d) and 284.9(d)).

In addition, by reaffirming the Commission's April 10, 1985 Policy Statement regarding take-or-pay "buy-outs" and by providing for expeditious action on producer abandonment and certification requests, the final rule provides pipelines and producers with tools to deal with so-called problem contracts.

If we have designed these rate conditions properly, there should no longer be any real incentive for pipelines operating under the new rules to engage in denying access to "unbundled" transportation. Indeed, it may be more likely that the Commission will begin to receive complaints that the new rate conditions encourage a pipeline to attempt to transport *more* gas than it can or should. For example, one shipper may complain that a pipeline has accepted for transportation for another shipper a supply of gas with too many impurities or too low a heating content. Since the gas is commingled during transportation, the first shipper may complain that the gas redelivered to him no longer meets the quality specifications of the gas he delivered to the pipeline for transportation. But since the pipeline earned its fee simply by transporting the gas, it lacked an adequate incentive to refuse transportation to the inferior quality gas.

These kinds of problems can be addressed by the business participants, as they are in similar commercial contexts, through development of reasonable quality standards, quality "banking" services, market and price clearinghouses, etc.

Moreover, these problems are the kind of commercial problems faced in *any* properly functioning industry that deals in a reasonably fungible commodity of uneven physical qualities. By and large, it is reasonable to assume that most of these types of problems will be "sorted out" by the commercial parties without need for recourse to a utility regulatory body. The *regulatory* focus will be on cost allocations, projecting levels of services, determining cost of service (including rate of return) and similar straight-forward utility issues, including ensuring that the transporting pipeline does not favor affiliates over other shippers.

(ii) Non-discriminatory access condition. While *theory* indicates that the rate conditions would preclude unduly discriminatory practices in most instances, experience teaches prudence. There may well be cases where a pipeline might nevertheless engage in discriminatory practices. For example, a pipeline might deny access to exclude a particular competitor from a given market or to disadvantage a shipper engaged in a manufacturing business in competition with a pipeline affiliate.

Accordingly, the rate conditions are complemented in the final rule by a broadly worded condition expressly prohibiting unduly discriminatory or preferential practices under the self-implementing transportation authorizations. See §§ 284.8(b) (regarding firm service), 284.9(b) (regarding interruptible service) and 284.221(c) (subjecting blanket certificates to these conditions).

Thus, the final rule prohibits undue discrimination, or preference, including discrimination in the outright selection of customers. It also precludes more subtle forms of discrimination, such as adhering to the non-discriminatory standard within a customer class while establishing numerous customer classes. It prohibits discrimination among customer classes as well as on the basis of minimum volume requirements, the quality or duration of service rendered, the end-use to which the gas is put, or the type of gas transported.

Unjustified exclusion of shippers from transportation services is inconsistent with the mandate of the court in *MPC I and II.*[3] Where a pipeline is authorized to transport gas on a self-implementing rather than a case-by-case basis, it is extremely difficult for shippers and the Commission to determine whether the exclusion of certain shippers by the pipeline is justified.

Examples of discrimination that the Commission finds to be undue or preferential within the context of the self-implementing authorizations are refusals to transport for existing sales or non-fuel switchable customers and preference for affiliates. On the other hand, the final rule makes clear that reasonable minimum operating and load management conditions imposed on shippers are not unduly discriminatory, or preferential, if imposed on all similarly situated shippers and if stated in filed transportation tariffs.

b. Increased Flexibility

The final rule is also intended to respond to the increased demand by pipelines and their shippers for increased flexibility and consistency in the Commission's regulation of transportation services. The final rule does this by eliminating restrictions on the categories of gas, shippers, end-uses, and duration of transactions eligible for self-implementing transportation. Pipelines seek this flexibility and consistency in order to respond to increased demands for transportation services by natural gas consumers, producers, and marketers.

c. Rates

Rates for self-implementing transportation by interstate pipelines must conform to specific standards set out in §§ 284.7, 284.8 and 284.9. Intrastate pipelines are not subject to these rate conditions. Interstate pipeline rates for self-implementing transportation must be volumetric and downwardly flexible between a maximum and a minimum. A reservation fee may be charged for firm service. See § 284.8(d). In order for pipelines to respond flexibly to market conditions between rate cases, rates below the maximum may be charged as long as they are not unduly discriminatory and are filed at the Commission. Such "rate discounting" must be solely at the pipeline's risk of under-recovery of costs; no pipeline is permitted to seek to recover such costs retroactively in future rate cases.

Such transportation service must be offered as a stand-alone basis, unbundled from any other services and separately tariffed. This precludes any tying arrangements between transportation and other services unless the bundled transportation services are offered as options to the stand-alone transportation service.

In order for pipelines to have the opportunity to earn rewards commensurate with any changes in their risks under the self-implementing program, pipelines are required to set projected levels for transportation service in rate cases. Costs will be allocated to be recovered through this service. Accordingly, a pipeline will be permitted to retain all transportation revenues collected for services rendered. Self-implementing transportation services by interstate pipelines are required to be offered on both a firm and interruptible basis, and capacity may be allocated by the pipeline on a first-come, first-served basis, subject to availability and without preference as between firm sales and firm transportation or between interruptible sales and interruptible transportation. "First-come, first-served" means the pipeline may offer transportation services subject to prior claims on capacity. Conforming rates under the new program must be filed to be effective no later than June 1, 1986. Any interstate pipeline that files for a blanket certificate under § 284.221 or that operates under authority of § 284.102 may charge existing transportation rates for self-implementing transportation services on an interim basis until the new rates are effective.

d. CD Reduction and Conversion Options

If an interstate pipeline chooses to provide self-implementing transportation under the final rule, it must also agree to provide its existing firm sales customers the option to convert their firm sales service to firm transportation service. As a condition of providing such firm transportation capacity, a pipeline may recover a portion of its fixed costs by requiring its customers to pay a reservation charge not in excess of the fixed-costs in the demand charge allocated to the transmission component for firm sales service. The conversion option is detailed in § 284.10(d). In addition, a conditional opportunity is available to customers to reduce their firm sales contract demands or entitlements when their pipeline chooses to provide transportation services under the self-implementing program. See § 284.10(c). Pre-granted abandonment of its certificated service obligation would be available to any pipeline to the extent of any contract demand reduction, and no customer would have any right to resume firm sales service with the pipeline absent the issuance of a new or amended certificate to the pipeline required under section 7 of the NGA. See § 284.10(f).

The purpose of the reduction and conversion options in the final rule is to allow a "freeing up" of contracted firm capacity that customers no longer wish to reserve. This will allow that firm capacity to be contracted for by parties that do wish to purchase such firm service.

e. Transportation by intrastate pipelines

Because of the NGPA exemption of intrastate services from Commission jurisdiction under the NGA, intrastate pipelines that choose to transport under the self-implementing program are exempted from the rate conditions under § 284.7. Similarly, there is no requirement that the service offered by intrastate pipelines be firm. See §§ 284.8(a)(2) and 284.9(a)(2). Finally, intrastates would not be subject to the CD reduction and conversion options.

f. Grandfathering certain transactions

Transportation arrangements under previous section 311 programs and blanket transportation certificates under certain conditions, may continue beyond November 1, 1985, in order to allow a suitable transition period for the old programs to terminate and the new program to begin without a break in services to consumers consistent with the final rule. Thus, even where a pipeline does not ultimately elect to continue to provide service under the non-discriminatory access condition of the new rules, existing blanket certificates and section 311 authorizations will allow transportation to contine during the transition period.[4] Existing 311 arrangements will be permitted to continue until the expiration of their original term or October 31, 1987, whichever is earlier. Blanket transportation for high priority end-users under existing § 157.209(a) may continue until the expiration of their terms. Similarly, transportation for low priority end-users under § 157.209(e) may also continue subject, however, to the non-discriminatory access condition.

g. Individual certificates

Finally, the final rule does not apply a generic, non-discriminatory access condition to individual transportation and sales certificates under section 7 of the NGA. The consistency of such certificates with the purposes of this final rule can and will be reviewed by the Commission on a case-by-case basis at the time such certificates are sought.

h. Overview of comments

Commenters on the Part A transportation program raised several major issues. Among these issues were the scope and authority of the non-discriminatory access condition and its applicability to intrastate pipelines and to pipeline operational or load management conditions imposed routinely on shippers. Also raised as issues were the scope of and authority for conditioning availability of self-implementing transportation on a pipeline's agreeing to allow its customers to convert firm sales services to firm transportation service or to simply reduce contract demands. These comments also addressed the reallocation of risks and revenue responsibilities that would be required when customers adjust their contract demands. Commenters also addressed the authority and design of the downwardly flexible transportation rates and the quality of service requirements for firm and interruptible transportation services. Finally, commenters addressed the transition between current programs and the new transportation program established by the rule.[5]

These comments and others are discussed in detail below.

2. *Commission authority to prescribe the non-discriminatory access condition.* a. Authority to impose on interstate transportation by interstate pipelines. The proposed rule provided that self-implementing transportation authorizations under section 311 of the NGPA and blanket transportation certificates issued under section 7 of the NGA would be subject to an express non-discriminatory access condition. The express condition provided that any interstate or intrastate pipeline that provides any transportation service pursuant to such authority or certificate shall provide such service for all shippers willing to pay the applicable tariff rate on file with the Commission for the service requested, without discrimination in the quality of service provided, the categories, prices, or volumes of natural gas transported, customer classification, or discrimination of any kind.

Comments. Some commenters misunderstood the non-discriminatory access condition to require that *all* self-implementing transportation requests, including patently unreasonable requests, be accepted by transporters.[6]

Commission Response. This was not the Commission's intent. Therefore, the non-discriminatory access condition has been revised in the final rule to insert the word "undue" to track the NGA statutory standard.[7] The final rule thus is intended to prohibit undue discrimination, or preference, including but not limited to undue discrimination or preference in the quality of service; duration of service; categories, prices, or volumes of gas transported (including as between affiliated and non-affiliated producers or shippers); and customer classification (including whether or not transportation would displace sales to an existing sales customer of the transporting pipeline).

Moreover, the final rule expressly provides that a pipeline may impose reasonable operational conditions on any request for self-implementing service. See §§ 284.8(c) and 284.9(c). Such conditions are required to be made a part of the pipeline's tariff, however, and thus will be subject to public scrutiny and Commission review. *Id.*

Comments. Most of the commenters who address the non-discriminatory access condition support the Commission's proposal. Those in favor of the proposal include a quarter of the major interstate pipelines, nearly half the intrastate pipelines, a majority of local distribution companies (LDCs) and virtually all industrial end-users, producers and public entities. The majority of interstate and intrastate pipelines oppose the proposal.[8]

Those in favor of the non-discriminatory access condition generally state that it is necessary in order to effectuate the consumer protection and competition goals of the NGA and NGPA. They assert that it is reasonable in light of the increased demands for transportation of lower-priced gas in natural gas markets, and that it should be clearly stated and broadly applied in order to avoid evasion by pipelines on a case-by-case basis. They conclude that the

Commission has legal authority to impose the condition.

The majority of commenters support the application of the non-discriminatory access condition to pipelines that choose to participate in the Commission's self-implementing transportation programs. They generally indicate the view that the Commission has sufficient authority to implement the non-discriminatory access condition under both NGA section 7(e), which grants the Commission authority to attach reasonable conditions to certificates, and NGA sections 4(b) and 5(a), which prohibit undue discrimination or preference in rates, charges, or practices.[9]

Among the cases cited in support of the Commission's authority under the NGA to impose the non-discriminatory access condition are: *Gulf Oil Corporation v. FPC*, 563 F.2d 588, 596–97 (3rd Cir. 1977) and *American Trucking Association, Inc. v. Atcheson, Topeka, & Santa Fe Railway Company*, 387 U.S. 397 (1967). Process Gas Consumers Group (PGC) also cites several cases in which the courts have read NGA section 7 very broadly to uphold certificate conditions imposed by the Commission: *Atlantic Refining Company v. PSC*, 360 U.S. 378 (1959); *Transcontinental Gas Pipeline Co. v. FERC*, 589 F.2d 186, 190 (5th Cir. 1979), *cert. denied*, 445, U.S. 915 (1980) (conditioning of certificates to ensure appropriate allocation of risk); and *Alabama-Tennessee Natural Gas Co. v. FPC*, 203 F.2d 494 (3rd Cir. 1953) (imposition of rate conditions).

The main argument of the commenters that oppose the non-discriminatory access provision is that the condition would, in effect, subject interstate and intrastate pipelines to regulation as common carriers.[10] According to these commenters, while participation in the self-implementing program may be voluntary, participation for all practical purposes is mandatory because pipelines will be forced by economic and competitive necessity to participate in the program in order to remain financially viable. Others argue that the non-discriminatory access provision could have the effect of imposing increased costs on customers, such as take-or-pay costs when transportation displaces sales.[11]

Furthermore, these commenters argue that the Commission does not have legal authority to apply the condition to either certificates issued under section 7 of the NGA or self-implementing transportation authorized under section 311 of the NGPA.

Several of the commenters point to the legislative history of the NGA in support of their view that the Commission is abusing its section 7 conditioning authority in attempting to do indirectly that which Congress has expressly declined to give the Commission authority to do directly, i.e., make pipelines common carriers.[12] These commenters point to the express omission of common carrier authority in the legislative history of both the NGA and NGPA, as well as several legislative proposals to impose non-discriminatory access or express common carrier requirements on natural gas pipelines which have been introduced in Congress but not enacted since enactment of the NGA.[13]

For example, Panhandle Eastern Pipe Line notes that there has been but one exception to what it perceives as Congress' long-standing reluctance to legislate common carriage by natural gas pipelines. That exception is the requirement in the Outer Continental Shelf Lands Act of 1978, 42 U.S. 1334 (e) and (f), that natural gas pipelines to which the Secretary of the Interior has granted authority to transport Outer Continental Shelf (OCS) gas must provide transportation on a non-discriminatory basis. Panhandle reasons that the absence of a similar provision in the NGA or NGPA demonstrates that Congress concluded that the Commission should not have the authority to require that pipelines authorized to transport natural gas under those Acts do so in a non-discriminatory manner.

Intrastate pipelines and their state regulatory bodies assert that the access condition is an unsupportable attempt to pre-empt state regulation of intrastate activities.[14]

Commission Response. In considering those comments that suggest the Commission lacks legal authority to apply the non-discriminatory access condition to interstate transportation under the NGA, the Commission has reviewed the requirements of the NGA, including legislative history and relevant case law.

Section 7(e) of the NGA states, in pertinent part, that:

> The Commission shall have the power to attach to the issuance of the certificate and to the exercise of the rights granted thereunder such reasonable terms and conditions as the public convenience and necessity may require.

According to the Supreme Court:

> The Act was so framed as to afford consumers a complete, permanent and effective bond of protection from excessive rates and charges . . .
>
> . . . In view of this framework in which the Commission is authorized and directed to act, the initial certification of a proposal under § 7(e) of the Act as being required by the public convenience and necessity becomes crucial. This is true because the delay incident to determination in § 5 proceedings through which initial certificated rates are reviewable appears high interminable.[15]

Thus, the Commission's certificate and conditioning authority is the means by which it effectuates the purpose of the NGA to underwrite just and reasonable rates to the consumers of natural gas.[16] Any attack on a condition in a certificate issued by the Commission must confront the well-established principle that generally the Commission has extremely broad authority to condition certificates of public convenience and necessity.

This broad conditioning authority must be examined in the context of Congress' consideration of the NGA itself. It is abundantly clear from the history of the Act and from the events that prompted its adoption that Congress considered the natural gas industry to be heavily concentrated and that monopolistic forces were determining the amount of natural gas that could be marketed by fixing the amount that could be transported.[17]

Thus, section 7(e) of the NGA gives the Commission the power to attach conditions to certificates where required by the public convenience and necessity.

Beyond section 7, however, sections 4 and 5 of the NGA also prohibit unduly discriminatory or preferential practices by natural gas companies. The Commission has determined that the practice of restricting access to transportation is unduly discriminatory and preferential; and, importantly, has prevented consumers from obtaining the lowest reasonable rates for both transmission services and gas costs. Therefore the Commission intends the final rule to be an exercise of its conditioning authority to effectuate the non-discrimination requirements of the Act and to insure that consumers will obtain gas and transportation at just and reasonable rates.

Given the breadth of our section 7 conditioning authority and our obligation under sections 4 and 5, we must ask whether the proposed non-discriminatory access condition is so broad as to impose, either directly or indirectly, common carrier obligations on pipelines in violation of the NGA.

Notwithstanding the basis of the condition in sections 4, 5 and 7 of the NGA, several commenters have asserted that Congress failed to enact amendments to the NGA which would have imposed mandatory transportation requirements on natural gas pipelines, and therefore the NGA by implication does not authorize the Commission to impose common carrier status on pipelines.[18]

Of key interest to the Commission in its review of the legislative history are sections 303 and 304 of Title III of H.R. 5423 introduced in 1935 by Representative Sam Rayburn, Chairman of the House Committee on Interstate and Foreign Commerce.[19]

Sections 303 and 304 of H.R. 5423 provided in pertinent part (emphasis added):

> Section 303(a). *It shall be the duty of every distributor to* furnish natural gas, to exchange natural gas with, and *transmit natural gas for any person* upon reasonable request therefor; and to furnish and maintain such services and facilities as shall promote the safety, comfort and conveniences of all its customers, employees, and the public, and shall be in all respects adequate, efficient and reasonable . . .
>
> Section 304. Whenever the Commission after notice and opportunity for hearing finds such action necessary or desirable in the public interest, *it may by order direct a distributor* to make additions, extensions, repairs, or improvements to or changes in its facilities, to establish physical connection with the facilities of one or more persons, to permit those of its facilities by one or more persons, or utilize the facilities of, sell natural gas to, purchase natural gas from, *transmit natural gas for*, or exchange natural gas with *one or more other persons* . . . [T]he Commission may prescribe the terms and conditions of the arrangement to be made between such persons, including the apportionment of reimbursement reasonably due to any of them.[20]

If these sections would have imposed common carrier obligations on natural gas pipelines, and therefore were rejected by Congress, a principal attribute of common carrier status must be its *mandatory* nature. Thus, section 303 would have imposed an affirmative "duty" on pipelines to "transmit" natural gas "for any person." Section 304 would have provided the Commission with the concomitant authority to "by order direct" any pipeline to "transmit natural gas for . . . one or more other persons. . . ."

Sections 303 and 304 must be read in the context of sections 4(b) and 5(a) of the NGA as enacted. In contrast to proposed section 303's affirmative duty, section 4(b) flatly prohibits "any undue preference or advantage" and "any reasonable difference" in service or as between classes of service. In contrast to proposed section 304's discretion to *order* transportation, section 5(a) contains *no express authority to order transportation*. Instead, section 5 permits the Commission to find that "any rule, regulation, practice or contract" affecting transportation rates, charges or classifications is ". . . unduly discriminatory, or preferential" and thereafter fix prospectively by order the "just and reasonable . . . rule, regulation, practice or contract" to be observed.

On the one hand, sections 303 and 304 would have imposed an affirmative duty on pipelines to transport for others and backed up that duty with discretionary authority on the part of the Commission to order such transportation.

On the other hand, sections 4, 5, and 7 of the NGA attach non-discrimination obligations to the "practices" of pipelines and back up those obligations with broad conditioning authority on the part of the Commission. But the Natural Gas Act does not expressly *require* pipelines to transport for others as an affirmative duty.

We have considered whether the non-discriminatory access condition in the final rule amounts to a "direction" or a "mandate" to pipelines to transport for others as an "affirmative duty." First, the condition is just that: A *condition* on the certification or authorization of certain self-implementing transportation services which a pipeline may *voluntarily choose to perform or not*, strictly at its own option. Thus, it does not "direct" or "mandate" a pipeline to do anything. Second, the condition, even when accepted by a pipeline as part of its self-implementing transportation program, does not impose any "affirmative duty" on a pipeline to transport. It only requires that when a pipeline *does* choose to transport on a self-implementing basis, it must provide those transportation services in a nondiscriminatory manner. Nor does the condition cover all transportation services and thus operate as mandatory *in effect*. A pipeline remains free to seek authorization for other transportation programs not covered by the condition and the Commission will review them on a case-by-case basis.

In addition, the condition expressly applies, verbatim, the statutory prohibitions on unduly discriminatory or preferential practices, rates or charges imposed by Congress when it enacted sections 4 and 5 of the NGA.[21]

The Commission need not decide in this rulemaking whether it may ever order transportation on a mandatory basis. The Commission plainly has broad powers to enforce the congressional directives and these powers are at their height when the Commission is fashioning a remedy for a violation of the statute or an existing regulation. *Niagara Mohawk Power Co. v. FPC*, 379 F.2d 153, 159 (D.C. Cir. 1967). But while these powers may be available in appropriate cases, there is no need to test their scope here, where the regulatory obligations are voluntarily assumed.[22] Further, the condition only applies with regard to each of the individual types of transportation service offered and does not cover transportation under existing individual section 7 certificates or new individual section 7 certificates filed outside of the optional expedited certificate procedure.

Judicial recognition of the Commisssion's authority to impose the non-discriminatory access condition has already been indicated in the companion cases *Maryland Peoples Counsel v. FERC*, Nos. 84–1019 and 84–1090 (D.C. Cir. 1985). In those cases, the court vacated Columbia Transmission Company's special marketing program and the Commission's rule allowing pipeline transportation for certain industrial end-users. In both instances, the court found the Commission had not justified the programs to the extent they allowed pipelines to transport gas to some customers without requiring pipelines to furnish the same service to all customers on non-discriminatory terms.

In its order on the blanket certificate program (No. 84–1090), the court noted, *id.* at n.19, that MPC's plea that blanket transportation certificates be conditioned on non-discriminatory access accords with the recommendation of the Department of Energy: "To achieve the benefits of a properly developed spot market for natural gas . . . FERC should use its authority over natural gas transportation to require pipeline companies to provide carriage on a non-discriminatory basis whenever there is idle pipeline capacity." DOE Report, *supra* p. 3, at 82. The court further noted that the Commission does not question that it has such authority, *citing Tennessee Gas Pipeline Co. v. FERC*, 689 F.2d 212, 214–15 (D.C. Cir. 1982); *Transcontinental Gas Pipe Line Corp. v. FERC*, 589 F.2d 186, 190 (5th Cir. 1979) (invoking "the well-established principle that generally the Commission has extremely broad authority to condition certificates of public convenience and necessity"), *cert. denied*, 445 U.S. 915 (1980).

Finally, we view section 311(c) of the NGPA as conferring sufficient authority to require a comparable condition under transactions authorized under that statute. The effect of NGPA section 602(b) is discussed below.

b. Authority To Impose on Interstate Transportation by Intrastate Pipelines

Comments. Interstate pipelines and state regulatory commissions cite the NGPA section 602(b) prohibition on common carrier status for section 311 transporters as an absolute ban on application of the non-discriminatory access condition to their operations.[23] They also state that the condition is illegal under NGPA section 601(a)(2)(A), which exempts transportation by intrastate pipelines under section 311(a) of the NGPA from Commission jurisidiction for purposes of section 1(b) of the NGA.[24]

These intrastate pipelines perceive the access conditions as a back door through which the Commission may intrude on their non-section 311, purely intrastate activities. They fear that the non-discriminatory access requirements ultimately will result, if they agree on any section 311 transportation, in more and more of their capacity being obligated to section 311 transportation. Consequently, they assert, the capacity available for intrastate activities would diminish, threatening their viability in the intrastate market. Further, the rate charged by a pipeline in each new section 311 transportation arrangement would be subject to regulation by the Commission under the proposed rule. Therefore, intrastate pipelines, as well as many state regulatory agencies, view the non-discriminatory access condition as an indirect but substantial threat by the Commission to preempt state authority over intrastate pipeline activities. These commenters argue that the non-discriminatory access provision, therefore, violates NGPA sections 601(a)(2)(A) and 602(b).

Commission Response. The Commission has absolutely no intention of regulating *intra*state transportation of natural gas. Rather, the intent of the proposed rule was simply that the same non-discriminatory access condition should apply to all transportation in interstate commerce, whether by an entity subject to FERC jurisdiction under the NGA or to other entities allowed by the Commission under the NGPA to engage in such interstate commerce without becoming subject to the NGA.

Several changes have been made in the final rule to clarify this intent. First, there is no requirement that intrastate pipelines under section 311 provide such transportation service on a firm basis. See § 284.8(a)(2). Firm transportation is not prohibited, however. In the event an intrastate pipeline offers firm transportation then § 284.8(b) requires that it provide "such" service on a non-discriminatory basis.

Similarly, if an intrastate pipeline offers interruptible interstate transportation (under § 284.8(a)(ii)), the only obligation is to provide "such" interruptible service on a non-discriminatory basis. See § 284.9(b).

Thus, the final rule completely avoids the situation whereby an intrastate pipeline is required to offer firm service for out-of-state shippers, thus, progressively being turned into an interstate pipeline against its will and against the will of the responsible state authorities.

With regard to the rate conditions of § 284.7, the proposed rule would have required intrastate pipelines to comply with the same conditions. The final rule makes it clear that the rate conditions of § 284.7 apply only to transportation under Subparts B, G and H and not to transportation by intrastate pipelines under Subpart C. The final rule retains the pre-existing rules regarding rates for Subpart C transportation. See section 284.123. In essence, there have been no real concerns with transportation by intrastate pipelines and therefore there is no need to modify the current rules.

With regard to the comment that the non-discriminatory access condition violates section 602(b), we note that the NGPA does not define "common carrier." Section 602(b) has scant legislative history. The only mention of the purpose of section 602(b) in the Conference Agreement merely states that the House bill had provided that "the intrastate pipeline would not have been subjected to regulation as a common carrier. . . ."[25] The Commission notes that Congress did not directly authorize section 311 transportation but gave the Commission the discretion to authorize such transportation under such terms and conditions as the Commission might prescribe under sections 311(c) and 501(a) of the NGPA.[26]

All the Commission is doing here is ensuring that where a new entity enters into the field of offering interstate transportation services, that it do so on a non-discriminatory basis. We cannot accept the premise that section 602(b) is a Congressional license to "intrastate pipelines" to enter into the field of interstate commerce on an avowedly discriminatory basis. Whatever else the prohibition regarding "common carriage" status may do, it does not sweep so broadly as to license unduly discriminatory rates or practices.[27] The same conclusion applies to interstate pipelines operating under section 311.

Further, it appears from the legislative history of the NGPA that the Commission's conditioning authority under NGPA sections 311(c) and 501(a) is coextensive with the broad discretion granted to the Commission under section 7(c) of the NGA.[28] Section 311(c) must be read in light of the fundamental intention of the NGPA to facilitate the movement of gas between the intrastate and interstate markets following a period of severe curtailment of interstate supplies coincident with ample intrastate supplies.[29]

Hence, the Commission has determined that the non-discriminatory access condition does not violate section 602(b).

The Commission emphasizes that it fully respects the bounds of its jurisdiction under section 1(b) of the NGA as reaffirmed by section 601(a)(2)(A) of the NGPA. The Commission does not intend that any aspect of the final rule intrude in any way whatsoever on the sound discretion of the states to regulate strictly intrastate transactions in the public interest. Nor does the Commission intend the final rule in any way whatsoever to impair the ability of intrastate pipelines to provide reliable service to their intrastate customers.

3. *The reasonableness of the non-discriminatory access condition.*

Comments. Some commenters complain that the non-discriminatory access condition is unreasonable, and therefore not authorized under law or otherwise appropriate, because it would interfere with pipelines' ability to make necessary and appropriate business decisions such as choosing a product/market mix of transportation and sales services, or declining to provide transportation services that would impair their ability to meet their obligations to existing sales customers.[30] Intrastate pipelines state that the non-discriminatory access condition could potentially affect their ability to provide services in the intrastate market. Several commenters suggest that the harm to the reliability of existing services to pipeline customers would outweight the benefits of the non-discriminatory access condition to new transportation customers.[31]

Some industrial end-users state that the imposition of the non-discriminatory access requirement on intrastate pipelines is unreasonable because most state agencies already have authority with respect to intrastate pipelines to accomplish the Commission's goal in proposing the condition. These commenters point to New Mexico and other states that have enacted or are considering statutes that require non-discriminatory gas transportation.

One industrial end-user, Air Products, argues that the Commission's proposal to apply the non-discriminatory access provision to intrastate pipelines would diminish the interstate-intrastate pipeline integration achieved since enactment of the NGPA. Lack of system integration would hinder the ability of interstate pipelines and their customers to gain access to reserves connected to intrastate pipelines. Accordingly to Air Products, the undesirable effects would result because intrastate pipelines would rather forego NGPA section 311 transportation altogether than expose all of their intrastate operations to possible Commission jurisdiction.

Other commenters, such as Oklahoma Natural Gas Company, suggest that the Commission revise the proposals to specifically limit application of the non-discrimination and firm transportation requirements to an intrastate pipeline's excess capacity in order to reassure intrastate pipelines and state regulatory agencies that the Commission will not intrude on local activities beyond its jurisdiction.

On the other hand, commenters supporting the non-discriminatory access condition assert that the condition is reasonable and absolutely necessary in order to ensure access, by pipeline customers and other shippers, to competitively priced gas supplies at the wellhead. They point to the proliferation of individual pipeline transportation programs and the expanded flexibility of the program proposed by the rule as direct benefits to pipelines which agree to the non-discriminatory access condition. Finally, they point to the history of pipeline gas purchasing practices over the last 30 years as justification for requiring pipelines who transport for others to do so on a non-discriminatory basis for all consumers.[32]

Commission Response. With regard to *intrastate* pipelines, we repeat what was stated above: intrastate pipelines are under no requirement to offer firm service under Subpart C, and the non-discriminatory access condition will apply only to the intrastate pipeline which provides "such" interruptible or firm service. Thus, where an intrastate pipeline offers only interruptible service, the access condition can in no way adversely affect its ability to provide firm service to intrastate customers.

With regard to *interstate* pipelines, the condition is also reasonable. First, the actual condition is voluntary. There is no requirement under the statutes or the rules that an interstate pipeline provide transportation under the self-implementing regulations. Moreover, the condition imposes, verbatim, the statutory ban against undue discrimination. The access condition, therefore, must be included in certificates and self-implementing transportation agreements in order to assure that gas supplies and transmission services are provided as broadly as possible in response to new demands from consumers and new competition in gas markets.

In addition, the final rule expressly recognizes in §§ 284.8(c) and 284.9(c) the need for reasonable operational flexibility. Finally, the condition is imposed in the context of a rate structure under §§ 284.7 and 284.8(d) which fully contemplates self-implementing transportation. Costs will be properly allocated among services to be offered; unit rates will be designed; and the pipeline will have a reasonable opportunity to recover its prudently incurred costs by providing services for its customers. This is the core of utility ratemaking.

Thus, the access and rate conditions *prohibit* a regulated pipeline from engaging in unduly discriminatory or preferential behavior and *provide* a rate structure under which the pipeline may earn its allowed return without engaging in such behavior. To assert that such a condition is unreasonable is simply not credible.

4. *Applicability of non-discriminatory access condition to pipeline operations*. The Commission intends to apply the non-discriminatory access condition broadly as an express condition of any self-implementing transportation services provided by a pipeline under the final rule.[33] The term "transportation," defined by existing § 284.1(a), includes "exchange[s], backhaul[s], displacement or other methods of transportation." No change in this definition was proposed in the May 30th NOPR or made in the final rule. As with any generic standard, the condition must be capable of being applied by pipelines and their shippers to the everyday realities of the natural gas business, particularly the reasonable, routine operational and load management decisions faced by those that provide natural gas transportation services.

a. Applicability in general

Comments. Many pipeline commenters stated that the non-discriminatory access condition as proposed in the NOPR was overly broad and could be interpreted to require pipelines to transport for shippers who were unwilling to accept the gas quality standards, minimum volume requirements, or minimal financial solvency standards set by a pipeline.[34] Would a pipeline be required to accept for transportation gas of such a poor quality that it cannot be operationally redelivered or of such a marginal quality that it may cause operational problems? Must a pipeline accept for transportation gas which may only be delivered on certain days or in very small quantities?

Others stated that certain pipeline load management activities should not be subject to the non-discriminatory access condition if they involve the pipeline's not holding itself out generally as a transporter. They assert that such services as gas exchanges, storage, backhauls, and displacement should not be subject to the access condition.[35]

Other commenters asked that the Commission clarify the non-discriminatory access condition in light of the express provision in the proposed rule that a pipeline offering firm transportation service is not required to construct or acquire new facilities in order to comply with the "firm" quality of service requirement. These commenters pointed out that pipelines could defeat the purpose of the non-discriminatory access condition by refusing to construct relatively inexpensive or minor facilities, such as sales taps and metering stations necessary to provide transportation services.[36]

One commenter, Yankee Resources Inc., suggests that pipelines currently are attempting to discourage transportation by imposing onerous conditions. In its presentation at the public conference (tr. 533), Yankee's representative stated that it had received a recently approved transportation tariff of an interstate pipeline providing for daily load balancing enforced by a $5.00/Mcf daily penalty for over-or-under delivery into that pipeline's system. As the term implies, daily load balancing means that the amount of gas entering the pipeline each day must equal the amount of gas leaving the pipeline each day. Yankee, in effect, requests that the rule prohibit such types of conditions from being included in any transportation tariffs filed under the rule.

Commission Response. The Commission has determined that reasonable operating and load management conditions imposed routinely by pipelines or shippers do not *per se* violate the non-discriminatory access provision, *provided* that such conditions are stated "up-front" in the pipeline's transportation tariffs on file at the Commission and are applied by the pipeline fairly to all similarly-situated shippers and shipments. See §§ 284.8(c) and 284.9(c). With these operating conditions required to be stated in tariffs on file at the Commission, shippers will be provided advance guidance on how the pipeline will apply the non-discriminatory access condition to routine, day-to-day operations of the pipeline system. In addition, in those circumstances where a pipeline may not be able to determine whether a particular situation is governed by the stated tariff conditions, it may impose reasonable operating conditions on a shipper as long as identical conditions are placed on all similarly situated shippers and an appropriate tariff filing is made.

A clear example is one in which a shipper requests that a pipeline transport gas of such poor quality that it may damage pipeline facilities. It would not be discriminatory for the pipeline to refuse that shipper's request to transport such gas, since the pipeline certainly would refuse any shipper's request for transportation of such gas. Furthermore, it may or may not be discriminatory for a pipeline to refuse transportation to a customer in bankruptcy proceedings. It might be appropriate for a pipeline to propose, subject to Commission review, special payment arrangements in its tariff for such a customer. However, if the pipeline determines on some basis that the shipper is nevertheless credit worthy and accepts the request for transportation, such acceptance would not be discriminatory, provided the pipeline permits like-situated shippers to demonstrate their credit worthiness on the same basis.

b. Applicability to Exchanges

Comments. A number of commenters discussed whether exchanges should be subject to the non-discriminatory access condition.[37] In a gas exchange between two parties, gas is received from (or delivered to) the first party in exchange for gas delivered to (or received from) the second party. An exchange arrangement provides a means for delivering gas supplies to a customer without the necessity of constructing and operating duplicative facilities. Central to the concept of an exchange is mutual benefits to the two pipeline systems engaging in the exchange. The transaction must involve reciprocal benefit or the trade of comparable values. If the gas exchanged by one party is not of equal value to the gas exchanged by the other party, because one party has less gas and/or gas that is of lower quality, the party receiving the lesser-valued gas volumes may also receive cash.

Most of the pipeline commenters that specifically addressed the issue of whether non-discriminatory access should apply to such transactions indicate that exchanges should not be subject to the non-discriminatory access condition. These pipeline commenters observe that these activities do not involve transportation as such. They view an exchange more as a sale than as a transportation arrangement. Several commenters point out that the purpose of exchanges is the movement of gas without the wasteful construction of facilities or longer-than-necessary transportation. They argue that there should be no condition inhibiting parties from entering into such arrangements. They believe that the non-discriminatory access provision would be an inhibiting condition.

The commenters point out, as the Commission is aware, that pipelines usually engage in exchange arrangements only with producers that are suppliers or other pipelines if there is a mutual benefit.

The commenters supporting extension of the condition to exchanges argue that exchanges are the least expensive and the most desirable form of transportation. As such, they argue that it would be inconsistent to permit exchanges to remain subject to discrimination.

Commission Response. This issue presents an excellent example of the implementation problems that would arise were the Commission to attempt to impose the non-discriminatory access condition without restructuring transportation rates. The pipelines are arguing for exemption of exchanges from the types of transportation service they must offer under the condition. In essence, they argue that opportunities to effectuate a transaction via an exchange are fact-specific and lend themselves poorly to the application of uniform rules. For the Commission to require a pipeline to seek out the most efficient exchange arrangement would probably result in hearings to determine if an alternative transportation routing would have been preferable. This could quickly, the pipelines assert, remove operational and dispatching decisions from the pipeline managements and turn them over to the Commission. To a large degree we agree.

The commenters arguing the other side assert that they ought not have to pay for a front haul transaction perhaps over hundreds of miles when the pipeline might actually be able to effectuate the same transaction via an exchange with another pipeline. Accordingly, they urge the Commission strongly to require pipelines to provide such exchange services on a non-discriminatory basis. To a large degree we agree with these commenters as well. A pipeline ought not be able to circumvent the access condition simply by characterizing a transaction by one name or another.

But we have coupled rate revisions with the access condition. In most instances, rates should be structured in such a way that the pipeline has every incentive to move gas in the most efficient way possible. For example, if one transaction could be effected via an exchange, that would typically leave the pipeline with additional capacity elsewhere in its system. That capacity would then be available for other sales or transportation, allowing the pipeline to earn revenue from *two* transactions rather than just the one.

Accordingly, the final rule does not exempt exchanges from operation of the non-discrimination conditions. Instead, existing § 284.1(a) continues to include exchanges within the definition of transportation. For example, a pipeline may wish to file with its tariffs definitions of those types of non-recurring exchange transactions that it proposes to be exempt from the non-discriminatory access condition. The Commission will review such definitions as part of its case-by-case review of the tariffs. Because of their efficiency and benefits, all other exchanges will be subject to non-discriminatory access conditions. We note that in no way does this final rule alter existing regulations dealing with those situations where costs associated with a purported exchange may or may not qualify for recovery through a PGA clause.

c. Applicability to Storage

Storage permits gas produced from one formation to be injected into another formation generally near the market. System storage facilities are considered to be within the Commission's transportation jurisdiction because they enable the pipelines to move the gas needed to meet peak requirements on their systems. The purpose of storage is normally to serve temperature sensitive requirements during peak demand periods. "System supply" storage includes facilities owned by the pipeline and used by the pipeline to store its own gas for operational reasons. In "contract" or "customer-nominated" storage, the customer owns the gas. Thus, the transaction would involve a sale accompanied by transportation of gas to a point of storage during an off-peak period and a later redelivery of the gas from storage during a peak demand period.

Comments. Storage was briefly discussed by a few commenters.[38] The commenters responding to this issue support extension of the non-discriminatory condition to storage on the grounds transportation to and from storage may be an integral part of transportation service when it is purchased or offered as a bundled service with transportation.

Commission Response. System storage facilities are essentially used for the same types of transactions as are mainline transmission facilities and the transportation rates generally reflect this relationship. Accordingly, it is reasonable to allow access to these facilities in order to assure firm transportation service. And, of course, transportation to and from contract storage would also be covered.

d. Applicability to Backhauls

Comments. Backhauls are accomplished by the pipeline's delivery of gas upstream from its point of receipt. Simplified, a backhaul can be described by the following example. A producer in Oklahoma sells gas to an end-user in Texas. An interstate pipeline, whose system flows from south to north, agrees to perform the transportation service. It picks up the end-user's gas from the producer in Oklahoma. The gas physically flows north to the interstate pipeline's market area. It delivers equivalent volumes from other sources to the end-user's plant in Texas. While all of the gas physically moves north, the effect of the transaction is to bring the end-user's Oklahoma gas to Texas. The term backhaul is used because the movement of the gas is opposite or backwards from the pipeline's flow direction.

Citizens Energy Corp. and Yankee Resources, Inc. argue for the extension of the condition to backhaul transactions. One commenter argues for the extension of the condition on the basis that backhauls are an integral part of any transportation program and are essential to efficient system supply. The commenter believes that exclusion of backhauls from the rule would disadvantage local distribution companies and would unjustifiably provide the pipelines with a highly preferred position in making gas available in a competitive environment. The commenter urges clarification of the proposed rule by development of rate provisions that take into consideration cost distinctions between forward haul versus backhaul transactions.

Commission Response. We believe it is appropriate to apply the non-discriminatory access condition to backhaul transactions. The nature and functions of backhaul transactions are not substantially different from forward hauling. Both may involve use of the pipeline's mainline transmission facilities to transport gas. Moreover, pipelines usually have tariff provisions providing rates for backhaul service as well as for forward hauls. The Commission sees no reason why the non-discriminatory access provision should not apply to backhaul services.

e. Applicability to Displacement

Displacement permits lateral movement of gas through a transportation network. The configuration of some pipeline systems is such that it may not be readily apparent whether a given movement of gas is forward or backward from the point of receipt. Nevertheless, gas is received and delivered by the pipeline using its facilities to provide the service. Displacement transactions are widespread and commonplace in that they permit efficient delivery of gas. The Commission's definition of transportation in § 284.1(a) includes displacement of gas.

Although no comments were received on this issue, the Commission believes that it is appropriate to clarify that the non-discriminatory access condition does apply to displacement transactions. As in the case of backhaul, the end result of displacement is delivery of gas. This is true for all categories of transportation. Transportation rates for displacement are normally included in the tariff provisions. To exclude displacement of gas from the non-discriminatory access condition would foster a loophole in the regulations which would serve to undermine the goal of consumer protection which the condition seeks to achieve. Accordingly, the condition applies to displacement transactions.

f. Applicability to Construction of Minor Facilities

Comments. Some commenters urged the Commission to prohibit pipelines from discriminating in the offering of transportation services by refusing to construct minor facilities, such as sales taps or metering stations.[39]

Commission Response. Sections 284.8(e) and 284.9(e) both provide that no pipeline providing self-implementing transportation is required to provide service for which capacity is not available or that would require construction or acquisition of any new facilities. These provisions are consistent with Commission and court precedents under section 7 of the NGA. The fact that construction of such facilities is not required *by rule* does not mean that the Commission may not be empowered to require such construction as a remedy in an appropriate case, however. See discussion of *Niagara Mohawk, supra*. Moreover, it is noted that § 157.208 provides self-implementing authorization for the construction of such facilities within certain dollar limits (except sales taps).

g. Applicability to Other Tariff Provisions

Comments. One commenter asserted that some pipelines impose other unreasonable conditions such as daily load balancing.[40] This commenter urged the Commission to hold that such a condition is unreasonable.[41]

Commission Response. There is no need to address this issue in the rule. There is an argument to be made that load balancing on the basis of some period of time may be reasonable. This is due to the operational effects that "banking" of the gas has on the pipeline system. If more gas enters the pipeline than leaves it, the effect is that the excess gas is "banked" or stored within the pipeline. Pipelines may argue that this amounts to a service for which they should be compensated.

Such a practice may or may not be a reasonable operational practice within §§ 284.8(c) and 284.9(c). In any event, such practices must be filed for and may be reviewed on a case-by-case basis.

h. Transactions Between Affiliates

Comments. A number of commenters express apprehension that pipelines could manipulate their corporate structure to defeat the non-discriminatory access provision. For example, Natural Gas Equal Access, an association of independent producers, asserts that if any segment or component of a pipeline system, or any affiliate, subsidiary, or division of any pipeline company, does anything that the Commission categorizes as the equivalent of holding itself out to be a transporter, then the entire system or company must comply with the non-discriminatory access provision.

As pointed out by the American Paper Institute (API) interstate pipelines could conceivably participate in, and receive the benefits of, the voluntary program and at the same time, create and require the use of the facilities of an affiliate company that could refuse to participate in the programs and effectively block non-discriminatory access to transportation. API suggests preventing such abuse by certificating any new affiliates with the non-discriminatory access condition and imposing that condition in existing certificates of the pipelines.

Panhandle Producers and Royalty Owners (PPRO) recommends that the Commission adopt regulations similar to the "Ultimate Parent Entity" concept regulations adopted in connection with the Hart-Scott-Rodino Antitrust

Improvements Act of 1976, 15 U.S.C. 18a (1973), to govern the scope of the election of a pipeline so that, once one pipeline of an "ultimate parent entity" elects to provide transportation, all pipelines under the "ultimate parent entity" should be required to perform the same transportation services. Another commenter suggests adopting the definition of "affiliate" in section 2(27) of the NGPA and requiring any of a pipeline's affiliates to perform the same services in the same manner as the certificated pipeline.

Commission response. We agree with the comments that a pipeline that has been issued a certificate under the new program should not be allowed to circumvent the conditions of the certificate or the overall objective of the program by establishing new corporate entities or by implementing some form of corporate reorganization.

The Commission expects the rate conditions under which the self-implementing transportation must be provided will sharply mitigate any incentives for a pipeline to evade the non-discriminatory access condition by manipulating its corporate structure or creating affiliated entities outside the jurisdiction of the self-implementing program. However, the Commission will not hesitate to take appropriate action to assure that the purposes of the non-discriminatory access condition are not evaded. We note that pipelines may well seek to offer gas sales service through an unregulated affiliate. While such a move would make it all the more important to prevent a pipeline *qua* transporter from conferring unlawful preferences on its affiliate *qua* merchant, the basic decision to divorce transportation from merchant activities probably would not be contrary to the public interest.

5. *Availability of access to persons outside NGA jurisdiction.*—a. *Condition distributor access to interstate transportation on requirement that they provide transportation to retail markets.*

Comments. Several commenters suggested that non-discriminatory access to transportation should be available to an LDC only as a reciprocal condition on the distributor providing access through its own facilities to self-implementing transportation services under the final rule. [42]

Commission response. The Commission declines to condition distributor access in this manner.

An argument could be made that such a condition on a non-jurisdictional entity is beyond the scope of the Commission's jurisdiction. But while we note this argument, we do not rely upon it for our ruling here. See *FPC* v. *Transcontinental Gas Pipe Line Corp.*, 365 U.S. 1 (1961) (the Transco "X–20" case) (holding that the FPC had authority to deny a transportation certificate based on the end-use of the gas at retail).

Rather, our decision is based on the fact that such a condition would bring the Commission into direct conflict with responsible state authorities. For example, as detailed above, a number of states have adopted statutes or regulations dealing with transportation services by local distribution companies. [43] In other states the issue remains under review. A federal requirement that distributors provide a certain type of transportation service as a condition to obtaining interstate transportation could put the distributor under conflicting federal and state obligations. Thus, it is not a case where the Commission might veto on federal grounds a transaction which state public utility commissions might favor as a matter of state policy. Rather, the proposed condition would essentially mandate on federal grounds a transaction that a state may wish to forbid or to structure in a different manner.

Moreover, as noted above, questions of cost allocation and rates are intimately tied into the issue of the reasonableness of a transportation obligation. Yet we wholly lack jurisdiction over the rates of local distribution companies.

Indeed it was for the express purposes of avoiding such federal-state conflicts that Congress adopted section 1(c) (the "Hinshaw Amendment") of the NGA in 1953. The legislative history of the Hinshaw Amendment makes it clear that it was enacted to essentially overturn a Supreme Court decision (*FPC* v. *East Ohio Gas Co.*, 338 U.S. 464 (1950)), that had interpreted the NGA to allow FPC regulation over local distribution companies. See Rep. No. 817, 83d Cong., 1st Sess. 2102 (1953). Since the proposed access condition on distributors would put us in the business of regulating rates and practices of the distributors in order to enforce the conditions, it would bring about exactly the kind of conflict the Congress intended to avoid. Accordingly, we decline to adopt it.

b. *Condition producer access to interstate transportation on requirement that they waive contractual rights under take-or-pay provisions*

Comments. Just as some commenters argued for conditioning distributor access, so at the other end of the pipeline, many (but not all) interstate pipelines urge the Commission to condition access by producers. These commenters assert that the Commission has the authority to require producers to waive contractual rights under the take-or-pay provisions of existing contracts as a condition to obtaining non-discriminatory transportation. They further assert that the exercise of such authority is reasonable to enhance the pipelines' bargaining leverage in renegotiating contracts with producers. [44]

Commission Response. As with the request to restrict access to non-discriminatory transportation at the distribution end of the pipeline, so the Commission declines to restrict access to only certain producers. If transportation is to be available to the public on an equal and non-discriminatory basis, we cannot allow some shippers to be "more equal" than others.

In addition, for gas that has been removed from the Commission's NGA jurisdiction, there is a serious question as to whether the Commission has the authority to require a non-jurisdictional party to give up a valid contractual right as a condition to obtaining service. At the August hearing, a number of pipeline representatives expressed the opinion that such a course of action was a "close question," [45] or one to which a "definitive answer" could not be given. [46]

This uncertainty is reinforced by the court cases defining the limits of the Commission authority over natural gas production. See *e.g. Shell Oil Co. v. FPC*, 566 F.2d 536 (5th Cir. 1978) (reversing FPC Policy Statement regarding "prudent operator" standard), and *Pennzoil v. FERC*, 645 F.2d 360, 380–82 (5th Cir. 1981), *cert. denied*, 454 U.S. 1142 (1982) (holding that FERC lacks the power to even interpret gas purchase agreements between producers and pipelines for the sale of gas which has been removed from NGA jurisdiction).

It is one thing for the Commission to exercise its conditioning authority over regulated natural-gas companies to require them to provide access to shippers on a non-discriminatory basis. It is quite another to *deny* access to some shippers unless they agree to take action which is beyond our power to compel.

We also note that some pipelines continue to make progress in renegotiating their contracts with producers while others have been able to renegotiate much of their take-or-pay exposure, particularly for past periods. [47] For example, while the potential take-or-pay liability for pipelines as a group has been estimated at $7–10 billion, actual prepayments in rate base have been far smaller. See Exhibit O. Moreover, actual prepayments in rate base in July of 1985 were over $100 million *lower* than in December of 1982. (Exhibit O.)

In addition, as noted in Table C–1, over $470 million in take-or-pay liability has been bought out for about $80 million in amounts sought to be recovered through filings with the Commission. We also note the repeated statements in the comments [48] that negotiations remain active in this area and that the Commission's proposed "safe harbor" rule has slowed that process rather than encouraging it. It is mainly for this reason that we have determined not to promulgate rules relating to such buy-outs.

Accordingly, under these circumstances and given the fact that conditioning access would run completely counter to the whole idea of opening up the transmission grid on a non-discriminatory basis, the Commission declines to condition producer access as suggested.

6. *Withdrawal of a pipeline from self-implementing transportation.*

Comments. Some interstate and intrastate pipelines request that the final rule permit them to discontinue or abandon their self-implementing transportation authority in the future as a matter of sound business judgment and therefore avoid the non-discriminatory access condition on all subsequent individual transportation transactions.[49]

Other commenters, notably industrial end-users, urge the Commission to assure that pipelines do not use any "pre-grant" of abandonment authority for self-implementing transportation as a means of discriminating against shippers by moving "in and out" of a self-implementing transportation program initiated under the rule.

Commission Response. The Commission intends the self-implementing transportation authority in the final rule to provide incentives for pipelines to accept a conditioned certificate and to make use of Part 284 authorization. However, a pipeline's decision to do so is not irrevocable. The Commission does not intend to foreclose a pipeline from making a business decision to discontinue self-implementing transportation in the future and thus resume its status as a "merchant," only.

The rules governing a request to terminate all service under a Subpart G blanket certificate are the same basic rules as apply whenever a pipeline seeks to discontinue a particular service.[50] See 18 CFR 157.18. The Commission would review these requests on a case-by-case basis exactly as it does under the existing regulations.[51]

With regard to transportation under Subparts B and C, the Commission declines to promulgate regulations addressing termination of service. These services are not subject to section 7(b) of the NGA and we decline to impose comparable procedures by way of a condition issued under NGPA section 311(c). Instead, the Commission will view termination of service under Subparts B and C as subject to the non-discrimination condition. For example, a decision by an intrastate pipeline to cease providing interruptible service that it has been providing under Subpart C must be non-discriminatory. In other words, the decision to terminate transportation cannot be a subterfuge to avoid the regulations. But a bona fide decision to cease providing any self-implementing transportation would be non-discriminatory.

7. *Enforcement of the access conditions.*

Comments. Many producer and end-user commenters, while lauding the purpose behind the non-discriminatory access condition, nonetheless expressed doubts that its benefits would be realized without more specificity in the final rule as to what constitutes preference or undue discrimination, and how the generic standard will be enforced by the Commission on a case-by-case basis.[52]

Commission Response. As indicated above, the Commission believes that the changes in the ratemaking structure (and the tools for addressing take-or-pay obligations), once fully implemented, should avoid any need for an extensive policing mechanism. But we recognize that there may still be instances, especially initially and especially involving transactions between affiliates, where complaints of undue discrimination may be made.

Accordingly, the Commission believes it may be helpful to provide some guidance as to the types of conduct that we consider to be unreasonable and undue under the new rules.

First, it should be stressed that the Commission intends the non-discriminatory access condition imposed in this rule to be construed broadly as a first line of defense against arbitrary or exclusionary transportation practices. For example, the Commission finds that a refusal by a pipeline to transport gas in competition with its own sales services, is unduly discriminatory or preferential and in violation of the non-discriminatory access condition.

As another example, the Commission finds that transportation tariffs, terms and conditions, including but not limited to prices, minimum volume or operational requirements, or schedules, that are designed to favor pipeline affiliates over non-affiliated shippers are preferential or unduly discriminatory practices under this rule.

Similarly, the Commission finds that arrangements by pipelines that tie or "bundle" gathering, production, storage, or other services not requested by shippers to self-implementing transportation service offered under this rule would constitute undue discrimination in violation of the non-discriminatory access condition (and probably the rate conditions, as well), if the costs of such services are not properly allocable to a fully-allocated transportation rate.

In addition, § 284.12 of the final rule includes a requirement that all pipelines operating under the new rules make yearly filings showing the estimated peak day capacity of the system under reasonably representative operating assumptions. The Commission recognizes that pipeline capacity is not a single, fixed quantity, but something that varies according to time and operating conditions. Thus, the purpose of this filing is not to establish pipeline capacity, but to allow the pipeline, itself, to determine its total capacity and to submit that determination for public review.

Finally, we note that the Commission, in setting projected levels of transportation in individual rate cases, may include the express consideration of whether complaints of undue discrimination or preference have been made concerning a pipeline's transportation practices. For example, if it is determined that a pipeline has capacity available for transportation in excess of its filed for projected levels, the Commission may take into account verified complaints that such capacity is being withheld on a discriminatory basis or is being under-utilized, and set higher projected levels as a disincentive to such discrimination or under-utilization. The Commission could also disallow the inclusion in rate base of unused assets.[53]

Comments. Some commenters request assurances that there will be a mechanism that will permit reliable determinations as to whether pipelines are in fact providing transportation on a non-discriminatory basis. In this regard, some commenters recommend that each pipeline be required to file monthly reports listing all persons who requested transportation service during the prior month, the volumes for which transportation was requested and whether the pipeline agreed to transport and, if so, the volumes it agreed to transport.[54]

Commission Response. The Commission recognizes the importance of ensuring that it be made aware of pipelines that are not complying with the non-discriminatory access conditon. As noted above, the rate structures for self-implementing transportation, once fully implemented, help minimize the need for a special enforcement procedure. However, the Commission notes that shippers that believe they have been refused service in a discriminatory manner may, and can be expected to, apprise the Commission of that allegation. Such complaints may be reviewed on an expedited basis and further appropriate action taken. In addition, as noted above, a new § 284.12 has been included in the final rule requiring an annual filing by the pipeline regarding its total capacity. This filing should assist disappointed shippers in determining whether filing of a complaint may be appropriate or not.

The Commission has determined not to extend the non-discriminatory access condition on a generic basis to all section 7 transportation certificates at this time. The Commission does not consider undue discrimination or preference any more acceptable under individual section 7 transportation or sales certificates than under self-implementing transportation authority. However, individual section 7 transportation arrangements can be scrutinized in advance by the Commission on a case-by-case basis when they are applied for; whereas, self-implementing transportation authority permits such arrangements to proceed on a "blanket" or generic basis.

For this reason, the Commission will continue to review individual section 7 certificates on a case-by-case basis to determine whether they should or should not be subject to an express (as opposed to the statutory) nondiscriminatory access condition.

8. *Quality of self-implementing transportation service and allocation of capacity.* a. *Background on pipeline capacity.* Pipelines currently transport gas on a firm or interruptible basis for any of three purposes:

1. To transport their own "system supply" gas as a transportation component "bundled" with sales service to firm or interruptible sales customers;

2. To transport gas they do not own for an individual shipper, such as on behalf of an interstate pipeline or a pipeline customer, on a firm or interruptible basis under an individual transportation certificate issued by the Commission under section 7(c) of the NGA; or

3. To transport gas they do not own for shippers generally on a self-implementing and on an interruptible basis on behalf of other interstate pipelines or local distribution companies under section 311 of the NGPA or on behalf of other interstate pipelines or high- or low-priority end-users under a "blanket" transportation certificate pursuant to section 7(c) of the NGA.

The essence of firm service is that it is not subject to a prior claim by another customer or another class of service. All firm services share the same priority, which is the priority of "first-come, first-served" that pipelines have traditionally applied to firm sales and transportation service.

In general, a large percentage of a pipeline's capacity may be reserved at any given time for firm sales and firm transportation. However, customers that have reserved or "booked" pipeline capacity and thus have first claim on its use may not always use the entire amount they have reserved. Traditionally, pipelines have taken advantage of that unused (but "booked") capacity by offering a sales or transportation service that is subject to being terminated or "interrupted" by the prior claim of firm sales or transportation customers. Although this interruptible service is inferior to and less valuable than firm service, its offering seeks to maximize utilization of idle pipeline capacity and therefore is in the public interest and must be encouraged by ratemaking. *Any* pipeline capacity not in use at any given time may be used for interruptible transportation, for example.

The firmness of interruptible transportation can be expected to vary from day to day. It may approach the reliability of firm transportation in certain periods, such as periods when a pipeline's transmission facilities are not subject to maximum or "peak" demand. For example, for ratemaking purposes, pipelines with temperature-sensitive loads in the wintertime generally plan for peak demand on the coldest days of the year, and thus expect to be able to provide interruptible transportation of a quality very close to "firm" service during off-peak periods, such as the summertime.

The proposed rule required pipelines to offer self-implementing transportation services on a firm basis, but neither required not precluded that such services be offered on an interruptible basis as well. The proposal also stated that self-implementing transportation service would be subject to the same curtailment priorities and procedures established for a pipeline's sales customer, and that self-implementing transportation customers could not be discriminated against in the quality of service they receive compared to any other transportation services offered by the pipeline.

However, the proposed rule did not expressly state that firm or interruptible transportation capacity would be allocated in any particular way, and the requirement that firm transportation service be offered did not expressly state that it be offered *subject to available capacity.*

Many commenters addressed the interrelated issues of quality of transportation service, curtailment priorities for transportation service, and allocation of transportation capacity.[55] The issues can be narrowed to three major issues discussed below.

b. *Requirement to offer interruptible service.*

Comments. A number of industrial end-users criticize the Commission for not proposing to require that pipelines accept requests for interruptible transportation, as well as firm transportation, if capacity is available. Several of these commenters, such as the New England Energy Group, request the Commission to provide in the final rule that interruptible transportation is a mandatory obligation on the part of those pipelines that elect to participate in the Commission's self-implementing transportation programs. The Industrial Energy Services Corporation, Inc. (IESCO) states, further, as a rationale for this suggestion, that interruptible service is the only practical type of service for many end-users. These are end-users that have a sufficiently large load and that require the lower interruptible service rate for economical reasons. They assert that if pipelines are allowed to terminate interruptible service, the bulk of end-user transportation may become uneconomic.

Commission Response. As discussed above, one function of the non-discriminatory access condition is to prevent pipelines from discriminating among shippers of a particular class that seek transportation service. Accordingly, the non-discriminatory access condition requires that pipelines allocate available capacity to persons requesting transportation not only for gas purchased from a source other than the pipeline, but also for gas purchased from the pipeline.

Implicit in the proposed rule's requirement that self-implementing transportation be offered on a "firm" basis was the intention that pipelines be indifferent as to the benefits of transporting gas at peak and off-peak periods. The ratemaking goals of rationing capacity, maximizing throughput, and apportioning revenue responsibilities can only be achieved if transportation services of the same quality are offered at different times of the year at seasonally differentiated rates and subject only to the capacity priority of peak "firm" customers over nonpeak "interruptible" customers.

However, the use of the word "firm" may be confusing. The Commission has concluded that, in order to achieve the goal of non-discriminatory access to transportation services during off-peak as well as on-peak periods, the final rule should require that an interstate pipeline that chooses to hold itself out as a transporter should offer *both* firm and interruptible transportation service, on a non-discriminatory basis. This is reflected in the final rule in § 284.9(a)(i).

If the non-discriminatory access condition applied only to firm transportation service, only a small minority of transportation services, available only on a firm basis to shippers, would be covered, and the large majority of transportation "deals" sought by shippers today on an off-peak, interruptible basis would remain uncovered.

However, because transportation services offered by intrastate pipelines under section 311 of the NGPA are often by business nature and state regulation required to be interruptible and subject to the priority of the pipeline's strictly intrastate services and operations, the Commission has determined to *not* impose any quality of service requirement on intrastate pipelines under this rule. See § 284.9(a)(2). Thus, intrastate pipelines under the final rule are expressly free to choose whether or not to offer firm transportation, interruptible transportation, or both. Once an intrastate pipeline chooses, however, it must offer such quality of service on a non-discriminatory basis.

c. Application of sales curtailment priorities to transportation capacity

Comments. Many commenters argue that the NOPR's proposal that transportation service provided by a pipeline pursuant to the non-discriminatory access provision be subject to the same curtailment priorities and procedures as those established by the pipeline for its sales customers is infeasible. These commenters argue that this aspect of the proposal does not recognize the inherent significant differences between capacity-induced curtailment and supply-induced curtailment. For example, Tennessee Gas Pipeline (Tennessee) points out that supply-induced curtailment of firm sales service is based on the ultimate end-use of the volumes sold and is subject to the emergency allocation procedures of Subtitle A of Title III of the NGPA. Other commenters emphasize that pipeline end-use curtailment plans for sales customers were established in the 1970's to protect high priority end-uses from lower priority end-uses and were not intended to be used in a time of excess gas supplies. While some commenters indicate that capacity curtailment priorities should not give preference to some end-users over others, several LDCs take the opposite position, requesting that all LDCs be given preference during capacity curtailments, regardless of whether a particular LDC relies on a pipeline to both secure and transport gas supplies on a firm basis or relies on a pipeline only for firm transportation of gas purchased by the LDC elsewhere.

One pipeline that functions primarily as an LDC, Equitable Gas, asserts that the Commission lacks authority to establish priorities for the curtailment of pipeline transportation of gas owned by others. Equitable Gas asserts that the Commission may require curtailment plans only for the purpose of allocating pipelines' own supplies. Because gas supplies transported by a pipeline under the Commission's self-implementing transportation programs is owned by the shipper, not the pipeline, Equitable Gas concludes that the shipper should continue to receive those supplies despite the curtailment priorities established by the transporting pipeline or the Commission.

Commission Response. The Commission agrees that there is a significant difference between curtailment due to lack of gas supplies and priorities for firm and interruptible transportation due to limited capacity. Almost all of the pipeline curtailments during the 1970's related to *supply* shortages, not *capacity* allocation. Gas demand at the prevailing price level exceeded supply available at that prevailing price and supplies had to be spread equitably among all pipeline customers. Each pipeline company had a separate curtailment proceeding, and most now have curtailment priorities on file at the Commission. Nor during the supply curtailment era were gas supplies owned by individual shippers allocated among sales customers of the pipeline. In fact, the need to *encourage* "self-help" transportation of gas from areas of ample supply to areas of curtailment was a prime impetus behind Title III of the NGPA and its goal of a nationally integrated gas transportation system.

The reference to curtailment priorities in the proposed rule was intended to make clear that in any era of capacity curtailment, firm transportation service is not to be accorded any lesser priority than firm sales service. The same equality should exist as between interruptible transportation and interruptible sales service under the rule. In any future era of supply curtailment where the pipeline is unable to honor all of its firm sales contracts, as in the earlier era of supply curtailment, gas being transported normally should not be subject to curtailment by the pipeline at all, because it would be the pipeline's system supply, not the shipper's gas, that would be curtailed.

Thus, for example, capacity may have to be allocated in *force majeure* circumstances, *i.e.*, a sudden loss in capacity due to an unanticipated failure of some aspect of the pipeline's system, such as failure of a compressor station. Under these circumstances, pipelines will continue to allocate the limited capacity among its firm and interruptible customers—whether sales or transportation customers—on the same basis that it currently allocates capacity when there is a decrease in capacity.

Under the transportation program implemented by this rule, the only other form of capacity curtailment which might be expected to occur would be due to a pipeline's overbooking or overselling its capacity. With the modification in the final rule allowing for capacity reservation charges to be imposed for the reservation of firm service, overbooking of firm service is not expected to be a problem.

However, the Commission intends nothing in the final rule to affect the contractual provisions between the parties that may govern the liability and rights relating to a pipeline's overselling or overbooking transportation capacity. Normally, a pipeline's contracts for firm and interruptible transportation service will detail the rights of the shipper to reserved "firm" capacity, or "interruptible" service subject to the availability of capacity on a first-come, first-served basis.

d. Application of "first-come, first-served" principle to capacity

Comments. Many commenters request clarification as to how available capacity is to be allocated, as the NOPR did not explicitly address this issue. A majority of the commenters favor the allocation of capacity on a first-come, first-served basis rather than on a pro-rated basis.[56]

"First-come, first-served" means pipelines would only be required to provide transportation where capacity is available. "Prorated" means a pipeline would be required to provide service to all shippers and prorate capacity among all shippers to provide such service.[57]

These commenters indicate that the first-come, first-served approach would be consistent with an interpretation of the non-discriminatory access condition as a contract carriage, as opposed to a common carriage, condition. Further, these commenters oppose capacity allocation on a prorated basis because they do not believe that shippers that make early requests for firm transportation and are allocated capacity sufficient to meet their needs should be subject, once all capacity available has been allocated, to having their allocations adjusted downward because late-comers request firm transportation.

In addition, the majority of commenters oppose prorated allocation on the grounds that it would encourage customers to nominate volumes far in excess of their needs in order to assure favorable treatment in the event of a reallocation.[58] This, according to the commenters, in turn would create planning problems for pipelines especially if fully volumetric rates are mandated by the Commission. However, some commenters favor prorated allocation in order to ensure that all customers will be able to realize some benefit from the non-discriminatory access condition.[59]

Several commenters propose an "auction" of capacity allocation whereby capacity would be allocated to those shippers willing to pay the most for it, within certain minimum and maximum limits. According to the American Gas Association, there are several advantages to this approach, such as: (a) Unlike a prorated allocation, the shipper could rely on its contract rights; (b) unlike first-come, first-served allocation, there would be minimal regulatory distortions because the parties' bids would reflect the relative value of the service, so that capacity would be allocated efficiently and (c) even though some bidders might be willing to pay more for their service than others, all charges would be allocated to recover the pipeline's cost of service, thus benefiting all of the pipeline's customers.[60]

A small group of commenters, consisting of a number of LDCs and pipelines, including Natural Gas Pipeline Company and Tennessee Gas Pipeline, recommend that pipelines themselves retain the right to designate available capacity for both firm and interruptible transportation on their system.

Designated Producers suggests establishing two classes of firm service for capacity allocation purposes. The first class would be comprised of a pipeline's "existing" firm sales and transportation service—*i.e.*, firm service authorized under NGA section 7(c) certificates issued before the effective date of the proposed rules. The second class of firm service would be for existing customers, not authorized under NGA section 7(c) certificates as of the effective date of the proposed regulation. Under Designated Producers' proposal, if an interstate pipeline elected to offer transportation service separately from sales, it would be required to provide firm capacity for transportation service first to existing firm sales customers that opt to switch to firm transportation through the term of their existing contracts. In addition, Designated Producers suggests that a pipeline should be required to offer all new firm service—whether such service was regular NGA section 7 pipeline sales or transportation service or NGPA section 311(a) or blanket certificate transportation service—on a non-discriminatory basis. To the extent that sufficient firm capacity was not available to satisfy all requested new firm sales and transportation service for a particular time period or segment of the pipeline's system, the available firm capacity would be prorated among all shippers requesting new firm service.

Under this arrangement, according to Designated Producers, an interstate pipeline's existing firm sales customers would continue to receive as much transportation service as they were entitled to under their purchase contract prior to the effective date of the proposed rules. In addition, customers requesting first-time sales or transportation service would have equal access to the pipeline's remaining capacity available for firm service, which would increase as the contracts underlying existing NGA section 7(c) certificated service expired.

Commission Response. In response to these comments, the Commission clarifies what was always intended in the proposed rule: self-implementing transportation services must be offered to all shippers on a non-discriminatory basis *to the extent capacity is available, that is, on a first-come, first-served basis.*

Section 284.10 of the final rule provides a transitional rule under which existing firm sales customers of a pipeline may convert the remainder of a firm sales service agreement to firm reserved transportation through payment of appropriate reservation fees as detailed in the rule.

Thus, a distributor (or other firm sales customer) may obtain firm transportation capacity outside the general first-come, first-served rule. This results simply because a firm sales customer has *already* booked the transportation capacity currently "bundled" with, and necessary to effectuate, the sale; accordingly, there is essentially no harm to allowing a conversion of the already booked transmission capacity from transportation "bundled" with sales to "unbundled" transportation service.

Firm sales customers that convert their contract demand rights to transportation rights, as described below, will have the same priority of service under their converted transportation service as they did under their firm sales service agreements. There is no change in the quality or priority of their service, because the priority of their claim on the pipeline's capacity is unchanged by conversion.

Other customers that seek transportation service under the self-implementing transportation program (or customers that wish to utilize capacity in excess of the conversion amounts) will be offered firm transportation on a first-come, first-served basis equivalent to the quality of other firm transportation offered by the pipeline. This means that the traditional customers that receive firm transportation or sales service under traditional section 7 procedures will not be able to pre-empt those that purchase transportation service under the self-implementing procedures. Stated differently, once a customer has contracted for, or "booked," a pipeline's firm capacity under this rule, that customer will be entitled to the same firm service as any other firm customer since it is guaranteed that capacity is available.

The first-come, first-served principle has not been expressly stated in the final rule for the same reason that it is not stated in the existing rules. The scheme of regulation established by the NGA is predicated on a system of private contracts.[61] With the possible exception of Commission remedial action, the only mechanism for a customer to compel a pipeline to serve it is section 7(a). Under all other sections, the Act presupposes a contractual agreement. The present rules do the same. The only change is that the present rules make explicit in the regulations the statutory obligation that a pipeline may not unduly discriminate in deciding with whom it will contract for transportation.

The question as to how much of a pipeline's capacity will be available for other than traditional firm sales and transportation service (including converted transportation) will be determined on an as-available basis. Factors that will be considered in determining the capacity available for this service include the pipeline's overall physical capacity, firm sales capacity, adjustments and conversion of customers with contract demands and any existing firm transportation obligations. The remaining available capacity would be available for nominations by shippers for firm or interruptible service.

Once that level of capacity available for nominations has been determined, the pipeline will be able to accept nominations from customers willing to contract for the capacity. Customers making offers for that capacity will specify in their nomination relevant information such as volumes to be transported, origins and destinations of those volumes, and periods for transportation. Pipelines will review these nominations and make determinations as to available capacity. Thus, under the first-come, first-served rule, last-comers cannot jeopardize the capacity that was contracted for by the first customer. Once a pipeline and a customer agree that a portion of that capacity will be contracted to that customer, that customer should have firm or interruptible transportation rights to that capacity as contracted for, *i.e.*, no later customer will have greater priority to that capacity.

As discussed above, pipelines will be required to offer interruptible service to any customer who requests it, subject to the same non-discriminatory access provision applicable to its other activities. Customers willing to accept that available capacity on an interruptible basis may submit nominations for that capacity. Since that customer's claim to a pipeline's capacity is interruptible, its claim is inferior to that of the firm customers. Therefore, if any of the pipeline's firm customers, including customers with converted transportation rights or customers with other firm transportation rights under this rule, demand their firm transportation, the firm customer will pre-empt the interruptible customer.

The Commission has reviewed the "auction" of capacity rights proposed by AGA, and believes that the requirement that a pipeline establish downwardly flexible, seasonally differentiated transportation rates accommodates the concept of "auctioning" transportation capacity consistent with competitive conditions in the marketplace. Moreover, the provision in the final rule for reservation charges for firm service means that shippers will be able to rely on firm, reserved service. Therefore, the Commission has declined to adopt AGA's proposal for a "bidding" process.

The Commission also rejects the option proposed by some pipelines of retaining discretion to designate the capacity they would make available for self-implementing transportation. Such a designation would be inconsistent with the requirement that pipelines offer such services to all shippers on a non-discriminatory basis to the extent capacity is available in an objective, factually verifiable sense.

9. *Transitional options of firm sales customers to reduce firm sales entitlements and to convert to firm transportation.* a. Background. The final rule is intended in part to assure all pipeline customers, including customers served by or through a single pipeline, an opportunity to obtain access to the competitive market for the natural gas commodity, at least where the pipeline chooses to operate under the authority of the new rules. In order to achieve this goal, the proposed rule has been modified so that a firm sales customer will have an option to reduce its firm sales entitlements (or contract demand) (hereafter "CD") and an option to convert firm sales entitlements into firm transportation, as specified below. This option becomes available because a pipeline agrees to provide it as a condition for operating under the self-implementing rules. The options would be phased-in at up to 25 percent a year. They are not available to the customers of a pipeline which chooses not to avail itself of the benefits of the self-implementing transportation program.

Typically, a firm sales contract between a pipeline and customer obligates the pipeline to be ready to sell a certain amount of gas, say 1,000 Mcf, each day. This amount is typically called the contract demand. In the final rule, the Commission has used the broader term "firm sales entitlement." See §§ 284.10(c) and 284.10(d). For those pipelines where the application of this term may be unclear, the matter may be addressed on a case-by-case basis.

As noted above, while pipelines may have considerable capacity to transport gas on an interruptible basis (Chart I), the *firm* capacity of most pipelines is generally contracted for. Yet, with the changes in the natural gas markets over the last decade, the levels contracted for by customers on a firm sales basis may no longer correspond to what they desire to purchase.[62] This means that on some systems, interruptible transportation is *as a practical matter* virtually the same quality of service as firm. This state of affairs then raises issues as to the equity of allowing an interruptible customer to purchase essentially firm service at a substantially lower rate than that paid by firm customers. Moreover, it deprives potential customers that would be willing to contract for firm service from being able to purchase such service.

Accordingly, the CD reduction option is designed to allow a "freeing up" of presently contracted firm service so that the transmission capacity presently "bundled" with the sales entitlement may be sold separately to willing shippers. As discussed below in section IV.A.9.b.(iii)(D), the purpose of the CD reduction option is thus *not* to reduce the total fixed charges paid by a firm customer. That may or may not occur, depending on other factors. The purpose rather is to allow a freeing up of unwanted firm capacity.

The conversion option is essentially a particular type of reduction in which the firm sales customer still wishes to contract for firm capacity, but seeks firm transportation capacity, "unbundled" from gas sales service. Since the firm sales customer has already reserved the transportation capacity (when it was "bundled" with the sales service) and since the customer already has a contract with the pipeline which includes that transportation capacity, the conversion from firm sales to firm transportation is, with regards to the pipeline's transmission costs, a fairly straightforward arrangement.

With regard to the costs associated with the displacement of sales that would otherwise have been made by the pipeline, the issue is one of treatment of take-or-pay costs, discussed below, and recovery of those costs not included in any demand or reservation charge.

The transitional contract demand reduction and conversion options are essential if the goal of non-discriminatory access to transportation is to be achieved when pipelines operate under the new transportation rules. With such an option, full-requirements customers—especially small, sole-supplied local distribution companies with primary temperature-sensitive residential and commercial loads—will have access to competitively-priced supplies of the gas commodity.

Thus, they will no longer be dependent on a single merchant for their gas supplies, and will have some flexibility to swing their purchases of the gas commodity among alternative merchants, just as partial-requirements customers are already able to do under the Commission's Order No. 380, which prohibits the imposition of variable costs in pipeline minimum commodity bills for gas not taken.

To the extent full-requirements customers will be able to convert a portion of their CDs under this rule to firm transportation in order to obtain access to the competitive wellhead market, even on a limited basis, they will be provided an opportunity somewhat comparable to the opportunity enjoyed by partial-requirements customers to "swing" among pipeline suppliers under the minimum bill rule.[63] In this regard, the CD conversion option is the logical complement to the minimum bill rule.

On the other hand, the customer's right to adjust a CD is balanced with a "two-way" street of rights and obligations with its pipeline supplier. Costs must be, and are, recognized in the final rule. To accomplish this balance, the final rule allows the conversion and reduction options only to customers of pipelines that offer self-implementing transportation and gives such pipelines the right to apply for commensurate abandonment of their certificated sales obligations under § 157.18. In addition, pipeline customers who chose to adjust their CDs risk the inability to automatically "swing" back to sales service on the same pipeline without filing and approval by the Commission of new or amended sales certificate obligations under section 7 of the NGA. Thus, such decisions will not be lightly taken.

b. *Comment analysis.*

Several issues regarding the access of firm sales customers to transportation were raised by commenters. Pipeline and producer commenters who opposed the CD adjustment asserted that the Commission lacked legal authority to impose it as a condition of self-implementing transportation.[64] Commenters who supported the right to adjust CDs supported the Commission's legal authority but urged the Commission to permit customers to *convert*, as well as *reduce*, their CDs into firm transportation service upon payment of a reservation charge.[65]

Other commenters asserted that the proposed rule would allow customers to reduce CDs unilaterally, and they questioned the Commission's authority to allow such purported unilateral action, especially if the fixed costs attributable to the reduced CDs would be reallocated among the pipelines' remaining customers.[66]

Still other commenters addressed the scope of the CD adjustment rights, including the 4-year phase-in period; applicability to intrastate customers; applicability to sales service agreements entered into after a pipeline begins self-implementing transportation; and the operation of the CD adjustment rights in relation to fixed cost minimum bills, sole supplier clauses and a customer's allotment of "Block 1" gas under the block billing procedure proposed by the rule.[67]

These comments and issues are discussed below.

(i) Legal authority.

Comments. Many commenters, especially producers and pipelines, oppose the CD adjustment rights on legal grounds.[68]

Some commenters assume that the right is based on our authority under 7(e) to condition certificates. They argue that section 7(e) does not give us this authority, citing *Panhandle Eastern Pipeline Co. v. FERC*, 613 F.2d 1120 (D.C. Cir. 1979), which held that:

> the Commission may not, as a condition on a section 7 certificate, require the pipeline to adjust rates previously approved by it for customers not receiving the services to be certificated. In other words, the Commission may not tinker with rates found just and reasonable in conditioning a certificate dealing with other sales and services.

Commission Response. These comments appear based on the assumption that the proposed rule would automatically allow firm sales customers to shift cost responsibility onto other customers or onto the pipeline's shareholders. As explained more fully in section IV.A.9.b.(iii)D., this is not how the final rule operates.

First, by adding the conversion option and specifically allowing for reservation charges for firm service, the final rule recognizes cost responsibility for firm service and sharply reduces the potential for cost shifting. Second, the primary purpose of the CD reduction option is to allow a freeing up of firm capacity, not to allow existing customers to simply reduce the level of the monthly payments. The issue of establishing rate *levels* is left to individual cases; the instant rule seeks only to establish a rate *structure*.

Moreover, reliance on the *Panhandle* case is misplaced. *Panhandle* held that to adjust rates previously set, the Commission must follow the procedures specified in section 5(a) of the NGA. With regard to establishing the rate conditions, that is exactly what we are doing here.

This response is equally applicable to the argument of Panhandle Eastern and Trunkline that section 311(c) does not give us sufficient authority to issue § 284.10 (§ 157.21 in proposed rule). To the extent Panhandle Eastern and Trunkline argue that by enacting section 311 of the NGPA Congress intended to limit our authority under section 5(a), we reject the argument. Nothing in the NGPA or its legislative history suggests that Congress intended by enacting section 311 of the NGPA to limit our authority over NGA-jurisdictional transactions under section 5(a) of the NGA.

Comments. Many commenters opposing the CD adjustment right recognize that section 5(a) gives the Commission the authority to impose the rule if the requirements of the statute are satisfied. The commenters argue that the requirements of the statute cannot be satisfied. Several commenters argue that this is so because we can allow a customer to reduce its demand charge only after we have made findings concerning the impact on each pipeline and its other customers. In short, these commenters argue that we cannot impose the right on a generic basis but must proceed on a case-by-case basis.[69]

Commission Response. Again, the changes made in the final rule largely address the underlying concerns raised by these comments. We note in any event that the courts have held we can make a section 5 determination generically. *See Wisconsin Gas Co. v. FERC*, No. 84-1358 (D.C. Cir. Aug. 20, 1985). See also DOE Organization Act, section 403(c).

Comments. Other commenters, such as Amoco, argue that the CD adjustment right is inconsistent with the requirement of section 5(a) that the Commission "shall fix" the just and reasonable rate or practice to be thereafter observed. This requirement, it is argued, means that the Commission, not a customer, must decide whether a contract is in force. The CD adjustment right, it is asserted, gives the customer the discretion to make this determination.

Commission Response. The conversion and reduction options are in no way an abdication by the Commission of its section 5 responsibilities, nor do they create any "unilateral" rights to breach contracts. Rather, the regulation merely provides that, if a pipeline desires to provide service under the self-implementing transportation rules, it must also agree to provide its existing customers the CD reduction and conversion options in § 284.10. The rates charged for converted transportation will continue to be set by the Commission under the NGA. Accordingly, the Commission disagrees with the comment that § 284.10 is somehow unlawful.

Comments. Other commenters argue that we cannot make the findings required by section 5(a)—that the rate be unjust, unreasonable, unduly discriminatory, or preferential. A number of these commenters argue that this is so because the effect of the CD adjustment right is to modify contracts.

The Commission may modify contracts, these commenters argue, only "in circumstances of unequivocal public necessity," citing *Permian Basin Area Rate Cases*, 390 U.S. 747, 822 (1968).

Commission Response. The final rule does not modify these pipeline-distributor contracts. The rule provides only that if a pipeline voluntarily chooses to operate under the self-implementing rules, then it must agree to provide the reduction and conversion options to its firm sales customers as a condition on the exercise of that choice. While the Commission certainly has authority to modify jurisdictional contracts under section 5 of the NGA, *Permian Basin Area Rate Cases*, 390 U.S. at 784, that authority need not be invoked here. It is the voluntary decision of a pipeline to accept the self-implementing transportation authority that reflects the concomitant agreement to provide the contract reduction and conversion options to its customers.

(ii) Reasonableness of the CD reduction and conversion options. Other commenters argue that the CD adjustment option is an unreasonable condition to place on self-implementing transportation.[70]

Comments. These commenters note that the pipelines, having entered into a sales contract with the customer, acquired gas reserves to supply the customer and built facilities to deliver the gas to the customer. Panhandle Eastern Pipe Line Co. and Trunkline Gas Co. note that in many instances pipelines did not enter into the contract with the customer voluntarily. Instead, they entered into the contract only because the Commission, acting pursuant to section 7(a) of the NGA, ordered them to serve the customers. Panhandle Eastern and Trunkline say that 44 of their 77 firm sales customers are customers because of section 7(a) orders. Since the NGA is premised upon a continuing system of private contractual arrangements, the commenters argue that the Commission must consider the parties' reliance on their contracts and must not override the parties' expectations except in the clearest of situations.

Commission Response. The comments assume that the CD reduction right proposed in the NOPR allowed customers to simply breach contracts and avoid costs. The comments have been very helpful in emphasizing the need to articulate that this was not intended and does not result from the final rule. The comments also have helped refine the focus on the potential cost-shifting consequences of the proposal.

The final rule has been modified as a result. First, the Commission reiterates that the final rule does not override contracts. There is no requirement that a pipeline operate under the self-implementing rules. Moreover, with the inclusion of the conversion option in § 284.10(d) and the provision for reservation fees for such converted transportation, the concern that pipelines expressed over cost recovery is vastly diminished. The concern among customers of cost shifting is similarily diminished.

A discussion of the operation of the CD reduction and conversion option is useful in understanding these issues and the basic reasonableness of the conditions.

The commenter misconstrues the purpose and effect of the CD reduction option. It does not necessarily provide for a reduction in the level of demand charges paid. That result may or may not obtain, depending on many other factors.

What it does do is enable the customer to reduce the *volumetric* level of its firm sales entitlements. The effect of such a reduction must be evaluated in conjunction with the conversion option also provided for under the rule.

If all customers of a pipeline convert an equal percentage of their existing firm sales entitlements to an equal volume of firm transportation and if they pay the maximum permissible reservation fee for that service, then the level of fixed charges they pay will be essentially identical. The only difference will be the portion of the sales demand charge attributable to firm sales that is not properly allocable to firm transportation. This will be a very small amount except in those instances where the pipeline purchases gas from other pipelines and these pipeline supplies account for a significant portion of total supplies. Moreover, if in the rate proceeding these costs are reallocated back over remaining firm sales services, then the customers will pay an identical level of fixed charges as before the conversion. The difference, of course, is that they will be able to purchase the gas commodity from an alternative merchant in a competitive market. The judgment as to whether the customer is likely to be better or worse off under this arrangement is left with company managements. That is why the program is optional, both with respect to whether a pipeline wishes to operate under the new rules and whether its customers wish to exercise the options that a pipeline's participation make available.

If all customers reduce their firm sales entitlements by an amount that is, in the aggregate, greater than the amount which is converted to firm transportation, then there is an excess of reductions over conversions. Under these circumstances, the pipeline may *not* recover essentially the same level of fixed costs through fixed demand and reservation charges, depending upon whether additional firm sales or transportation can be contracted for. It may ultimately be necessary for the pipeline to file a rate case to spread the difference over all firm sales and transportation services. If such a reallocation of costs is approved by the Commission, then the level of fixed charges to the customers will change to reflect such reallocation. If the reallocation is found by the Commission to be unjust, unreasonable, unduly discriminatory or preferential, then a different allocation of costs would be prescribed.

Again, the major purpose of the CD reduction option is to allow a "freeing up" of unused firm capacity that existing customers presently have "booked" but no longer desire to reserve. This capacity is then free to be sold on a firm basis to other customers.

To the extent the risk of underutilization is assigned to customers through a reallocation of costs to them, then the pipeline has less need of flexibility in pricing its services. To the extent the risk of underutilization is assigned to the pipeline's *shareholders*, however, as some commenters appear to wish, then the pipeline must be given the maximum flexibility to price its services to meet all competition.

Three hypothetical examples illustrate more concretely how the procedure works.

The first case involves a customer's 25 percent conversion of its sales CD to firm transportation. If the customer's sales contract demand is 1,000 Mcf per day, the customer would convert 250 Mcf to firm transportation. Thus, the pipeline would be obligated to sell the customer up to 750 Mcf per day and transport up to 250 Mcf per day.

The second case is that of a firm sales customer whose contract demand exceeds its expected maximum usage. For example, if the customer's sales contract demand was 1,000 Mcf, but the customer expected to need no more than 800 Mcf on any day, the customer could reduce its contract demand to 800 Mcf. The pipeline would then not have to stand ready to sell 1,000 Mcf per day to the customer. It would only have to stand ready to sell 800 Mcf per day. This would free up the capacity for other services, including firm transportation.

Third, the firm sales customer may reduce its contract demand and buy an equivalent amount of firm sales or transportation service from another pipeline. Thus, for example, the firm sales customer may reduce its contract demand by 250 Mcf and buy 250 Mcf per day of firm sales or transportation service from another pipeline. The customer may also reduce its contract demand and take the interruptible service provided for by this rule. This is really a special case of the first situation.

In the first case, by paying a demand charge the customer bore a portion of the costs of the pipeline's demand-related production, gathering, storage, and transmission costs. When the customer converts, it will continue to be allocated the same portion of the pipeline's demand related transmission costs. But it will not necessarily be allocated the same portion of the pipeline's other demand related costs. Depending on the operation of the pipeline and the type of transportation service provided, some of the pipeline's demand-related storage costs may be allocated to the transportation service. On some pipeline companies, such as El Paso, gathering costs are significant. Hence in some cases, cost-shifting may occur. In addition to these consequences, with the loss of sales to the customer, the pipeline may incur take-or-pay liabilities. If the pipeline does incur these liabilities, the costs will, consistent with the Commission's established rules, be eligible to be included in rate base. *See* Order No. 380, slip op. at 44, n. 47. The carrying costs of the liabilities will then be recovered in the pipeline's rates.

In the second case, there would also be a change in revenue-responsibility. What will happen is the pipeline will lose the revenue produced by the customer's demand charge payments, but may be able to make them up through other services. However, should the pipeline experience a revenue deficiency, we would assume, for the sake of argument, that it seek a rate increase from its remaining sales and transportation customers.

In the third case, costs will be re-allocated among the remaining sales and transportation customers, assuming the capacity is not utilized by other services. In addition, the pipeline may incur take-or-pay liability.

We do not believe these effects will be significant. In the first case, the customer will continue to pay its share of the pipeline's fixed transmission costs, which today account for a small percentage of the overall delivered price of gas at the city gate. Fixed transmission costs are by far the largest component of pipeline's fixed costs. The amount of costs shifted to the pipeline's remaining customers will generally not be large. The opponents of the CD adjustment right recognize this, for they argue that, if the Commission adopts the rule, customers should be required to, or at least be given the right to, convert to mitigate the shifting of costs. Such a conversion option is provided for in § 284.10 of the final rule.

The second situation should be rare. Most firm sales customers need their full contract demands on peak days.

In the third case, costs will be shifted to the pipeline's remaining customers. But by switching to another pipeline, costs will be allocated away from that pipeline's other customers. Hence, viewed from a national perspective of increased competition, there may not be much of a problem. The same is true also for take-or-pay problems in the first and third cases, for the customer will continue to buy gas. If it does not buy the gas from one pipeline, it will buy it from another merchant.

Moreover, our description of the cost-shifting consequences of a reduction in contract demand assumes the pipeline will do nothing in response. As illustrated by the experience since implementation of the minimum bill rule, suppliers and customers, is not a reasonable assumption. As customers reduce their contract demands, unused pipeline capacity will be freed up for sales or transportation, or more costs will be allocated to the remaining customers, who will then reduce their contract demands, unless the pipeline lowers its costs to maximize its capacity utilization. Either way, the pipeline will seek out new business at more competitive prices. If it does the new savings will be spread among the new customers as an offset to any increased costs. Since the reduction in contract demand will make available additional capacity for firm service and since this rule gives pipelines increased ability to attract new customers and retain revenues, the pipeline should be able to expand its capacity utilization and revenue stream. If it does not, we can impute projected levels to give the pipeline an incentive to do so. Thus, the problem of cost-shifting should be small. Alternatively, the pipeline may reduce its capacity by discontinuing the use of unneeded compressor facilities or similar steps. Reductions in actual capacity would mean a reduction in the pipeline's rate base. The assets removed could then be deployed in more productive uses.

Nevertheless, there will be some cost-shifting in the short-term and, in some cases, in the long-term. Many commenters argue that this should not happen. Some, principally distributors who otherwise support the CD adjustment right argue that the pipeline's remaining customers should not bear any increased costs. Other commenters argue that neither the pipeline nor its remaining customers should bear any burden.

Fundamentally, there is no mechanism available to the Commission which will prevent all shifting of revenue responsibility (i.e., costs) among customers. A number of possible mitigating mechanisms have been considered.

One way to protect the pipeline's remaining customers is simply to prohibit the pipeline from shifting any costs to them. This, however, would put the risk of any loss on the pipeline. While we have essentially adopted this approach under the optional expedited certificates for new service, the case for applying such a rule across the board to existing facilities is not very well supported. Another way to protect the remaining customers and the pipeline would be to require the customer that converts to bear, at least until that customer or the pipeline found another customer, the same fixed cost burden it did as a sales customer. In addition, the customer would be responsible for any take-or-pay liabilities the pipeline incurred. Yet another possible way of protecting the pipeline and its remaining customers is to require the customer that converts to pay essentially an exit fee. Yet another device is to require the customer to convert rather than reduce CDs. In short, this suggestion would prohibit a customer from reducing its contract demand because it is unneeded or because the customer wants to switch to another pipeline.

The Commission concludes that each of these proposals, while mitigating cost shifting, would in effect prevent customers from making use of the transportation services provided for in this rule or protecting themselves from any adverse consequences of the pipeline's efforts to compete, particularly as a merchant.

More important, in most cases no specific pipeline facilities can be identified as being used in servicing only one customer. Instead, the pipeline is built and is operated on an integrated basis to serve all customers. Hence, it is generally appropriate for the pipeline's remaining customers to bear the burden of paying for the facilities used to serve them.

Finally, the reason costs will be shifted is because the customer that converts can get a better deal on the gas commodity from an alternative merchant. This is simply another way of saying that constructive competition exists. Hence, it cannot be said that either the pipeline or its remaining customers should be immune from feeling the "pinch of competition." Indeed, the law is just the opposite. *Atlantic Seaboard Corp. v. FPC*, 404 F.2d 1268, 1273 (D.C. Cir. 1968).

Take-or-pay costs stand on a somewhat different footing, since these costs are not incurred as a function of providing sales service but as a function of *not* providing that service. Thus, it may be possible to identify these costs as being caused by a given customer's decision to convert. If that can be done, the allocation of these costs can and will be equitably apportioned among a pipeline's transportation and sales customers in a rate case.

In adopting the conversion and reduction options as part of the final rule, we recognize that there is at least the possibility that some costs of the excess of reductions over conversions may ultimately be shifted to remaining customers. But only through such reduction can firm transportation capacity be made available; only through conversions can sole-supplied customers have access under self-implementing transportation to the national market for competitively priced natural gas supplies. Thus, for purposes of evaluating the final rule, we have determined that the benefits of § 284.10 to both sole supplied customers and all other customers outweigh these potential cost shifting detriments which might be incurred by sole-supplied customers.

We cannot gloss over the impact of the final rule. But if there is one thing nearly 50 years of Federal regulation of natural gas has taught this Commission, it is that the failure to "pragmatically adjust" our regulations in changing circumstances in the regulated industry more likely than not will harm the industry and the millions of Americans who depend on it.

Section 284.10(g) expressly provides that a pipeline must file appropriate adjustments in its rates when a firm sales customer exercises its option to reduce its CD. The rule in no way resolves the issue of how those costs will be allocated, however. Hence, the cost allocation issues will be decided on a case-by-case basis. This approach creates an overall structure which furthers the Commission's overriding goal while retaining the flexibility to make such equitable adjustments as may be appropriate in exceptional cases.

The Commission shares the concerns over the cost-shifting issues, and intends to carefully scrutinize the initial rate cases that are filed under this rule in order to assure that pipelines and their transportation customers will not "unload" fixed costs and risks disproportionately on full-requirements sales customers. In particular, the Commission fully intends to closely scrutinize projected levels of service and rates of return filed in rate cases as a means of assuring that pipelines bear their fair share of the risks of maintaining pipeline throughput.

Comments. Commenters assert that the demand charge is used to recover costs the pipeline has incurred to serve the customers. If the customer reduces the demand charge, these costs will be shifted to other customers or the pipelines. Many commenters argue that this in inequitable. Other commenters argue that this is inconsistent with the promise made in the Preamble of the proposed rule (mimeo at 34) that there will be no cost shifting as a result of this rule. These commenters argue that to avoid inequity and inconsistency with the rule we should not allow firm sales customers to reduce their demand charges.[71]

Commission Response. As noted above, the inclusion in the final rule of the conversion option and the provision for reservation charges blunts most of the thrust of these comments. But again we recognize that the costs previously recovered from the customers through demand charges do not disappear. If customers' reductions are greater than conversion and new sales of firm transportation, then someone—either the pipeline's remaining customers or its shareholders—must pay them. The question therefore is, how significant is the shifting of costs and what, if anything, should be done about it.

These are "hard choices,"[72] and the Commission has wrestled with the implications in the proposed rule for indirect effects on the allocation of risks and revenue responsibility. The provision for conversion options and for reservation charges—which will recover costs largely comparable to those recovered in the transportation component of the demand charge paid for firm sales service—vastly reduces the scope of the potential cost shifts. The provisions for the cost adjustments to be made on a case-by-case basis provides a forum for remaining issues to be discussed and decided.

Accordingly, the Commission finds that the benefits of flexibility and access to the competitive commodity market outweigh the potential harms associated with the possible shifting of fixed costs among customers.

To deny full-requirements customers the opportunity to thus adjust their sales services simply because the adjustment is accompanied by additional risks to both the customer and its pipeline supplier is to condone the fundamental form of undue discrimination by monopoly power which the NGA intended to prohibit. The record in this rulemaking demonstrates that between 1973 and 1983, total U.S. natural gas consumption declined by 24 percent and industrial consumption dropped by 35 percent. The Commission also notes that the substantial "bubble" of surplus gas deliverability that has persisted for the last 42 months (Exhibit L) and that the United States Department of Energy has estimated that adverse effects on consumers from the lack of non-discriminatory transportation are at least $9.7 billion annually. These benefits outweigh the risks of cost-shifting raised by the commenters.

(iii) *Operation of the CD adjustment options.*

A. Relationship to Block Billing Mechanism

Comments. A number of commenters address the question of the effect a reduction in contract demand will have on the proposed allocation of block 1 and block 2 gas under the block billing procedure in Part D of the final rule. Indicated Producers, for example, argue that a customer that reduces its contract demand should lose a proportional amount of its block 1 allocation. Indicated Producers argue that this is necessary to avoid giving existing firm sales customers an undue preference. Other producers argue that the customers should not be able to specify which block will be reduced. A number of other commenters, however, argue that a reduction in contract demand should result in a proportional reduction in the customer's allocation of both blocks. Still others argue that any reduction in gas allocated to the customer should first come from block 2.

Commission Response. In view of the decision to call for further comment on revised Part D, it is not necessary to respond to this comment at the present time. The Commission expects to revisit the issue in its further review of the revised Part D proposal.

B. Relationship to a Pipeline's Certificates and Its Contracts With Producers

Comments. The proposed rule provided that, when a customer reduces its contract demand, the pipeline would be able to apply for abandonment of its certificate obligations to the extent of the reduction and that abandonment would be deemed in the public convenience and necessity under section 7 of the NGA. Several commenters oppose giving the pipeline the discretion to seek abandonment. Consolidated Edison Company argues that the pipeline should be *required* to seek abandonment unless the customer pays a reservation charge to retain its right to the pipeline's gas supply. Con Ed suggests that this reservation charge could be based on the carrying costs of the pipeline's gas supplies or the pipeline's minimum bill obligation. Stating the same point in a somewhat different manner, other commenters argue that a pipeline ought not to be permitted to apply for abandonment if the customer is willing to pay a reservation charge. Another commenter takes a different tack. It argues that to prevent the pipeline from discriminating among customers, the rule should specify the conditions under which the pipeline may seek such abandonment.

Panhandle Eastern and Trunkline argue that this abandonment authority is unlawful because it grants abandonment without the searching, case-specific inquiry said to be required by section 7(b) of the NGA. INGAA, however, argues that it does not go far enough. According to INGAA, the final rule should provide that abandonment authorization will issue automatically upon the filing of the application.

Northwest Central Pipeline raises a different point. It urges us to make clear that a pipeline that abandons service to a customer under the CD adjustment right may later compete for the customer's business under the optional expedited certificate procedures.

Commission Response. The purpose of the CD reduction and conversion options is to provide both firm sales customers *and* their pipeline suppliers with increased flexibility to enjoy self-implementing transportation service in response to new demands in natural gas markets. In order for these mutual benefits to be achieved, the exercise of the option must be a "two-way street;" that is, customers who reduce their contractual obligations to buy sales service must be willing to release their pipeline suppliers from their commensurate obligations to *sell* sales service. In return, pipelines who provide self-implementing transportation service must be willing to release their firm sales customers from their CDs if the customers are willing to assume the risks that the pipeline will abandon its certificate to serve them under the NGA. Accordingly, § 284.10(f) of the final rule retains the provisions deeming such abandonment to be permitted by the public convenience and necessity.

We emphasized that this abandonment flexibility is not mandatory; a pipeline at its discretion may choose to retain its section 7 sales certificate in order to stand ready to permit its customer to "swing" back on to sales service. A pipeline may believe it appropriate to establish a "standby charge" for standing ready to provide sales service should the customer wish to automatically resume sales service. Such a charge could be sought and reviewed through an appropriate section 4 filing. In addition, a customer and its pipeline retain the flexibility, even where the certificate is abandoned, to apply for a new or amended section 7 certificate which would permit the customer to resume sales service. In either case, the pipeline in exercising its discretion must file with the Commission, and the application will be available for the public to review on a case-by-case basis.

Comments. Several commenters address the question of the circumstances under which a customer could return for pipeline sales service. INGAA urges us to make clear that former sales customers will have no special right to return. The American Public Gas Association argues that rather than permitting a pipeline to file tariffs setting forth the conditions under which it would be willing to serve, we should require the pipeline to file such a tariff.

Commission Response. The Commission has established no special rights in this regard. Thus, a customer which has left a pipeline's sales service stands in exactly the position of an entity that seeks such service for the first time. Of course, a pipeline could file a tariff sheet setting forth the conditions under which it would be willing to serve a former sales customer. Such filings would be subject to Commission review when filed. For the customer that has not left totally the pipeline's sales service, it may still retain a right to overrun service as provided in the pipeline's tariffs.

Comments. Several pipelines argue that if the Commission adopts the CD reduction option, the Commission should adopt a similar right for contracts between producers and pipelines. That is, the rule should allow pipelines to reduce their purchase obligations to producers.[73] In a similar vein, one producer, Sabine Corporation, argues that when a firm sales customer reduces its contract demand, the producer should be relieved of its contractual responsibilities to the pipeline for the affected volumes. Sabine states that this will allow the producer to market the gas to alternative buyers.

Commission Response. As noted above, the purpose of the CD reduction and conversion options is to allow a freeing up of pipeline capacity. It is not intended to override a pipeline's contracts to purchase gas from producers. Indeed the courts have held that we lack jurisdiction under the NGA to modify the wellhead contracts for gas that has been removed from the Commission's NGA jurisdiction by the NGPA.[74] Thus, the Commission is not in this rule in any way whatsoever affecting the contractual *rights and obligations* of parties under producer-pipeline contracts.

We recognize that the exercise of the reduction and conversion options by a pipeline's customers might require steps by the pipeline to adjust its "inventory" of gas supply under contract with producers. It is for this reason that Part B of the final rule reaffirms the April 10, 1985 Policy Statement on buy-outs and provides for expedited processing of producer abandonment applications in a number of instances.

Producers may argue that adjustments in pipeline service agreements with customers could affect the marketability of gas under separate producer contracts with pipelines. To the extent producers seek protection from the risk of unmarketable gas, the Commission concludes that such risks are exactly the type the parties, not the Commission, should apportion under private contracts.

However, we agreed that Commission procedures should not impede private contract renegotiation between pipelines and producers. Therefore, the Commission has included in the rule expedited procedures for the review of producer abandonment requests and take-or-pay contract "buy-outs" agreed to by the parties. These procedures should assure that producers and pipelines have flexibility to adjust their contracts in response to the changes occurring in the natural gas industry and to the exercise of the CD adjustment rights by pipeline customers. In fact, some producer commenters have pointed to the adjustment of sales customers CDs as a crucial prerequisite to increased access of producers to unused pipeline capacity for directly marketing shut-in gas to pipeline customers under the final rule's self-implementing transportation program.[75]

Comment. Another commenter, Natural Gas Pipeline Company, argues in a related way that the CD adjustment right is unlawful because this right, in conjunction with the block billing rules, has the effect of nullifying the guaranteed passthrough provision of section 601 of the NGPA and "would violate section 601(c)(1) of the NGPA which prohibits the denial or condition [of] any certificate under section 7(c) of the NGA based upon the sales price of the gas, if such price is deemed just and reasonable under section 601(b)."

Commission Response. This argument is not persuasive. Nowhere in the final rule is there a provision which denies or conditions the issuance of any section 7(c) certificate on the basis of the sales price of the gas. The Part A rules apply only to certificates for the transportation of gas owned by someone other than the pipeline. In no way is the issuance of a blanket transportation certificate under section 284.221 tied to the price of the gas to be shipped under that certificate. In addition, the block billing proposal has been revised and further comment has been requested.

C. Eligibility of Interruptible Customers, Direct-Sales Customers, and Intrastate Pipeline Customers

Comments. The proposed rule provided the right to reduce contract demand to a "firm sales customer of an interstate pipeline." Several commenters raise questions concerning this eligibility provision. Process Gas Consumers (PCC) recommends that interruptible customers should be given a similar right. PGC argues that even though interruptible customers do not pay a demand charge, interruptible customers should have the same right as firm sales customers to adjust their contracts especially where minimum commodity bills remain. Another commenter recommends that interruptible customers should be allowed to adjust contractual obligations to the extent future interruptible supply volumes are not accompanied by allocations of block 1 gas.

Commission Response. The purpose of the CD adjustment right is to provide firm sales customers, especially full-requirements customers, a transitional opportunity to adjust CDs that operate as an economic disincentive to taking advantage of transportation services or that prevent unwanted contracted-for firm capacity from being sold to willing shippers. This economic disincentive takes the form of both demand charges and fixed cost minimum bills imposed by the pipeline as a part of "standing ready" to meet the customer's CD on a firm, "booked" basis subject to no other prior claim.

Interruptible sales customers face no similar economic disincentive, even where they may be obligated to pay minimum commodity bills. This is because interruptible customers do not expect the pipeline to guarantee or "book" firm capacity on their behalf, and thus do not normally pay a demand charge for such capacity. In essence they are using capacity that has been reserved by someone else but that is not being actually used by the purchaser at that time. These interruptible customers pay either (a) a negotiated one-part rate if they are a non-jurisdictional direct sales customer or (b) the pipeline's commodity charge if they are a jurisdictional customer. On the other hand, the minimum commodity bills incurred by interruptible sales customers, at least since Order No. 380, merely recover a portion of the fixed costs of the capacity used by the pipeline to provide the customer service on a flexible, interruptible basis. As such, the extent to which these minimum commodity bills operate as a disincentive on interruptible customers enjoying self-implementing transportation need not be addressed in this rule.

Moreover, interruptible customers do not tie up *any* firm capacity. Hence, there is no need to apply CD adjustment options to these customers.

Comment. Inland notes that a "firm sales customer" could include a direct sales customer. Inland argues that our authority to modify sales contracts and rates under section 5(a) of the NGA extends only to sales for resale. Since direct sales are not sales for resale, Inland concludes that we have no rate-setting authority over direct sales and hence no authority to modify the direct sales contracts. Inland cites *FPC* v. *Louisiana Power & Light Co.*, 406 U.S. 621, 637–39 (1972) to support the argument.

Commission Response. Inland misconstrues the effect of the rule. It does not override the firm sales contracts between a pipeline and its customers, whether jurisdictional or non-jurisdictional. Rather, the provisions of § 284.10 constitute a condition imposed under both the NGA and the NGPA that a pipeline must accept if it wishes to operate under the new self-implementing rules. Accordingly, the final rule retains the conditions as it applies to all "firm sales customers" of an interstate pipeline.

Comments. Arkla argues that the eligible customers should not be limited to customers of interstate pipelines; customers of intrastate pipelines should also be eligible. This is required, Arkla argues, because intrastate pipelines will have a competitive advantage over interstate pipelines in that interstate pipelines will have to open their markets to competition but intrastate pipelines will not.

Commission Response. As indicated below, the Commission has no intention of regulating the intrastate activities of intrastate pipelines. Rather, the various conditions that do apply to intrastate pipelines under the final rule apply only to interstate transportation. Accordingly, we do not accept Arkla's suggestion.

D. Relationship to Minimum Bills, Sole-Supplier Clauses, and Other Charges Similar to Demand Charges

Comments. Several commenters raise concerns about limiting the customer's right to reducing its contract demand. One commenter points out that under some rate schedules a customer's demand charge is not based exclusively on contract demand. For example, under a modified fixed-variable rate design, a demand charge may be based on expected annual purchases or curtailment entitlements. This commenter argues that the customer ought to be able to reduce all demand charges, not just those based on contract demand.[76]

Commission Response. We reiterate what was said above. The CD reduction and conversion options are intended to allow reductions in the *volumetric* levels of service, not in the amount of fixed charges paid to the pipeline. Accordingly, we do not adopt the commenter's suggestion.

Comments. Another commenter points out that although the Preamble to the proposed rule (at p. 32) states that the rule requires adjustment to all fixed charges, such as minimum bills and minimum takes, the proposed rule speaks only of contract demand. This commenter requests clarification.[77]

Commission Response. The final rule has been revised. Section 284.10(c) makes it clear that the provision applies to reducing a customers "firm sales entitlements." Therefore, this includes not only contract demand but also other vehicles that operate as fixing firm sales entitlements, such as Annual Contract Quantities, or perhaps certain curtailment entitlements. To the extent that there may be some particular questions as to whether a specific vehicle operates to fix firm sales entitlement, these issues may be appropriately addressed on a case-by-case basis.

In addition, the final rule provides (§ 284.10(c)(4)) that any minimum commodity bill must be reduced by an amount proportionate to the reduction in firm sales entitlements. As noted above, such a reduction may or may not reduce the total bill paid by a customer for fixed charges, depending on the treatment of the remaining costs and the ultimate level of throughput.

Comments. Some commenters (for example ANR Pipeline Co.) argue that in this rule we should abolish all minimum bills to ensure that all pipelines operate on a level playing field.

Commission Response. We decline to adopt this suggestion in this rule. It goes considerably beyond our proposal. The provision in § 284.10(c)(4) is consistent with our goal of freeing up unwanted firm capacity for resale on a firm basis. The considerations raised by a proposal to eliminate all minimum bills entirely goes beyond that. We will, however, continue to examine fixed cost minimum bills for these pipelines as they are presented to us in individual cases.

Comments. Several commenters ask how the rule applies to full requirement contracts and rate schedules containing a sole supplier clause.[78] Typically, a full requirement contract provides that a pipeline will supply the customer with all of its requirements and obligates the customer to purchase its full requirement from the pipeline. A rate schedule containing a sole supplier clause provides that the rate is available only to customers that buy their full requirements from the pipeline. In most cases the pipeline will also have on file a rate that is available to customers who purchase only part of their requirements from the pipeline.

Several commenters argue that full requirements contracts and sole supplier rate schedules are inconsistent with the CD adjustment right since these contracts and rate schedules prevent a customer from making use of the transportation services offered by the rule.[79]

Commission Response. We agree with these commenters that to the extent full requirements contracts or rate schedules containing sole supplier clauses prevent a customer from making use of the rule's transportation services they are inconsistent with the CD adjustment right. Sections 284.10 (c) and (d) make this clear by providing that a pipeline subject to that section must agree to offer its customers those options. For a pipeline with sole supplier clauses, that agreement would necessarily include the agreement to modify any existing contract terms that would prevent the reduction conversion.

We do not necessarily agree, however, with the argument of these commenters that customers that previously purchased under a full requirements rate should be allowed to continue to purchase under that rate schedule even though they no longer purchase their full requirements from the pipeline. There can be differences in the costs of providing full and partial requirements service. If there are such differences, and if the rates fairly reflect these differences, we can perceive no reason why a partial requirements customer should be allowed to purchase under the full requirement rate schedule. It is a question of fact whether the existing full and partial requirements rate schedules appropriately reflect these differences in costs. If there are disagreements on this question and hence on whether the customer exercising its CD adjustment rights should be charged under the full requirement rate schedule or partial requirement rate schedule, they may be resolved in individual cases.

Comments. Northwest Central Pipeline notes that its full requirements contracts do not specify a contract demand. Accordingly, Northwest Central asks how the CD adjustment right will apply to its contracts.

Commission Response. Since Northwest Central's situation appears to be unique, it would be impossible to resolve the problem here. Rather, Northwest Central should propose a method in a rate case as to how customers will exercise their rights under this section.

iv. Transitional nature of the CD reduction and conversion options.

Comments. The propose rule did not extend the CD reduction right to customers who were not customers of an interstate pipeline "as of the effective date of the rule."

Several commenters question whether the proposal applies to sales service agreements entered into after the effective date of the rule. These commenters argue that the right should not apply to these contracts because the customer would be entering into the contract in full awareness of the transportation services available. Hence, the customer would be making knowing decision to purchase a firm sales agreement rather than a transportation service. Accordingly, these commenters argue that the customer should live with its choice.[80]

Commission Response. We agree with the substance of the comment, both with regards to the CD reduction option in the proposed rule as well as with the conversion option added in the final rule. The key date, however, is not the effective date of this rule. Rather, the key date is the date on which the pipeline accepts self-implementing transportation authority provided for in this rule, for it is only then that the customer has non-discriminatory access to the transportation services available. Accordingly, we shall modify the rule to provide that the rule does not apply to contracts entered into or re-negotiated after a pipeline accepts self-implementing authority. This is done in the definition of "eligible firm sales service agreement" in § 284.10(b) of the final rule.

Comments. The proposed rule provided that a customer may at any time reduce its contract demand upon giving the pipeline 30 days written notice. The majority of the commenters argue that some limitation should be placed on the time when the customer can reduce its contract demand.[81] These commenters argue that a limitation is necessary because continual changes in contract demand would make it impossible for a pipeline to manage its gas supply. Moreover, these commenters note, because the rule requires the pipeline to file adjustments to its rates whenever a customer reduces its contract demand, giving customers the right to reduce at any time could mean that the pipeline would continually have to file rates. To avoid these problems, the commenters recommend that all customers be required to give their pipeline notice once a year, *e.g.*, January 1. These commenters also argue that 30-day advance notice is insufficient time to allow the pipeline to adjust its system to the change. They recommend notice periods ranging from 60 days to 305 days.

Commission Response. We agree with the substance of these comments. They persuade us that the most practical approach is to require all the pipeline's customers to exercise the reduction option under § 284.10(c) on a specific date once a year. To accommodate the unique circumstances of each pipeline, we shall give the pipelines the discretion to choose the date on which the customers must exercise their rights. The date must be the same for all of the pipeline's customers. Since a pipeline requires more than 30 days to prepare a case, the customer's election will be effective six months later.

Comments. The proposed rule provides for a phasing-in of the CD adjustment right during the first four years after the effective date of the rule. The phasing-in provides that, in the first year of the rule, the customer may reduce its contract demand by 25 percent, in the next year by another 25 percent, and so on.

Some commenters interpret this exception as making the option to reduce contract demand a transitional right only. That is, the commenters read the proposed rule as allowing customers to reduce contract demand only during the first four years of the rule's operation. Some commenters argue that customers should always have the right to reduce contract demand.[82] Other commenters argue that the right to reduce is properly limited to a four-year period.[83]

Commission Response. The proposed rule intends to give only existing sales customers, not *new customers*, the right to reduce contract demand, and only with regard to existing firm sales service agreements as defined in the regulations. The effect of the phase-in period is simply to exclude new customers from the right and limit existing customers' exercise of the right during the first four years of the rule to allow pipelines the time to adjust to the new business environment created by the rule. The commenters, however, do not persuade us that the right of *existing* customers to reduce contract demand should be limited to only a four-year transitional period. The consequences of a pipeline's operating under the new transportation rules may not become clear for some time. Accordingly, the customers should retain the conversion and reduction options to be able to react to such charges, assuring adequate notice is provided. However, we will be able to revisit this question during the transition period.

Comments. A number of commenters challenge the selection of a four-year phase-in period. Some commenters argue that the phase-in period is too long.[84] They point out that under the rule pipelines will be able to compete immediately for a distributor's customers but the distributor will be tied to its sales agreement. To equalize the competitive position between the pipeline and distributor, these commenters suggest that a shorter phase-in period, such as two years, is appropriate. Other commenters argue that a four-year phase-in is too short.[85] They point out that CD adjustments may cause significant shifting of costs. This fact, the commenters contend, argues for a cautious approach. These commenters recommend that we adopt a longer phase-in, such as 10 percent of the first five years of the rule and 25 percent in the next two years.

One commenter argues that the customer's right to reduce contract demand by 25 percent in each year of the phase-in period should be cumulative. Thus, for example, if a customer had a contract demand of 100 Mcf per day, the customer might elect to reduce its contract demand by 20 Mcf in the first year. In the second year the customer will then be able to reduce its contract demand by 30 Mcf per day.

Another commenter seeks clarification of how the rule will apply to contract demands that vary each month. This commenter recommends that the contract demand in each month should be reduced by a uniform percentage.[86]

Finally, Mississippi River Transmission Corporation argues that a customer's right to reduce contract demand during the phase-in period should be in addition to any termination right the customer may have in sales contracts.

The proposed rule provided that, when a customer exercises the right to reduce contract demand, the pipeline shall file appropriate adjustments to its rates. Several commenters oppose requiring the pipeline to file an adjustment. Rather, this commenter argues, the rule should simply permit the pipelines to file adjustments.

Other commenters request clarification of the filing the company must make and the rights of customers. For example, one commenter argues that the pipeline should not be required to make a general section 4 rate filing. Other commenters urge that the customers be given the right to participate in any case. Other commenters urge that the rate filing be synchronized with PGA filings. Other commenters oppose this idea.[87]

Another commenter argues that the pipeline's rate of return must be increased to reflect the increased risk that costs will not be recovered.[88]

Commission Response. In considering these comments, the Commission has evaluated two alternatives for making self-implementing transportation services accessible to firm sales customers regardless of their CD obligations.

The first alternative would provide all firm sales customers, new and old, an immediate, permanent right under their sales service agreements to adjust their sales entitlements to respond to the changed commercial conditions in the market place and the availability of alternative natural gas merchants. Under this alternative, a pipeline that provides transportation services would be required to compete with its own firm sales service on a gas-for-gas and pipeline-to-pipeline basis immediately and permanently under the rule.

The advantage of this alternative is that it maximizes both the availability of transportation services and the distribution of the benefits of competition in natural gas markets to firm sales customers. The disadvantage is that pipelines are provided little flexibility and bargaining power to adjust their commercial risks and revenue responsibilities in an orderly fashion in response to their new role of competing with themselves as both merchant and transporter. In addition, the pipeline and its remaining customers face the increased risks that the pipeline will not be able to market the unused capacity attributable to the customer reduction in CDs. For this reason, fewer pipelines may choose to hold themselves out as transporters under this alternative than under existing law.

The other alternative considered by the Commission would establish a conditional opportunity for existing firm sales customers to "unbundle" their sales service into a transportation component and a sales component and convert their CDs to firm transportation service upon reasonable notice to their pipeline suppliers in order to take advantage of new firm transportation services made available under this rule. The conversion right would be conditional on a pipeline choosing to hold itself out as a transporter on a self-implementing basis. These adjustments could only take the form of conversion to transportation, not merely reduction of CDs to marketable levels. In no case could such conversions exceed a specific percentage of a customer's CD on a cumulative basis over a suitable phase-in period. Only existing CDs, not new or renegotiated CDs, would be subject to conversion, in order to assure that the right is only available for a suitable transition period.

The advantage of this alternative is that a pipeline's revenue stream attributable to its sales demand charge is, as explained above, little affected, because its customers' adjustment rights are limited to conversion of firm sales service into firm transportation service requiring payment of a reservation charge comparable to its demand charge for the transportation component of its sales service. In addition, the risks to a pipeline are minimized by limiting the conversion right during a phase-in period and making it available only to existing sales customers.

The disadvantage of this alternative is that a firm sales customer's access to transportation will be limited to firm converted transportation services on the same pipeline. In addition, transportation customers on the same pipeline as well as on other pipelines will not be able to "shop around" flexibly for unused transportation capacity "booked" pursuant to under-utilized CDs.

The final rule adopts a balance between these two alternatives. Thus, under the final rule, firm sales customers may adjust their CDs to convert to firm transportation, or merely to shop around for services on other pipelines and make capacity available to other shippers or buyers on their own pipeline. However, this CD adjustment right is limited to existing firm sales customers and is phased-in over the four-year transition period. For ease in implementation, the CD reduction and conversion options will be triggered by a pipeline transporting natural gas on or after January 1, 1986 under authority of a certificate issued pursuant to § 284.221 or under authority of §§ 284.102 or 284.143. See § 284.10(a).

In addition, where the amount by which CDs are reduced is in excess of the amount converted (plus the amount resold to other customers), the pipeline will file adjusted rates and the Commission will review the reallocation of fixed costs on a case-by-case basis. During this review, the Commission will strictly scrutinize a pipeline's projected levels of transportation service to assure that it is provided an adequate incentive to maximize its utilization of the unused capacity. At the same time, the Commission will scrutinize the pipeline's rates to assure that it is not loading fixed costs and risks disproportionately on any customers.

Finally, the Commission has determined that the CD adjustment rights should be triggered generally only when a pipeline chooses after January 1, 1986, to hold itself out as a transporter on a self-implementing basis, not when it is providing transportation service on an individual basis under section 7 of the NGA. This assures that any increased risks to pipelines resulting from the CD adjustment right are balanced reasonably with the increased benefits of self-implementing authority conferred upon them under the rule.

For this reason, the Commission considers the CD adjustment rights to be a reasonable condition to apply to self-implementing transportation services authorized in this final rule.

10. *Rate conditions.*—a. Background. The final rule adopts most of the rate conditions proposed in the NOPR. These conditions do not determine actual rate levels for self-implementing transportation. The determination of the actual levels will be made in individual pipeline rate proceedings. Thus, determinations as to the costs of service, allocation of costs among services and related issues will be made on a case-by-case basis.

The final rule does adopt provisions allowing transportation to be provided under interim rates until rates conforming to the new conditions can be developed. The interim rule is set out in § 284.7(b).

The rate conditions are designed to assure that rates for transportation service reflect a proper balancing of the interests of pipeline shareholders who contribute the capital assets to provide the service and the pipeline customers who ultimately utilize the assets so provided. This balancing involves an apportionment of the risk, an opportunity to earn a reasonable return on the capital assets contributed, and assurance that the cost burden reasonably approximates the cost of providing service.

Accountability is inherent in a competitive environment; each participant assumes responsibility for the success or failure of its own market participation. Accountability is ultimately achieved in the marketplace through revenue collections that are either sufficient or insufficient for cost recovery. The risk that revenues will be insufficient for cost recovery is part of what motivates the firm to recognize the potential consequences of its decisions. Efficient firms can expect to recover their costs of providing service. Inefficient firms cannot. Thus, in a competitive environment, involuntary cost shifting and cross-customer subsidies do not occur.

Clearly, the question of how risks are allocated among market participants is intimately tied to the question of accountability. Where risks are allocated by legal rules to one party to a transaction, there tends to be little accountability borne by the other party. But the more competitive environment that has begun to emerge in the natural gas industry has required firms within the industry to respond in new and innovative ways. For the Commission to allow *regulated* companies to respond flexibly and quickly to these requirements (by authorizing new ventures, or allowing companies to alter the way in which some traditional service has been rendered because of an unregulated entity's market threat), the pipeline must be held accountable for such decisions. To do otherwise is to eliminate a very powerful incentive to reasoned and rational behavior on the part of pipeline companies, and require more explicit regulatory requirements and oversight instead.

Common sense and economic theory both suggest that putting a firm at risk for the consequences of its investment and operational decisions can affect the incentives to undertake those decisions judiciously: a firm is more likely to work to minimize its costs if its financial health is at stake than if its costs, even some fraction of its costs, are guaranteed. It is generally accepted that the potential for profit and the fear of financial loss create strong incentives for firms to hold down costs. Thus, pipelines that bear significant business risk, that is, firms that are ultimately accountable for their business decisions, are more likely to operate efficiently than are those firms that bear little or no risk.

These considerations are reflected in the final rule. Thus, the risk of under recovering the costs of transportation services in question between rate periods is appropriately assigned to the pipeline. No deferred cost accounting (or cost "banking") similar in operation to the Account No. 191 for the purchased gas costs will be allowed.[89] See § 284.7(d)(5)(iii). Similarly, § 284.7(d)(1) provides that, except for firm service, volumetric rates must be used. For firm service, all minimum bill and minimum take-type provisions are forbidden; only a reservation charge may be collected.

In general, the rate conditions are designed to promote four ratemaking goals. First, ratemaking policies should lead to prices that communicate clear market signals to all participants in the gas industry. Buyers should see the current resource costs associated with purchasing services. Sellers should see the true market value of providing increments of services.

Second, the pricing system should embody strong incentives to minimize costs in order to provide services at the lowest reasonable cost consistent with reliable long term service.

Third, customers should be given maximum flexibility in making choices among services and among suppliers of these services.

Finally, the Commission must also be concerned with the development and maintenance of a regulatory framework that is appropriate under all conditions of gas supply and pipeline investment. Specifically, the Commission should not make *ad hoc* regulatory adjustments that are applicable only in periods of excess gas deliverability or reduced levels of pipeline investment in new facilities. The Commission recognizes that, ideally, its basic regulatory framework should apply equally well to different market conditions.

More particularly, rates for transportation should be designed to achieve three objectives concurrently:

—Peak rates should ration capacity;

—Off-peak rates should maximize through-put; and

—The pipeline's revenue responsibility allocated to transportation should be attained through transporting the expected peak and off-peak volumes at the maximum rates.

The final rule requires pipelines to design their transportation rates with these goals in mind. See § 284.7(b). The Commission recognizes that the goals at times pull in conflicting directions and that good ratemaking reflects large amounts of fairly subjective judgments. The purpose of promulgating these objectives as part of the rule is to provide greater focus on these goals in the ratemaking process.

The other rate elements in the final rule generally track the provisions of the proposed rule. Thus, rates under the final rule must be cost-based. The rates for self-implementing transportation must be based on the fully-allocated costs of providing the service established by the pipeline through a section 4 filing. They must also reasonably reflect any material variation in the costs of providing service due to the geographic area in which the service is provided or the time at which the service is provided. Second, the rate must be designed so that the pipeline has a reasonable opportunity to recover its costs. Third, the rates should be designed to ration capacity at the pipeline's peak. The Commission intends that at times when the pipeline's capacity is constrained, the capacity should be made available to those who value it and hence are willing to pay for it. Fourth, the rates should be designed to encourage full utilization of the pipeline. Finally, in light of the goals of this rule, rates should be so designed so that the transportation component will not differ whether the customer is purchasing sales or transportation service.

Every proposed cost allocation and rate design methodology for self-implementing transportation must meet the first requirement. The rates for firm or interruptible transportation under this rule will be based on the fully allocated, separately established cost of providing the service, and shall separately identify the cost-component attributable to transportation, storage, and gathering. These conditions are all spelled out in §§ 284.7, 284.8 and 284.9.

b. *Comment analysis.* Most commenters on the rate conditions in the proposed rule raised issues of rate design, revenue responsibility and allocation of costs and risks similar to those raised in individual rate cases before the Commission. In addition, issues relating to the design of one-part "volumetric rates" for firm transportation were raised, especially by pipeline customers that requested the ability to purchase or "book" firm transportation capacity upon payment of a "reservation charge" comparable to the demand charge component of a multi-part sales rate established under the approved ratemaking methodology applicable to individual pipelines.[90]

Commenters also raised issues regarding the Commission's authority to establish downwardly flexible rates between a maximum and minimum, especially where such rates could be offered on a "selective discount" basis to individual customers. Commenters requested clarification whether so-called "firm" transportation service purchased at off-peak periods under the one-part volumetric rate would be subject to interruption during peak periods by prior claims of firm sales and transportation customers.[91]

These comments are discussed below.

(i) *Legal authority and reasonableness of rate conditions.*

Comments. Panhandle Eastern and Trunkline contend that we have no authority to impose the rate conditions. This is so, these commenters argue, because the rate conditions are "tantamount" to initial ratemaking. Initial ratemaking is said to be beyond our authority in conditioning certificates under section 7(e). Instead, all we may do under section 7(e), these commenters argue, is to impose rate conditions until the pipeline can file a rate application under section 4. In that application the pipeline may impose any type of rate it wants.

Commission Response. There might be something to this argument if, in this proceeding, we were acting solely on the basis of section 7(c) and section 7(e). But we are not acting solely on the basis of these sections. We are also acting under section 5(a) of the NGA, section 403(c) of the DOE Organization Act, and section 311 of the NGPA. These sections give us ample authority to establish by rule rather than adjudication the ratemaking principles pipelines must follow. *Wisconsin Gas Co. v. FERC,* No. 84–1358 (D.C. Cir. August 20, 1985).

Comments. Other commenters, while not challenging our legal authority to impose the rate conditions by rule, argue that it is unwise to proceed on a generic basis. Instead, we are urged to proceed on a case-by-case basis. The reasons offered for so proceeding are the reasons usually offered for proceeding on a case-by-case basis: there are differences among pipelines and these differences should be reflected in individual rates.

Commission Response. In the final rule we establish a basic ratemaking *framework* for self-implementing transportation. Actual rates will continue to be set on a case-by-case basis as in the past.

(ii) *Volumetric rates for firm service.*

Comments. Many commenters criticize the requirement that firm transportation rates be one-part "volumetric" rates based on representive levels and therefore preclude the imposition of demand charges or "reservation" charges.[92]

A volumetric rate is simply a one-part rate. With such a rate, the customer's bill is determined by multiplying the rate by the volumes of gas transported or purchased.[93]

A volumetric rate differs from the two-part rate the Commission has traditionally used for firm service. Under a two-part rate the customer must pay a certain amount (called the demand charge) to the pipeline whether or not the customer uses the service.[94] With a volumetric rate, however, the amount the customer pays is determined simply by multiplying the rate by the amount of service used, *i.e.*, the volumes of gas transported or purchased. Thus, if the customer does not use the service, it pays the pipeline nothing, and the pipeline bears the risk of capacity utilization.

The proposed rule reinforced this point by prohibiting any billing mechanism, such as a demand charge, that has the effect of guaranteeing revenue.

The essential arguments commenters make are that a volumetric rate does not ration capacity nor does it fairly compensate a pipeline supplier that is under a legal obligation to provide the service. Thus, the commenters point out that a customer may sign a contract with the pipeline that requires the pipeline to stand ready to provide service. But because with a volumetric rate, the customer only pays for service the pipeline actually provides, the customer has no incentive to accurately contract for the service required. Thus, the customer may contract with the pipeline for service it may not need or use. Since a pipeline's capacity to provide service is limited, the commenters argue that the result will be that other customers who could use the service will be denied service, for the pipeline must continue to stand ready to honor its contract. Other commenters contend that requiring a volumetric rate will also result in the pipeline not recovering its costs. To remedy these problems, most commenters argue that we should require or at least permit pipelines to use a two-part rate in which the customer must pay a "reservation" or demand charge whether or not it uses the service. This is so, it is said, because the demand charge places the risk of overestimating usage on the customer. Hence, the customer is not likely to contract for service it does not think it will use. Moreover, a demand charge will guarantee some revenue to the pipelines. Hence, the pipeline should be more likely to recover the costs.

Commission Response. These commenters pursuade us that the opportunity for customers to "book" firm transportation capacity by payment of a "reservation" charge can be an effective and appropriate means of allocating scarce capacity and providing customers an incentive not to overbook capacity which they have little intention of using. Hence, we think that reservation charges should be permitted. Moreover, because firm sales rate schedules of most pipelines require a demand charge, permitting reservation charges for firm transportation will tend to make pipelines indifferent as to whether the customer purchases sales or transportation service.

Accordingly, §§ 284.8(d) and 284.10(d)(4) of the final rule permit use of a reservation fee for firm transportation. There is no limitation imposed in the rule as to how the fee must be billed. Thus, for example, the rule contemplates that there may be very short term (*e.g.* two weeks) firm transactions in which the reservation fee might be paid in a single lump sum. But the rule would also accommodate a long-term firm deal with the reservation charge being billed in the same fashion as a pipeline's sales rate demand charge, *i.e.* on a monthly basis. Billing schedules must, of course, be on file as part of the tariff, however.

The point is that a limit is fixed on the maximum amount of the reservation charge through the rate proceeding. Once that has been established, the Commission intends for the commercial parties to have considerable flexibility in subsequent structuring of self-implementing transportation transactions.

No reservation charges may be collected for interruptible service, however. This rule is set forth in § 284.9d).

To give the pipeline this flexibility does not, of course, give the pipeline a free hand. The Commission will apply established standards for testing any cost allocation and rate design methodology.

(iii) *Use of projected levels of service.*

Comments. Other commenters complained about the use of representative levels. These commenters argue that using representative levels will produce windfalls for the pipeline.[95]

Commission Response. The rule requires use of "projected" levels of throughput for each service. The existing regulations allow the use of "representative" levels of service as one rate option. The use of the term "projected" instead of "representative" is not intended to modify the ratemaking concepts. The change is made to underline the fact that the ratemaking approach under the final rule is intended to be forward looking. The use of representative or projected levels of service is important because it allows costs to be allocated to the service and the pipeline to be able to be retain the revenues received. This approach thus offers an incentive to provide as much service as it can. If the pipeline fails to actually transport the projected level used in designing its rates, it will fail to earn its full allowed return on equity; if it is able to market more than its projected level to willing customers, it will exceed its allowed return. This does not constitute a "windfall." For during the next rate proceeding, the level projected for the service may be adjusted to reflect the best estimate of what is likely to occur during the period of time the rates are in effect. Thus, *between rate cases,* the regulated pipeline will have an incentive to provide the maximum amount of the service to the public. *Across* rate cases, the level of the pipeline's costs and the design of unit rates will be subject to full regulatory scrutiny.

The commenters' proposed alternative is to require the crediting of revenue to various accounts. This approach gives the pipeline little or no incentive to provide service under the rule. Revenue crediting means that costs are not allocated to the service. Instead, all costs are recovered from other services, for example, sales customers. Revenues received for transportation are then credited to, to give one example, the deferred account for purchased gas, in effect paying over the revenues to customers on the basis of how much gas they buy during the period the deferred account is to be amortized. While this approach may attain a rough equity *among customers,* it gives the pipeline no incentive to provide transportation access to the commodity markets. We must, therefore, adhere to our earlier judgment that projected levels of service must be established for self-implementing transportation.

(iv) *Ability to change projected levels.*

Comments. A number of pipelines complain that the projected levels, once established, will never change. They argue that this is unfair. Projected levels, they argue, should be subject to change in either a section 4 or section 5 proceeding.[96]

Commission Response. The pipelines' complaint appears to be based on a misunderstanding of the preamble to the proposed rule. In the preamble we said that, if a pipeline undertakes to provide a service under the optional expedited certificate, it must assume full responsibility. In short, the pipeline cannot incur costs to provide a service and, if the venture turns out bad, expect other customers to pay for it. The way this is accomplished is by prohibiting the pipeline for reducing the projected levels used to allocate costs to the service.

We did not say, however, that the projected levels used to allocate costs to services provided under *other* certificates would never change. Indeed, there are instances where they must change in order to allocate accurately the cost of service. Hence, we agree with the pipelines that the projected levels for services, other than those performed under an optional expedited certificate, may be changed in a section 4 or section 5 proceeding. This is expressly stated in § 284.7(c)(2) of the final rule.

(v) *Requirement of time differentiated, mileage based rates.*

Comments. Although no commenter opposed the concept of maximum and minimum rates, many commenters complained of the specific requirements of the rates. For example, El Paso argued that, because many of the terms used—"on-peak," "incremental costs"—are terms of art and are left undefined in the proposed rule, the specific rates cannot be determined. Other commenters argue that, consistent with long-standing Commission practice concerning rate design, the off-peak rate should make a substantial contribution to fixed cost recovery. Other commenters argue that the minimum rate is too low while others argue that there is no need for a minimum rate.

Still other commenters argue that a pipeline's rates should not be set on a time-of-service basis. Other commenters argue that for some pipelines, it is inappropriate to require rates reflecting variations in the costs of providing service due to the area in which the service is provided. They recommend that we allow these factors to be considered in individual rate cases.[97]

Many commenters made a more general point. It is that, because the volumetric transportation rates are so radically different from the way sales rates are developed, customers will be biased toward either sales or transportation. The commenters argue that this defeats one of the basic purposes of the rule: to allow customers to choose gas suppliers on the basis of gas prices rather than the availability of sales or transportation service.[98]

Commission Response. The commenters' arguments are based on the assumption that we have required that rates for all self-implementing services to be mileage-based or be time-of-service rates. This is not quite the case. The final rule requires that the rate *reasonably* reflect any *material* variations in the cost of providing service. Thus, for example, if the cost of providing service does not materially differ during different periods, rates will not differ. But if the costs of providing the service in the winter season materially differ from the costs of providing service in the summer, the rate should reflect this fact. The cost issues will be determined on an individual case-by-case basis. It is only the general standard which is imposed in the rule.

To take another example, on most pipeline systems the costs of providing service are materially affected by the distance the gas is transported. The rates for such a pipeline should reflect these differences. But on other pipelines or for particular types of services distance may not materially affect the cost of providing service. In these situations the rates need not be based on mileage or zones. In short, all that is required is what is required of all rates: that they reflect the cost of providing the service. Again, the rate standards imposed by the rule will be applied in individual fact-specific cases.

A simple example of how pipelines will design volumetric rates and reservation charges in individual rate cases is useful. The final rule requires that pipelines file volumetric, seasonal, distance-sensitive rates for firm transportation.

In determining the maximum volumetric rate [*] for firm transportation services, the total fixed costs are divided between two components. The first is divided by projected requests for service that would be accepted by a pipeline while the second is divided by projected throughput. All variable costs are assigned to the second component. This can be illustrated in the following formula:

Maximum volmetric rate = A + B

where

$$A = \frac{\text{Total allocated fixed costs} \times \text{Percentage of fixed costs recovered in pipeline's sales demand charge}}{\text{Projected test period requests for firm transportation service that would be accepted by the pipeline}}$$

$$B = \frac{\text{Total projected variable costs} + \text{Fixed costs excluded in the numeration of A}}{\text{Projected test period throughput volumes}}$$

It should be noted that projected requests for firm transportation service accepted by the pipeline may exceed projected throughput volumes, since the pipeline may accept requests for service that the customer does not fully use. These rates will reasonably reflect material variations in cost due to when service is provided and distance of transportation.

The minimum rate a customer may pay is the short-run variable cost, computed as follows:

$$\text{minimum per unit rate} = \frac{\text{total projected variable costs}}{\text{projected test period throughput volumes}}$$

Pipelines may bill individual customers for transportation service at less than the maximum per unit rate, but not less than the minimum rate.

Pipelines are at risk with respect to recovery of fixed costs associated with capacity made available for firm transportation. Moreover, customers are not obligated to actually transport the volumes they have nominated. Consequently, pipelines may wish to impose a reservation fee on nominating customers. This reservation fee would be imposed at the pipeline's discretion on a case-by-case basis, and must be stated in tariffs, pursuant to § 284.7(a). However, the reservation fee may not recover any variable costs nor may it recover any fixed costs in excess of those costs that would be recovered by using the same rate-making methodology used for determining the demand charge in the pipeline's sales rates, pursuant to § 284.8(d).

Regardless of whether a pipeline elects to impose a reservation fee, it must impose a per-unit rate. This per-unit rate will recover no more than any fixed costs not recovered through the reservation fee plus the variable costs.

Pipelines also have the discretion to charge a reservation fee and an associated per-unit rate which are less that the respective maximum fee to individual customers. However, any such discounts must be filed with the Commission in the same manner as discount rates offered to individual customers under this rule and the pipelines are at risk for any under collections. This requirement is set out in § 284.7(d)(5)(iv).

In regard to the design of interruptible rates, the availability of interruptible transportation may vary between seasons. It may approach the reliability of firm transportation in certain periods. Consequently, the minimum and maximum rate for interruptible transportation might be identical to the minimum and maximum rates for firm transportation in such periods. In periods where interruptible service is materially less firm than firm service, then the maximum rate will be less than the firm service maximum rate, reflective of the inferior quality of the interruptible service. It is expected that during pipeline rate cases, pipelines may propose interruptible rates which are less than the firm maximum rate to estimate the revenues that would be generated from interruptible service.

Where an interruptible rate is established in a rate case at less than the firm maximum rate, that rate is the just and reasonable rate for that service. Therefore, the pipeline does not have the discretion to charge a higher rate for that service. The pipeline will have the discretion to adjust the price downward within that band, subject to the filing conditions set forth in § 284.7(d)(5)(iv).

Prior to offering any firm transportation services pursuant to the rule, a pipeline will make a determination of capacity available for such services. The pipeline will presumably take into account overall physical capacity, firm sales capacity, adjustments and conversions to customer CDs, and any existing firm transportation obligations. The pipeline may make any remaining capacity available for new firm services under the rule. The amount so determined will be proposed and supported in the pipeline's rate case. In fulfilling its non-discrimination obligations, a pipeline must accept nominations up to this level. As the pipeline accepts nominations for firm transportation services, the amount of remaining capacity available for firm transportation will decrease. For

[*] It may be helpful to define terms in order that there not be any semantic problems with what we are discussing. We use the terms "rate," "charge," and "fee" to mean the dollars associated with a unit of service. Thus, for example, the "rate" for transporting one Mcf of gas in the peak period within a rate zone will be $1.00.

We use the term "bill" to mean the total dollars that will be paid for providing service for the total units of service. Thus, for example, the bill or charge for transporting 25 Mcf in the peak period within a rate zone will be $25.00 [$1.00 (rate) × 25 (units of service) = $25 (bill)].

example, assume a pipeline makes 10% of its capacity available for firm transportation and it can move 1000 Mcf a day through that capacity, the pipeline would be required to accept nominations up to 1000 Mcf per day. If it accepted a nomination by a customer for 250 Mcf a day, it would then be required toaccept further nominations up to 750 Mcf. If it did not, it would be in violation of the non-discrimination condition in its blanket certificate.

Projected firm transportation volumes established in a rate case may be less than the amount of capacity the pipeline proposes to make available for firm transportation. The assignment of cost responsibility for fixed costs associated with firm transportation capacity in excess of projected firm transportation volumes will be determined in the pipeline's rate case. Options include removal of unused assets from rate base (thus decreasing the amount of pipeline capacity available for firm transportation services in excess of projected firm transportation volumes), allocation among firm services, or a combination of these.

(vi) *Maximum/minimum rates and selective discounting.*

A. *The proposed rule.* The proposed rule provided that a pipeline may charge a customer any rate between the maximum and minimum rate on file for the service. The proposed rule also stated that a pipeline may not file revised rates to recover any revenue lost as a result of charging less than the maximum rate. This sentence merely restated the prohibition against retroactive ratemaking. This restatement was included in the proposed rule to make clear that customers not receiving the discount could not be made to subsidize the customer receiving the discount. Since the rates are designed to prohibit cross-subsidizaton, selective discounting to individual customers would not be unduly discriminatory.

Under the proposed rule, the rates determined by applying the rate conditions would have been the maximum rates the pipeline may charge for a particular service at a particular place at a particular time. The minimum rate would have been the short-run variable costs of providing the service.

The proposed rule reflected a judgment that to allow pipelines to provide service at a rate that does not even recover the variable costs of the service would be pure social waste. In addition, the minimum rate was designed to serve as a check on pipeline's engaging in anti-competitive behavior.

B. General Legal Authority To Permit Selective Discounting

Comments. Many comments were received on this aspect of the proposal. A number of commenters assert that the Commission does not have the legal authority to permit a pipeline to charge one rate to one customer and a different rate to another customer as proposed in the NOPR.[99] These commenters recognize that the proposed rule was designed to ensure that all customers faced a just and reasonable cost-based rate and that no cross-subsidization was to result from the pipeline's discounting.

But the commenters opposing the selective use of discounting essentially argue that rate discounts available to some but not all customers are inconsistent with the NGA's prohibition against undue discrimination. Some commenters argue that the prohibition against undue discrimination requires the pipeline to treat all customers equally. Hence, these commenters argue that a discount offered to one customer must be offered to all customers, or all customers similarly situated in terms of distance, or to all customers in a zone or area, or any distributor serving the intended customer. More specifically they assert that: the rule as proposed does not in fact prevent cross-subsidization; that competitive harms may flow from allowing selectivity in discounting, even if customers are protected from cost shifting; and that selectivity in discounting may forestall price adjustments in the field markets for the natural gas commodity.[100]

Other commenters argued in favor of both the Commission's authority to provide for such discounting and the benefits that would result from such increased pricing flexibility.[101]

Commission Response. The Commission has reviewed its legal authority to permit selective discounting.

Section 4(b) of the NGA states that:

> No natural-gas company shall, with respect to any transportation or sale of natural gas subject to the jurisdiction of the Commission, (1) make or grant any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.[102]

For transportation by interstate pipelines under section 311 of the NGPA, Congress has required that the rates must be "just and reasonable (within the meaning of the Natural Gas Act)." While a textual argument could be made that there is no ban under section 311 on any discrimination in rates among customers, the Commission does not take that position here.

There is no per se rule under the NGA for determining when a preference or advantage is "undue" or when a difference in rates is "reasonable." The general rule is that discrimination is "undue" when there is a difference in rates or service among similarly situated customers that is not justified, whether by differences in the costs of providing the service or by some other legitimate factors.

A review of the cases under the Natural Gas Act indicates that in virtually all cases, the finding of undue discrimination was predicated on actual or potential harm to the non-qualifying customer. Thus, the Commission has frequently found preferential treatment in natural gas curtailment plans or practices to be unduly discriminatory where similarly situated customers did not receive comparable amounts of gas from the pipeline. *See e.g. City of Detroit*, 6 FPC 196, 203 (1947); *Panhandle Eastern Pipe Line Co. v. Michigan Consolidated Gas Co.*, 7 FPC 48, 62 (1948); *Panhandle Eastern Pipe Line Co.*, 13 FPC 301, 310 (1954), *aff'd* 232 F. 2d 467, 472 (3d Cir. 1956), *cert. denied*, 352 U.S. 891 (1956); and 58 FPC 2795, *Louisiana Power & Light Co. v. FPC*, 526 F.2d 898 (5th Cir. 1976).

In all of these cases, the advantage conferred on the favored party came at the expense of some other customer since an increase in the quantity rationed out to one customer under a curtailment plan necessarily meant a decrease in the supplies available to all other customers.

In the few cases involving claims of undue discrimination relating to rate treatment, the touchstone again seems to be whether a preference offered to one customer or class imposes any harm to other customers that do not qualify. For example, in *Transcontinental Gas Pipe Line Corp.*, 28 FPC 979 (1962), the Commission was faced with a preferential rate offered to a customer in a precarious financial condition. The pipeline offered to absorb all the economic costs of the discount in the hope of increased future sales to the customer. 28 FPC at 981.

The Commission found, 28 FPC at 983, the preferential rate treatment to be undue, stating:[103]

> The fact that Transco, in the case now before us, is ready to underwrite the expense of assisting [the financially struggling customer] for a three-year period would not, in itself, necessarily constitute a sufficient basis of differentiation to permit denial of similar requests made by other financial distressed distribution companies whose suppliers may

not be so willing to undertake the loss involved in subsidizing their operations. (Emphasis added).

Thus, the concern there was not with the case presented but rather with a possible precedent for allowing discounts where the pipeline would *not* absorb the risk of under collection. Under the rate conditions in the final rule issued today, the pipeline is fully at risk for any under collections. Hence, the final rule does not raise the same concern as in the 1962 case regarding establishing a precedent for discounting where the pipeline is not at risk.

We find that generally allowing a pipeline to selectively discount between a ceiling and a floor set by this Commission will not result in rates that violate the non-discriminatory requirement of section 4(b) of the NGA as long as the ceiling and the floor are properly designed. We have designed three rate standards that will protect customers from undue discrimination. First, all ceiling rates will be fully allocated, cost justified, just and reasonable rates. A pipeline can *never* charge any customer any more than this ceiling rate. Thus, no customer, no matter how captive and devoid of competitive alternatives, need fear that a pipeline will exercise its monopoly power to charge more than the just and reasonable rate set by this Commission in the full exercise of its authority under section 4 of the NGA.

Second, all floor rates will be no less than the average variable costs of a pipeline in the relevant period. This is the economic test ordinarily used for determining when discount pricing becomes predatory pricing. A pipeline can never charge a customer less than the floor. Thus, a competitor of the pipeline or competitor of the customer receiving the discount need not fear that the pipeline will engage in transparent predatory pricing. We note, however, that charging the floor rate may not necessarily constitute a defense to a predatory pricing charge under the antitrust laws. We state only that the test of average variable costs for the floor rate is sufficient to ensure that the Commission has met its obligation under the NGA to ensure that rates are non-discriminatory—an important economic component of which is the prevention of predatory pricing.

Third, the Commission has structured the transportation rate conditions to prevent a pipeline from requiring a captive customer to cross-subsidize a discount to a competitive customer. A pipeline's rates are developed by establishing projected units of service. That is, how many units of service can the pipeline be reasonably held accountable for over some future period. Costs are allocated on the basis of projected units and the maximum rate is developed by dividing units into costs. The pipeline will not recover its allocated costs if it does not sell at the ceiling as many units as were projected. On the other hand, the pipeline retains any revenues over the costs allocated if it sells at the ceiling or some lesser rate more units than were projected.

Thus, a pipeline may decide to discount to one customer to collect *some* contribution to the costs allocated to the transportation service, rather than lose the customer and make *no* contribution to fixed costs. The discount, however, does not mean any customer pays a higher unit rate to make up the difference between the costs *actually* recovered and those that would have been recovered if the pipeline *could* have charged the ceiling price. This difference in costs comes out of the shareholders pockets if there is any underrecovery. Indeed, other customers paying the ceiling rate may benefit by selective discounting because, if those customers who received the discount were lost to the pipeline, it raises the spectre that the pipeline may be justified in proposing to reallocate its costs so that its captive customers bear more of the fixed costs of the system. Flexibility will be essential in the new competitive environment and all customers should benefit if the pipeline is given to tools to compete effective.

In *Sea-Land Service v. ICC*, 738 F.2d 1311 (D.C. Cir. 1984), the court suggested that the contract rate or discount must be offered to shippers who are "similarly situated" or who face "substantially similar circumstances and conditions." The court recognized that "unique competitive conditions" and "different competitive circumstances" might justify a discount contract rate what the court viewed as a "non-discrimination" requirement. The court's analysis is equally applicable, we believe, to the non-discrimination requirement of the NGA. We are confident that the may that rates are structured will ensure that this will be the case for contracts for transportation service. As noted above, pipelines are at risk for discounts below the ceiling rate. We are confident that pipelines will always seek to charge the ceiling rate in order to maximize profit and will only discount when necessary to make a sale that would not otherwise be made. Thus, two customers similarly situated with respect to their competitive conditions—if, for example, both can switch to No. 6 residual fuel oil or both can switch to a competitor pipeline offering a lower rate—can be expected to receive similar treatment from the pipeline.

Thus, we believe that selective discounting does not per se constitute a violation of the non-discrimination requirement. Nonetheless, to ensure that this general analysis is correct even in specific cases, the Commission will require a pipeline to file its selective discounts (section 284.7(d)(5)(iv)) and will entertain complaints under section 385.206 from any party who believes that a particular discount violated the non-discrimination requirement under section 4(b) of the NGA.

That Congress intended to allow a range of rates to be set under the NGA is also supported by the legislative history of the NGA. During the floor debates on the bill that became the NGA, Congressman Lea, the Chairman of the House Interstate and Foreign Commerce Committee, twice stated that under section 5, the Commission "has the power to fix a maximum, minimum or a specific rate."[104] Since the only purpose of allowing maximum and minimum rates is to allow flexibility in pricing to meet competition, Congress contemplated that pipelines could be allowed to discount rates selectively to meet competition. Furthermore, specific "customized" natural gas rates were a prevalent and well-known rate-making practice by interstate pipelines immediately prior to enactment of the NGA.

We also note that for many years *after* enactment of the NGA, pipelines sold gas at the city-gate under "sharing equation" type rate schedules where the jurisdictional rate was a stated percentage of the retail sales rate. The reason for this arrangement was the need to meet competitive conditions at the burner-tip. The Commission phased out these arrangements in 1948 by requiring that all rates be "stated" rates.[105]

Thus, the issue is not whether selective discounting is per se lawful or unlawful under the NGA. The issue is whether such discounting—at the pipeline's risk—as provided for in the final rule is reasonable in light of the relevant facts and circumstances. Accordingly, we turn first to the general pro's and con's of selective vs. uniform discounting and then to the more particular criticisms raised in the comments.

C. The Advantages and Disadvantages of Selective Discounting

In evaluating these comments, the Commission has first reviewed the economics of price discounting as a response to competitive conditions in commodity and transportation markets.

Under economic theory, price discounting is a rational policy to pursue only when the pipeline perceives it is better to earn less than a full return on a service than to risk losing the service and failing to achieve the volumes on which its rates for the period in question were based. Such flexibility will better equip the industry to respond to unregulated commodity traders who are free to change their prices at will and also to respond to the emerging competition between pipelines in transmission services.[106]

The price band within which the pipeline can vary its rates depends upon the time of use, namely, whether it is a peak, non-peak, or shoulder period. The floor in each period is the expected short-run variable cost. This price floor is consistent with both economic and antitrust theory on preventing predatory pricing.[107] When the short-run average variable cost is less than marginal cost, the pipeline which charges less than marginal but greater than short-run average variable cost is still making some contribution to its fixed costs and is covering its out of pocket expenses. Thus, short-run variable cost is an acceptable price floor. Further, and most significantly, when the pipeline prices below marginal cost, any loss of fixed cost recovery comes from the stockholders. Regulation should be limited when it comes to the specification of how stockholder's funds are used.

The rule on price flexibility also provides the pipeline the ability to lower its rates on an individual customer basis. Questions arise over whether or not this promotes economic and social efficiency. We find there are greater social and economic gains that occur under this proposed rule than the gains which arise if price uniformity is imposed on discounting.

The gains which arise under uniform discounting are that the captive customers will sometimes benefit from lower rates as the pipeline attempts to hold onto other customers who have more economical alternatives. However, due to the cost to the pipeline of uniformly discounting, this gain may only seldom be observed and only when there is the potential of severe loss of throughput. In these unique cases, the pipeline would elect to uniformly discount, provided it could not practice selective discounting. In all other cases, if discounting must be done on a uniform basis, the pipeline would not choose to discount. Rather it would charge the price ceiling, and no customer would gain greater economic welfare. Further, the firm will lose revenue that would not occur were the pipeline to selectively discount. This loss of revenue will first drive the per unit cost of serving the remaining customers up and will ultimately drive up the cost of capital to the pipeline and over time lead to an undersizing of transmission. Thus, these latter results are to the detriment of all customers. The captive customer will gain less from required uniform discounting than when selective discounting is possible.

The pipeline's use of selective discounting will permit the pipeline to hold onto greater throughput, provide certain customers with transmission service at less than the maximum price, and place the risk of under-recovery of its revenue requirement on the pipeline, as opposed to on the customers, to the benefit of all its customers. Further, because the Commission has stated that it can and will hold the pipeline responsible for any unused capacity below projected volumes, the pipeline should be given the tools legally possible such that it can reach this revenue target.

By providing the pipeline the opportunity to selectively discount, the Commission may permit the pipeline to exercise greater market power than is typically observed in a workably competitive market.

In a workably competitive market, because of consumer mobility and the inability of firms to prevent resale, the ability of the firm to selectively discount is limited except were the transaction cost of discovering prices is relatively high. Once the workably competitive firm posts a price discount, this discount is available to all in that market. However, this firm may not choose to lower its price in all the markets in which it competes. Thus, a price inelastic customer gains the benefits of price discounting only in the market in which prices have been lowered. Natural gas transmission companies possess market power over some customers in some of their geographical markets. These captive customers are not mobile and they are not generally capable of benefiting from resale. The pipeline, unlike many workably competitive firms, can more easily price discriminate among customers, yet the pipeline sells under a regulated price ceiling that constrains the price charged to the captive customer to a just and reasonable level.

We are not, however, granting the pipeline any immunity from antitrust or fair-pricing laws.[108] Further, we have coupled the ability to lower rates on an individual basis with general pricing rules such that maximum social welfare is achieved.

As indicated by section II.A., above, competition in the natural gas industry today is proliferating.[109] In these circumstances, it makes little sense to withhold from pipelines the basic weapon other businesses have to wage the competitive battle: the ability to lower prices to beat the competition.

Indeed, giving pipelines the ability makes very good sense. An example will make this clear. Suppose a pipeline, providing self-implementing transportation services, has a maximum rate of $1.00 for transportation service, based on projected levels of 1,000 Mcf, including 100 Mcf to be transported for an electric utility. Assume also that the wellhead price of gas is $2.95 and that the delivered price of residual fuel oil is $4.50. Assume also that the delivered price of residual fuel oil drops to $3.50. The utility can switch and tells the pipeline that, unless the pipeline can beat the price of residual oil, it will switch from gas.

In this situation, there are three possibilities. First, the pipeline may do nothing. In that case the pipeline will lose 100 Mcf of throughput and will fall 10% short of fully recovering its fixed costs. Second, if allowed, the pipeline will discount its transportation rate by $.50 so that the delivered price of gas is $3.45, which beats the delivered price of residual fuel oil. The pipeline will retain the 100 Mcf throughput. The pipeline will still fall short of recovering its fixed costs (including its full authorized return on equity). But the shortfall will be only 5% rather than 10%. Third, if selective discounting is not permitted the pipeline may reduce its transportation rate by $.50 to all customers. The pipeline would retain the 100 Mcf of throughput. But it would fall 50% short of recovering its fixed costs. The pipeline is not likely to be willing to do that. Instead, it will not discount at all since that will cause it to fall only 10% short.

Thus, the pipeline really has only two choices: do nothing or selectively discount. As between these two, selective discounting serves the public interest best. If the pipeline does nothing, everyone loses: the electric utility, because it has to pay $3.50 for fuel rather than $3.45; the pipeline, because it will be 10% short of recovering its fixed costs rather than 5%; and the other customers, because the pipeline's failure to recover all its costs will cause the pipeline's asset costs and eventually its rates, to increase and be reallocated among its remaining customers. If, however, the pipeline selectively discounts, everyone is better off: the electric utility, because it has gotten fuel for $.05 less; the pipeline, because it has minimized its loss; the customers, because the pipeline's cost of capital will not increase as much.

D. Whether the Rules As Proposed in Fact Will Prevent Cross-Subsidization by Customers Not Receiving the Discount

Comments. The Maryland People's Counsel (MPC), argues that the proposed rule would not preclude the possibility of all cross-subsidization. MPC points out that the customers not receiving the discount would be subsidizing the customers receiving the discount if the revenue projection for the service were based on the actual revenues to be received rather than on the revenues that would be received if the pipeline charged the maximum rate. MPC argues that we should preclude cross-subsidization of this sort by requiring base revenue projections in rate filings to assume that all sales and transportation volumes will be charged at the maximum rate.

Commission Response. The Commission agrees. This oversight has been remedied in the final rule in §284.7(c)(4). That section requires that the maximum rate must be designed to recover fully, on a unit basis, solely those costs that are properly allocated to the service to which the rate applies.

E. Whether Selective Discounting May Be Anti-Competitive?

Comments. Commenters have argued that selective discounting may be used by the pipeline to attempt to prevent new entry into a portion of the pipeline's market. This new entry could take the form of relatively short interconnections to other major pipelines with excess capacity.

Thus, Maryland's Peoples Counsel, independent producers and marketers, and several state commissions have claimed that pipelines will use selective discounting to favor their own marketing or producers affiliates, or to limit entry of new pipelines.

Other commenters—including many distributors—argue that a pipeline may offer the discount to a buyer that is currently served by a distributor but charge the distributor the maximum rate, causing the distributor to lose the sale.

Commission Response. The Commission does not agree that selective discounting will harm competition.

With respect to relatively short interconnections, the capital barriers to this entry are small. And we are removing unnecessary regulatory barriers to new entrants. See Part B. See also existing § 284.3(c) of the Commission's regulations. Thus, short-term discounting is unlikely to generate potential long-term predatory or monopoly profits as Maryland's Peoples Counsel hypothesized. Rather, in order to keep this market, the pipeline will have to perpetually discount and therefore any potential harm to customers is highly unlikely.

While we favor new entry and the resulting competition, we also recognize that the customers in these markets can gain nearly the same benefits of competition without new entry through selective discounting. That is, the existing pipeline selectively lowers its price in this one market due to potential competition. The pipeline sells above its average cost and thus is better off than leaving this market. The customers have roughly the same lower price. Society has the resources, which the new entrant would have commanded, to deploy elsewhere.

The prohibition against undue discrimination has traditionally been interpreted as prohibiting discrimination among customers simply because of the identity of the customer. We do not change that interpretation. Rather, the final rule is permitting differences in prices because of business factors, such as competitive circumstances. Hence a pipeline may not offer a discount to its affiliate simply because of the affiliation. This would be a violation of the prohibition against undue discrimination of §§ 284.8 and 284.9.

We do not believe, however, that it is appropriate to prohibit a pipeline from offering a discount to an affiliate. There may be valid, competitive reasons for a discount. Moreover, the rule we issue today provides adequate safeguards against this abuse. The pipeline must file the discount with us and the filing will be attached to the pipeline's rate schedule. See § 284.7(d)(5)(iv). Interested persons will have all the opportunities provided by the statute to challenge a discount given to an affiliate. In any such hearing, the discount would have to withstand the strict scrutiny, traditionally applied to affiliate transactions under Commission precedents.

Pipelines can undoubtedly attempt to use selective discounting in the way suggested. But the basic complaint in this situation is under the antitrust laws. *See United States v. Aluminum Company of America*, 148 F.2d 416 (2nd Cir. 1945). Our rule does not grant a pipeline immunity from the antitrust laws.[110] More important, these complaints are reviewable by the Commission under Section 5 of the NGA. *See FPC v. Conway Corp.*, 426 U.S. 271 (1976).

There may of course be situations where a short-term discount would be potentially effective in excluding entry. In that case, selective discounting might be alleged to adversely affect competition. If that can be shown, it can be scrutinized and prohibited on a case-by-case basis.

In short, the rule only provides that a discount offered because of competitive conditions is not unduly discriminatory.

F. Whether Selective Discounting in Transportation Rates May Forestall Price Adjustments in Field Markets

Comments. MPC also argues that selective discounting will adversely affect other customers by relieving competitive pressure on the wellhead price of gas. The argument can be illustrated by means of the example we used earlier to show the consequences of not permitting selective discounting. In the example, the price of residual fuel oil was $4.50, the well-head price of gas was $2.95, and the maximum transportation rate, $1.00. The price of residual fuel oil then dropped to $3.50. In the example the pipeline met the competition by reducing its transportation rate to $.50 so that the delivered price of gas was $3.45 MPC's argument is that, if selective discounting were not permitted the producer would have reduced its price to $2.45. Thus, selective discounting prevented the realignment of the well-head price to the current market price. The result is, MPC contends, that the pipeline's other customers will pay more for gas than they would if the pipeline had not discounted its rate.

Commission Response. This comment is premised on the view that the Commission is the best judge of how the net back value of gas at the city gate should be allocated as between regulated pipelines and unregulated producers. We decline to accept that premise.

Our responsibility here is to set just and reasonable rates for interstate transportation and to ensure that customers—*i.e.* shippers—are not subjected to undue disadvantage or unreasonable difference in rates.

We do not believe that a pipeline's ability to selectively discount to individual customers is likely to have an impact on the overall price levels for the commodity prevailing in the field.

But even if it did, we note that the wellhead market for gas has been determined to be sufficiently competitive to remove federal price controls on all new gas supplies.

Pennzoil v. FERC, supra. Under MPC's approach, one could argue that pipeline rates of return should be lowered to the bottom end of the range of reasonableness during periods of short supply in order to raise the net back to producers as an incentive, or that they should be raised to the maximum during periods of surplus to reduce the wellhead net back.

We do not accept the view that Congress had that sort of pipeline ratemaking in mind when it acted to remove the federal entry, exit and price controls over gas at the wellhead.

G. Whether Selective Discounting Encourages Inflated Rate Base

Comments. Maryland People's Counsel notes that because a pipeline's earnings depend on an accounting rate base, the pipeline has an incentive to inflate its rate base. Regulation generally does not constrain the pipeline from doing so, but competition does. MPC states that selective discounting removes this pressure by allowing the pipeline to reduce its rates where competition exists while continuing to charge inflated rates (because the rate base is inflated) to other customers.

Commission Response. The Commission has included in the final rule an express prohibition on a pipeline's recovering between or in rate cases any costs attributable to but not recovered from a customer charged a rate less than the maximum. The Commission intends this proscription to apply to indirect as well as direct cross-subsidization, such as the inflation of a rate base. To the extent inflation of a pipeline's rate base results in higher maximum rates prospectively, the pipeline faces increased risks that it must "absorb" the increment of fixed costs added to the difference between its former maximum rate and the selective discount rate.

H. Whether To Impose a Minimum Rate

Comments. Several pipelines argue that there should be no minimum on the transportation rates that may be charged.[111]

Commission Response. The Commission determines that to allow pipelines to provide service at a rate that does not even recover the variable costs of the service would be pure social waste. In addition, the minimum rate serves as a check on pipelines engaging in anti-competitive behavior.

I. Filing of Any Discount

In response to the comments identifying the potential for abuse, the Commission has also determined to require that every discount rate be filed with the Commission and attached to a pipeline's stated rate schedules no later than 45 days after the end of the billing period during which the discount rate is being charged. The final rule requires that this filing include the name of the transporter, the shipper, the corporate affiliation of each, the maximum rate and the rate charged. These requirements are set forth in § 284.7(d)(5)(iv) of the final rule.

(vii) Applicability to intrastate pipelines and grandfathering of existing transportation rates.

Comments. One commenter proposes that, if the Commission proceeds to impose the proposed rate conditions, they should apply only to future rate filings by intrastate pipelines for NGPA section 311 transportation. Because numerous section 311 transactions are ongoing at this time, this commenter asserts that calling all rates for such transactions into question would be unduly costly and disruptive.[112]

Transok, Inc. states that, should the new rules be made applicable to existing NGPA section 311 arrangements, intrastate pipelines may have to renegotiate existing contracts, re-file numerous reports, and re-petition for rate approval on all transactions. Since the underlying contracts for existing section 311 service did not contemplate the new conditions of the proposed rules, those contracts will have to be changed, creating an unduly burdensome task for pipelines. Transok believes that the Commission should not revise its regulations where such action will effectively force modifications of the terms and conditions of existing section 311(a)(2) transportation arrangements. Further, Transok points out the pipelines have relied on § 284.125 of the existing regulations, which provides that transportation arrangements may only be modified at the time of extension requests.

Transok alleges that it has in good faith entered into binding transportation arrangements in reliance upon the Commission's regulations which provide that approved transportation arrangements cannot be modified until expiration of the current term of the arrangement. In order to ease the transition to the requirements of the new rules and to allow the parties to realize their contractual expectations, Transok requests that the Commission grandfather existing arrangements to continue, in accordance with the conditions applicable at the time service began, until the current terms of such arrangements expire. The Commission, Transok suggests, could then provide that all renewals or extensions after the effective date of the proposed rules would be subject to the new terms and conditions. When an existing arrangement's term expires, the intrastate pipeline could determine whether it desires to re-commence the service under the new conditions.

Commission Response. The Commission has determined, for the reasons given by the commenters, that section 311 transportation arrangements commenced prior to the effective date of this rule by intrastate pipelines should be grandfathered so as to shield them for the remainder of their terms (but no later than October 31, 1987) from the non-discriminatory access condition adopted herein. This provision is contained in § 284.125 of the final rule. In addition, as discussed *supra*, the Commission has determined to exempt intrastate pipelines generally from the rate conditions.

Since the reasons given by intrastate pipelines for grandfathering their existing section 311 transportation from the access condition apply as well to such services already being provided by interstate pipelines, the Commission has determined that interstate pipelines' ongoing arrangements should also be grandfathered as to access, although not as to rates.

The final rule will allow existing section 311 transportation arrangements by both intra- and interstate pipelines to continue without becoming subject to the access condition until the expiration date of their original terms but no later than October 31, 1987. See §§ 284.105 and 284.125 of the final rule. In the great majority of instances, grandfathered section 311 transportation will end within two years of the effective date of this rule, since the current regulations limit section 311 transportation arrangements to two years, unless an application for authorization for a longer period had been approved by the Commission prior to the final rule.

After the effective date of the final rule, any continuation of currently existing section 311 transportation arrangements beyond their scheduled expiration dates shall be fully subject to all the rate, access, and other conditions adopted in the final rule.

All other self-implementing transportation under the final rule must be subject to rates on file at the Commission consistent with the rate conditions, to be effective no later than July 1, 1986. During the interim period between the November 1, 1985, expiration of the section 7 blanket transportation certificates pursuant to the court's mandate in *Maryland People's Counsel*, and July 1, 1986, a transporter may file and the Commission will authorize on an interim, temporary basis rates for self-implementing transportation that depart from these rate conditions, provided the rates are consistent with valid rates charged for such transportation prior to the final rule and provided the transportation is provided consistent with all other terms and conditions in this rule, including the non-discriminatory access condition. The provision governing interim rates for transportation are set forth in § 284.7(b) of the final rule.

The Commission intends this transition period to be available in order to provide pipelines and shippers a suitable time to flexibly plan and adapt their transportation rates in a phased and orderly fashion to conform to the conditions in the final rule.

In the case of intrastate pipelines, however, the Commission has revised the final rule to expressly exempt intrastate pipelines from the requirements that firm and interruptible transportation be offered under self-implementing authority. This exemption permits intrastate pipelines to choose what types of service to offer under section 311 transportation in order to protect their strictly intrastate operations.

The final rule retains the option for intrastate pipeline rates either to be filed at the Commission or to be on file at the relevant State regulatory agency with authority over the intrastate pipeline, provided such rates are consistent with these rate conditions in the existing regulations and thus "fair and equitable" consistent with section 311 of the NGPA.

For all these reasons, the Commission concludes that the rate conditions in the final rule are reasonable and necessary standards that should be applied to self-implementing transportation services.

11. *Flexibility of self-implementing transportation.* In consolidating the existing transportation programs under both section 7 of the NGA and section 311 of the NPGA, the Commission intends to provide pipelines increased flexibility to offer self-implementing transportation services. This flexibility should enable pipelines to tailor their services to the individual and varied needs of gas customers and in turn allow both gas customers and gas merchants the ability to transact business on a timely and competitive basis. At the same time the final rule preserves the ability of the Commission to regulate the rates charged for both pipeline sales and transportation services consistent with its statutory obligations under the NGA and NGPA.

Finally, the final rules seek generally to remove any bias against unbundled transportation that may be created by the existing ratemaking framework.

The proposed rule simplified and consolidated self-implementing transportation programs in a number of ways in order to accomplish this goal. The final rule generally tracks the proposal in these areas.

For example, the final rule eliminates restrictions on what categories of gas, what classes of shippers, and what end-uses are eligible for self-implementing transportation services under either section 7 of the NGA or section 311 of the NGPA. In order to place local distribution companies on an equal footing with pipelines in providing transportation services to direct endusers, the final rule eliminates the "system supply" test applicable to section 311 transportation. See section 284.102. The rule instead incorporates the statutory requirement that such transportation be "on behalf of" the intrastate pipeline or LDC.

The final rule also provides pipelines with flexibility to change receipts or deliveries of gas at already authorized points without prior notice. See, for example, § 284.221 (g) and (h).

Finally, the final rule simplifies application procedures, deletes restrictions on the term or duration of transportation arrangements, and provides for "grandfathering" certain existing transportation arrangements for a suitable transition period after the effective date of the final rule. Reporting requirements are also reduced.

The final rule retains the prior notice and protest procedures under the blanket certificates for new individual transactions. These protections assure that the Commission's responsibility to review pipeline transportation programs and determine whether they are in the public interest is carried out in a manner that also enables pipelines to flexibly respond to transportation requests.

Specific comments in these issues are discussed in more detail below.

a. Flexible Receipt and Delivery Points

Comments. A number of commenters address the proposal to permit flexibility in receipt and delivery points. Briefly stated, under sections 157.103 (g) and (h) and sections 284.221 (g) and (h) a pipeline may, at the request of the shipper and without prior notice, reduce or discontinue, or commence or increase, receipts or deliveries of natural gas at a particular point and may commence or increase receipts or deliveries at another point.

A number of commenters support this proposal but request modifications.[113]

Several commenters state that these sections provide the pipeline with too much discretion and create the potential for discriminatory treatment. They suggest requiring pipelines to make changes in receipt or delivery points at the request of the shipper where sufficient capacity exists on the system. They state that without the assurance of flexible delivery points, they will be "locked in" to specific delivery points where only one or a few sellers have gas available. They also fear that since the authority is permissive, some pipelines may discriminate against some shippers by refusing to construct minor facilities, such as "taps" needed to receive the gas the shipper needs transported.[114] At least one commenter suggests that pipelines should be required to construct certain types of minor facilities if the shipper requests transportation.[115]

One distribution company suggests that the regulations be amended to provide that a delivery point can be used only for the purpose specified in the blanket certificate application and as authorized after the notice and protest procedures. Without such an amendment, they are concerned that there would be no future review of the facility once it was authorized.

Some commenters request clarification as to whether the construction of new delivery points is authorized under section 284.221 or whether this section applies only to to the decrease or increase of deliveries at existing delivery points. Some commenters state that pipelines must have the authority to establish new delivery points to transportation customers, as well as flexible authority to establish new sales points for existing customers, provided the deliveries at these points do not exceed the pipeline's authorized delivery quantities. They state that this authorization is necessary if all parties are to be treated equally.[116]

Commission Response. As proposed, pipelines that transport gas under the transportation provisions will be subject to the non-discriminatory access condition. The Commission intends for this provision to prevent pipelines from discriminating against any shipper in constructing minor facilities to either accept or deliver those supplies. While we recognize that it is difficult to define precisely what type of activity or refusal would fall within the ambit of this provision, and while there is no per se requirement to construct any facilities to perform self-implementing transportation, a discriminating refusal to construct minor facilities to the undue advantage or disadvantage of a shipper would be suspect. As noted, the final rule does not require pipelines to construct any facilities. However, the Commission has broad remedial powers to enforce valid regulations. Hence, a discriminatory application of a policy regarding the construction of such minor facilities might well be found to be a violation of the terms and conditions of the self-implementing authorization. The Commission need not determine at this time whether a requirement to construct facilities might be an appropriate remedy in such a case. See discussion in section IV.A.4.f., *supra*.

We note that there is no regulatory barrier to the pipeline constructing minor facilities since their construction is automatically authorized under the current blanket certificate regulations. Moreover, where the pipeline does construct such facilities, generally there is little cost, if any, to the pipeline since the beneficiary of those facilities (*e.g.*, the shipper) usually reimburses the pipeline for its costs.

We agree that once a facility is constructed under the blanket certificate procedures for a specific purpose, the facility must be used only for the certificated purpose. If the facility is to be used for a new purpose, the pipeline should file a new prior notice application setting forth the new proposed use. This is consistent with the rule, in which authorization to construct and *operate* a sales tap is subject to the prior notice procedure. This approach will ensure that existing facilities built for one purpose will not be used for a new purpose which could by-pass an LDC or have adverse consequences on some party without an opportunity for notice and protest. This requirement is implicit in the existing prior notice provisions of §§157.205 and 157.211. No substantive changes are made in these provisions in the final rule.

By way of clarification, the final rule merely authorizes decrease or increase at receipt or delivery points. These sections do not authorize the construction of new delivery points necessary to effectuate those changes. Some of these facilities may, however, be constructed and operated under the blanket certificate authority in Subpart F of Part 157. Alternatively, an applicant may use the optional expedited procedures implemented by this rule or a traditional section 7 application.

With respect to pipelines' establishing new delivery points to transportation customers and new sales points for existing customers, we note that pipelines will have this authority under the final rule. Thus, pipelines may construct and operate sales taps to deliver gas to end-users who are or will be served directly or indirectly by the certificate holder's system supply provided the volumes are within the certificated entitlements of the customer. Under current regulations, certificate holders may add new delivery points for a customer or reassign volumes of gas to be delivered from one point to another. The combination of these two provisions, both of which are subject to the prior notice procedure, should provide pipelines sufficient authority and flexibility to meet the needs of their transportation and sales customers.

For clarification, by certificated volumes we mean volumes that are authorized by the applicant's certificate. Since the certificate authorizing service to a customer sets forth specific volumes or entitlements to that customer, any reassignment of volumes must not exceed those certification volumes.

Comments. The NOPR noted that in light of recent orders, the Commission sought comments on the "role and function" of existing §284.3(c) "including the impact on the Commission's jurisdiction and how facilities constructed under section 311 may be used in the future."

That provision, which the May 30 notice did not propose to modify, states that facilities used solely for transportation authorized by section 311(a) of the NGPA are not subject to NGA jurisdiction. Few comments were received in response to the Commission's request.[117]

Some of the commenters, including UGI, urged the Commission to leave this regulation unaltered on the grounds that the current provision promotes competition among pipelines. UGI states that it supports the Commission's recent decisions in *Columbia Gas Transmission Corporation* v. *Transcontinental Gas Pipeline Corp.*, 30 FERC ¶ 61,298 (1985) (dismissing a complaint by Columbia regarding the construction of section 311 facilities by another pipeline to serve one of Columbia's customers), and *Columbia Gas Transmission Corp.* v. *Consolidated Gas Transmission Corp.*, 31 FERC ¶ 61,057 (1985) (same). UGI believes these decisions uphold the intent and purpose of the NGPA and, therefore, that section 284.3(c) should not be altered.

Commission Response. The Commission has determined not to propose any change in the regulation. We believe this decision is appropriate because the current provision carries out the mandate of the NGPA by encouraging pipelines to engage in section 311 transportation and by assuring them that the facilities they construct to provide section 311 transportation will not become subject to the Commission's jurisdiction under the NGA. By encouraging pipelines to transport for others, the existing exemption promotes access to the commodity market by otherwise "captive" customers that may be able to acquire access to alternative transporters as well as merchants.

Also, the Commission believes that the regulation is consistent with the language and goals of NGPA sections 311(a) and 601(a)(2) because it shields from NGA jurisdiction only those facilities that are used solely for section 311 transportation.

b. Whether To Retain the "System-Supply" Requirement

Under current regulations, transportation under Part 284 is limited to gas delivered directly to an interstate pipeline, intrastate pipeline, or local distribution company that receives the gas for its "system supply for resale". The Commission proposed to eliminate this system supply test, but also noted that the transportation must still, as required by section 311 of the NGPA, be "on behalf of" the pipeline or local distribution company.

Comments. Virtually all commenters support elimination of the system supply requirement, stating that it is no longer needed in today's market. They asserted that the "system-supply" test is inconsistent with the goal of providing self-implementing transporters the maximum flexibility to provide services to all natural gas consumers for all end-uses, regardless of the status of the shipper.[118] Many commenters in the NOI and this proposed rule also stated that the "system-supply" requirement places LDCs at a unique disadvantage in obtaining transportation service in competition with pipelines serving industrial end-user shippers directly under section 7 blanket certificates.[119]

Several commenters also agree that the "on behalf of" test is a statutory test that cannot be eliminated. They believe, however, that the Commission's interpretation is too narrow. They state that the NOPR implies that the entity on whose behalf the transportation is performed must either actually take title to the gas during transportation or have a direct contractual relationship with the transporting party. They suggest that this interpretation is too narrow and that the test would be satisfied so long as the entity on whose behalf the transportation is performed receives some tangible benefit associated with the transaction, such as ultimate receipt of the gas or assistance in fulfilling a contractual obligation related to section 311 transportation.[120]

Commission Response. The final rule eliminates the "system-supply" requirement. Instead section 284.103 provides that the transportation must be "on behalf of" an intrastate pipeline or local distribution company. With regard to the meaning of the "on behalf of" requirement, we reiterate what was said in the NOPR:

> However, as we discussed in Order No. 46, which implemented section 311, this test is a legal test, not a physical test, and only requires some nexus between the transporter and the intrastate pipeline or local distribution company. Thus, the intrastate pipeline or local distribution company need not physically receive the gas, but need only have the gas transported for its account.

(NOPR, *mimeo*, at pp. 57–58) (footnote omitted).

By commenting on the "on behalf of" test, we did not intend to alter the current application of that test as it was more fully explained in Order No. 46.[121] This rule does not change our interpretation of the "on behalf of" requirement which will continue to be applied as it has been applied in the past.

c. Whether to Retain Separate Criteria for "High Priority" end-Users

Under current regulations, interstate pipelines with a blanket certificate are authorized to transport gas on behalf of "high priority" end-users, subject to certain restrictions. Such transportation is automatically authorized for a period of up to five years, if the gas was purchased from certain eligible sellers or for a period equal to the life of the reserves up to a maximum of ten years provided the end-user owns and developed those reserves.[122] The May 30th notice proposed to eliminate special treatment for these end-users and place all potential shippers on an equal footing.

Comments. Some commenters express concern that this provision would be eliminated and that transportation to these end-users would be subject to a prior notice procedure in which alternative suppliers or competitors of the end-user could protest the transportation. They state that once their current self-implementing authorization for transportation expires, high-priority end-users will be unable to continue to make direct purchases of gas if a pipeline refuses to offer transportation service. They contend that this will result in a significant decrease in regulatory flexibility for high-priority users as well as severe hardship on high priority end-users that rely on those transportation services.[123]

Commission Response. As proposed and implemented in the final rule, transportation for high priority users that has been authorized under § 157.209(a) is "grandfathered", *i.e.*, authorized to continue for the term of the transportation arrangement subject to the terms and conditions at the time it was authorized. See § 284.223(g) of the final rule.

New transportation arrangements to high-priority users, however, will be subject to the same procedures as for all other end-users. As we said with regard to the determination not to condition producer access, if we are to have a framework for equal and non-discriminatory access to transportation, all shippers must be treated equally.

We also note that the final rule eliminates a number of restrictions that currently apply to transportation for such users. Thus, there are no longer restrictions as to the type of gas the high priority end-user may purchase and from whom the gas may be purchased. Eliminating the restrictions on sources of supply will increase the pool of supplies available to high priority users and all other users. Moreover, the final rule establishes the new rate structure and the non-discriminatory access condition for self-implementing transportation. Accordingly, there is no need to retain special procedures for a limited group of shippers.

d. *Self-Implementing, 120-Day Transportation Authorization*

Section 284.223(a) automatically authorizes transportation to any end-user for a period of 120 days. During that period of time, the certificate holder must make a prior notice filing if the transaction is to continue beyond 120 days.

Comments. Many commenters state that the 120 day period is too short and should be either extended, or alternatively, authorized on a self-implementing basis without any prior notice procedure. Under current procedures, they state there is a risk that the 120 day period will expire or a protest will be filed and the transportation will be interrupted. A better approach, according to some commenters, is to permit the arrangement to extend for the period of the transportation contract without any prior notice procedure or to permit such transportation for at least six months, or possibly five years.[124]

Several commenters request clarification of proposed § 284.223(a)(3). That section authorized additional 120 day transportation terms provided that (i) the gas is transported by the same pipeline for the same shipper, and (ii) the transportation arrangement between that shipper and transporter was authorized under the prior notice procedure. They state that the prior notice procedure merely appears to authorize successive 120 day roll-over periods.

One commenter suggests that the 120 day limitation is discriminatory since transportation under NGPA section 311 is not subject to similar restrictions. Thus it argues that shippers who do not meet the "on behalf of" test under section 311, or, for other reasons, do not have section 311 transportation available to them, are subject to possible delay or interruption when their self-implementing authorization expires. It urges that the self-implementing authorization be permitted for an unlimited time period to eliminate this discrimination.[125]

Commission Response. We disagree with the suggestion to extend automatic authorization for a period equal to the duration of the contract or for periods longer than 120 days. Since implementation of the blanket certificate transportation program, pipelines have been transporting gas under the prior notice procedures in section 157.209(e). It is our experience that these procedures have been successful in achieving their purpose—to move gas quickly to a ready market while interested parties are provided the opportunity to protest.

Under section 7 of the NGA, pursuant to which the blanket certificate rule is promulgated, we have an obligation to issue certificates only where they are required by the public convenience and necessity. The blanket certificate rules set out a class of transactions, subject to specific conditions, that the Commission has determined to be in the public convenience and necessity. Experience since August of 1983 indicates that the transactions are infrequently protested, but that the protest procedure ensures the integrity of the regulatory function mandated by statute. Accordingly, the final rule retains in § 284.223 the prior notice approach for all transportation beyond 120-days. If experience under the new transportation rules demonstrates that prior notice filings for these transactions serve no useful function, the Commission may entertain petitions to modify the rules accordingly.

We wish to clarify the confusion as to the operation of proposed § 284.223(a)(3). That section was intended to prevent parties from using successive 120 day transportation arrangements to circumvent the prior notice procedures. Accordingly, it has been retained, but will be § 284.223(a)(2) in the final rule. It permits a successive 120 day transportation period between the same shipper and same transporting pipeline only if the previous transportation arrangement was approved under the prior notice procedures in § 157.205. For example, a shipper and pipeline may commence a 120-day transportation arrangement for a contract period of 18 months and satisfy the prior notice procedures for that arrangement. Several months after the 18 month contract expires, the same shipper and pipeline may wish to enter into another transportation arrangement. Since the prior arrangement was approved under the prior notice procedures, § 284.223(a)(2) would authorize that same shipper and pipeline to commence transporting for a new 120-day automatic authorization period, during which time they could file a prior notice application for their new arrangement. If their previous prior notice application for the 18 month contract was not approved, § 284.223(a)(2) would prohibit the second 120-day automatic authorization period. Thus, the effect and intent of this section is to prohibit the same shipper and pipeline from commencing a new 120-day automatic authorization arrangement if their previous transportation arrangement was not approved under the prior notice procedures.

We agree that the conditions for transportation under § 284.223 are different from those which apply to transportation under section 311 of the NGPA. However, this is in part because the statutory tests are different. Unlike § 284.223 transportation, section 311 transportation does not require a determination as to the public convenience and necessity. In addition, transportation is subject to the statutory "on behalf of" test. As discussed in more detail elsewhere, such transportation does not raise the same concern for bypass of an LDC since normally the transportation will be "on behalf of" the affected LDC. However, since no such test applies to § 284.223 transportation, it is necessary to limit the period of self-implementing authorization in order to minimize any harm and to provide a notice and protest period during which affected persons can raise their objections.

e. The "Grandfathering" of Existing Self-Implementing Transportation

Comments: With respect to transportation under current §157.209 (a) and (e), pipelines are authorized to perform transportation for certain end-users under certain conditions. Several commenters suggest that it appears from the proposed rule that transportation arrangements under §157.209(a) would be allowed to expire after the term of their authorization, which may be five or ten years, depending on the terms, and that arrangements under §157.209(e) would expire as of October 31, 1985. They request clarification on whether or not this was the Commission's intent.[126]

Commission Response. As discussed in more detail above, transportation under existing §157.209 (a) and (b)(1) would be permitted to continue under the terms and conditions of the applicable transportation authorization. Section 284.223(a)(2) of the May 30th proposed rule was intended to grandfather the remaining transportation terms that were commenced under the authority in §157.209(e) that are continuing as of November 1, 1985. Since the proposed rule was issued on May 30, 1985, however, the U.S. Court of Appeals for the D.C. Circuit has ordered that no further extensions of that program will be permitted. *Maryland People's Counsel* v. *FERC*, No. 84–1090 (issued June 28, 1985). Thus, except as provided below, all transportation under current §157.209(e) must cease as of November 1, 1985.

However, the Commission is concerned that end-users who presently rely on supplies transported under that section ought not to have service interrupted where the pipeline is prepared to operate under the new self-implementing rules. See §284.223(g).

First, under paragraph (g)(1) of §284.223, transactions that were previously certificated under Order No. 319 for a term extending beyond October 31, 1985 are allowed to continue on the same terms and conditions originally certificated; *i.e.*, the certificate holder can fulfill its existing certificate obligations without becoming subject to the access conditions contained in §§284.8 and 284.9. The rate conditions under §284.7 (including the provision for interim rates) will apply effective November 1, 1985, however.

Paragraphs (g)(2) and (g)(3) of §284.223 provide a *brief* transitional arrangement for ongoing transportation under the Order No. 234–B program which must otherwise halt on October 31, 1985. The section provides that the transportation may continue to November 1, 1985 if several conditions are met. Most important is the condition that the transporting pipeline must file, prior to November 1, 1985, a statement that it will, effective November 1, 1985, comply with the express non-discriminatory access condition spelled out in §§284.8(b) and 284.9(b) and with the rate conditions in §284.7. Paragraph (g)(3)(ii) makes it clear that transportation under the transitional rule is subject to the non-discrimination and rate conditions of the final rule.

The remaining provisions allow for continuous authorization so long as the notice and protest procedure has been followed or where the transaction is within a 120-day automatic authorization period that has not expired.

The authorization under paragraph §284.223(g)(2) ends on December 15, 1985 unless the pipeline has filed for a new blanket certificate prior to that date.

To facilitate the transition, the final rule allows the use of existing rates for an interim period. Thus, during the interim period, the transporting pipeline should charge its generally applicable tariff rate already in use for transportation under existing §157.209. Rates conforming to the new rate standard must, however, be filed to be effective July 1, 1986.

f. Filings by Shippers on Behalf of Pipelines

Comments. The NOPR proposed to permit an end-user (or its authorized agent) to make filings on behalf of the pipeline certificate holder.[127] Many commenters (mostly pipelines) object to this proposal.[128] They argue that the authority to make filings resides solely with the interstate pipeline, and that only pipelines can adequately make a determination of available capacity and complete an application in a timely and accurate manner.

Commission Response. Although the Commission believes it has the authority to permit an end-user to file on behalf of a pipeline certificate holder, we have decided not to adopt this proposal.

The proposal only has practical value where the pipeline is not as interested in selling transportation service as the shipper is in purchasing it. Under the rules adopted today, a pipeline that decides to operate under the self-implementing rules will be operating under rates and conditions which contemplate that a pipeline that moves more gas and moves it more efficiently will increase its revenues. Under these circumstances only confusion could result from allowing filings by the shipper on the behalf of the pipeline. If a potential shipper believes it is being discriminated against unduly, it may file a complaint against the pipeline, not a prior notice request on its behalf.

g. Notice and Protest Procedures

Comments. Under the current and proposed procedures, many transactions are subject to the notice and protest procedure in §157.205 by which interested parties are provided an opportunity to protest an on-going or proposed activity. Some commenters suggest that these procedures are no longer necessary and suggest they be eliminated or significantly modified. They contend that elimination of these procedures will promote pro-competitive free-market forces and enhance competition. Alternatively, one commenter suggests establishing a complaint procedure by which a party objecting to a transaction could file a complaint protesting the activity. The protesting party would be required to set forth its reasons with specificity in its complaint. It suggests that the activity would be allowed to continue, pending resolution of the complaint.[129]

Commission Response. We believe the notice and protest procedure remains an important procedure in the scope of the new program, at least for the present. While some activities are automatically authorized, such as the 120 day transportation authorization, other activities potentially could adversely affect interested parties. The notice and protest procedure serves as an effective mechanism for those parties to receive notice of the activity and to protect their interests. As noted above, it is our experience that very few activities are interrupted or delayed because a protestor has not withdrawn its protest. For those that are not withdrawn, the concerns raised by the protest must be addressed. Given the success with which this procedure has worked under the blanket certificate program, we choose to neither eliminate it nor change it.

Comment. Under proposed §284.221(g), interstate pipelines may reduce or discontinue, or commence or increase, receipts at certain receipt points without prior notice. Similarly, under proposed §284.221(h), interstate pipelines may reduce or discontinue, or commence or increase, deliveries at certain delivery points. However, in either case, the total amount of gas affected by these arrangements would not be allowed to exceed the total volume authorized under the certificate. Some commenters suggest that these sections include increases beyond certificated volumes without any prior notice requirement. They claim this will add flexibility to the market and permit timely execution of business opportunities. Alternatively they suggest a notice of increased volumes could be sent to the Commission after the arrangement is executed.[130]

Commission Response. We think it would be inappropriate to permit increases beyond certificated volumes without some procedure to permit interested parties to intervene or this Commission to review the consequences of the increase. An increase in deliveries beyond certificated volumes requires a new finding as to the public convenience and necessity under section 7(c) of the Natural Gas Act. Without some procedure to give notice of that increase and to review the impact of the increase, it would be difficult for the Commission to justify a finding that the increase meets the statutory criteria or for affected parties to intervene to protect their interests. Therefore we decline to implement this suggestion.

h. Traditional section 7 applications

Comment. A few commenters question the priority that will be given to traditional section 7 applications assuming the other procedures in Part 284 and Part 157 are implemented. Since those procedures are optional, they request clarification as to whether the Commission intends to act promptly on those transactions that are not subject to those procedures.[131]

Commission Response. The Commission believes that the concerns of the commenters are unfounded. To the extent that some traditional section 7 transactions may now qualify under the self-implementing rules or the new optional procedures, the number of section 7 applications will decrease. As for the remaining section 7 applications, the Commission will continue to process these and all applications it receives in the same manner as they were processed before the adoption of this final rule.

6. *Reporting Requirements.* The proposed rule sets forth a number of reporting requirements and requests comments on how those requirements should be modified to eliminate unnecessary filings. Many commenters support the proposed changes but also suggest that the reporting requirements be reduced to the minimum necessary to assure that pipelines are not engaged in discriminatory transportation.[132]

a. Section 311 report requirements

(i) 48-hour report.

Comment. The notice proposed to eliminate the 48-hour telegram report required by §284.4(b) for interstate pipelines engaging in section 311 transportation. One commenter states that this requirement should not be eliminated since it requires the pipeline to choose whether the transportation is performed under section 311 of the NGPA or section 7(c) of the NGA.[133] Other commenters support the elimination since the information was redundant and unnecessary.[134]

Commission Response. The Commission's experience with the 48-hour report indicates that this requirement is unnecessary. The information normally included in that report is contained in the reports submitted pursuant to the other reporting requirements in §284.106 and 284.126. Therefore, this requirement will be deleted.

(ii) Initial full reports

Comment. Sections 284.106(a) and 284.126(a) require the pipeline to file an initial full report within 30 days after commencing transportation under these sections. One interstate pipeline states that it is administratively difficult to file initial full reports within 30 days after commencing blanket certificate transportation and that this time period should be extended or the report eliminated since the final report contains the same information.[135]

Commission Response. This suggestion is not adopted in the final rule. We think it is reasonable to require initial full reports within 30 days of commencing the transportation arrangement. This requirement has been in effect since these transportation programs were implemented and pipelines do not appear to have encountered any serious difficulty in meeting this deadline. Moreover, since we are eliminating the 48-hour report and final report, the only notice of the transportation arrangement will be receipt of the initial report. Therefore, it is important that this report be received on a timely basis.

(iii) Subsequent and final reports.

Comment. Proposed §§ 284.106(b) and 284.126(b) require the pipeline to file a subsequent report within 30 days of any significant changes with respect to the initial full report. Sections 284.106(d) and 284.126(d) require the filing of a final report within 30 days after terminating a transaction authorized under those sections.

One commenter suggests eliminating the subsequent and final reports and incorporating that information into the annual report.[136] Several commenters suggest modifying Form 2 to include this information and thereby eliminate these reporting requirements.[137] Another commenter suggests eliminating § 284.106(d)(3) requiring a statement on treatment of revenues since the option to credit Account No. 191 has been eliminated.[138]

Commission Response. The Commission agrees that the final report required by proposed §§ 284.106(d) and 284.126(d) is unnecessary and should be deleted. Since the information set forth in the final report would already have been filed, in part, in the initial full report, this information will ultimately be available. However, the Commission does need to know when the transportation arrangement has terminated. This information was previously required in the final report which has now been eliminated. Therefore, §§ 284.106(d) and 284.126(d) are amended to require the pipeline to file a notification of termination stating the termination date, the total volumes transported and the revenues received. The notice may be a simple one page notice or telegram.

The Commission is retaining the subsequent report required by §§ 284.106(b) and 284.126(b) because it is necessary to know if any significant changes have been made since the filing of the initial full report. Since the Commission is eliminating the final report, the subsequent report is the only remaining vehicle to notify the Commission of any changes in a timely manner.

With respect to several commenters' suggestion that the subsequent and final reports be eliminated and that the information called for therein be incorporated into Form 2, the Commission believes its decision to eliminate the final report should substantially reduce any redundancy that may exist between the proposed filings and the Form 2 information. The Commission, however, intends to review Form 2 and make any modifications or deletions to that form and the remaining section 311 reports as appropriate to further minimize duplicative reporting requirements.

(iv) Annual report.

Comments. Sections 284.106(c) and 284.126(c) require the pipeline to file an annual report by March 1 for transportation provided during the preceding calendar year.

One intrastate pipeline requests that changes in receipt and delivery points be eliminated from the annual report. One local distribution company suggests that interstate pipelines be required to include in their annual report volumes transported, revenues received, and mileage, by month, for sales and transportation customers. Another local distribution company suggests that the reports in § 284.106 (c)(2) and (d)(3) should set forth the maximum revenue chargeable under the tariffs. Another commenter states that § 284.106(a)(1)(v) (A) through (D), requiring rate information, can be eliminated if interstate pipelines are required to file tariffs. Finally one interstate pipeline requests clarification as to whether the annual report requirement in § 284.106(c) on total volumes and revenues applies to each agreement authorized under § 284.102 or to all transportation volumes transported under that authority.[139]

They also request that a copy of any report filed with the Commission also be filed with the state regulatory commission. One commenter states that it is not feasible to file the annual report by March 1 and that the Commission should set the due date at May 1, the same date for submitting blanket certificate annual reports.[140]

Commission Response. We agree with the commenters that the information on changes in receipt and delivery points is not necessary. The final rule reflects this deletion. In contrast, we do not agree that volumes transported and revenues received should be reported on a monthly basis. Since we are requiring the information be reported for each docketed transaction, we believe it would be excessively burdensome also to require the information on a monthly basis. Similarly, the Commission does not see any need for pipelines to report the maximum chargeable revenue in their annual reports and therefore is not requiring this information.

The Commission agrees, however, that the statement in proposed § 284.106(d)(3) regarding the treatment of revenues, depending on whether a pipeline establishes representative volume or revenue levels, can be eliminated from the annual report since under the revised regulations all pipelines must establish projected levels, and, therefore, there no longer will be an option to credit Account No. 191.

We also agree with the commenter suggesting that proposed § 284.106 (a)(3)(v) (A) through (D), which require certain rate information to be filed with the initial report, can be eliminated. While the regulations have previously permitted interstate pipelines to commence section 311 transportation prior to filing rates for such service, § 284.7 requires interstate pipelines to have tariffs on file that conform with the conditions set forth in § 284.7 prior to commencing section 311 transportation. Since the regulations pertaining to the filing of rates require the information that would be required under proposed § 284.106(a)(3)(v) (A) through (D), these latter reporting requirements have been eliminated.

In addition, again because § 284.7 will require for the first time that interstate pipelines file rates prior to commencing section 311 transportation services, pipelines will no longer be able to utilize the rate election options set forth in § 284.103(c), and those provisions, therefore, are also deleted. Finally, new §§ 284.106(c) and 284.126(c) require that information be provided for each docketed transportation service provided during the previous calendar year.

The Commission also agrees that extension of the filing date for annual reports from March 1 to May 1 will permit the Commission to fulfil its regulatory responsibilities in a timely fashion. It will also give pipelines sufficient time to compile the necessary information. Furthermore, it will ensure the reporting of accurate information based on actual data. The May 1 date is reflected in §§ 284.106(c) and 284.126(c) of the final rule. Thus, the annual report will include only a docket by docket reporting of volumes and revenues.

b. Section 7 Blanket Certificate Filing and Reporting Requirements

(i) Prior notice application.

Comments. Section 284.221(c) sets forth the filing requirements for a prior notice application. One local distribution company requests that § 284.223(c) require the applicant to set forth the commencement and expiration dates of the proposed transportation, since the information is necessary to determine whether to file a protest.[141] One state commission suggests that the Commission retain the requirement that copies of the gas purchase contract with the seller be provided and that the proposed end-use of the gas be provided.[142]

Commission Response. The Commission believes this information is unnecessary. The notice of the transaction sets forth the information contained in the application. If a party wishes more information, it may review the application on file with the Commission. Further, we are not requiring the purchase contract or proposed end-use to be filed with the Commission. Since there are no restrictions on end-use of the gas and market demand will allocate gas supplies, there is little or no need for end-use information. In addition, we do not believe the purchase contract provides any useful information not already provided in the application requirements.

(ii) Initial reports.

Comments. Proposed § 284.223(e)(1) required the filing of an initial report for transportation authorized under this section within 30 days after commencing the transportation.

Several commenters suggest changing these requirements.[143] Section 284.223(c) set forth the filing requirements that a prior notice application would contain under § 284.221 transportation. One intrastate pipeline states that information required in the initial report pursuant to § 284.223(e)(1) (i), (iii), and (iv) is identical to information filed in prior notice applications in § 284.221 and, therefore, should be eliminated if an initial report has been filed. They state that there is no need to require: (1) An initial report within thirty days after commencing the 120-day automatically authorized transportation period under § 284.223(a) if a request for authorization under § 284.223(b) to transport for a period longer than 120 days is ultimately approved under § 157.205(g); (2) another initial report thirty days after (a) expiration of the forty-five day prior notice period to allow opportunity for protests to request for authorization under § 284.223(b) to transport for periods longer than 120 days, or (b) all timely protests are withdrawn, whichever occurs first. Another interstate pipeline requests elimination of the price paid by the end-user in the initial report (§ 284.223(e)(1)(vi)) since the pipeline may not have this information.

Commission Response. The Commission agrees that there is no need to file an initial report for transportation arrangements which have commenced under the prior notice procedure since information on those arrangements has already been submitted under that procedure. Therefore, § 284.223(f)(1) is amended to require initial reports within 30 days after commencing self-implementing transportation under § 284.223(a) only. Due to other changes in the rule, this provision is now paragraph (f)(1) rather than (e)(1). Finally, the information required by § 284.223(f)(1)(vi) in the initial full report relating to the price paid has been deleted.

(iii) Annual report.

Comments. Proposed § 284.223(e)(2) required the interstate pipeline to file an annual report by March 1 setting forth the information about transportation performed under this section during the preceding year.

One interstate pipeline suggests eliminating the total cost and completion dates for facilities in § 284.221 (g) and (h). However, they state that it is not possible to report the increases or decreases at those points, since no specific volume is assigned to a particular receipt or delivery point under the agreement.[144]

Commission Response. The Commission agrees that it is unnecessary to require pipelines to state in their annual report information regarding the construction of facilities to effectuate the transportation. This information is already contained in the filings required by Subpart F of Part 157 under which those facilities are constructed.

We also agree that it is not relevant to report increases or decreases at particular receipt or delivery points. Therefore, this requirement in proposed § 284.223(e)(1)(iv) is deleted in the final rule. For consistency, we are also changing the deadline for filing the report from March 1 to May 1.

c. Format for Reporting Requirements

Finally, in order that the information be reported in the same format, the Commission is issuing instructions for filing the self-implementing reports. As the format does not alter any of the filing requirements, but merely prescribes a uniform format by which the information should be submitted to the Commission, it is also being promulgated today. The instructions for filing these reports as well as the specified format are set out in new § 250.15.

B. Take-or-Pay Buy-Outs and Producer Abandonment

1. *Overview.* In Part B of the NOPR, the Commission proposed to offer pipelines a rebuttable "safe harbor" presumption of prudence for certain one-time payments made to extinguish all minimum payment or purchase obligations in certain qualifying contracts. The proposal was intended to help pipelines address take-or-pay obligations in so-called "problem contracts." The Commission proposed that this method of handling take-or-pay payments be available only to pipelines that offer transportation on a non-discriminatory basis. The Commission proposed definitions of qualifying contracts and payments, accounting and cost recovery procedures, and filing requirements. The Commission also proposed to amend § 2.76 of its regulations,[1] which called for a case-by-case resolution of recovery of take-or-pay payments.

The majority of commenters express great dissatisfaction with or reservations about the safe harbor presumption. Very few express support without proposing some modification. Many commenters object to the overall theory of the proposal as well as to its specific requirements. We are persuaded that an attempt to impose a regulatory solution at this time may actually aggravate the situation rather than improve it. Accordingly, we are persuaded by the comments that the prudent approach regarding take-or-pay buyouts is to retain the April 10, 1985 Statement of Policy and Interpretive Rule. We have also determined to establish additional procedural rules to be codified in a new § 2.77 to provide for expedited consideration of producer abandonment applications under the present substantive criteria.

2. *Summary of comments.*—a. General. The interstate pipelines generally believe the proposal is unworkable or inadequate, or will exacerbate the take-or-pay situation. They say financing these amounts will be difficult, and together with denial of carrying costs or return, pipelines' income will be affected. Pipelines point out that they have substantial take-or-pay exposure under large numbers of contracts, and it is doubtful that producers will agree to a buy-out of such large obligations for a modest percentage. Many pipelines believe it is likely that producers will hold out for the maximum obtainable in qualifying payments, thereby leaving large liabilities under remaining qualifying contracts to be recovered on a case-by-case basis anyway.[2]

Various producers state the proposal will cause problems with, *inter alia,* financing, cash flow, drainage, cancellation of leases should wells not produce in "paying quantities", state proration requirements, and royalty payments.[3] Several producers argue that without take-or-pay provisions, gas wells become, in effect, gas storage fields for pipelines. The producer cannot sell the gas since the pipeline holds the contract right to it, yet the pipeline has no obligation to take gas. According to one producer, the proposal is bad for producers as they receive some unknown percentage of a speculative unrecoupable obligation covering only two years of a contract.[4]

Distributors and customers were also generally lukewarm about the proposal, expressing opinions ranging from flat opposition to any safe harbor arrangement, to urging the Commission to encourage existing negotiation. A distributor association believes the rule will probably increase total take-or-pay liabilities, and the proposed safe harbor formula will encourage producers to demand greater buy-out amounts.[5]

According to one state commission, the Commission has not demonstrated either that a "safe harbor" is needed or that it will not cause more problems than it cures. The state commission says pipelines are now renegotiating take-or-pay, often for pennies on the dollar, and, by presuming prudent set percentages, the Commission may actually raise buy-out costs and hinder the restructuring of the industry.[6]

Another state commission references an offer of settlement made by Northern Natural Gas Company, a Division of HNG-InterNorth, in which Northern proposed a permanent tariff permitting any distributor on its system to convert sales into transportation service. The state commission notes that Northern's proposal is not conditioned on the availability of safe harbor or other NOPR incentives, the costs of which would be borne primarily by a pipeline's captive customers. It believes the simple fact that the proposal exists demonstrates that the NOPR incentives are unnecessary.[7]

Some commenters believe that the current negotiation process, market forces or both are sufficient to resolve the take-or-pay problem. The Department of Energy fears the safe harbor rule may be so mechanical as to distort ongoing and future negotiations and to undermine the efficient operation of market forces.

Many of the comments reflect the view that present procedures are working to realign contract rights and obligations. Commenters from a broad spectrum of the industry assert that the present system of renegotiating take-or-pay provisions under the guidelines of the April 10, 1985 Statement of Policy is working well, and that the Commission should encourage this process. A strong reaffirmation of the Policy Statement is recommended by several commenters.[8]

b. Legal Authority and Applicability of the Presumption

A few commenters address the Commission's legal authority to establish such a presumption. Several commenters point out that under section 4 of the NGA pipelines have the burden of proving their rates to be just and reasonable. Consequently, the safe harbor presumption conflicts with this statutory standard. One commenter says that it discerns no rational reason for a presumption that qualifying lump-sum payments would be deemed prudent. It urges that the Commission require pipelines to meet the traditional just and reasonable standard and shoulder the burden of proof.[9]

The Commission proposed that the safe harbor presumption apply to future payment or purchase obligations. However, the Commission recognized that past and/or current take-or-pay prepayments may affect a pipeline's current and future business decisions. The Commission specifically requested comments on whether the safe harbor presumption should be expanded to include previously incurred and outstanding liabilities.

Many commenters suggest, if there is to be a safe harbor presumption, the Commission should expand it for additional categories of take-or-pay obligations. A number of commenters advocate extending the presumption as the Commission proposed, with the same percentage level for qualifying payments.

Several commenters propose that neither the safe harbor presumption nor amortization of take-or-pay payments apply to any payments made by a pipeline to its production division/affiliate. They suggest the pipelines should have the burden to prove the prudence of payments to affiliates, or, payments to affiliates could be limited to the average of all other supplier payments. One distributor asserts there is no rational basis for permitting a pipeline to charge the consuming public for this buy-out of a contract it negotiated with itself.

c. Requirement That all Obligations be Extinguished

Many commenters object to the requirement that payments must extinguish *all* obligations under a contract. "Onerous," "extreme," and "unworkable" are but a few of the terms used to describe this requirement.[10] They request the Commission to consider extending the presumption to *buy-downs*, i.e., partial extinguishment, of take-or-pay obligations. Several suggest the safe harbor presumption apply to payments which lower the take-or-pay level to at least 50%. They note that take-or-pay provisions play a role in a producer's financing of its operations, maintaining of lease rights, royalty payments, etc.

Producers were especially reluctant to give up all take-or-pay. A major producer group suggests that contract provisions which set the maximum percentage of deliverability as the minimum contract quantity, e.g., the 75 percent prescribed in the 1982 Policy Statement, be eligible for the safe harbor presumption.[11]

d. Requirement That Pipelines Offer Transportation

The Commission proposed that the safe harbor presumption be available only to those pipelines that agree to offer transportation services on a non-discriminatory basis as discussed in Parts A and C of the NOPR. Relatively few persons commented on this aspect of the NOPR.

A coaltion of industrial users fully supports the condition and says the safe harbor presumption should be reserved solely for such pipelines.[12] A major producer, however, argues that the presumption should not be limited just to those pipelines which choose to be transporters, and that it would be discriminatory to differentiate among pipelines for purposes of take-or-pay settlements.[13] A major pipeline also believes the measure should be available to *all* gas purchasers, not simply those pipelines which are willing to accept consequences such as giving up their contract demand rights.[14]

e. Qualifying Contracts

Only certain first sales contracts—"qualifying contracts"—were eligible for the safe harbor presumption under the proposed rule. In § 161.2(a), the Commission defined "qualifying contract" as:

> A contract for a first sale of natural gas entered into before January 1, 1982, the primary term of which will continue beyond January 1, 1986.

A significant number of commenters address the cut-off date for determining qualifying contracts. Many support the Commission's proposed January 1, 1982 date.[15]

Several commenters propose that all first sales contracts entered into prior to the effective date of this final rule should be deemed qualifying contracts. Others suggests May 30, 1985, the date of the notice issued.[16]

f. Minimum Purchase of Payment Obligation

In proposed § 161.2(b), the Commission defined "minimum payment or purchase obligation" as the mathematical product of:

> (1) The minimum take-or-pay quantities specified in a qualifying contract for the time period remaining in the primary term of such contract after January 1, 1986, multiplied by
> (2) The contract price for such quantities.

Many commenters believe calculation of the minimum payment or purchase obligation will be difficult, if not impossible. Several point out that many natural gas contracts do not specify a minimum take in terms of fixed volume of gas, but provide for a yearly calculation of take based on well deliverability.[17]

g. 1986–1987 Unrecoupable Obligation

The Commission defined "1986–1987 unrecoupable obligation" as those minimum payment or purchase obligations of a pipeline which are reasonably estimated to (1) obtain under all of a pipeline's qualifying contracts for a two-year period commencing January 1, 1986 and (2) not be recouped under the terms of the contract.

Many commenters complain that this term is not adequately defined. A producer states the arbitrary two-year period is not representative of the remaining years in gas purchase contracts in any event. Many commenters point out that calculating the amount likely to be unrecoupable will be difficult since no one knows now the extent of reductions in contract demand.[18]

h. Qualifying Payments

The Commission proposed to set certain percentage limitations on the amount of payments that may be deemed prudent. For qualifying contracts with a primary term remaining of five years or less on December 31, 1985, the Commission proposed that total qualifying payments be no more than X percent of a pipeline's total 1986–1987 unrecoupable obligation. For qualifying contracts with a primary term of more than five years, the Commission proposed Y percent. The Commission specifically requested comments on what the X and Y percentages should be.

Approximately half of the commenters on this issue set forth, in differing levels of detail, specific proposals on the qualifying payments formula. The proposals range from 0 to 50 percent. A sub-group of these commenters disagrees with the Commission and argues that a single X percent, rather than X and Y, should be used for ease of administration of the rule. Another small group of commenters on this issue recommends that the Commission undertake further procedures (*e.g.*, a supplemental rulemaking devoted to the development of the X and Y percentages, or an analysis of all pipelines' expected unrecoupable obligations). Another group of roughly half the commenters on this issue, predominantly pipelines, argues that no fair percentages for X and Y could be set.[19]

The majority of commenters assert that these percentages, while intended to be ceilings, would quickly become floors in the negotiations with producers.[20] Several commenters recall that NGPA Title I "maximum" lawful prices quickly became the uniform prices.

i. Allocation of Qualifying Payments

The Commission requested comments on how the costs of the qualifying payments should be allocated. The majority of commenters appear to favor some sort of allocation between sales and transportation.

A number of commenters are adamant that responsibility for the costs of buying out take-or-pay obligations rests upon the customers that caused the pipeline to incur the obligation. They argue that the pipelines procured gas supplies for the benefit of their existing customers and are experiencing the present take-or-pay problems due to efforts to augment supply and meet their service obligations.[21]

3. *Commission response*.—a. Decision not to promulgate Part B. We continue to believe that current and future take-or-pay obligations could possibly impede development of a more competitive gas market. In our April 10, 1985 Statement of Policy we responded to the information obtained through the Notice of Inquiry and our own observations of the gas market. We delineated the basic approach we intended to adopt toward solving the take-or-pay problem. As the comments to the NOPR point out, many producers and pipelines are currently renegotiating contracts under the guidance of the Policy Statement.

All segments of the industry responded to this portion of the rule. While virtually all commenters agree that take-or-pay obligations remain a problem for the industry, they are clearly unhappy with the safe harbor proposal as an additional means to resolve it. Many feel it is unworkable, or inadequate. Others are concerned that it will hinder, or even halt, the contract renegotiation that is underway between pipelines and producers. Many fault the requirements for eligibility as too rigid or mechanistic. Finally, many commenters urge us not to implement the proposed safe harbor rule, or to maintain the status quo.

As we stated briefly in the beginning of this section the imposition of a generic rule to handle take-or-pay buyouts at this time will not improve the take-or-pay problem and may actually aggravate the situation. In particular, we have no wish to upset current renegotiations. Therefore, in light of the many concerns raised by the written comments and at the public hearing, we will not promulgate Part B as proposed. Instead, and as requested by a number of commenters, we reaffirm our April 1985 Policy Statement. We shall clarify that those guidelines also apply to settlements of future take-or-pay obligations.

We note that pipelines have been successful in buying out past incurred take-or-pay liabilities in a number of instances. See Table C–1 below.

TABLE C–1.—THE LIST BELOW SHOWS COSTS OF "BOUGHT OUT" TAKE-OR-PAY SOUGHT BY PIPELINES AS OF SEPT. 30, 1985, WITH REFERENCES TO DOCKET NO., DATE OF FILING, AMOUNT SOUGHT, AND AMOUNT OF LIABILITY BOUGHT OUT [1]

Pipeline Company	Docket No.	Date of filing	Amount sought	Amount of liability bought out
ANR Pipeline Company	TA85-2-48	Mar. 29, 1985	$12,818,499	$64,092,495
Northern Natural Gas Company	RP82-71	Apr. 26, 1982	2,700,000	13,500,000
Tennessee Gas Pipeline Company	TA85-1-9-001	Nov. 30, 1984	4,436,757	22,183,785
Panhandle Eastern Pipeline Company			[2] 13,000,000	45,000,000
Trunkline Gas Company	RP83-93 *et al.*	June 15, 1983	[3] 33,219,751	166,098,755
United Gas Pipeline Company	RP72-133 (TA85-2-11)		(4)	
Prebuild (Northwest Alaskan Pipeline Co.)	RP85-6	Oct. 16, 1984	5,400,000	48,400,000
Sea Robin Pipeline Company	RP85-167-000	June 28, 1985	9,166,000	62,000,000

[1] According to published reports, Columbia Gas Transmission has proposed buy-outs to producers totalling some $800 million dollars as part of an overall approach to regain its competitive position in the market for natural gas sales.
[2] Company has not filed to recover this amount.
[3] Amount included in settlement pending in the Commission.
[4] None, except payments made to Northwest Alaskan Pipeline Co.

These arrangements appear to have provided the parties the greatest flexibility to deal with some particularly difficult contractual problems. Accordingly, we have determined that the proven course at the present time is to take no substantive action in this area.

b. Conditioning Producer Access to Transportation

Some commenters, mainly pipelines and local distribution companies, have suggested the Commission consider addressing existing high-cost take-or-pay "problem contracts" as an alternative means of removing the distortions of rolled-in pricing.[22] The Commission has before it in other dockets specific petitions which variously urge it to declare certain take-or-pay provisions in high-cost gas contracts void and unenforceable as against public policy, or to approve pipeline purchase cut-back programs.[23] In addition, many commenters have urged the Commission to require producers to waive take-or-pay claims as a condition to the producer obtaining open and non-discriminatory transportation by interstate pipelines.[24] The Commission has declined to seek to follow this approach. As the reasons were detailed in the discussion of the transportation rules above, the explanation for the decision will not be repeated here.

c. Expedition of Producer Abandonment Applications

In the April 1985 Policy Statement, the Commission recognized that the payments made to first sellers as consideration for waiving or amending take-or-pay or similar minimum payment provisions of a contract may be accompanied by a change in or termination of the first seller's service obligation.[25] In cases where a take-or-pay buy-out results in termination of the contractual service obligation and where the gas involved is subject to Commission jurisdiction under the Natural Gas Act, the first seller must obtain abandonment authorization pursuant to section 7(b) of the NGA before it can terminate its service obligation to the buyer and must obtain a section 7(c) sales certificate prior to making a subsequent jurisdictional sale in interstate commerce.[26]

The Commission stated that as a matter of general policy it would expeditiously grant abandonment authorizations necessary to implement the agreements reached by the parties under the guidelines of the Policy Statement.[27] The Commission reaffirms its intention to expeditiously grant abandonment authorizations required to implement agreements made pursuant to the Policy Statement. In addition, we will expeditiously review producer abandonment applications in those instances detailed below. Accordingly, this section outlines the policies and procedures that the Commission intends to follow in ruling on abandonment applications filed as a consequence of the Policy Statement and, more generally, applications filed in accordance with the policy objectives of this rule.

In general, the Commission intends that producer abandonment applications be considered on an expedited basis by means of existing administrative procedures in several situations.

Expeditious consideration will be appropriate in cases where the producer is subject to substantially reduced takes without payment or where the producer and pipeline have engaged in a "buy-out" as contemplated by § 2.76 of the Commission's General Policies. This policy is set out in § 2.77(a).

The procedures to be followed are spelled out in § 2.77(b). They provide that applications will be noticed promptly and a period not in excess of 15 days will be provided for comments or interventions. In cases where the applications are unopposed, they will be promptly granted by the Director of the Commission's Office of Pipeline and Producer Regulations pursuant to delegation of authority contained in § 375.307 of the Commission's regulations. In cases where an abandonment application is based on the cancellation of a contract by mutual agreement between buyer and seller upon payment of consideration by the buyer in accordance with the Policy Statement, it would be contradictory and unreasonable for the buyer to oppose the abandonment. Therefore, in cases of this nature, the Commission will consider the buyer to have waived any right to oppose the abandonment.

In cases where a proposed abandonment is opposed, the Commission will consider the objections and rule on the application if possible or, if necessary, will set the application for expedited hearing. In doing so, the Commission will establish deadlines for the conclusion of the hearing and for the issuance of an initial decision. The periods to be allowed for hearing and issuance of an initial decision will not exceed those specified in the Commission's recent abandonment hearing orders issued in *Exchange Oil & Gas Corporation*, 31 FERC ¶ 61,371 (1985) and *Felmont Oil Corporation and Essex Offshore, Inc.*, 31 FERC ¶ 61,233 (1985).[28] The Commission will, in addition, consider establishing in future cases an expedited schedule for filing of briefs on and opposing exceptions to the initial decision. Following the submission of briefs, the Commission will endeavor to issue a final decision within 60 days.

In the Commission's judgment, new § 2.77 is consistent with the policies reflected in this rule, in that producers should be able to sell shut-in gas and purchasers, to the extent possible, should be able to renegotiate or buy-out higher priced contracts so that the gas under those contracts can be sold at market-clearing prices. To this end, the Commission will consider requests for permanent, limited-term, or partial abandonment of sales subject to reduced takes irrespective of the NGPA price category of such gas.

The Commission is also concerned about the need for abandonment in cases where the underlying contract has expired. In such cases, the purchaser has no obligation to continue purchasing gas from the seller, but the seller has a continuing obligation under its certificate to continue to provide service if requested to do so. *Mississippi River Transmission Corporation*, 30 FERC ¶ 61,155 (1985); *Sunray Mid-Continent Oil Co. v. FPC*, 364 U.S. 137 (1960). The market disordering effects of reduced sales of lower-priced gas as well as the adverse economic effect on sellers in such situations, especially in the case of expired contracts, are of serious concern to the Commission.[29]

In ruling on abandonment applications under § 2.77 based on these and similar economic circumstances, the Commission intends to follow the expedited procedures previously outlined, except that purchasers will not be precluded from objecting to the proposed abandonments. Unopposed abandonments will be granted expeditiously under delegation of authority. In cases where abandonments are opposed, the Commission will likewise follow the procedures previously discussed in connection with abandonments related to the Policy Statement.

It is not possible to foresee all issues that may arise in connection with abandonment applications that are opposed and that must therefore be decided by the Commission on a formal basis consistent with the requirements of section 7(b) of the NGA. The Commission will therefore not attempt at this time to establish criteria to be applied in determining whether contested abandonment requests should be granted or denied. The standards to be applied will instead be developed on a case-by-case basis. The Commission will review the matter based on experience gained in individual proceedings and will, if it appears reasonable and desirable to do so, establish guidelines to be applied in ruling on future contested abandonments as a means of further expediting the determination of such abandonments.

In certain cases, once abandonment is granted, the abandoning seller will require a certificate under section 7(c) of the NGA prior to commencing sales to another purchaser. In the Policy Statement, the Commission stated its general policy to expeditiously grant certificate authorizations necessary to implement agreements reached under the Policy Statement guidelines. The Commission reaffirms its policy in this regard. The procedures to be followed will parallel those described for abandonment applications. Unopposed certificate applications will be expeditiously granted pursuant to delegation of authority under § 375.307 of the Commission's regulations. The Commission does not anticipate that opposition to requested certificate applications or amendments will be filed in a significant number of cases. However, any cases involving opposition will be treated generally in the same manner previously described in connection with contested abandonments. If a hearing is found to be necessary, it will be expedited to the maximum extent possible.

As a matter of procedure, and to assure implementation of the described procedures, the Commission requests that parties seeking expedited consideration of section 7(b) or 7(c) authorizations pursuant to this rule include in their applications a request for expedited consideration and a reference to Docket No. RM85-1-000.

The Policy Statement, which is codified as § 2.76 of the Commission's General Policy and Interpretations, 18 CFR § 2.76 is reaffirmed and a new § 2.77 is added to incorporate the expedited procedures outlined in this rule.

d. Pre-Granted Abandonment Authority

As noted in the proposed rule, the categories of gas eligible for transportation as proposed are broader than the current restrictions on movement of gas committed or dedicated to interstate commerce and therefore subject to producer abandonment requirements. In particular, gas from "new wells" on "old leases" in the Outer Continental Shelf (section 102(d) of the NGPA) is eligible under the proposed rule for transportation services. But this gas is "committed or dedicated to interstate commerce" and may not be transported without prior abandonment or "release." In the past few years, large quantities of this gas have been "shut-in" and therefore producers and pipelines have sought temporary producer abandonment and certificate authority to transport the gas to willing buyers in other markets at competitive prices.[30]

Comments. The comments suggest procedures to eliminate this disparity in gas eligibility and abandonment procedures. A few comments suggest that all certificate applications for producer sales become effective on the date of filing, as is the case with small producer blanket certificates, provided certain conditions are met. Such conditions might provide that the sales price not exceed the maximum lawful price and that the contract include certain market responsive provisions such as market out clauses.[31]

Some comments suggest that the abandonment be effective on the filing date if both the purchaser and seller of the gas agree to the abandonment, or alternatively, that the abandonment be subject to the prior notice procedure. They state that since abandonments are relatively routine, this procedure would expedite the process and still provide parties the opportunity to protest in relevant cases.[32]

Another commenter suggests that the Commission issue a blanket abandonment of producer commitments at the termination or expiration of all jurisdictional gas sales contracts.[33] However, another commenter suggests that such a pre-grant of abandonment should be authorized only for section 102(d) OCS gas and section 108 stripper gas, gas which is still subject to NGA regulation. This commenter goes on to suggest that section 104 "old" gas, and other low-priced, pre-NGPA gas should not be granted such abandonment authorization, however, because that gas is being preserved for the pipeline's existing customers in the billing mechanism proposed in Part D.[34]

Another commenter, the U.S. Department of Energy (DOE), also urges a pre-grant of abandonment of shut-in gas supplies because large volumes of gas, especially old gas, are being shut-in. They suggest defining shut-in gas as gas to which a "first purchaser" has a right to take, but has not taken over a specified period of time. DOE believes that the availability of this gas to consumers will provide strong competitive pressure and could replace higher priced supplies and alternative fuel.

The proposed rule provides for a parallel pre-grant of abandonment for transportation performed under self-implementing authority under the rule. One commenter suggests that this pre-grant of abandonment should depend on a customer's election not to extend the contract. It states that this additional condition would prevent pipelines from unilaterally terminating transportation service to a firm customer upon termination of the contract if the customer elects to extend the contract.

Commission Response. One of the principal goals of this rulemaking is to satisfy the mandate of the NGPA by encouraging the movement of gas from the wellhead to the burner-tip in response to the demands of natural gas consumers for reliable service at the lowest reasonable price. For this reason, the Commission intends the final rule to *increase*, not *decrease*, the flexibility of producers and pipelines to move gas supplies to meet consumer demand under self-implementing transportation programs. This is even more compelling when the gas being moved is either (1) high-cost gas being released and transported by a pipeline at more marketable prices and terms than under an existing contract for the gas, such as a contract with uneconomic take-or-pay requirements; or (2) low-cost price-controlled gas, that has been shut-in by a pipeline due to lack of demand for its system-supply or due to priority for takes of other gas supplies under more rigid contracts, and therefore is being released in order to be transported to willing buyers under more marketable conditions.

Examples of high-cost gas include gas supplies from new wells on old Outer Continental Shelf leases (subject to the ceiling price in section 102(d) of the NGPA) and gas from stripper wells, especially in Appalachia and the Southwest, which is subject to the ceiling price under section 108 of the NGPA.[35]

Examples of low-priced gas which may be "shut-in" include "old" price-controlled gas under sections 104, 106(a) and 109 of the NGPA.

Although the NGPA established incentive price ceilings for section 102(d) OCS gas, and section 108 stripper gas, it did not remove such gas from the producer abandonment and certificate requirements of sections 7(b) and 7(c) of the NGA. The NGPA also did not remove any NGA certificate or price jurisdiction over "old" price-controlled gas still regulated under sections 104, 106(a) and 109. For this reason, when a producer-pipeline contract for the purchase of any of these categories of committed or dedicated gas expires, or even when takes of these gas supplies under an existing contract are "shut-in" unilaterally by a pipeline purchaser, a producer is powerless to sell these supplies elsewhere to willing buyers unless it first obtains abandonment authority from the Commission under section 7(b) and thereafter a section 7(c) certificate to sell the gas elsewhere.

With the disorders in natural gas markets beginning in 1981 came innovative and experimental arrangements by producers and pipelines to release and transport quantities of these "shut-in" gas supplies consistent with the abandonment and certificate requirements of the NGA.[36] In addition, producers whose gas had been unilaterally shut-in by their pipelines filed increased requests for stand-alone abandonment authority to the Commission.[37]

Demands for these arrangements have increased and are likely to continue to increase after the effective date of the final rule. Thus, as many commenters pointed out, the success of the transportation flexibility provided in this final rule is directly related to the ability of producers and pipelines to receive prompt regulatory approvals at the Commission for the "release" and sale of shut-in gas supplies under section 7 of the NGA.[38] These commenters also pointed out that, to the extent their existing transportation arrangements for shut-in gas must be "converted over" to the self-implementing transportation program after the expiration of those arrangements November 1, 1985, the Commission must issue any required abandonments and new certificates as soon as possible after November 1, if producers and shippers are to avoid the gas being shut-in again during the transition period.[39] Finally, some commenters point out that abandonment authority will be necessary for additional supplies of incentively-priced gas, such as 102(d) OCS gas or 108 "stripper" gas, if they are shut-in.[40]

Based on these comments, the Commission is directing staff in this final rule to expedite the applications. For example, uncontested abandonment applications should not be delayed because the producer has not provided information pertaining to the disposition of the gas after abandonment. In addition, with regard to applications presently on file with the Commission, the staff is directed to process any abandonment and certificate applications for shut-in or untaken gas supplies, especially 102(d) OCS gas and 108 stripper gas, so that Commission decisions on all such applications are issued no later than March 1, 1986. The applications given priority should be those for gas which had limited-term abandonment and certificate authority under transportation arrangements that existed prior to the effective date of this rule; and those whose terms include take-or-pay or price relief.

As to the suggestion that pre-grant of abandonment for transportation be made dependent on a customer's election not to extend the contract, we disagree. First, in most instances, it is unlikely a shipper will be able to unilaterally extend an existing transportation contract when the transporting pipeline prefers to terminate the arrangement. Since the transportation authorization is meaningful only if transportation is available, there is no reason to extend the authorization absent a bilateral agreement to continue the arrangement. Second, by accepting a certificate under § 284.221, a pipeline will be subject to the non-discriminatory access condition applicable to that certificate. Therefore, pipelines will have an incentive to continue the arrangement if such termination would otherwise constitute discriminatory treatment.

C. Optional Expedited Certificates

1. *The proposed rule.* The NOPR proposed and the final rule now establishes optional certificate procedures providing expedited treatment of applications for new service under section 7 of the NGA.[1] A certificate and pre-granted abandonment are available under these procedures to allow any applicant to institute new jurisdictional service and to construct and operate facilities for such services. To qualify, the applicant must agree to comply with the specific terms and conditions under which the certificate is offered. Most important, the applicant must accept the full risk of the proposed venture. These procedures are completely voluntary. The alternative of applying for a certificate under conventional procedures remains available, with the conventional assignment of risks.

The rule is designed to provide consumers with greater options in the array of gas services available by giving pipelines the ability to offer new service and construct facilities on a timely basis. To this end, the rule removes certification as a barrier to entry where certain conditions are met, and thus helps ensure that pipelines propose the most efficient scale for new facilities. (Suboptimally sized facilities will have higher costs at design volumes and will be vulnerable to entry by more correctly-sized facilities.)

The rule is also designed to maximize the use of alternative market access for producers and consumers and to provide incentives for competition where none exists. Distributors that are now restricted to one pipeline, even where new hook-ups involve construction of minimal tap facilities, may gain access to more than one pipeline. Offerings of new pipeline services to off-system markets will be more readily possible, and willing competitors may enter established markets. This rule, then, removes any federal prohibition against adding new receipt or delivery points and does not permit discrimination which would permit some customer groups to add delivery points more easily than others.

A detailed discussion of the various provisions of the rule and the comments that addressed those provisions follows.

2. The Commission's Jurisdiction

a. *The jurisdiction of the states.—Comments.* The American Gas Association (AGA) states its concern that the proposed expedited certificate procedures should not replace legitimate state authority with respect to distributor by-pass issues. Citing *Panhandle Eastern Pipe Line Co. v. Michigan PSC,* 341 U.S. 329, 334 (1951), they argue that direct sales for consumptive use were left to state regulation under the Natural Gas Act and that *Panhandle Eastern Pipe Line Co. v. Indiana PSC,* 332 U.S. 507, 520 (1947), supports the view that Congress "meant to create a comprehensive and effective regulatory scheme complementary in its operation to those of the states and in no manner usurping their authority." Thus, they are concerned that the proposed rule might extend Commission authority into an area that the Natural Gas Act left to the states. This view is supported by a number of other commenters, including Commonwealth Gas Pipeline Corporation, who contend that the Commission's proposals would interfere with the states' jurisdiction and responsibility to set reasonable rates for end-user service by LDCs. They argue that the states are uniquely suited to determine whether, and under what conditions, customers of LDCs should be permitted to become customers of the pipelines. Southern Indiana Gas and Electric Company and a number of other LDCs contend that the Commission's proposal exceeds its authority or that it would preempt state law in those states which have already addressed this issue. For example, Indiana has a statute that requires by-pass proposals to be approved by the state's utility commission after a hearing. Some commenters request assurance from the Commission that such statutes will not be preempted.

While some commenters believe that the states should determine whether a by-pass should be permitted, others believe that, at a minimum, coordination with the states should be provided in the final rule. Commonwealth Gas Pipeline Corporation, for example, suggests convening a joint hearing with all state commissions pursuant to the provisions of section 17(b) of the NGA, with follow up comments from state commissions, LDCs, and other interested parties six months after the implementation of the NOPR.

Commission Response. The Commission does not intend the final rule to intrude in any way on the jurisdiction of the states over the local distribution of natural gas. The commission recognizes that under our system of federalism it is within the traditional, sound discretion of the states and local governments to regulate local distribution companies in the public interest. The states, not the Commission, have the opportunity, and indeed the right, to determine the appropriate mixture of transportation and sales service provided to customers by local distribution companies not within the Commission's jurisdiction. In order to ensure that the final rule respects this jurisdiction, the final rule, as detailed below, is intended to ensure that the optional expedited certificates do not permit "LDC by-pass" without a full notice and opportunity for those affected by the alleged by-pass to challenge the certificate application. See § 157.104. Moreover, the Commission believes the "contract demand" adjustment rights and the elimination of the "system supply" test for § 311 transportation under the new transportation regulation in Part A, *supra*, should provide pipeline customers, especially full-requirements customers, with the full panoply of competitive gas supply options recently made available to partial-requirements customers under Order No. 380.[2] For these reasons, the commission expects local distribution companies will have the flexibility and options available under the final rule to "meet the market" in most, if not all, future "by-pass" situations, and therefore to retain their industrial loads.

The Commission makes no judgment here on whether "LDC by-pass" is in the public interest or not. The Commission does, however, intend to ensure that LDCs are provided an opportunity to demonstrate any alleged adverse effects resulting from LDC by-pass in the optional certificate procedures provided in the final rule and that their state regulatory bodies have an opportunity to exercise the state's authority over these issues.

The Commission considers the fact that LDC by-pass may be an end-result of an optional certificate is not in and of itself dispositive of the public convenience and necessity under the NGA. Accordingly, the final rule retains the presumption that applications for new service that meet the conditions set out in the final rule are presumptively in the public convenience and necessity.

AGA is correct in its observation that in developing a comprehensive scheme of regulation under the Natural Gas Act, Congress left the regulation of direct sales to the states. Nothing in the final rule is intended to disturb these boundaries that Congress fixed between state and federal regulation of such sales. The rule thus includes appropriate procedures allowing protestors who will be affected by a proposal to raise material issues for consideration prior to approval of the transaction.

b. Effects on Distributors

Comments. Many LDCs and state public utility commissions commented that the procedures of Subpart E could be used to by-pass an LDC currently providing service to an end user. These commenters are concerned that an end user may secure pipeline transportation for gas purchased directly from a producer or other gas merchant and by-pass the local distribution company in whose franchised service area the end user is operating, even where the end user was previously a sales or transportation customer of the LDC.

In order to protect the local interests of the LDCs and states, a number of commenters, including Columbia Distribution Companies, Southern Indian Gas and Electric Company, and UGI Corporation, recommend that the proposal require prior notice before permitting transportation by-passing LDCs. Some commenters believe that actual notice rather than constructive notice should be required. Iowa Electric Light and Power Company suggests that the end user should be required to provide prior notice to the existing supplier so that the supplier would have an opportunity to induce the end-user to continue as a customer before losing the customer.

Commission Response. The final rule has been designed to ensure that affected parties, especially small LDCs, receive adequate notice of applications under Subpart E that may affect their interests. Specifically, paragraph (b)(1) of § 157.102 requires applications under Subpart E to contain a statement that a copy has been served on any LDC in whose service area a customer for the proposed new service is located.

Comments. A larger number of commenters expressed concern about the economic results of allowing pipelines to by-pass LDCs to serve large end users. According to these commenters, including Wisconsin Power and Light Company and UGI Corporation, the loss of a large end user would ultimately shift fixed costs to the distributor's remaining small volume commercial and residential customers and increase their rates. The problem is exacerbated, say these commenters, by the requirement, imposed by many states, that LDCs provide service to all customers that request it, even to customers who previously left the system. Accordingly, many LDCs have invested heavily in the capital equipment necessary to meet this continuing obligation. Commenters including Minnegasco and New Jersey Natural Gas Company argue that the pipelines, which have no such obligation, may "skim the cream" from a distributor's franchised service territory. This involuntary shifting of costs to the remaining customers, they contend, would run contrary to the policy objectives of the proposed rule. Citing *Atlantic Refining Co. v. PSC*, 360 U.S. 378, 388 (1959), they argue that the NGA was designed to protect consumers and that the Commission has a statutory duty to carry out its responsibilities under the NGA so as to "afford consumers a complete, permanent and effective bond of protection from excessive rates and charges."

In this connection, some commenters have suggested specific requirements for applications that will result in by-passing an LDC. For instance, UGI Corporation suggests not authorizing a by-pass unless the local distribution company refuses to provide the requested transportation or sales service to the end user; Columbia Distribution Companies suggests requiring the permission of the state regulatory agency prior to Commission approval; American Public Gas Association suggests requiring the consent of the affected LDC; and American Gas Distributors and American Gas Association suggest requiring an order from the state or local regulatory body having jurisdiction declaring the particular hook-up to be in the public interest.

Commission Response. The overall goal of the final rule is to ensure that all natural gas markets are sufficiently competitive so that consumers are provided natural gas at the lowest reasonable rates consistent with reliable, long-term service. This goal is achieved by the various elements of the final rule working together. It is true that pipelines could rely on Subpart E to by-pass LDCs. But in focusing only on the cost-shifting that could occur under certain circumstances, the commenters take a view that is too narrow and ignores the balancing effects of the other elements of the final rule. To be specific, commenters ignore the fact that the equal access provisions of Part 284 of the rule compel pipelines that transport gas for others (such as an end user previously served by an LDC) to transport gas for all. And this includes transportation for LDCs, even where such transportation would displace the pipelines own sales.

Of course, in order to be effective, the final rule must ensure that participants in the market all compete on an equal footing. No one group can be allowed an advantage over the others. Yet this is the result that would occur if LDCs are allowed to veto pipeline proposals to transport in their service areas. The LDCs could compel pipelines to displace their own sales and transport gas to the LDCs when cheaper supplies were available—in effect, "by-passing" the pipeline. At the same time LDCs could deny market access to the end users they serve. In other words, the LDCs would have the best of both worlds.[3] They could avail themselves of the benefits of competition among pipelines and producers, but would be insulated from any factors that would induce them to act competitively.

The Commission will not insulate the LDC markets from the competitive incentives that are the foundation of the final rule. In order to promote economic efficiency—a necessary factor in providing gas to consumers at the lowest reasonable rates—the rule must provide sufficient competitive incentives to all elements of the market. This means making all market participants, including LDCs, accountable for the success or failure of their market participation. Where incentives exist for producers to offer gas at market clearing prices and for pipelines to provide the necessary transportation, LDCs are in a position to compete aggressively to make gas available to their customers at the lowest possible cost. Section 157.102(b)(1) requires that applicants provide LDCs with the prior actual notice necessary to meet such competition.

Of course, if pipelines engage in unfair competitive practices or other circumstances are present that would make it unfair for a pipeline to by-pass the distributor, LDCs may present these issues for consideration at the hearing provided for by § 157.104. But the simple fact that a pipeline is offering service under more competitive terms than an LDC is not, by itself, sufficient grounds to deny a certificate, or even to hold a formal hearing.

As for the possibility that LDCs will shift costs to their other customers if large end users are lost in competition with pipelines, the Commission does not believe that this is necessarily an inevitable result. LDCs rates are regulated by the states, not the Commission. States may, if they choose, prevent such cost shifting by LDCs that fail to compete aggressively.[4] Other issues pertaining to state regulations are discussed below.

c. Protest to Abandonment of New Service

To ensure that the public interest is in no way disserved by abandonments granted under § 157.103(f), § 157.106 provides that, if a customer has received notice from a certificate holder in accordance with § 157.103(f), that it intends to abandon any part of new service being provided to the customer under Subpart E upon expiration of their contract, the customer may, within thirty days prior to such expiration date, file a petition under § 385.207 of this chapter protesting the abandonment and requesting issuance of an order by the Commission directing the certificate holder to continue the new service in accordance with the expired contractual agreement. The Commission may require the certificate holder to continue to provide the new service described in the abandonment notice, if the Commission determines that continuation is necessary because the customer is unable, after having made reasonable efforts, to arrange for alternative service and the customer will pay the rate on file for the new service.

3. *Availability.* The final rule establishes a new Subpart E to Part 157, Optional Certificate and Abandonment Procedures for New Service Under section 7 of the Natural Gas Act. New Subpart E provides, pursuant to a new § 157.100, optional procedures whereby any eligible applicant may obtain a certificate authorizing "new service." Under the certificate, the applicant may sell and/or transport natural gas, and construct or acquire the natural gas facilities necessary to provide the new service and operate those facilities. Upon request, the certificate will include pre-granted abandonment of such activities and facilities upon termination of any underlying contractual obligations.

The new Subpart E replaces the existing Subpart E, "Transportation Certificates under section 7(c)(2) of the Natural gas Act," as the regulations set forth therein, which pertained to the transportation of natural gas on behalf of certain high-priority end users, are no longer necessary. Any transactions already authorized under the superseded Subpart E, however,may continue until expiration.

4. *Definitions.* The definition of terms for purposes of Subpart E are set forth in § 157.101. Terms defined in the Natural Gas Policy Act of 1978 have the same meaning for purposes of Subpart E as they have under that Act.

"Eligible applicant" is defined in § 157.101(b)(1) as a natural-gas company or person who will be a natural gas company upon completion of any proposed construction or extension of natural gas facilities. (Section 2 of the Natural Gas Act defines "natural-gas company" as a person engaged in the transportation of natural gas in interstate commerce, or the sale in interstate commerce of such gas for resale.)

Comments and Commission Response. ANR Pipeline Company, Arkansas Louisiana Gas Company, and several other commenters have asked whether the expedited certificates would be available for any sales by a pipeline to any customers, including sales to a new contract demand customer. The certificates are available for such sales. Any entity can apply for an expedited certificate, as long as it agrees to comply with the specified conditions. Of course, by accepting a certificate under these procedures, a previously non-jurisdictional entity would become a "natural gas company" and therefore become subject to the jurisdiction of the Commission.

The Commission rejects a suggestion by the Indicated producers that producers should be allowed to use these optional procedures to construct or operate pipelines connecting their gathering systems to new markets without being reclassified as pipelines. The expedited procedures established by this rule, as an alternative to more conventional, less procedures, are designed to provide flexibility to respond to competition in an area of regulation where such flexibility does not currently exist. They are not intended to provide a loophole whereby a company that would otherwise be subject to federal regulation may evade it. Moreover, nothing in the rule precludes a producer from preserving its status by forming a separate corporate entity for purposes of engaging in business under an expedited certificate.

"New service," the only activities for which certification is available under the optional procedures of Subpart E, is defined in § 157.101(b)(2) as a service for which the applicant does not have certificate authority. In cases where service is being provided under a certificate issued pursuant to Subpart A of Part 157, the optional Subpart E procedures could be used to obtain certification for an increase in the existing service or an additional kind of service that might be needed pursuant to renegotiation of the contract underlying the service. Further, certification may be obtained under Subpart E only if all facilities that are to be constructed and operated satisfy the definition of "qualifying facilities" in § 157.101(b)(3) which limits certification to facilities or portions of facilities that will be used solely to provide new service.

5. *Application Procedures.* Application procedures under Subpart E are set forth in § 157.102, which requires that applicants provide all information necessary to fully describe the proposed transportation, sales, and other services to be provided and the facilities needed to provide such service. The application must also state whether pre-granted abandonment authorization is requested and, if so, to what extent.

The provisions of § 157.11 of Subpart A relating to hearings will not apply to applications for certificates under Subpart E. Hearing procedures for Subpart E are set forth in § 157.104, discussed below.

With the exceptions discussed below, Subpart E applications will be subject to the provisions of § 157.14, which require the filing of information necessary to determine a pipeline's cost of service, compliance with relevant non-federal requirements, and other matters to be considered by the Commission in determining whether proposed services, under the proposed terms, would be in the public convenience and necessity.

Paragraph (b)(1)(v) of § 157.102 requires an applicant to file a statement of rates to be charged for the proposed new service, including *pro forma* copies of the rate schedule to be included in the effective tariff, a statement explaining fully how the proposed rate was derived, showing clearly whether the proposed rate results from negotiation, cost-of-service determination, competitive factors or others, and explaining the bases for the findings and conclusions of any related studies. Any rate filed for transportation services provided under a certificate granted under Subpart E must comply with the conditions set forth in § 157.103, discussed below.

Because the statement of rates required by Paragraph (b)(1)(v) of § 157.102 requires information similar to that required by § 157.14(a)(18), the provisions of § 157.14(a)(18) will not apply to applications under Subpart E.

Since applicants under Subpart E would be required to furnish information described under § 157.6(b), they should plainly state that they are requesting consideration under the optional procedures of Subpart E and that they agree to comply with all terms and conditions specified in Subpart E. Any person wishing to intervene in the proceeding on an application or protest an application under Subpart E must include in its filing, in addition to the information required under § 157.10, which sets forth the requirements generally applicable to interventions and protests, a statement of any issues of fact that the intervenor wishes to raise. The statement must specifically identify those issues that the intervenor alleges to be material to determining whether the requested certificate will be required by the public convenience and necessity.

Paragraph (c) of § 157.102 provides that if the application requests a certificate to provide transportation or sales service for others under Subpart E, the applicant must state that it has filed for, and will accept, a blanket transportation certificate under § 284.221 and identify the docket number assigned to that application and state that it will comply with the conditions in Subpart A of Part 284. The Commission intends the benefits of the optional certificate procedures to be an incentive for pipelines to provide transportation services on a non-discriminatory, self-implement basis. In addition, the availability of such non-discriminatory transportation is one of the criteria the Commission considers relevant to the presumption that an optional certificate is in the public convenience and necessity. Accordingly, the final rule provides that an application for an optional certificate must meet the condition stated in § 157.102(c).

Comments and Commission Response. A number of commenters suggest that the filing requirements proposed in the notice were more extensive than necessary, given that the applicant assumes the risk of the project. They urge that filing requirements be minimized. The Commission agrees. Accordingly, applicants under Subpart E will not be required to supply the specific gas supply and market exhibits required by § 157.14(a) (10) and (11). Since all risks are assumed by the applicant, this information is not needed. Similarly, the annual and subsequent reports that were proposed by the Notice will not be required. Moreover, the provisions of § 157.7 of Subpart A, which permit abbreviated applications, will be available for applications under Subpart E as well.

6. *Terms and conditions.*—a. *Competing applications.* Special terms and conditions applicable to services provided under Subpart E are set forth in § 157.103. Paragraph (a) provides that a certificate issued pursuant to Subpart E will be non-exclusive and non-prejudicial to any application for any other certificate under the Natural Gas Act or for authorization under the Natural Gas Policy Act.

Comments. A number of commenters, including Colorado Interstate Gas Company, argue that this proposal ignores the requirement of *Ashbacker Radio Corp. v. F.C.C.*, 326 U.S. 327 (1946), which held that if applicants before an administrative agency have a statutory right to hearing, in situations where there are two or more competing, mutually exclusive applications, the required statutory hearings must be completed for both before either application is approved.

In this connection, Mojave Pipeline Company recommends setting a cut-off date of 90 days measured from the date of notice of a certificate application, for the filing of each certificate that competes with the initial application. After the end of the 90 day period, competing or mutually exclusive certificate applications would not be consolidated with the initial application. Applications filed after the 90-day deadline would be dismissed without prejudice, pending Commission disposition of the initial application and any timely filed competing applications.

Commission Response. In the *Ashbacker* case, the Supreme Court reversed a decision of the Federal Communications Commission not to hold simultaneous hearings concerning two applications for licenses for a broadcasting station. The Court held that since the two broadcast signals would interfere with each other, only one could be granted and therefore the applications were mutually exclusive. The heart of the holding is contained in the following language:

> We only hold that where two bona fide applications are mutually exclusive the grant of one without a hearing to both deprives the loser of the opportunity which Congress chose to give him.

326 U.S. at 333

The *Ashbacker* case does not apply under the circumstances of the current rule. This is so by virtue of Paragraph (a) of § 157.103. Under that provision, competing applications will not be considered mutually exclusive if at least one of the applicants is willing to assume all economic risks in compliance with Subpart E. This provision is supported by section 7(g) of the NGA, 15 U.S.C. 717f(g),*which states:

Nothing contained in this section shall be construed as a limitation upon the power of the Commission to grant certificates of public convenience and necessity for service of an area already being served by another natural gas company.

Accordingly, there is no need to hold competitive hearings, nor is the 90-day waiting period proposed by Mojave Pipeline Company necessary.

b. Certification Limited to Qualifying Facilities and New Service

Comments and Commission Response. Paragraph (b) of § 157.103 states that a certificate issued under Subpart E provides only for authorization to construct or acquire and operate qualifying facilities and to provide new service. Several commenters sought clarification as to whether this precluded use of existing facilities to provide new service. Maryland People's Counsel observes that most new services will require some use of existing facilities, and therefore recommends that the final rule provide for that portion of a pipelines rates for new service attributable to the use of existing facilities. The Commission agrees and has included paragraph (c) in § 157.103 to require that to the extent the new service proposed will use existing facilities, the cost of those facilities must be allocated among the services provided under Subpart E and other services provided. The rule does not preclude the use of existing facilities to provide new service under an expedited certificate. Only "qualifying facilities" may be constructed or acquired under the certificate, however, and all facilities constructed to provide the new service must be "qualifying facilities."

c. Rate Conditions

As indicated above, an essential aspect of this rule is the principle of accountability in the more competitive environment. Applicants must be willing to assume the full responsibility of their ventures in order to qualify for the expedited procedures available in Subpart E. In order to ensure this, the rule adopts four principles to prohibit applicants from shifting costs among customers in future rate cases. First, rates for new services are required to be volumetric except as provided for under § 157.103(c). Secondly, only properly allocated costs may be included in the rates for new service. Third, applicants may not reduce projected volumes in future rate cases. Finally, pipelines may not recover past losses in future rate cases. These principles, as discussed below, are reflected in the rate requirements of the final rule.

Paragraph (d)(2) of § 157.103 states the objectives of the rate requirements. Specifically, maximum rates of both peak and off-peak periods must be designed, to ration capacity during peak periods and maximize throughput during off-peak periods. In addition, the certificate holder's revenue requirement allocated to firm and interruptible services should be attained by providing projected units of service in peak and off-peak periods at the maximum rate for each service.

Paragraph (d)(3) of § 157.103, except as provided in paragraph (c), requires one-part, volumetric rates for new service. Such rates must recover costs allocated to the new service to the extent that the projected units of that service are actually purchased. Provisions such as minimum bills, minimum take requirements, or other provisions designed to guarantee revenue are not allowed.

Comments. Some commenters, primarily interstate pipelines and LDCs, maintain that volumetric rates reduce the flexibility of the pipelines to negotiate a rate design to meet changing circumstances. Tennessee Gas Pipeline Company and the Interstate Natural Gas Association of America contend that volumetric rates jeopardize a pipeline's ability to finance any project of sufficient size to require project financing, because such projects must have a demand charge that includes, at a minimum, all operation and maintenance expenses, taxes and debt principal and interest. They would prefer to leave rates to the negotiation of the parties as long as there is no impact on other customers of the pipeline.

Commission Response. These commenters miss the essense of the expedited certificate regulations. In the first place, these procedures are entirely optional, and are only meant to provide an alternative to the conventional procedures of Subpart A. Projects that cannot be accomplished without project financing can be undertaken pursuant to that subpart. Expedited certificates for new service, on the other hand, are *only* intended to be available to applicants who are willing to assume *all* the economic risks of a project. Volumetric rates and the prohibition against cost-shifting in § 157.103(d)(8) are the heart of this proposal, because they are the primary means by which this risk is imposed. Allowing applicants to impose other rates through negotiation or to include demand charges would only provide a means for shifting some portion of the risk back to the ratepayers over their objection. This would be inconsistent with the purpose of these new procedures and would eliminate the basis for the rebuttable presumption (discussed below) that a certificate issued under these conditions is in the public interest. However, the Commission does not intend the final rule to preclude the negotiation by a pipeline and any of its customers of an appropriate reservation charge for new transportation service comparable to that under the new self-implementing transportation program. If all of the affected parties agree to such a reservation charge in the certificate proceedings, then the Commission will approve it in the same manner as it would approve comparable reservation charges under the new self-implementing transportation program. For this reason, paragraph (e) of § 157.103 of the final rule modifies the proposed rule to allow for such reservation charges for new transportation service under an optional certificate.

A reservation fee for transportation is permitted because it promotes *customer* accountability, but does not significantly insulate the pipeline from risk or shift accountability away from the pipeline. Commenters who were *customers* indicated that a reservation fee should be allowed because they feared that some customers would attempt to book or reserve all of a pipeline's available capacity if it were not required to pay something for booking.

This does not, however, insulate the pipeline from all risk in the same way a demand charge would. A pipeline must still find customers who want to buy firm transportation service and are willing to pay a reservation fee to book it. Since customers are given an opportunity to nominate the duration of service, a pipeline cannot require that a customer book service for a period longer than the customer desires. This, then, does not allow a pipeline to insulate itself by requiring long term contracts with reservation fees.

The Commission does not believe reservation fees should be allowed for sales service. A pipeline would not be under an obligation similar to the obligation for transportation service to provide service to all who request it under an optional sales certificate. Thus, there is not the need to prevent *customers* from overbooking where the pipeline is obligated to serve, in order to make sure the capacity is available for use by other customers. The pipeline has much more discretion in imposing conditions other than revenue guarantees in a sales service agreement, such as a use or lose condition, so that it can protect itself somewhat from customer caprice. While we recognize that this may make optional certificates less desirable than a traditional sales certificate, we deem it essential that the pipeline bear the full risk of utilization by charging volumetric rates with no revenue guarantee of any kind, even the limited reservation fee permitted for transportation services.

Comments. Tennessee Gas Pipeline Company and several other interstate pipelines say that if volumetric rates are established, the pipeline should be allowed to reduce projected volumes in future rate cases. They assert that for various reasons no one estimate of projected levels of volumes to be sold and/or transported under a new service certificate will be appropriate over the life of the project. They state that pipelines may be reluctant to enter projects if they may never change the level of projected volumes. In this connection, Northwest Central Pipeline Corporation states that the Commission has adequate means to prevent any inappropriate cost shifting or cost bearing if and when such circumstances actually arise in any future section rate change proceeding. Maryland People's Counsel, on the other hand, believes that reductions in projected volumes should be totally precluded and is concerned that there appears to be no actual proposed regulation clearly stating that projected volumes used to set the initial rate for new service cannot be reduced.

Commission Response. The applicant's willingness to assume assumption of all risks pertaining to a project is critical to our presumption that such projects are in the public interest, and may therefore be processed with expedition. Any dilution of this assumption of risk would gravely undermine the basis for this presumption. Accordingly, the Commission will not leave this issue open for resolution in future rate cases. An applicant who voluntarily chooses to proceed under these expedited procedures must do so with the knowledge that if the project is less successful than was hoped or expected, he will not be able to reallocate the costs to his other customers in some future rate case. To this end, paragraph (d)(4) of § 157.103 states that any rate filed for new service must be designed to recover costs on the basis of projected units of service. That paragraph clearly states that the units projected for the new service in the initial rates filed under Subpart E may be increased in a subsequent rate filing but may not be decreased. We note that this is the major difference between the rate conditions applicable to the optional certificates as opposed to the rate conditions for implementing transportation under Part A of the final rule.

In order to ensure that only costs properly allocable to the new service will be included and to prevent cross-subsidization, paragraph (d)(5) of § 157.103 states that rates for new service must reasonably reflect any material variation in cost attributable to whether the service is provided in peak or off-peak periods or, if the service includes transportation, variations attributable to the distance over which the transportation is provided.

The final rule also requires that rates be flexible. Thus, paragraph (d)(7) of § 157.103 states that any rate schedule for new service must state a maximum rate and minimum rate. The certificate holder may charge any rate that is neither greater than the maximum nor less than the minimum. However, paragraph (d)(6) states that any maximum rate must be designed to recover, on a unit basis, solely those costs properly allocable to the service, and any minimum rate must be based on average variable costs allocable to the service.

Comments. Maryland People's Counsel suggests that in most cases new services will increase loads, thus making greater use of existing facilities and thereby reducing costs. Thus, Maryland People's Counsel recommends that when increases in sale and transportation owing to the provision of new service accumulate to a threshold point—such as, for example, five percent of the total representative volume established in the pipeline's last rate case—the pipeline should be required to file a new rate case within 90 days after the threshold is reached. Maryland People's Counsel believes this approach would ensure that a pipeline continue to bear an appropriate share of the economic risk associated with a project while preventing the need to change existing rates every time a new service is certificated.

Commission Response. As indicated above, paragraph (d) (4), which allows an applicant to *increase* the units of service on which the initial rates were based, would allow a pipeline to increase projected levels for a new service in a subsequent rate case. The Commission sees no need to include a specific requirement for such filings in the final rule, however. At present, jurisdictional pipelines that have purchased gas adjustment clauses in their tariffs (and this includes virtually all major pipelines) must file tariff sheets restating their rates every 36 months. 18 CFR 154.38(d)(4)(vi)(a). When a pipeline files a rate case under that section, all of its costs and revenues are reviewed and new rates may be developed. The Commission does not believe it is necessary to require more frequent rate filings simply because a pipeline decides to exercise its option to proceed under an expedited certificate. The Commission notes, in addition, that the risks entailed by an expedited certificate provide a pipeline with a strong incentive not to include excess capacity in new facilities constructed under an expedited certificate. The same incentives apply to those portions of existing facilities the costs of which will be allocated to be recovered from the new service. This incentive to construct optimally sized facilities should further limit any potential for a windfall resulting from a pipeline's providing higher levels of service than projected.

Also, to ensure that costs are not shifted to other customers contrary to the principles underlying Subpart E, paragraph (d)(8) provides that no costs originally allocated to a new service may subsequently be allocated to any other services without a filing under § 154.63 and a determination by the Commission that the costs sought to be reallocated are in fact being incurred for the benefit of the other services.

d. Conditional Pre-Granted Abandonment

Where applicable, conditional pre-granted abandonment will be provided; the period for authorization of any given service will be coterminous with the contracts governing that service.

A part of accountability in a competitive market involves the negotiation of contracts defining rights and obligations, and assigning risk among the parties. Certificate applications are geared to fulfilling these contractual obligations. It is therefore logical to make new certificates coterminous with the governing contracts. Abandonments can thus be pre-granted to be effective at the expiration of the relevant contracts *when alternate suppliers exist.*

Paragraph (f) of § 157.103 therefore provides that, upon request by the applicant, any order issuing a certificate under Subpart E shall provide conditional pre-granted authority to abandon the proposed new service and qualifying facilities at the expiration of the contracts underlying the new service. That section also provides that, under certain conditions, any pre-granted abandonment authorization will be subject to protest under § 157.106 by any customer currently receiving any service that would be abandoned. In this regard, § 157.103(f) requires that a certificate holder provide at least forty-five days written notice to a customer, if it intends to abandon any new service being provided to the customer upon expiration of their contract.

e. Flexible Receipt and Delivery Point Authority

Under paragraphs (g) and (h) of § 157.103, certificate holders are authorized, at the request of a shipper, to reduce or discontinue receipts or deliveries at a particular point and to increase or commence them at another point without prior notice, as long as the total volumes received or delivered do not exceed the total volumes the certificate holder is authorized to transport under the certificate issued under Subpart E. The receipt and delivery points to which natural gas volumes may be reassigned include facilities authorized to be constructed and operated pursuant to a blanket certificate issued under Subpart F of Part 157. This would include any sale tap authorized to be constructed and operated pursuant to a blanket certificate issued under Subpart F of Part 157.

f. Environmental Compliance

Comments. The Notice of Proposed Rulemaking solicited comments on environmental issues raised by the proposed rule. The Commission proposed in § 157.103(k) for application to optional certificates an elaborate set of environmental conditions identical to those now applied to the blanket certificate program under § 157.206 (d). As a result of the comments, the Commission now provides that, under § 157.103 (i), any certificate issued under Subpart E is subject to all the terms and conditions of § 157.206(d). This provision, which has worked well in ensuring that any construction under a blanket certificate will not adversely affect a sensitive environmental area, is appropriately applied to any construction that might arise in connection with sales or transportation arrangements approved under the new Subpart E of Part 157. Rather than restate all of these conditions in the final rule as was done in the NOPR, the rule incorporates the conditions by reference. See § 157.103(i) referencing § 157.206(d).

The Massachusetts Siting Council opposes the Commission's proposal on several grounds. The Council states its belief that the expedited certificate procedures do not provide adequate environmental safeguards and that the rule may impair the ability of state and local agencies and potentially affected individuals to participate meaningfully in the Commission's consideration of environmental matters regarding proposed construction projects. In particular, the Council is concerned that, because the proposed regulations permit more than one competing certificate, environmental impacts or harm could be magnified. The Council would deny an applicant a presumption of public convenience and necessity absent case-specific environmental review. Accordingly, the Council recommends that pipelines bear the burden of proving that the proposed project is in the public convenience and necessity and that the final rule provide strict yet timely notice and comment procedures which would allow interested state or local governments and individuals to submit environmental comments to the Commission. Finally, the Council raises a question about how the rule will protect residential subdivisions or urban areas from the adverse impacts of construction.

Commission Response. The Commission recognizes that pipeline construction or abandonments with removal of facilities can have environmental consequences. Its responsibilities under NEPA include identification of any adverse consequences, mitigation of those effects if possible, and a full analysis of all environmental impacts by the Commission, with public participation, if any proposed action is a major Federal action significantly affecting the quality of the human environment. The new procedures do not present the Commission with difficulties of environmental protection that it has not successfully addressed before in the pipeline certificate area. The procedures adopted permit case-specific environmental review by the Commission and impose on any certificate on-going requirements to protect the human environment.

Although the rule as adopted affords the applicant a presumption of public convenience and necessity, the statutory burden rests with that applicant. The Commission's responsibilities under NEPA will be discharged in conjunction with its responsibilities under the Natural Gas Act, but a proposed project is not merely presumed not to have an adverse impact.

Any applicant for a certificate under Subpart E must, under the rule adopted, file an Environmental Report under Appendix B to Part 2 of the regulations and other data, as required by § 157.14, which includes a statement concerning any facilities located in scenic, historic, recreational, or wildlife areas (Exhibit F-II), a statement that the guidelines of § 2.69 have been adopted (Exhibit F-III), and a statement concerning the requirements of the National Environmental Policy Act of 1969 (Exhibit F-IV). The exhibits contained in the application filed with the Commission become part of the public record in the case. Public notice is issued for all applications filed with the Commission, and interested persons are invited to intervene and/or protest within a stated deadline. In short, applications filed under Subpart E are treated virtually the same as other applications for purposes of ensuring compliance with applicable environmental laws.

If a certificate is issued, the certificate service is subject to § 157.206(d). That section requires a certificate holder to adopt the Commission guidelines, as set forth in § 2.69, for adverse environmental effects of a project, and to follow all other applicable laws, including the statutes, regulations, and compliance plans specifically enumerated in that section. Certificate holders are prohibited from engaging in a transaction that has a significant adverse effect on a sensitive environmental area. Moreover, although § 157.206(d) does not specifically refer to protection of the urbanized areas that concerns the Council, the Commission recognizes that *all* aspects of the human environment must be considered during environmental revisions under NEPA. If the Commission finds that, based on all available data and the application, that the transaction authorized under the requested certificate would not be a "major Federal action" under NEPA, the environmental assessment underlying the filing would be included in a public file and an appropriate finding made. For any major Federal action, an environmental impact statement would follow and extensive public comment and analysis will be solicited and used in its preparation.

The Massachusetts Siting Council presents no facts or hypothetical arguments to support its conclusion that

Subpart E procedures will magnify environmental impacts. Subpart E provides adequate case-specific review procedures to satisfy the Commission's obligations under NEPA, while accomplishing other significant regulatory objectives. The Commission declines to adopt requirements for Subpart E proceedings in addition to those that have proven to be workable in the past.

g. Commencement of New Service

Paragraph (j) of § 157.103 provides that the certificate holder must complete any authorized construction, extension, or acquisition of qualifying facilities and place such facilities in actual operation and commence all authorized services within a date specified when the certificate is issued. The certificate holder may apply to the Director of Office of Pipeline and Producer Regulation for an extension of this deadline.

6. *Hearing procedures.—Comments.* Section 157.104 sets forth the hearing procedures for Subpart E. Paragraph (a) states that the Commission will give notice of and schedule each application for public hearing at the earliest possible date, giving due consideration to statutory requirements and other pending matters.

Process Gas Consumers Group, Inc., Northern Natural Gas Company, and Mojave Pipeline Company request the Commission to establish an expedited hearing schedule. They note that no specific proposals are made in the NOPR to assure expeditious handling of applications. Therefore, Mojave Pipeline Company proposes that specific detailed pleadings be required from intervenors and protestors so that the Commission can determine and review precise issues prior to the hearing. It also proposes prompt deadline dates and expedited scheduling procedures to be followed by administrative law judges.

Commission Response. Although the Commission is committed to processing applications under Subpart E as expeditiously as possible, it declines to adopt specific procedures or deadlines that would be generally applicable to every application. The time required to process specific applications varies, depending on the specifics of the application and the nature of the opposition to it. Numerous issues will undoubtedly be eliminated by the applicant's assumption of risk. Nevertheless, the record provides no basis for predicting with any certainty the specific information needed to process every application with due regard for the rights of all parties or what minimum time periods would be suitable in all instances. However, if no protest or petition to intervene raises a general issue of material fact, paragraph (b) of § 157.104 provides that the Commission may upon request of the applicant dispose of an application in accordance with the shortened provisions of § 385.802.

a. Determination of the Public Convenience and Necessity

As provided in § 157.104, if an application by any person for the issuance of a certificate under Subpart E fully complies with the requirements of §§ 157.102 and 157.103, thereby demonstrating the applicant's willingness to assume all economic risks of the proposed activities, the Commission will presume, subject to rebuttal, that the provisions of section 7(e) of the Natural Gas Act have been satisfied and that the proposed new service is required by the present or future public convenience and necessity. Section 157.105 provides that a certificate requested under this Subpart E will be issued if the application complies with these requirements unless the presumption established by § 157.104 is rebutted.

Comments and Commission Response. Algonquin Gas Transmission Company and several other commenters argue that sections 7(c) and (e) of the NGA have imposed obligations on the Commission to determine affirmatively whether a requested certificate would be in the public convenience and necessity. Therefore, they assert that the Commission cannot presume a certificate application to be in the public convenience and necessity. The Commission disagrees for the reasons indicated below.

1. *The factors involved.* At the outset, the Commission notes that the rebuttable presumption would be available in two situations: Where a new service is being provided in an area *not* being served by a pipeline, or where a new service is being provided to an area *already* being served by a pipeline.

In the first situation, the public convenience and necessity is served in that service is being provided to consumers where such services were not formerly available in interstate commerce. In the second situation, however, new gas services may be provided to consumers who are already served or able to be served by another pipeline. Most of the comments on the rebuttable presumption in the proposed rule relate to issues raised in this latter "pipeline by-pass" situation.[8]

In one of the earliest Commission proceedings concerning an application for a certificate of public convenience and necessity, the Commission defined public convenience and necessity as meaning "a public need or benefit without which the public is inconvenienced to the extent of being handicapped in the pursuit of business or comfort or both—without which the public generally in the area involved is denied to its detriment that which is enjoyed by the public of other areas similarly situated." *Kansas Pipe Line & Gas Company, et al.*, 2 FPC 29 (1939). The Commission determined that the public convenience and necessity involved certain minimum requirements upon which the applicant must make a favorable showing.

Specifically, the applicants must show that (1) they possess a supply of natural gas adequate to meet those demands which it is reasonable to assume will be made upon them; (2) there exist in the territory proposed to be served customers who can reasonably be expected to use such natural-gas service; (3) the facilities for which they seek a certificate are adequate; (4) the costs of construction of the facilities which they propose are both adequate and reasonable; (5) the anticipated fixed charges or the amount of such fixed charges are reasonable; and (6) the rates proposed to be charged are reasonable. These factors are still relevant today (although the emphasis on specific factors has changed as conditions in the industry have changed). Applicants for certificates of public convenience and necessity must file information relevant to the determination of these issues. 18 CFR 157.14.

Although the final rule does not require an affirmative showing on each of these factors, nevertheless, the rule is designed to ensure that each of these requirements will be satisfied as they apply to individual projects. With respect to several of these requirements, the rule represents a natural extension of the evolving Commission policy.

For instance, the supply of natural gas traditionally required to support a finding of public convenience and necessity was the natural gas reserves available upon firm commitment. During times of relatively abundant supplies, a showing of dedicated gas reserves sufficient to justify the substantial capital expenditures was required. *Mississippi River Fuel Corp.*, 9 FPC 198 (1950); *Michigan Wisconsin Pipe Line Company, et al.*, 8 FPC 293 (1949). The minimum deliverability life showing required of a new pipeline was generally determined to be twenty years, and the showing required of an existing pipeline seeking to serve new or expanded markets was generally determined to be twelve years. *Midwestern Gas Transmission Company, et al.*, 21 FPC 653,657 (1959).

In 1964, the Commission promulgated § 2.61 of its regulations which relaxed the twelve year deliverability life requirement with respect to established pipelines with active gas procurement organizations whose lines extended into production areas in which exploration was continuing. For a new pipeline company seeking to initiate service, or an existing pipeline company seeking to serve major new markets or to serve major existing markets from new sources of supply over new routes, however, the deliverability life was required to be no less than twelve years. In later years, however, the Commission has issued certificates where the pipeline's deliverability life was significantly less than twelve years. In projects where the gas supply is uncertain, however, the Commission has imposed a rate condition which insulates customers from at least a portion of the risk that the probable or potential supplies would not materialize.

For instance, in *Cities Service Gas Company*, Docket No. CP76-500, 4 FERC ¶ 61,268 (1978), the Commission approved a proposal by Cities Service to convert an existing oil line to transport gas from Wyoming to Kansas, even though the applicant had no proved gas reserves under certificated gas purchase contracts. To protect ratepayers from any undue burden, the Commission approved a 100 percent commodity rate and imposed a condition requiring that the annual component for computing the unit cost of transmission must be at least 90 percent of the design capacity of the pipeline. *See also Arkansas-Louisiana Gas Company*, 47 FPC 583 (1972) (imposing a 100 percent commodity charge based on the greater of actual annual throughput or design capacity), *reh. den.*, 47 FPC 1040 (1972).

The final rule addresses the adequacy-of-supply issue by providing rate incentives, for applicants who are willing to assume the risks of the project, including the adequacy of supplies. The rate provisions of the order protect ratepayers from bearing increased costs if the facilities are used at less than capacity because anticipated supplies do not materialize. Moreover, because the applicant will bear all risks of failure, there is a strong incentive not to initiate projects based on inadequate supply estimates.

In considering whether available markets are adequate to support a project, the Commission has not required applicants to show firm commitments from each and every customer to be an accomplished fact, but only that there exist in the territory to be served customers who can reasonably be expected to use such natural gas service. *E.g., Transcontinental Gas Pipe Line Corporation*, 17 FPC 360 (1957); *Midwestern Gas Transmission, et al.*, 16 FPC 466 (1956). Where all risks are on the applicant, as they are in the final rule, however, the existence of such markets can be safely presumed.

Related to the issues of estimated supplies and markets is the adequacy of the capacity and physical character of the facilities applicants propose to construct. *See Kansas Pipeline & Gas Company, supra.* In recent years, the emphasis has focused on whether the gas supply is sufficient to justify the construction of the increased capacity. *See, e.g., Ozark Gas Transmission System*, 16 FERC ¶61,099 (1981). With respect to this issue, the same features of the rule that encourage accurate supply and market estimates provide incentive for designing facilities of optimal capacity. An applicant that builds excess capacity because he overestimates the volume of business he will do cannot reduce his representative levels in future rate cases. And because the rates are volumetric, he cannot recoup his costs through demand charges to customers who do not require the gas.

Thus, the traditional public-convenience considerations of adequate supplies, markets, and facilities are addressed by the incentives built into the final rule. Applicants have every reason to embark on projects only where these requirements are met. This is true even where another pipeline would be "by-passed" by such a project, because one of the underlying purposes of the NGA is the provision of reliable services to consumers, and certificates under the NGA to provide such services may not be exclusive.[6] Accordingly, the Commission considers it reasonable to presume these requirements have been met (subject to rebuttal) in light of the protection that the rule provides for ratepayers.

In evaluating certificate applications under conventional procedures, the Commission considers whether anticipated costs of construction are reasonable, because the rates to be filed will reflect these costs. In this regard, the record must show that estimated revenues will produce earnings sufficient to retire debt as proposed and meet interest and preferred dividend requirements. *Transcontinental Gas Pipe Line Corp.*, 9 FPC 32 (1950). The final rule is designed to minimize the need for initial scrutiny of this factor also. Because the risks of failure are entirely on the applicant, the applicant has every incentive to keep costs down. Failure to do so will render the project vulnerable to competition. This is so because volumetric rates will recover costs only to the extent that projected units of service are actually purchased and because minimum bills, demand charges, and other devices to guarantee revenue recovery are prohibited.

The NGA does not require a determination of just and reasonable rates in a section 7 proceeding as it does in one under sections 4 and 5. Nevertheless, in a section 7 proceeding, a careful scrutiny and responsible reaction to initial price proposals is required. *Atlantic Refining Co. v. Public Service Commission*, 360 U.S. 378 (1959). This issue is addressed in the rate provisions of the final rule. These provisions, which were discussed in detail above, are designed to ensure that proposed initial rates will be reasonable.

The commenters who argue that the Commission cannot presume a certificate to be in the public convenience and necessity misapprehend the function of the presumption established by § 157.104. The presumption is not a substitute for our obligation to determine whether individual applications are required by the public convenience and necessity. Rather, § 157.104 represents a determination that in the absence of countervailing circumstances, the public interest is served where an applicant perceives a market demand for a service that it can offer, is willing to attempt to enter that market by offering its services at competitive rates, and is willing to assume all the attendant economic risks itself, thereby eliminating such risks to the ratepayers. Where these factors are present and where offsetting factors that would be detrimental to the public interest are not present, then the barriers to certification should be reduced. By establishing expedited procedures and a presumption favoring complying applications, the rule provides incentives for competition where none exists, encourages willing competitors to enter established markets, and encourages pipelines to offer their services to presently off-system customers thereby turning them into on-system customers. Where this occurs, producers and consumers will both have access to greater markets and will be provided with greater options in the array of gas services available. Distributors who are now restricted to one pipeline may gain access to more than one pipeline.

These are the competitive benefits to consumers that the Commission forsees resulting from increased competition. The Commission believes that these benefits serve the public convenience and necessity as that phrase has been traditionally understood. That is to say, the benefits amount to "a public need or benefit without which the public is inconvenienced to the extent of being handicapped in the pursuance of business or comfort . . . ." *Kansas Pipe Line and Gas Company, supra.* But a prerequisite for achieving these benefits is a reduction in the administrative barriers that inhibit easy entry to and exit from the marketplace in the provision of new or expanded services.

On the other hand, the expedited procedures are not intended to provide certificates for operations that are inconsistent with the public interest. As indicated above, the final rule is designed to accommodate all of the factors that are traditionally considered in determining whether a certificate application is required by the public convenience and necessity under conventional procedures. In addition, paragraph (c) of § 157.104 provides that the presumption is rebuttable and paragraph (b)(2) of § 157.102 provides for the filing of protests to a certificate under Subpart E in accordance with the requirements for protests and interventions in § 157.10.

In evaluating applications under these procedures, the Commission will consider carefully all protests filed. Protestors should take notice, however, that the Commission will not consider speculative or unsupported allegations a sufficient basis for withholding a certificate where an applicant is willing to offer new services to customers under the optional procedure. Nor can the presumption of public convenience and necessity be rebutted simply because the protestor happens to be operating in a particular market and would prefer to continue operations insulated from all competition. In order to rebut the presumption of § 157.104, a protestor must set forth in its filing the specific allegations of unfair competition or other material harm that will result from the new service and must demonstrate why it would be inconsistent with the public convenience and necessity to issue the certificate under these circumstances. Individual protests will be addressed as they arise on case-by-case basis.

To raise issues sufficient to justify an evidentiary hearing, protestors must comply with paragraph (b)(2) of Section 157.102, which requires an intervenor to file a statement of all issues of fact raised and to identify those alleged to be material to a determination of whether the applicant's certificate is required by the public convenience and necessity. The Commission will not require evidentiary hearings to consider speculative or unsupported allegations. *See, e.g., General Motors v. FERC,* 613 F2.d 939 (D.C. Cir. 1979).

Northern Indiana Public Service Company and other commenters objected to the provision in the Notice that would have shifted the burden of proof to intervenors seeking to rebut the presumption in favor of the applicant. This provision has been deleted from the final rule. Burden of proof issues, to the extent they arise in individual cases, will be resolved in accordance with the Administrative Procedure Act.

V. Administrative Finding and Notices

A. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA)[1] generally requires a description and analysis of final rules that will have "a significant economic impact on a substantial number of small entities." [2] Specifically, if an agency promulgates a final rule under the Administrative Procedure Act (APA),[3] a final regulatory flexibility analysis may be appropriate. Each final regulatory flexibility analysis must contain (1) a statement of need for and objective of the rule, (2) a description of significant alternatives to the rule consistent with the stated objectives of the applicable statute that the agency considered and ultimately rejected, and (3) a summary of the issues raised by the public comments in response to the initial regulatory flexibility analysis, and the agency response to those comments. An agency is not required to make an RFA analysis, however, if it certifies that a proposed rule will not have "a significant economic impact on a substantial number of small entities." [4]

In the NOPR, the Commission certified that the proposed rule would not have a "significant economic impact on a substantial number of small entities," since most companies that must comply with this rule do not fall within the RFA's definition of small entity. In light of that certification, the Commission was not required to prepare an initial RFA analysis. In its notice of inquiry, notice of proposed rulemaking, and in this final rule, the Commission has nevertheless detailed the reasons, objectives, and the legal basis for this rulemaking. To the extent possible, the Commission has also discussed the probable effects of the rule on the Natural gas industry and the consuming public. In addition, the Commission considered a variety of significant alternatives to the regulations that it is now adopting in this order. The reasons for rejecting those alternatives are discussed in this document.[5]

Two commenters argue that the proposed rule required an initial RFA analysis because the rule would have an adverse effect on small producers and on small businesses that market petroleum products, services, and equipment (petroleum marketers). The rule, the Maurice L. Brown Company argues, would cause, among other harms, reductions in takes of gas from producers, resulting in gas being shut-in at the wellhead and reserves being abandoned. Similarly, the Petroleum Marketers Association complains that the rule will permit natural gas companies to raid markets served by fuel oil dealers, particularly by permitting pipelines to selectively discount transportation rates, buy out future take-or-pay liabilities, and use expedited certificate procedures to enter new markets. Neither commenter questions the Commission's conclusion that most companies that must comply with this rule do not fall within the RFA's definition of small entity, however. Rather, Petroleum Marketers Association argues that the requirement to prepare an analysis arises "even when the potentially affected small entities are not the direct targets of the regulations," since the legislative history of the RFA indicates that agencies must examine both the "direct and indirect effects of proposed regulation." [6]

The Commission believes that these commenters misunderstand the intent of the RFA. Congress was not asking agencies to study any potential economic effects on small entities not subject to the rule. As noted in previous proceedings,[7] this Commission, like other agencies,[8] is required by the RFA to analyze only the effect of rules on regulated small entities to which the requirements of the rule applies.[9] Congress was clear about the reach of the statute: when an agency issues a rule that applies to small entities, the agency must consider, and try to mitigate, the burden on those small entities of compliance with the rule.[10] The legislative history also echoes this focus on burdensome reporting and compliance requirements.[11]

Although Commission regulation affects small producers directly in some ways, neither small producers nor petroleum marketers are subject to the requirements of this rule. Specifically, the transporation programs in the rule are simplified voluntary programs for interstate and intrastate pipelines. The rule also permits customers of pipelines to modify existing service agreements. Second, the Commission retains its earlier policy of reviewing the prudency of payments made by interstate pipelines to extinguish minimum payment or purchase obligations in their gas contracts. In addition, the Commission indicates that it intends to grant certain kinds of producer-requested abandonments expeditiously, and restates procedures that the Commission will follow when reviewing these requests for abandoment. But, no new requirements are imposed on any producer, large or small, by these new procedures.[12] Third, the rule establishes optional expedited certification procedures for sales or transportation services by interstate pipelines. The rule will permit a pipeline to offer new services, facilities, and operations to gas customers.

For these reasons, the Commission concludes that there is no provision of the RFA that requires an analysis of the impact of this final rule on either small producers or petroleum marketers, since neither are subject to any requirements of this rule. Accordingly, the Commission affirms its earlier conclusion that, pursuant to section 605(b) of the RFA, this rule will not have a "significant economic impact on a substantial number of small entities."

B. Finding of No Significant Impact

Under section 102(2)(C) of the National Environmental Policy Act of 1969, 42 U.S.C. 4321, *et seq.* (NEPA), Federal agencies must prepare an environmental analysis of "major Federal actions significantly affecting the quality of the human environment." NEPA requires that such an analysis, known as an Environmental Impact Statement (EIS), be made part of any record of decision on such major Federal actions. In order to determine the need for an EIS, agencies prepare an Environmental Assessment (EA). An EA, which is a general overview of the nature and probable effects of the action, provides the basis for a Finding of No Significant Impact (FONSI) when an EIS is not necessary or facilitates the preparation of an EIS when it is required. In preparing an EA, the agency is also able to identify potential adverse impacts and to recommend or devise mitigating measures that will enable it to make a FONSI.

In its Notice of Proposed Rulemaking, the Commission directed staff to prepare an EA. Among other things, the EA focuses on transactions under NGPA section 311.

The transportation services under revised Subparts B, C, and H of Part 284 are authorized pursuant to NGPA section 311.[13] Section 311 and the complementary provisions in NGPA section 601(a) were designed to facilitate the transportation of natural gas among interstate and intrastate pipelines and local distribution companies, without subjecting intrastate pipelines and local distribution companies to Natural Gas Act regulation. One main objective of this legislation was to "save interstate pipelines great expense by avoiding the need to duplicate intrastate pipeline routes in order to obtain natural gas. . . ."[14] Section 311 therefore aids development of a national transportation network that utilizes existing facilities to the maximum extent.

Although the Commission may condition section 311 transactions, it does not certificate facilities constructed or physically abandoned solely to implement those services. Nevertheless, the Commission has decided to impose environmental conditions under new § 284.11, on any Part 284 service authorized under section 311 that involves construction or abandonment with removal of facilities. That condition applies existing § 157.206(d), which provides for compliance with a variety of environmental laws, guidelines for planning, locating, clearing and maintenance of rights-of-way and certain construction, and prohibits any significant adverse impact on sensitive environmental areas, among other provisions. Compliance with § 157.206(d) is therefore an ongoing condition of authorization to engage in the subject section 311 transactions.

Selecting from among the alternatives presented in the Environmental Assessment, the Commission finds that imposition of the conditions under § 284.11 is a satisfactory protection from adverse impacts from facilities that could be constructed by interstate or intrastate pipelines on a self-implementing basis under NGPA section 311. It is generally expected that the services that necessitate construction will generally involve taps, metering, and interconnecting facilities.

The EA concludes, first, that two parts of the proposed programs—a policy for relieving take-or-pay obligations and a billing procedure for allocating the cost of purchased gas—do not provide authorization to construct or abandon facilities. Despite some significant economic effects, these rules and policies have no foreseeable effect on the natural and physical environment. NEPA does not require analysis of exclusively economic or social effects that may arise from a Federal action. Although the Commission has given detailed consideration to the effect of these aspects of the rule, it has not done so in the context of NEPA review. Second, the EA concludes that the proposed optional expedited certificate procedures in Subpart E of Part 157 could involve sales or transportation services that necessitate construction of facilities or abandonment with physical removal of facilities, either of which would fall within the Commission's Natural Gas Act jurisdiction. The Commission addresses that issue, as discussed above, by imposing terms and conditions and providing case-specific examination of applications. Third, the EA concludes that, although transactions authorized under NGPA section 311 (Subparts B, C, and H of Part 284) do not subject the participants to Natural Gas Act jurisdiction, they will rely largely on existing facilities. Environmental conditions will mitigate any adverse impacts.

Based upon its review of the Environmental Assessment, the record in this proceeding, and the changes made in this final rule to the proposed procedures, the Commission concludes that issuance of the final rule is not a major Federal action significantly affecting the quality of the human environment. Therefore, an Environmental Impact Statement for the rule is not required.

C. Effective Date and Paperwork Reduction Act Statement

1. Generally, a rule becomes effective not less than 30 days after it is published in the **Federal Register.** A rule may become effective sooner if it is an interpretive rule or policy statement, if it relieves a restriction or grants an exemption, or if the agency finds that there is good cause to do so.[15] As described earlier in the section entitled "Schedule of the Final Rule," the Commission finds good cause making certain parts of this rule effective November 1, 1985. The remainder of this rule will become effective 30 days (or later as specified in the "Schedule") after publication in the **Federal Register.**

The Commission's "special marketing programs" (SMPs) and one of its "blanket certificate programs" [16] were recently invalidated by the United States Court of Appeals for the District of Columbia Circuit finding them discriminatory.[17] But, the court permitted these programs to continue until October 31, 1985, to allow the Commission time to implement a nondiscriminatory transportation program in compliance with the court's decisions. As amended by this final rule, Part 284 of the Commission's regulations establishes a comprehensive transportation program that cures the infirmities that the court found in the programs it invalidated. As a means of transition, these rules provide that transportation arrangements previously approved under SMPs and the blanket certificate program invalidated by the court may continue in limited circumstances. For example, the pipeline involved in certain Order No. 234–B transportation arrangement may continue to transport up to the full term of the underlying agreement, if it files for a blanket certificate that requires transportation on a nondiscriminatory basis. The previous transportation arrangements must, however, comply with nondiscriminatory access provisions, as appropriate. *See* new § 284.223(g)(2).

The transportation program established in this proceeding is a voluntary program that relieves restrictions on interstate pipelines by providing streamlined procedures for obtaining authorization to engage in certain transactions. Specifically, it is designed to remove unnecessary regulatory obstacles and to facilitate transportation of gas to any end user that requests transportation service. As a result, interstate pipelines can transport natural gas on behalf of any interstate or intrastate pipeline or any local distribution company without prior Commission approval, provided the pipeline meets conditions imposed by the new regulations. Similarly, an interstate pipeline may seek authorization to transport gas for any customer in lieu of seeking a section 7(c) certificate for each individual transaction. In essence, the new regulations remove, among other restrictions, the two-year limitation on NGPA section 311 transactions and grant the interstate pipeline an exception to the Commission's general rules and regulations that implement the Commission's authority to grant or deny requests to tranport gas under section 7 of the Natural Gas Act. Since the invalidated programs may not continue past October 31, 1985, the Commission has decided to make its new non-discriminatory transportation program effective on November 1, 1985, in order to permit the invalidated programs to continue in modified form.

In addition, the Commission believes that the regulations implementing its new nondiscriminatory transportation program must go into effect by November 1, 1985, to prevent a serious disruption to the transportation of natural gas. Many end users rely on the invalidated transportation programs for their gas supplies and would experience serious service interruptions. Since the new program responds to the concerns of the court in MPC I, MPC II and MPC III, the Commission believes the program should be implemented without interruptions in service to these end-users. For these reasons, the Commission also finds good cause to make the amendments to Part 284 of its regulations effective November 1, 1985.

The amendments to Parts 157, 250, 375 and 381 contained in this rule become effective November 18, 1985. The amendments to Part 2 of the Commission's regulations constitute a statement of policy that articulates the Commission's policy disposition and does not have the force and effect of law. Although the Commission is mindful that application of this policy in individual cases must be supported as if the policy had not been issued, it expects that, where appropriate, this approach to disposing of the type of take-or-pay payments and applications for abandonment provided for §§ 2.76 and 2.77 of the regulations will apply to Commission proceedings. In accordance with section 4(d) of the APA (5 U.S.C. 553(d)(2)), this statement of policy is effective immediately.

2. The information collection provisions in this rule are being submitted to the Office of Management and Budget (OMB) for its approval under the Paperwork Reduction Act [16] and OMB's implementing regulations.[17] Interested persons can obtain information on these information collection provisions by contacting the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426 (Attention: Ellen Brown ((202) 357–8272). Comments on the information collection provisions can be sent to the Office of Information and Regulatory Affairs of OMB, New Executive Office Building, Washington, DC 20503 (Attention: Desk Officer of the Federal Energy Regulatory Commission).

List of Subjects

18 CFR Part 2

Administrative practice and procedure, Electric power, Environmental impact statements, Natural gas, Pipelines, Reporting and recordkeeping requirements.

18 CFR Part 157

Administrative practice and procedure, Natural gas, Reporting and recordkeeping requirements.

18 CFR Part 250

Natural gas, Reporting and recordkeeping requirements.

18 CFR Part 284

Continental shelf, Natural gas, Reporting and recordkeeping requirements.

18 CFR Part 275

Authority delegations, Seals and insignia, Sunshine Act.

In consideration of the foregoing, the Commission amends Chapter 1, Title 18 of the Code of Federal Regulations, as set forth below.

By the Commission.

Kenneth F. Plumb,

Secretary.

Footnotes—I. Introduction

[1] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 50 FR 24130 (June 7, 1985).

[2] Interstate Transportation of Gas for Others, 50 FR 114 (January 2, 1985) (Phase I); Natural Gas Pipeline Ratemaking, Risk, and Financial Implications After Partial Wellhead Decontrol, 50 FR 3801 (January 28, 1985) (Phases II and III).

[3] 15 U.S.C. 717–717w (1982).

[4] 15 U.S.C. 3301–3432 (1982).

[5] 15 U.S.C. 717c(a) (1982).

[6] 15 U.S.C. 717d(a) (1982).

[7] 15 U.S.C. 717f(e) (1982).

[8] *Atlantic Refining Co. v. PSC of New York,* 360 U.S. 378 (1959) (CATCO).

[9] 15 U.S.C. 3431 (1982).

[10] 15 U.S.C. 3431(c) (1982).

[11] *See generally,* Title I NGPA, 15 U.S.C. 3311–3333; 15 U.S.C. 3431 (1982).

[12] *Phillips Petroleum Co. v. Wisconsin,* 347 U.S. 672 (1954).

[13] *Pennzoil v. FERC,* 645 F.2d 360, 378–379 (5th Cir. 1981), *cert. denied,* 454 U.S. 1142 (1982).

[14] 42 U.S.C. 7101–7352 (1982).

Footnotes—II. Background and Discussion

[1] *Maryland People's Counsel v. FERC, et al.,* No. 84–1090, slip op. (D.C. Cir., May 10, 1985) at 19.

[2] As detailed below, the fundamental changes going on in the industry have been masked to a substantial degree by the deflationary pressures on natural gas prices. This downward price pressure is a phenomenon affecting many segments of American industry. *See e.g.,* "The High Cost of Low Prices," New York Times, August 11, 1985 at F 1.

[3] *Wisconsin Gas v. FERC,* ______ F.2d ______ (D.C. Cir., Aug. 20, 1985), *mimeo,* at 38 (quoting *American Public Gas Association v. FPC,* 567 F.2d 1016, 1037 (D.C. Cir. 1977)).

[4] *See* "Final Report of the Federal Trade Commission," Senate Document No. 92, 70th Cong., 1st Sess., parts 84–A (text of final report), 84–B and 84–C (legal and economic appendices) (1936) (submitted to the Senate December 31, 1935) (hereafter cited as "1935 FTC report") at 87. The FTC report lay the

Natural Gas Act of 1938. See section 1(a) of the NGA (referencing the FTC Report).

[5] *See, e.g.*, K. Landes, "Oil & Gas in Three Dimensions," in *Exploration and Economics of the Petroleum Industry* (1968) at 17–24. *See also*, Initial Decision in *Permian Basin Area Rate Proceedings*, Docket No. AR61-1 (issued Sept. 17, 1964), *mimeo*, at 53–64 (summarizing testimony regarding directionality and concluding that directional drilling capacity first became statistically apparent after 1956).

[6] Initial Decision, *Permian Basin Area Rate Proceedings*, *supra*, at 64–72 (comparing performance of oil and gas drilling to oil and gas prices from 1945 to 1963). For example, it was only in January of 1959 that Phillips Petroleum Company began to require that recommendations for drilling expenditures indicate whether gas or oil was the primary drilling objective. *See* testimony of Jesse H. Foster, Jr. in the *Permian* proceedings, *reprinted in* Joint Appendix in *Skelly Oil Co. v. FPC* (10th Cir. Nos. 83–85, *et al.*) at 157–176.

[7] Subsequent statistical and econometric studies have confirmed the existence of this high degree of directionality. *See e.g.*, Khazzoon, "Gas Production Directionality," Public Utilities Fortnightly (Dec. 18, 1969) at 20–25; Challa, *Investment and Returns in Exploration and the Impact on the Supply of Oil and Natural Gas Reserves* (1979) (econometric model comparing price elasticities for oil and natural gas).

[8] Area Rate Proceeding, et al. (Permian Basin Area), 34 FPC 159 (Aug. 5, 1965) at 185–188 (noting that the directional drilling capability was the "touchstone" of the Initial Decision and discussing basis for decision to adopt separate vintages for old and new gas).

[9] *See* 1935 FTC Report, 227 to 278.

[10] *Id.*, at 112.

[11] *Id.*, at 112–113.

[12] Thus, one delivery point initially proposed by the New York Mercantile Exchange for its natural gas futures contract was Bamel storage field outside Houston. The application to trade futures contracts in natural gas is on file with the Commodity Futures Trade Commission.

[13] Perhaps the most graphic experience was the industry's extraordinary efforts during the 1976–1977 winter emergency to move supply quickly to areas of greatest need. The enactment of the Emergency Natural Gas Act of 1977 in February of 1977 created temporary exemptions from market entry and exit restrictions that removed the legal barriers to this operational *tour de force*.

[14] Table IV below.

[15] *See e.g.*, Natural Gas Pipe Line Co. of America's acquisition of Mississippi River Transmission Corp. and United Gas Pipe Line Co. (providing access to the Houston Ship Channel and other Texas and Louisiana Gulf Coast markets); Tennessee Gas Pipeline Co.'s acquisition of several Louisiana intrastate pipelines (providing access to Louisiana Gulf Coast markets).

[16] For example, ANR Pipeline Co., acquired by Coastal Corp., is a major importer of Canadian gas.

[17] For example, by being acquired by Houston Natural Gas Corp., Transwestern Pipeline Co., which had virtually no storage facilities, may be able to make use of Houston Natural's extensive storage facilities.

[18] Trunkline Gas Supply Co., 8 FPC 250 (1949) (adopting rolled-in pricing of new gas and facilities over dissent of Commissioner Draper); Panhandle Eastern Pipe Line Co., 10 FPC 185, 192 (1951) (noting that new construction and supply would create "correlative benefits" for all customers through release of pipeline transportation capacity).

[19] 31 FPC 1180, 1195–1199 (1964) (finding that United's system was not yet sufficiently integrated to adopt full rolled-in treatment).

[20] *See* Pierce, Alison and Martin, *Economic Regulation: Energy, Transportation and Utilities* (1980) at 598–620.

[21] Except, of course, to the extent that these differences may have implied the exercise of monopsony power in the part of the pipeline. *See* discussion of differing field prices in 1935 FTC Report, at 127–128 and 132–133.

[22] 34 FPC 159, 185–188 (1965), aff'd., 390 U.S. 747 (1968).

[23] *See, e.g., FPC v. Louisiana Power & Light Co.*, 406 U.S. 621 (1972); *see also*, Willrich, *The Administration of Energy Shortages: Natural Gas and Petroleum* (1976) (Chapter 4).

[24] As noted at the public hearing by a representative of Process Gas Consumers Group, *et al.*, in commenting on the announcement that the Great Plains project was being terminated at a substantial loss: "If you had no rolled-in pricing it [Great Plains] would have been gone a long time ago." August Hearing, Tr. at 714.

[25] Opinion Nos. 622 and 622–A, 47 FPC 1624 (1972) (orders approving incremental pricing for Cove Point and Elba Island LNG projects) (*rev'd. sub nom. Columbia LNG v. FPC*, 481 F.2d 651 (5th Cir. 1974)); and Opinion No. 796, 58 FPC 726 (1977) (initial order requiring incremental pricing of Trunkline LNG project).

[26] Opinion No. 786, 57 FPC 354 (1977) (decision on remand of Columbia LNG case allowing projects to proceed on rolled-in basis); Opinion No. 796–A, 58 FPC 2935 (1977) (decision on rehearing allowing Trunkline LNG project to proceed on rolled-in basis); Opinion No. 119, 15 FERC ¶ 61,106 (1981) (decision allowing Great Plains gasification project to proceed on rolled-in basis).

[27] Minimum bill payments for the services of the LNG terminals in 1984 were:

Southern Energy (Elba Island) $12,829,655
Docket No. RP80–136–000
Columbia LNG (Cove Point) $12,888,398
Docket No. TA80–2–21–002 (PGA80–3)
Consolidated LNG (Cove Point) $19,270,716
Docket No. TA80–2–22–003 (PGA80–5)
(IPR80–3) (LFUT80–2) and (RD&D80–2)
Trunkline LNG (Lake Charles) $81,931,846
Docket No. CP74–138

The Columbia charges are subject to a possible refund of $13,628,398 (which would leave a net of minus $739,702); Consolidated charges are subject to a possible refund of $18,285,475 (which would leave a net of $985,241).

Trunkline LNG in 1984 delivered 3,406,059 Mcf so some of their revenue is for gas sold. At $7.50–8.50/Mcf for this gas, about $25.5–$29 million of the $82 million could be for gas sold. From July through December, when no gas was sold, the charges were about $5 million a month suggesting about $60 million in minimum charges for the year with no gas being sold.

In the case of Great Plains, as much as $2 billion may eventually be lost.

[28] Market absorption capability: 100 units × $3.00 = $300. Available old gas: 90 units × $2.22 = $200. Market absorption capability available for unregulated gas: $300 − $200 = $100. Per unit price available for unregulated gas: $100 − 10 = $10.00.

[29] *See e.g.*, U.S. Energy Information Administration, *Monthly Energy Review* at 90–91 (December 1979) (DOE/EIA–0035) (12/79). In 1978 the average wellhead price of all natural gas increased from 87.3¢/Mcf in January to 96.1¢ in December for a yearly average of 90.5¢. Interstate pipelines paid producers an average of 74.0¢/Mcf in January and 95.8¢ in December, 84.1¢ for the yearly average. The wellhead price of "old" gas is probably most accurately measured as the November 1978 price paid by pipeline to producers: 90.1¢ Mcf.

See also, U.S. Energy Information Administration, *Natural Gas Monthly*, Table 5 (June 1985) (DOE/EIA–0130) (85/06). The "old" and "new" gas prices from PGA filings were not reported until 1981 when the old gas price was $1.23/Mcf in January, $1.25 in December, year average $1.22. For July 1985 the price is reported at $1.56/Mcf.

[30] "New" gas prices as paid by purchasers were not summarized until two years after the NGPA went into operation. The ceiling prices for December 1978 new gas as shown in FERC Statutes and Regulations § 271.101, ¶ 24,111 were:

Section	Mcf	Percent
102	$2.078	(60)
103	1.969	(31)
108	2.078	(6)
109	1.630	(3)

Since most of the new gas would have been Section 102 gas (60% of the new gas was Section 102 gas in 1981 and 1982), the average price of new gas in December 1978 was about $2.03.

[31] *See e.g.*, U.S. Energy Information, *Natural Gas Monthly*, Table 5 (June 1985) (DOE/EIA–0130) (85/06). This price dropped to $3.62 in July 1985.

[32] According to the chief deputy clerk of the Bankruptcy Court in the Western District of Oklahoma, approximately 110 Oklahoma companies involved in gas drilling had filed for protection under Chapter 11 between the beginning of 1982 and April of 1983. *See* "Gas Slump in Oklahoma," *New York Times*, (April 26, 1983), at D–1.

[33] For a rather colorful account of the deep gas bust, *see* Singer, "Annals of Finance: Funny Money," *The New Yorker*, April 22, 1985, April 29, 1985 and May 6, 1985.

[34] Interstate Natural Gas Assoc. of America, "The Gas Contracts Problem: Results of an INGAA Survey (Policy Analysis 83P–1 (May 1983)).

[35] Policy Analysis of Current and Future Natrual Gas Prices Under the NGPA (Study

prepared by I. M. Olson & Associates) (September 1984).

[36] August Hearing, Tr. at 465–466; 524–525; and 526–528.

[37] An exception is section 107(c)(5). This gas is high cost gas which remains subject to and is not removed from NGA jurisdiction unless it also qualifies under one of the categories that is so removed.

[38] *Pennzoil Co., et al. v. FERC*, 645 F.2d 360, 378–379 (5th Cir. 1981), *cert. denied*, 454 U.S. 1142 (1982).

[39] *See also, Maryland Peoples Counsel v. FERC*, No. 84–1090, slip op. at 9–10 (D.C. Cir., May 10, 1985) (summarizing MPC's argument).

[40] *See* Exhibit B.

[41] *See* examples cited in Williams and Meyers, *Treatise of Oil and Gas Law*, § 722 and form of agreement in § 741.1 (Article XV).

[42] *Sun Oil Co. v. FPC*, 364 U.S. 170 (1960).

[43] *California v. Southland Royalty Co.*, 436 U.S. 519 (1978) and *United Gas Pipe Line Co. v. McCombs*, 442 U.S. 529 (1979). For a comprehensive view of the law of dedication *see* Conine and Niebrugge, "Dedication Under the Natural Gas Act: Extent and Escape," 30 *Okla. L.Rev.* 735 (1977).

[44] *Transcontinental Gas Pipe Line Corp. v. FPC*, 488 F.2d 1325 (D.C. Cir. 1973) (the "La Gloria" proceeding).

[45] Willrich, *Administration of Energy Shortages: Natural Gas and Petroleum*, at 78–79 (1976).

[46] Policy with Respect to Certification of Pipeline Transportation Agreements, Docket No. RM75–25, Order No. 533, 54 FPC 521 (1975), 40 Fed. Reg. 41,760, *rehearing granted in part and denied in part*, Order No. 533–A, 54 FPC 2058, 40 Fed. Reg. 54,724 (1975) (codified at 18 CFR § 279), *affirmed*, *American Public Gas Association v. FERC*, 587 F.2d 1089 (D.C. Cir. 1978).

[47] In addition, the Commission allowed 60-day "emergency" sales under Order Nos. 402 and 402–A and under the Order No. 491 series, whereby sellers could commit gas to the interstate market for short term transactions. *See* Willrich, *supra*, at 78.

[48] Over the first two years of the program, certificates had been issued authorizing the transportation of a total of 15.8 Bcf. Order No. 2 [Reg. Preambles 1979–1981] FERC Stat. & Reg. ¶ 30,005 at 30,023 and 30,036 (Appendix A).

[49] The Commission promulgated a series of transportation programs, as outlined in our Phase I Notice of Inquiry, FERC Stat. & Reg. ¶ 35,516 at 35,604–35,605. The present discussion is abridged. For a full discussion of the evolution of these programs *see* Means and Angyal "The Regulation and Future Role of Direct Producer Sales," 5 *Energy L.J.* 1 (1984).

[50] Letter dated January 14, 1983 from Ray J. Lynch, President, Michigan Wisconsin Pipe Line Co. to Philip R. Sharp, Chairman, House Subcommittee on Fossil and Synthetic Fuels, *printed in* 1983 House Hearings on Contract Problem, at 385. Less than two years later, after 18 months under the Blanket Certificate Program, Mr. Lynch's company *alone* had transported approximately 70 Bcf of spot gas during calendar year 1984, more than any other single pipeline. See Exhibit C.

[51] Exhibit C shows 1984 volumes of 350.8 MMMBtu. Exhibit C shows total sales for resale of major interstate pipelines for 1984 of 9,020 Bcf.

[52] Transcontinental Gas Pipeline Corp., 23 FERC ¶ 61,199 (1983) (letter order approving uncontested rate settlement containing first marketing program), 23 FERC ¶ 61,221 (1983) (amending certificates and authorizing limited-term and pregranted abandonment), 23 FERC ¶ 61,460 (same, for Transco gas acquisition affiliate), *rehearing denied*, 24 FERC ¶ 61,052 (1983), *amended*, 25 FERC ¶ 61,219 (1983) (imposing conditions on SMP), *clarified and rehearing granted for purpose of further consideration*, 25 FERC ¶ 61,402 (1983), *modified*, 26 FERC ¶ 61,029 (1984) (modifying conditions), *appeal docketed*, *Columbia Gas Transmission Corp. v. FERC*, No. 84–4040 (5th Cir. filed Jan. 18, 1984), *transferred* to D.C. Cir., No. 84–1136, *withdrawn* with approval of the Court on Jan. 4, 1985.

[53] Item 6 of DOE's "Data and Analysis Submissions for the Record," (submitted at hearing held on August 1–2, 1985): "Analysis of Gas Spot Markets: Size, Structures, and Corporate Attitudes" (January 1985). The executive summary of this study is attached as Exhibit G. Exhibit J lists the more than 230 distribution companies and intrastate pipelines that have participated in transactions under NGPA section 311. Exhibit K lists the more than 300 companies that have received gas under NGA blanket transportation certificate.

[54] *Id.* at I–1.

[55] *Id.* at I–2.

[56] *Id.* This statement was true in January. It is even more so today. *See* August Hearing Tr. at 242 (statement of Lee K. Harrington on behalf of Southern California Gas Co. indicated that commencing August 1, 1985, SoCal Gas began moving 850,000 Mcf a day of spot gas to its customers). If those volumes were taken every day it would amount to over 300 Bcf a year, about the total yearly sales of a mid-sized interstate pipeline.

[57] Transcript of Public Hearing on NOPR (August 1–2, 1985), at 608–617 and 631–640 (hereafter cited as August Hearing, Tr. at ——). *See especially* Tr. at 636 (Tenngasco exchange sales rising from 30,000 Mcf/d to 600,000 Mcf/d in two years); Tr. at 638 (Energy Marketing Exchange sales rising from 10 to 15,000 Mcf/d to nearly 200,000 Mcf/d); Tr. at 638–639 (Vesta Energy sales rising from 25,000 Mcf/d to in excess of 200,000 Mcf/d).

[58] Statement of Joseph P. Kennedy II, President, Citizens Energy Corp., August Hearing, Tr. at 237–238.

[59] *See* copies of a few representative publications contained as Exhibit H.

[60] *See generally*, *Yankee to Start Spot Gas Trading Unit*, The Oil Daily, Dec. 7, 1984, at 1, col. 1 (copy attached as Exhibit I).

[61] N.Y. Pub. Serv. Law § 66–d through 66–g (McKinney Supp. 1984–85).

[62] W. Va. Code § 24–3–3a (Supp. 1984).

[63] New Mexico Stat. Ann. § 62–6–4.1 (Supp. 1985).

[64] Ky. Rev. Stat. § 278.505 (Supp. 1984).

[65] *Pennsylvania Public Utility Commission vs. Peoples Natural Gas Co.*, R–832315 and I–82 0073 (Order adopted January 13, 1984 and Order entered July 11, 1984) (mimeo at 9).

[66] Public Utilities Commission of California, *Investigation on the Commission's own motion into the operations of all gas corporations regarding transportation of customer-owned gas from the California border to industrial facilities within California*, Case No. 84–04–080 (April 18, 1984) (mimeo at 4).

[67] U.S. Energy Information Administration, *U.S. Oil, Natural Gas, and Natural Gas Liquids Reserves, 1984 Annual Report* (1985 Advance Summary cited in *Oil and Gas Journal*, September 9, 1985, p. 64); H.R. Rep. No. 98–814, 98th Cong., 2nd Sess. (1984), Committee on Energy and Commerce, H.R. 4277, "Natural Gas Market Policy Act of 1984," p. 21; U.S. Department of Energy, *Increasing Competition in the Natural Gas Market: Second Report Required by Section 123 of the Natural Gas Policy Act of 1978*, pp. 17–29 (1985) (hereafter *Second DOE 123 Report*); Testimony of George H. Lawrence, President, American Gas Association, before the Subcommittee on Energy Regulation and Conservation, Committee on Energy and Natural Resources, United States Senate, July 11, 1985, p. 5 (citing "the dramatic improvement in natural gas supplies since the NGPA was enacted. These supply improvements in response to the higher NGPA prices have demonstrated conclusively that interstate market gas supply problems during the 1970's reflected the inadequacies of wellhead price controls rather than the limits of the domestic gas resource base."); *Wisconsin Gas Co. v. FERC*, No. 84–1358 (D.C. Cir. 1985) slip op., at 23.

[68] *Second DOE 123 Report* at 77, 113, 137; S. Rep. No. 98–205, 98th Cong., 1st Sess. (1983), Committee on Energy and Natural Resources, S. 1715, "Natural Gas Policy Act Amendments of 1983" p. 10 ("In part the NGPA is not operating as originally designed. . . . [W]hat was not fully appreciated was that despite federal cost-passthrough regulations, pipelines could in effect use this 'cushion' [of 'old' price-controlled gas] to subsidize the acquisition of new and deregulated gas supplies. This occurs as a result of 'rolled in' gas pricing whereby a pipeline's customers are charged the average price of the gas they are consuming, rather than the marginal cost of new gas supplies."); Comments of Natural Gas Supply Association, Docket RM85–1–000 (Parts A–D), at p. 1 (NGSA "believes that current disorders in the natural gas market can only be eliminated if the industry is placed on a true competitive footing. This can be accomplished if . . . (ii) existing market distortions resulting from prior regulatory policies are eliminated."); *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 610 (1944), cited by *MPC II*, 761 F.2d 781–82 (1985); *MPC I*, 761 F.2d 770–71 ("The problem ultimately giving rise to the present litigation is that the 1978 predictions of the 1985 market were much in error. Factors ranging from the increased wellhead prices and impending total decontrol, to greater energy conservation, to the lower prices of competing fuels, have turned the natural gas shortages of the 1970's into a natural gas surplus. Thus, as early as the summer of 1983—a year and a half before the scheduled

deregulation of new gas—the formulary statutory maximum price for new gas had already reached or exceeded the market-clearing price in many geographic markets").

[69] *Pennzoil v. FERC*, 645 F.2d 360, 378–379 (5th Cir. 1981), *cert. denied*, 454 U.S. 1142 (1982); S. Rep. No. 98–205, *supra* at 6; H.R. Rep. No. 98–814, *supra* at 21; *Public Service Commission of New York v. Mid-Louisiana Gas Co.*, 463 U.S. 319, 330–31; 103 S.Ct. 3024, 3031 (1983) (the NGPA "has been justly described as 'a comprehensive statute to govern future natural gas regulation.' "); H.R. Rep. No. 95–496 (Part 4), 95th Cong., 1st Sess. (1977), Committee on Interstate and Foreign Commerce, H.R. 6831, "National Energy Act" at 97 ("Sales of natural gas subject to the provisions of this legislation, with the singular exception of interstate sales of old natural gas under existing contracts, are 'deregulated' from the provisions of the Natural Gas Act. While the Federal Power Commission is granted substitute regulatory powers with respect to such deregulated sales, the scope of these powers is more limited than the regulatory powers of the Commission under the Natural Gas Act. The complaint of producers regarding retroactive interference by the Commission with contractual arrangements would not arise under the Committee's program. The Commission's regulatory powers are limited to prospective application to contract terms and conditions; sanctity of contract is thereby assured.").

[70] *Permian Basin Area Rate Cases*, 390 U.S. 747, 777 (1968) (". . . rate-making agencies are not bound to the service of any single regulatory formula; they are permitted, unless their statutory authority otherwise plainly indicates, 'to make the pragmatic adjustments which may be called for by particular circumstances. *FPC v. Natural Gas Pipeline Co.*, *supra*, at 586."); *Public Service Commission of New York v. Mid-Louisiana Gas Co.*, 463 U.S. 319, 330–31; 103 S.Ct. 3024, 3031 (1983) (in adopting the NGPA, one of the Congress' "motivating purposes" was "to eliminate the dual market that distinguished between interstate and intrastate sales of natural gas."); Testimony of C. M. Butler III, Chairman, Federal Energy Regulatory Commission, before Committee on Energy and Natural Resources, United States Senate, November 5, 1981, p. 2 (". . . the most serious deficiency of the NGPA has not been its complexity or the dependence on the active participation of state agencies, but rather the statute's establishment of a new *dual market*, that is, one in which some gas prices are regulated while others are not. . . . The market-ordering problems created by NGPA's regime of partial regulation are already evident in the prices being paid for deregulated gas and in the supply problems of some interstate and intrastate pipelines."); Executive Office of the President, *The National Energy Plan* (April 29, 1977) (GPO/040-000-00380-1) at 16–18 ("The opportunities for supplementing domestic production of natural gas imports are small. . . . Therefore, the growing imbalance between America's domestic natural gas resources and its annual consumption is of particular concern. . . . Between 1976 and 1985, total U.S. production of natural gas is projected by the model to decrease from the equivalent of 9.5 million barrels of oil per day to 8.2 million barrels. Consumption, however, is projected to be the equivalent of 9.4 million barrels of oil per day. Consumption would increase to a much greater extent if supply were not limited. The difference . . . would be made up by imports, amounting to the equivalent of 1.2 million barrels of oil per day."); *U.S. Natural Gas Availability: Gas Supply Through the year 2000* (Wash. D.C.: U.S. Congress, Office of Technology Assessment, OTA-E-245, February 1985) at 3 ("Since 1978, the national perception of future natural gas availability has changed for several reasons, to one of relative optimism."); Testimony of Theodore R. Eck, Chief Economist, Amoco Corporation, before Subcommittee on Fossil and Synthetic Fuels, Committee on Energy and Commerce, U.S. House of Representatives (July 11, 1985) at 3 ("Under FERC's proposed regulations, natural gas imports would have to increase from 1 trillion cubic feet in 1985 to 6 trillion cubic feet in 2000 in order to meet our gas requirements.").

[71] Interstate Natural Gas Association of America, "The Gas Contracts Problem: Results of an INGAA Survey" (May 1983); S. Rep. No. 98–205, *supra* at 10; *Second DOE 123 Report* at 57; United States Department of Energy, *The First Report Required by Section 123 of the Natural Gas Policy Act of 1978* (July 1984) at 3–1 to 3–8 (hereafter *First DOE 123 Report*); *MPC I*, 761 F. 2d at 771; *MPC II*, 761 F. 2d 782–83.

[72] *MPC I*, 761 F. 2d at 771–72; *MPC II*, 761 F. 2d 782–83; Comments of Independent Petroleum Association of America, Docket No. RM85–1–000 (Parts A–D) at p. 3; *First DOE 123 Report* at 1–1; U.S. Energy Information Admininistration, *Natural Gas Monthly*, Tables (June 1985) (DOE EIA-0130) (85/06) (hereafter cited as *Natural Gas Monthly*) (showing decline in natural gas consumption from approximately 19.9 Tcf in 1980 to 17.5 Tcf in 1984).

[73] *Second DOE 123 Report* at 17–29; *Natural Gas Monthly*, *supra*, at Table 5.

[74] Comments of Natural Gas Equal Access, Docket No. RM85–1–000, (Parts A–D); *Second DOE 123 Report*, Chapters 6 and 7; *MPC II*, 761 F. 2d 782–83; H. Rep. No. 98–814, *supra* at 27.

[75] Comments of Process Gas Consumers Group, Docket No. RM85–1–000 (Parts A–D), at Attachment A, "Producer and Pipeline Marketing Progams and the Transition to Decontrol;" *Second DOE 123 Report* at 82–88; FERC Form 11 data (1985).

[76] Volumes transported under section 311 self-implementing authorizations have been increasing since the program began in late 1978, as have the number of transactions themselves. Measured in terms of the number of dockets assigned, there has been a dramatic proliferation of these transactions: 110 in 1979; 340 in 1980; 469 in 1981; 496 in 1982; 758 in 1983; and 1304 in 1984 (dates refer to fiscal years). During the period December 1, 1978, through December 1983, roughly 3.1 Tcf of gas were transported by interstate pipelines on behalf of intrastates, distributors, and Hinshaws. During the same period, more than 4.2 Tcf were transported by interstate pipelines for interstates and distributors. Approximately 6.8 Tcf were transported under interstate blanket certificates. Sales of gas by intrastate pipelines totaled approximately 2.7 Tcf during the period; *see also* Delhi Gas Pipeline Corporation, 19 FERC ¶ 61,189 (1982).

[77] Interstate Natural Gas Association of America, "Special Marketing Programs: Update 4 (April 1983 to May 1985)" (September 1985); Docket No. RM85–1–000 (Notice of Inquiry, Phase I) (listing transportation programs); See "Transmission Lines Step Up Contract Carriage," *Oil and Gas Journal* (August 26, 1985) p. 36 (citing INGAA study showing contract carriage of 355 Bcf for distributors and end-users in first quarter 1985, up from 260 Bcf in same period 1984); *but see also* testimony of Nicholas J. Bush NGSA, before Subcommittee on Energy Regulation & Conservation Subcommittee, Committee on Energy and Natural Resources, United States Senate, July 11, 1985, p. 12 ("It is said that the level of so-called 'voluntary carriage' in 1984 was 6.8 trillion cubic feet. However, an examination of that claim reveals that only 1.1 trillion cubic feet or about 16 percent of carriage volumes—and only 6 percent of total consumption—was for end-users and distributors. The remaining bulk of the carriage volumes, that is, 5.7 trillion cubic feet, was transported between pipelines and their producer affiliates and for other pipeline shippers.").

[78] Statement of Policy on Off-System Sales, 23 FERC ¶ 61,140 at 61,306; Comments of Process Gas Consumers, *et al.*, Docket No. RM85–1–000 (Notice of Inquiry, Phase I) at p. 5, n. 1; (*citing* interventions opposing discrimination in SMPs); *see also* Columbia Gas Transmission Corp., Initial Decision of Presiding Administrative Law Judge on Purchased Gas Adjustment Filings, 21 FERC ¶ 63,100 at 65,277 (finding that the "record shows that prices paid for Columbia for its section 107 gas have exceeded current market clearing prices. Furthermore, it has been shown that Columbia would have had difficulty selling such high-cost gas, if it were not able to roll it in with its much cheaper regulated gas supplies. It would appear that if all natural gas had been deregulated and there were little or no 'cushion' of low priced gas, section 107 gas would probably have sold at a price approaching the market clearing price, rather than at the higher levels at which it was sold. It is apparent that the ability to use the rolled-in pricing method contributed to the escalation of deregulated gas prices."); Tenneco Oil Co., *et al.*, 28 FERC ¶ 61,383 at 61,687 (1984), order on rehearing, 29 FERC ¶ 61,334 at 61,699–701 (1984) (removing requirement that released gas not cost less than a pipeline's weighted average cost of gas, but continuing to require that released gas be priced above NGPA 109 price ceiling).

[79] Statement of Policy on Off-System Sales, *supra*; Tenneco Oil Co., *supra*.

[80] Tenneco Oil Co., *supra*; *see also* Tenneco Oil Co., 31 FERC ¶ 61,717 (establishing inquiries tailored to specific SMP dockets).

[81] Interstate Pipeline Blanket Certificates for Routine Transactions and Sales and Transportation by Interstate Pipelines and Distributors, *Order No. 234–B*, 48 FR 34872

(1983) (to be codified at 18 CFR 157.209(e), *but see also* Certificate of Pipeline Transportation for Certain High Priority Users, *Order No. 27*, 44 FR 28425 (1979) (*codified at* 18 CFR Part 157, Subpart E (§§ 157–100–157.105)); Interstate Pipeline Transportation on Behalf of Other Interstate Pipelines, *Order No. 60*, 44 FR 68819 (1979); Certain Transportation, Sales and Assignments by Pipeline Companies Not Subject to Commission Jurisdiction under Section 1(c) of the Natural Gas Act, *Order No. 63*, 45 FR 1872 (1980). Statement of Policy on Distributor Access to Outer Continental Shelf Gas, *Order No. 92*, 45 FR 49247 (1980). Sales and Transportation by Interstate Pipelines and Distributors, *Order No. 319*, 48 FR 34872 (1983), 48 FR 35635 (1983), *rehearing granted in part and denied in part, Order No. 319–A*, 48 FR 51436 (1983) (to be codified *at* 18 CFR 157.209 and 157.202(a)(13), (14)).

[82] *MPC I* and *MPC II*, and Maryland People's Counsel v. FERC, Nos. 85–1029 *et al.* (D.C. Cir. Aug. 6, 1985); *but see MPC II*, Docket Nos. 84–1019, *et al.*; (D.C. Cir. June 28, 1985) (order granting stay of mandate).

[83] Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Commodity Bill Provisions, 49 FR 22778 (June 1, 1984) (Order No. 380); *order on reh'g*, 49 FR 31259 (Aug. 6, 1984).

[84] *Wisconsin Gas Co. v. FERC*, No. 84–1358 (D.C. Cir. 1985) slip op. at 43–45.

[85] U.S. Energy Information Administration, *Natural Gas Monthly supra* at Table 5 (citing average wellhead price of "new" gas of $3.65 in June, 1985); Comments of Natural Gas Supply Association, Docket No. RM85–1–000 (Parts A–D) at Appendix B (study by Foster Associates, Inc., citing average spot gas prices of $2.45–3.15 per Mcf in June, 1985); Foster Associates, Inc., "Analysis of High-Cost Purchases by Contract Termination Date," sponsored by American Gas Association (August 1985) (estimating that average pipeline purchase price of high-cost gas under contract by interstate pipelines is $4.49 per MMBtu, compared to $2.64 per MMBtu for all field purchases by such pipelines).

[86] *E.g.*, United Distribution Companies, ANR Pipeline, Transco, Natural Gas Pipeline of America, Process Gas Consumers, Docket RM85–1–000 (Notice of Inquiry—Phase I).

[87] *Wisconsin Gas Co. v. FERC*, No. 84–1358 (D.C. Cir. 1985), slip opinion at 38–39, 43.

[88] Comments of Process Gas Consumers, RM85–1–000 (Parts A–D) at pp. 207, footnotes 1–12 and authorities cited therein.

[89] Comments of Maryland People's Counsel, Docket No. RM85–1–000 (Parts A–D) at A–3; Second DOE 123 Report at Chapters 6, 7 and Appendix B; *e.g.* Comments of Amoco, Natural Gas Equal Access, MichCon, Yankee Resources, Illinois Commerce Commission, Con Ed, Florida Cities, Associated Gas Distributors, Docket No. RM85–1–000 (Notice of Inquiry, Phase I).

[90] As of April 1985, 13 major pipelines were utilizing the "representing levels" retention of revenues option; 9 were crediting Account 191 and 3 had not had a recent rate case in which to execise their option; *see* also comments of Columbia Gas Transmission, Baltimore Gas and Electric, INGAA, Tennessee Gas, Panhandle/Trunkline, El Paso, Consolidated Gas, United, ANR Co., Pacific Gas Transmission Co., Texas Eastern, Texas Gas Transmission Transco, and William Co., Docket No. RM85–1–000 (Notice of Inquiry, Phase I) for discussion of pipelines' reluctance to provide transportation services to their existing sales customers.

[91] *Hope Natural Gas Co.*, Opinion No. 228, 3 FPC 150, 189–91 (1942) (Establishing volumetric or straightline rates, but recognizing concepts of service quality and load factor); Tennessee Gas and Transmission Co., 3 FPC 574, 576–577 (1943) (Pipeline expansion during World War II required allotments of steel from War Production Board); *see also* 6 FPC 164 (1947) (recognizing that "a serious gas shortage exists in the Appalachian areas as well as throughout natural gas-consuming areas depending upon interstate gas transmission lines.").

[92] *United Gas Pipeline Company*, 50 FPC 1348 (1973); *First DOE 123 Report* at 3–3 ("Average take requirements increased dramatically in the 1973–1977 period as pipeline companies were encouraged to increase take requirements while bidding for scarce supplies."); Statement of Policy on Take-or-Pay Provisions in Gas Purchase Contracts, Docket No. PL–83–1–000, 3 FERC Stat. and Reg. ¶ 30,410 (1982), 47 Fed. Reg. 57,268 (1982), (*codified at* 18 CFR Part 2); Statement of Policy and Interpretative Rule on Regulatory Treatment of Payments Made In Lieu of Take-or-Pay Obligations, 50 Fed. Reg. 16,076 (April 24, 1985) (Docket No. PL85–1–000) (to be codified at 18 CFR 2.76).

[93] U.S. Energy Information Administration, *Structure and Trends in Natural Gas Wellhead Contracts* (November 1983); Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Commodity Bill Provisions, *supra* 49 FR 22778, n.12 (*citing* Atlantic Seaboard Corp., 38 FPC 91, 95 (1967).

[94] 15 U.S.C. 717b; 15 U.S.C. 717f (1982); *See* Comments of Process Gas Consumers, Columbia Distribution Companies, Panhandle Eastern, Natural Gas Pipeline/MRT, Pacific Gas Transmission (Supporting simplification of Commission's transportation regulations), Docket No. RM85–1–000 (Notice of Inquiry, Phase I); *cf.* Permian Basin Rate Cases, *supra*, 390 U.S. at 758 and n.14, (the Commission's regulation of producers' sales is "the outstanding example in the Federal government of the breakdown of the administrative process," citing Landis, Report of Regulatory Agencies to the President-Elect, printed for use of the Senate Committee on the Judiciary, 86th Cong., 2d Sess., 54).

[95] Comments of Natural Gas Supply Association, Docket No. RM85–1–000 (Parts A–D), (also at Notice of Inquiry, Phase I) ("Current [wellhead] ceiling prices, which are below just and reasonable rates, create market distortions that give some pipelines significant competitive advantages over others. . . . Any time the Commission makes a decision which might create the opportunity for gas-on-gas competition, it must take wellhead price disparities into consideration."); comments of Maryland People's Counsel, Docket No. RM85–1–000 (Parts A–D) at D–1 to D–5; comments of Department of Energy, (Parts A–D) at 44; *Second DOE 123 Report* at 137; comments of INGAA, (Parts A–D) at 3 (conceding the "average weighted price of Block 2 gas . . . generally exceed[s] current market clearing levels."); Comments of IPAA, (Parts A–D) at 3 ("Thus, as we approached January 1, 1985, the 'drop dead' date for much of NGPA's pricing features, we found wellhead prices of natural gas ranging from 28 cents on the low end to nearly $10 on the high end. But more importantly, we had seen average wellhead prices of gas increase by 30 percent between 1981 and 1984 while alternate liquid fuel prices had dropped by 20 percent."); S. Rep. No. 98–205, *supra* at p. 10.

[96] Permian Basin Rate Cases, *supra*, 390 U.S. at 793 (1968) (*citing* the "inability or unwillingness of interstate pipelines to bargain vigorously for reduced prices,"); H.R. Rep. No. 95–496 (Part 4), *supra* at 99–100 ("Using rolled-in pricing, interstate pipelines can bid the price of new supplies of natural gas to unprecedented levels of $5 per Mcf or more. . . . Using their unique ability to roll in new natural gas prices, interstate pipelines will literally suck natural gas away from the intrastate markets."); Hearings before Committee on Energy and Natural Resources, United States Senate, March 9–12, 22, 1983, S. Hrg. 98–85, Pt. 1, "Natural Gas Legislation" at 685 (testimony by NCGSA, "Eliminating the gas price 'cushion' brought about by forever-regulated gas will also end the subsidy which NGPA provides for the purchase of foreign natural gas and LGN imports."); at 691 (testimony by IPAA, "The high prices consumers are paying today are the direct result of regulatory machinations under NGPA."); at 791 (testimony of Texas Independent Producers & Royalty Owners Association, "We agree with Secretary Hodel who said that no consumer of natural gas should be forced to purchase supplies at a high price when lower priced supplies are available."); Hearings before Subcommittee on Fossil and Synthetic Fuels Committee on Energy and Commerce, U.S. House of Representatives, July 20, 26, August 6, 9, 1982, Serial No. 97–187A at 560–1, 570–590 (testimony by Petrochemical Energy Group that potential exists for pipelines to use rolled-in pricing to bid-up new gas costs after partial wellhead decontrol in 1985, citing American Gas Association, "A Statistical Analysis of Bidding Trends for Decontrolled Natural Gas under the NGPA," March 19, 1982, and Foster Associates, Inc. study concluding "The cost roll-in effects resulting from continued [wellhead price] controls on such a large volume of relatively low-priced gas [after January 1, 1985] will allow gas transmission companies to pay substantial premiums for decontrolled gas supplies."); *Natural Gas Monthly*, *supra* at Table 5.

[97] Comments of DOE at 38–40; AGA at 33; Process Gas Consumers at C–1 to C–5; Columbia Gas Transmission Corp. at 15–16; Mojave Pipeline Company, Docket No. RM85–1–000 (Parts A–D).

[98] *U.S. Natural Gas Availability: Gas Supply Through the Year 2000*, Office of Technology Assessment, *supra* at 21–22 (*citing* potential of small gas fields, new gas from old fields, and uncertanties over potential of frontier areas, such as deepwater

Gulf of Mexico, deep Anadarko Basin, and Western Overthrust Belt).

[99] *Second DOE 123 Report*, at S–2, 5–16; *Natural Gas Monthly*, *supra* at Table 5 (average wellhead prices of NGPA sections 102, 103, 108 and 109 "new" gas have dropped from $3.77 per Mcf in January, 1985 to $3.65 per Mcf in June, 1985); AGA *Monthly Gas Utility Statistical Report*, June, 1985 (average monthly gas utility prices to residential consumers have increased from $5.70 per MMBtu in January, 1985 to $6.80 per MMBtu in June, 1985); "Consumer Prices: Energy and Food," Bureau of Labor Statistics, U.S. Dept. Labor, for period ending August, 1985 (survey of 12-month changes in natural gas prices to residential consumers in 25 metropolitan areas, showing median change of −0.7 percent, increases of 0.5 percent to 7.7 percent in ten cities, declines of 0.4 percent to 12.4 percent in fourteen cities, no change in one city); Producer Price Index, Bureau of Labor Statistics, U.S. Dept. of Labor, August, 1970 to August 1985 (*cited* in *Energy Users News*, September 30, 1985 at 16):

ENERGY PRICE CHANGES: AUGUST 1970 TO AUGUST 1985

[The figures below show how much energy prices have changed from year to year, based on August components of the Producer Price Index. All figures are percentages, sometimes plus, sometimes minus. The items are steam coal, natural gas, liquefied petroleum gases (such as propane), electricity, gasoline, distillate oil and residual oil]

	Steam coal	Natural gas	Liq. P. gases	Elec.	Gasoline	Dist. oil	Resid. oil
1984–85	−0.5	−6.6	−13.1	1.5	4.6	−11.2	−16.2
1983–84	3.9	2.9	−19.2	6.9	−11.3	−6.3	0.7
1982–83	0.4	3.1	20.0	3.0	−9.5	−10.5	−1.7
1981–82	8.6	22.6	−12.8	7.5	−5.5	−6.5	−6.0
1980–81	8.1	29.1	6.5	15.6	11.7	22.2	24.7
1979–80	7.9	31.0	44.9	19.7	41.1	28.4	21.6
1978–79	8.4	34.5	34.8	9.9	52.4	72.7	63.3
1977–78	21.1	15.2	−11.5	3.7	6.5	1.2	−6.4
1976–77	12.1	45.6	30.0	14.5	6.4	14.9	14.2
1975–76	−3.3	31.8	19.3	9.4	4.7	6.5	−1.7
1974–75	−0.5	44.6	−19.6	14.4	17.7	6.5	1.6
1973–74	64.2	15.8	142.3	32.1	73.6	105.2	144.8
1972–73	12.4	9.2	33.4	5.7	15.7	30.1	14.0
1971–72	4.7	6.8	0	3.3	5.2	2.0	−5.3
1970–71	19.7	7.5	0	11.0	7.2	2.5	13.8

Source: "Energy Price Changes" is from Bureau of Labor Statistics data compiled for the Producer Price Index. Except for steam coal, the items are the same as those used in "Energy Price Trends."

[100] Comments of DOE at 3, 6, estimating proposed rulemaking, if adopted, could have net economic benefits of $1.2 to $4.9 billion (non-discriminatory transportation) and $2.2 billion (block billing procedure); Process Gas Consumers at 13 (*citing* DOE estimate that lack of non-discriminatory transportation has adverse economic effects of $9.7 billion annually), and 14–16 (discussing example of impact on specific manufacturing plants of lack of access to transportation services); *Second DOE 123 Report*, *supra* at Appendix B, Examples of Anticompetitive Behavior in Gas Transmission.

Section III. Response to General Comments and Review of Alternatives

[1] E.g., Comments of DOE, INGAA, AGA, NGSA, IPAA, PGC, United Distribution Companies, Maryland People's Counsel, Central Illinois Light Company, PEG, California Public Utilities Commission, Docket RM85–1–000 (parts A–D).

[2] See *generally*, comments in Docket No. RM85–1–000 (Notice of Inquiry, Phases I–III) especially PGC at pp. 1–16; Exhibit R (attached list of take-or-pay dockets); letter dated May 20, 1985, to Raymond J. O'Connor from the Honorable Jim Wright, Majority Leader, Robert H. Michel, Republican Leader, John D. Dingell, Chairman, Committee on Energy and Commerce, and James T. Broyhill, Ranking Minority Member, Committe on Energy and Commerce, U.S. House of Representatives; letters of December 18, 1984, and March 14, 1985, to Raymond J. O'Connor, Georgiana Sheldon, Anthony Sousa, Oliver Richard, and Charles Stalon, from the Honorable John D. Dingell and James T. Broyhill; MPC I, II, and III, *supra*; Comments in Docket No. RM84–7–000 (Impact of Special Marketing Programs on Natural Gas Companies and Consumers); Comments in Docket No. RM82–26–000 (Impact of the NGPA on Current and Projected Natural Gas Markets); Wisconsin Gas Company v. FERC, *supra*; S. Hrg. 98–95 Pts 1, 3, 98th Cong., 1st Sess., Committee on Energy and Natural Resources, United States Senate, Hearings on Natural Gas Legislation (1983); H. Rep. Serial No. 98–7, 98th Cong., 1st Sess., Subcommittee on Fossil and Synthetic Fuels, Committee on Energy and Commerce, U.S. House of Representatives, Hearings on Natural Gas Contract Renegotiation and FERC Authorities (1982); testimony in Special Marketing Program dockets Nos. CP83–452–000, CI84–332–000, CI84–374–000, CI83–269–000, CI84–485–000, CP83–333–000, CP84–244–000, CI85–36–000, CI84–510–000, CI85–89–000, CI85–51–000, CI84–556–000, CI84–555–000, CI85–17–000, CI84–571–000.

[3] E.g., Maryland People's Counsel, Natural Gas Equal Access, Docket RM85–1–000 (Parts A–D).

[4] E.g., Iowa State Commerce Commission; *but see* testimony of Christine Hansen, Commissioner, Iowa State Commerce Commission, on behalf of National Association of Regulatory Utility Commissioners, H. Rep. Serial No. 98–19, 98th Cong., 1st Sess., Subcommittee on Fossil and Synthetic Fuels, Hearings on Proposed Changes to Natural Gas Laws (1983) at 46 ("We believe it is time to look closely at alternatives which would reduce or eliminate the monopoly position of pipelines in the natural gas industry.")

[5] See Notice of Request for Supplemental Comments, Docket RM85–1–000 (Part D) (October 9, 1985).

[6] E.g., PGC at D–3 and D–6, D–14; but see at D–28 (". . . 'the market ordering' purpose of [NGPA Title II] incremental pricing has been a dismal failure . . .".)

[7] E.g., Colorado Interstate Gas Co.

[8] E.g., ANR.

[9] *See generally* Docket No. RM85–1–000 (Notice of Inquiry, Phases I–III).

[10] MPC I, *supra* at 6.

[11] American Smelting and Refining Company v. FPC, 494 F.2d 925, 940–941 (1974), cert. denied, 419 U.S. 882 (1974).

[12] See, e.g., MPC II, *supra* at 15, citing Gulf States Utilities Co. v. FPC, 411 U.S. 747, 760 (1973); Northern Natural Gas Co. v. FPC, 399 F.2d 953, 958 (D.C. Cir. 1968).

[13] MPC I, *supra* at 17; MPC II, *supra* at 15.

[14] Wisconsin Gas Co. v. FERC, No. 84–1358, slip. op. at 23–24 (D.C. Cir., August 20, 1985).

[15] *Id* at 41.

[16] *Id* at 40.

[17] *See generally* L. Sullivan, Antitrust 354–65 (1977).

[18] Impact of the NGPA on Current and Projected Natural Gas Markets, 47 FR 19157 (May 4, 1982) (Docket No. RM82–26).

[19] Indicated Producers, initial comments filed in Docket No. RM82–26.

[20] California Public Utilities Commission, initial comments filed in Docket No. RM82–26.

[21] Columbia Gas Transmission Corp. RP84–11 (Oral Argument held on March 7, 1984).

[22] Revisions to PGA Regulations, 49 FR 18539 (May 1, 1984).

Section IV. A. Transportation

[1] Bonbright, J., *Principles of Public Utility Rates*, 287–316 (1961) (New York: Columbia University Press).

[2] Maryland People's Counsel v. FERC, 761 F.2d 768 (D.C. Cir. 1985); Maryland People's Counsel v. FERC, 761 F.2d 780 (D.C. Cir. 1985).

[3] *Id.*

[4] *See* §§ 284.105 and 184.125.

[5] Transok, Inc., for example, states that, if the new rules are made applicable to existing NGPA section 311 arrangements, intrastate pipelines will face an unduly burdensome task since they may have to renegotiate existing contracts, refile numerous reports, and re-petition for rate approval on all transactions. Transok believes that the Commission should not revise its regulations where such action will effectively force modifications of the terms and conditions of existing section 311(a)(2) transportation arrangements. Further, Transok points out the pipelines have relied on § 284.125 of the existing regulations which provides that transportation arrangements may only be modified at the time of the extension requests.

As discussed, *infra*, the Commission has determined, for the reasons given by Transok and other commenters, that NGPA section 311 transportation arrangements commenced prior to the effective date of this rule should be grandfathered to shield them, for the remainder of their current two-year terms only, from the transportation access conditions, but not the rate conditions adopted herein.

As another example, several commenters were concerned because the proposal was not clear as to how the access requirements could affect existing customers' contract demand rights. Designated Producers, for example, suggests that, if sufficient firm capacity is not available to satisfy all requested new firm transportation service, only the available firm capacity would be pro-rated among shippers requesting new firm service. Designated Producers believes such a qualification to the access requirements is necessary and appropriate to ensure that a pipeline's existing firm sales customers would continue to receive as much transportation service as they were entitled to under their gas purchase contracts prior to the effective date of the proposed rules.

[6] *E.g.*, INGAA.

[7] Section 4(b) of the Natural Gas Act, 15 U.S.C. 717c(b), provides that,

No natural-gas company shall, with respect to any transportation or sale of natural gas subject to the jurisdiction of the Commission, (1) make or grant any *undue preference or advantage* to any person or subject any person to any *undue prejudice or disadvantage*, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

Section 5(a) of the Natural Gas Act, 15 U.S.C. 717d(a), provides that,

Whenever the Commission, after a hearing had upon its own motion or upon complaint of any State, municipality, State commission, or gas distributing company, shall find that any rate, charge, or classification demanded, observed, charged or collected by any natural-gas company in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory, or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.

[8] Some of those commenters that support the non-discriminatory access condition as proposed or subject to certain clarifications include Indicated producers, NGS Association, Texaco, Association for Equal Access to Natural Gas Markets and Supplies (NGEA), Independent Producers Association of America (IPAA), Panhandle Producers, Oklahoma Independent Petroleum Association, Delhi Gas, Acadian Gas, Williston Basin, Valero, Great Lakes Transmission, Texas Gas Transmission, CIG, Process Gas Consumers, American Paper Institute, B. F. Goodrich, Fertilizer Institute, New England Energy Group, Petrochemical Energy Group, American Bakers Association, Aluminum Company of America.

Those that oppose the non-discriminatory access condition include INGAA, Tennessee Gas, Panhandle Natural Gas, Pacific Gas Transmission, Northern Natural, TETCO, Texas Gas Transmission, Air Products, Texas Railroad Commission, Association of Texas Intrastate Pipelines, Transco, Mountain Fuel Resources, and Algonquin Gas Transmission.

[9] *Id.*

[10] CIG, Panhandle, Louisiana Resources, City of Wilcox, Arizona, and INGAA.

[11] *See* comments of those persons listed *supra*, note 8, as opponents of non-discriminatory access condition.

[12] INGAA, CIG, and Panhandle. In support of this position, CIG and several other comments cite Central West Utility Co. v. FPC, 247 F.2d 306 (3rd Cir., 1957), and Northern California Power Authority v. FPC, 514 F.2d 184, 189 (D.C. Cir. 1975). In addition, several commenters, including Panhandle, cite Manhatten General Equipment Co. v. Commission of Internal Revenue, 297 U.S. 133 (1936), and Campbell v. Galeno Chemical Co., 281 U.S. 599 (1930), for the proposition that non-discriminatory access to firm transportation condition would modify and extend the statutory provisions of the NGPA; i.e., make law rather than merely administer the statute and prescribe implementing rules.

[13] Panhandle and Amoco Production Company.

[14] Oklahoma Natural Gas Company, Amoco, Louisiana Intrastate, Louisiana Resources Company, Transok, Algonquin, Commonwealth Gas, Monterey, Producer's Gas, Mesa, Texaco, Inc., and Mustang, Fertilizer Institute, American Bakers Assoc., Air Products, Association of Texas Intrastate Pipelines, and Indicated Producers.

[15] Atlantic Refining Co. v. Public Service Commission of New York, 360 U.S. 378, 388–89 (1959) (CATCO).

[16] *Id.* at 389.

[17] *See* "Final Report of the Federal Trade Commission," Senate Document No. 92, 70th Cong., 1st Sess., Parts 84–A (text of final report), 84–B and 84–C (legal and economic appendices) (1936) (submitted to the Senate December 31, 1935) (hereafter cited as "1935 FTC report") at 87. The FTC report lay the basis for the legislative proposals that soon became the Natural Gas Act of 1938). *See* section 1(a) of the NGA (referencing the FTC Report). *See also*, Memorandun on the Necessity for Federal Regulation of Interstate Transportation of Natural Gas, as Discussed by Reports of the Federal Trade Commission, Other Reports Made Pursuant to the authority of Congress and Decisions of the Supreme Court of the United States, submitted by Dozier A. DeVane, Solicitor.

[18] *E.G.*, INGAA.

[19] H.R. 5423, introduced February 6, 1935, 74th Congress 1st Sess.

[20] *Id.* at 143–44.

[21] 15 U.S.C. 717c and 717d (1982).

[22] *See* Consolidated Gas Transmission Corp. v. FERC, Nos. 84–1240, *et al.*, slip op. (D.C. Cir. Sept. 17, 1985) ("FERC has the authority under section 16 of the Natural Gas Act to order retroactive refunds to enforce conditions in certificates.")

[23] *E.g.*, Lousiana Intrastate Pipeline Company.

[24] *Id.*

[25] Joint Explanatory Statement of the Committee on Conference, H.R. 5289, Natural Gas Policy Act of 1978, at 106.

[26] Section 311(c) provides that "any authorization granted under this section shall be under such terms and conditions as the Commission may prescribe." Section 501(a) provides in part that the Commission "is authorized to perform any and all acts," and "to prescribe, issue, amend, and rescind such rules and orders as it may find necessary or appropriate to carry out its functions under this Act."

[27] Neither NGPA section 601(a)(2)(A)(ii) nor 311(a)(2)(B) exempt intrastate pipelines transporting under section 311 from the NGA prohibitions on undue discrimination.

[28] 124 Cong. Rec. H. 13,118–13, 119 (Oct. 14, 1978).

[29] Committee on Interstate and Foreign Commerce, Report on *H.R. 6831*, "National Energy Act" (July 19, 1977) at 92–95.

[30] Algonquin Gas Transmission Co.

[31] Valero Transmission Co.

[32] Department of Energy, pp 14–17.

[33] *See* § 284.8(b) and 284.9(b).

[34] Great Lakes Transmission Co., Texas Gas Transmission Co. and Colorado Interstate Gas.

[35] *E.G.*, El Paso Natural Gas Co., the Iowa State Commerce Commission, Inland Gas Co., Natural Gas Pipeline Co., Mountain Fuel Resources Co., Pacific Gas Transmission Co., Phillips Petroleum Co., Tennessee Gas Pipeline Co., Texas Eastern Transmission Co. and Williston Basin Interstate Pipeline Co.

[36] *E.g.*, Citizens Energy Corp.

[37] *E.g.*, Natural Gas Equal Access, Seagull Energy Corporation, NGS Association, Washington Water Power Co., National Fuel Gas Corp., Citizens Energy Corporation, Northridge, American Paper Institute, Terra Chemicals, Inc.; Dept. of the Air Force, Tennessee Gas Pipeline Co., El Paso Natural Gas Co., Northern Natural Gas (HNG—Internorth), Pacific Gas Transmission Co., Natural Gas Pipeline Co., Texas Eastern Transmission Co. and Williston Basin Interstate Pipeline Co.

[38] *E.g.*, Natural Gas Equal Access and Yankee Resources Inc.

[39] *E.g.*, Public Service Electric Gas Co.

[40] *See* Transcript, Public Conference, RM85–1–000, p. 533 (August 1, 1985)

[41] *Id.* at p. 533.

[42] Process Gas Consumers Group.

[43] *E.g.*, Fertilizer Institute.

[44] Transcript, Public Conference, RM85–1–000 (Aug. 1, 1985) p. 128.

[45] *Id.* at 188.

[46] *See* Comments of Process Consumers, Docket No. RM85–1–000 (Parts A–D) at B–2 to B–4, and Appendix F; *Second DOE 123 Report* at Chapter 5.

[47] *See* Table C–1, discussed in Part B, *infra.*; see also Process Gas Consumer Comments at Appendices B and F.

[48] *E.g.*, INGAA.

[49] *E.g.*, Mustang Fuel Corporation.

[50] *See*, § 284.223(c)(4).

[51] *Id.*

[52] *E.g.*, Designated Producers.

[53] Tennessee Gas Pipeline Co., 21 FERC ¶ 61,004 (1982). *See also*, MPC I *supra*, 761 F.2d at 781–8.

[54] *E.g.*, Oklahoma Independent Petroleum Association.

[55] The majority of these commenters were local distribution companies but also included a substantial number of interstate pipelines, industrial end-users and public

[56] *E.g.*, American Gas Association, Northern Border Pipeline Co., Petrochemical Energy Group, Tennessee Gas Pipeline, Tenneco Oil Co., and Texaco Inc.

[57] *E.g.*, Process Gas Consumers.

[58] *E.g.*, Algonquin Gas Transmission Co.

[59] Seagull Energy Corporation.

[60] American Gas Association.

[61] H.S. Phillips v. FERC, 586 F.2d 465, 469 (5th Cir. 1978) (5th Cir. 1978) and authorities cited therein.

[62] For example, Columbia Gas Transmission Corp., *et al.*, 31 FERC ¶ 61,307 *modified on rehearing*, 31 FERC ¶ 61,372 (1985), the Commission approved a reallocation of total daily entitlements (TDE) on the Columbia system, resulting in many customers cutting the TDE by as much as 15 percent. In recent years the Commission has dealt with a number of similar cases in which firm sales entitlements were plainly in excess of that which the customers custoemrs desired to purchase. *See* Transcontinental Gas Pipe Line Corp., Docket No. CP85-264-000 (application filed Feb. 4, 1985), Northern Natural Gas Co., Docket No. CP85-183-000 (application filed Dec. 17, 1984).

[63] Elimination of Variable Cost From Certain Natural Gas Pipeline Minimum Commodity Bill Provisions, 49 Fed. Reg. 22,778 (June 1, 1984); *reh'g denied*, 49 Fed. Reg. 31,259 (Aug. 6, 1984).

[64] *E.g.*, Indicated Producers, Mobil Oil Corp., Pan Alberta Gas Ltd., Natural Gas Pipeline Co., INGAA, and ANR Pipeline Co.

[65] *E.g.*, Pacific Gas & Electric, Consolidated Edison, and Mountain Fuel Resources.

[66] *E.g.*, INGAA, Panhandle Eastern Pipeline Co., and Trunkline Gas Co.

[67] *E.g.*, Indicated Producers, Texaco, Inc., INGAA, Tennessee Gas Pipeline, T.W. Phillips, Panhandle Eastern/Trunkline Gas Co., Natural Gas Pipeline, Transco, Arkla, KN Energy, Memphis Light, Gas, and Water, and APGA.

[68] *See supra* note 64.

[69] *E.g.*, Tennessee Gas Pipeline Co.

[70] INGAA, Panhandle Eastern Pipeline Co., Trunkline Gas Co., Natural Gas Pipline Co., Columbia Gas Transmission Co., and Marathon Oil Co.

[71] INGAA, Panhandle Eastern Pipeline Co., Trunkline Gas Co., and Natural Gas Pipeline Co.

[72] Wisconsin Gas Company v. FERC, —— F.2d ——, Docket Nos. 84-1358 *et al.* (D.C. Cir. Aug. 20, 1985) slip op. at 44.

[73] *E.g.*, Columbia Gas Transmission Co.

[74] Pennzoil v FERC, 645 F.2d 360, 381 (5th Cir. 1981), *cert. denied*, 454 U.S. 1142 (1982).

[75] Producer access via CD adjustments.

[76] Memphis Light, Gas, and Water.

[77] Cincinnati Gas & Electric Co., and Southern Natural Gas Co.

[78] Memphis Light, Gas and Water, APGA, CILCO, and SIEGCO.

[79] *Id.*

[80] Tennessee Gas Pipeline Co., Natural Gas Pipeline Co., Arkla, MRT, and INGAA.

[81] *E.g.*, Columbia Gas Transmission Co., Natural Gas Pipeline Co., INGAA, and Tennessee Gas Pipeline Co.

[82] Arkla.

[83] Panhandle Eastern Pipeline Co./Trunkline Gas Co., MRT, and Tennessee Gas Pipeline Co.

[84] SIEGO, and T.W. Phillips.

[85] APGA, and Sabine Corp.

[86] Panhandle Eastern Pipeline Co., and Trunkline Gas Co.

[87] Northwest Central Pipeline Co., and Entex, Inc.

[88] Northwest Pipeline Co.

[89] 18 CFR Part 201 (1985), Account 191, Unrecovered purchased gas costs.

[90] Indicated Producers, Department of Energy, Illinois Commerce Commission, Process Gas Consumers, California Public Utility Commission, Kentucky Public Service Commission, Southern Natural Gas Co., Fertilizer Institute, United Distribution Companies, NI Gas, Baltimore Gas & Electric Co., AGA, Iowa Southern Utilities Co., and Northern States Power Co.

[91] *E.g.*, NIPSCO, APGA, Associated Gas Distributor Co., South Carolina Pipeline, NI Gas, and American Paper Institute.

[92] *See supra* note 91.

[93] *See generally*, Williams *et al.*, Staff Report on *Interstate Gas Pipeline Ratemaking* (Federal Energy Regulatory Commission, Office of Pipeline and Producer Regulation) (September 1982).

[94] For a discussion of the history of two-part rates, *see id* at Part III and Tab A.

[95] Peoples Gas Light & Coke Co., Associated Gas Distributors, United Distribution Companies, Southern Indiana Electric & Gas Co., Niagara Mohawk Power Co., Department of Energy, State of Michigan and the Michigan Public Service Commission.

[96] INGAA, Panhandle Eastern Pipeline Co./Trunkline Gas Co., Consolidated Natural Gas Co., ANR Pipeline Co., Northwest Central Pipeline Co., Commonwealth Gas Co., New England Energy Group, and Seagull Energy Corp.

[97] INGAA, Columbia Gas Transmission Co., Texas Eastern Transmission Corp., AGA, National Fuel Gas Co., and Northern States Power Co.

[98] Northwest Pipleline Co., Northwest Central Pipeline Co., Peoples Gas Light & Coke Co., New York Public Service Commission, and Kentucky Public Service Commission.

[99] Southern Indiana Electric & Gas Co., and California Public Utility Commission.

[100] Czar Resources, Arkla, Consolidated Edison Co., United Distribution Companies, Southern Indiana Electric & Gas Co., NI Gas, City of Wilcox, Consolidated Fuel Supply Inc., and Process Gas Consumers.

[101] Indicated Producers, NGS Association, Natural Gas Pipeline Co., Williston Basin Interstate Pipeline Co., Northern States Power Co., Air Products, and Department of Energy.

[102] 15 U.S.C. 717(c)(1982).

[103] 28 FPC at 983.

[104] 81 Cong. Rec. 6722 and 6727 (1937).

[105] For a discourse of the rate practices prior to the enactment of the NGA, *see* 1935 FTC Report, *supra*, n.17. For a discussion of the Commission's industrial use rate, *see generally*, Marston, P., *An Historical Perspective on Industrial Natural Gas*, Pub. Util. Fort. July 11, 1985, at 13.

[106] *See generally*, *Second DOE 123 Report*, *supra* at ch. 6.

[107] *See* Areeda and Turner, Predatory Pricing and Related Practices under Section 2 of the Sherman Act, 88 Harv. L. Rev. 697, 716-720 (1975).

[108] *See generally* Sherman Antitrust Act, 15 U.S.C. 1-7 (1982); Robinson-Patman Act, 15 U.S.C. 13, 13a, 13b, 21a (1982).

[109] *See supra* pp. II-32-35.

[110] *E.g.*, Ottertail Power Co. v. United States, 410 U.S. 366 (1973) (congressional rejection of comprehensive regulatory scheme for electric industry supports rejection of anti-trust exemption claim). *See also* Gulf States Utilities Co. v. FPC, 411 U.S. 747 (1973).

[111] *E.g.*, Texas Eastern Transmission Corp.

[112] *E.g.*, Transok, Inc., Assn. of Texas Intrastate Pipelines, Monterey Pipeline, and INGAA.

[113] *E.g.*, Valero Transmission Co. Indicated Producers, Michigan Consolidated Gas Co., Public Service Electric and Gas Co., NI-Gas, Seagull Energy Crop., and Maryland People's Counsel.

[114] *E.g.*, Public Services Electric and Gas Co.

[115] Indicated Producers.

[116] Mountain Fuel Resources Inc.

[117] Maryland People's Counsel, Process Gas Consumers Group, and UGI Corp.

[118] *E.g.*, Valero Transmission Co. Baltimore Gas & Electric, Alcoa, Northwest Pipeline, The Fertilzer Institute, Michigan and Consolidated Gas Co.

[119] *E.g.*, Comments to the Notice of Proposed Rulemaking of Baltimore Gas and Electric Co. and United Distribution Cos. and the Comment to Phase I of the Notice of Inquiry of Indicated Producers, TRANSCO and Baltimore Gas and Electric Co.

[120] *E.g.*, Seagull Energy Corp., and Alcoa.

[121] Sales and Transportation of Natural Gas, 44 FR 52179 (Sept. 7, 1979).

[122] 18 CFR 157.209(a)(1985).

[123] *E.g.*, Seagull Energy Corp, Air Products, Michigan Paperboard Co., and the New England Energy Group.

[124] *E.g.*, Northwest Pipeline Co., N.Y. Mercantile Exchange, Process Gas Consumers Group, DuPont de Nemours Carolina Utility Customers Assoc., Inc., National Fuel Gas Distribution Corp., and Yankee Resources, Inc.

[125] Oklahoma Independent Petroleum Association. Also, see Northwest Pipeline Corporation, New England Energy Group, and DuPont.

[126] *E.g.*, Texas Gas Transmission Corp., ANR Pipeline, and Yankee Resources, Inc.

[127] *See* proposed § 284.223(b).

[128] *E.g.*, INGAA, Northwest Pipeline and El Paso Natural Gas Co.

[129] Yankee Resources, Inc. and Seagull Energy Corp.

[130] Yankee Resources, Inc.

[131] *E.g.*, ANR Pipeline Co., Great Lakes Gas Transmission Co. and Northridge Petroleum Marketing, Inc.

[132] *E.g.*, Mesa Petroleum, Seagull Energy Corp., NI-Gas, Acadian Gas Pipeline System, Williston Basin Interstate Pipeline Co., National Gas Pipeline Co., Texas Gas Transmission Co., Natural Gas Pipeline Co., and Michigan/Michigan PSC.

[133] Mesa Petroleum Co.

[134] Seagull Energy Corp., NI-Gas, and Acadian Gas Pipeline System.

[155] Williston Basin Interstate Pipeline Co.

[156] Natural Gas Pipeline Co. and Texas Gas Transmission Corp.

[157] *E.g.*, Natural Gas Pipeline Co. And Michigan/Michigan PSC.

[158] NI-Gas.

[159] Seagull Energy Corp., Michigan Consolidated Gas Co., NI-Gas Co. and Texas Gas Transmission Co.

With regard to the suggestion of commenters to modify FERC Form No. 2 to provide for reporting of this information, we note that page 312, Account 489, Revenue From Transportation of Gas of Others, currently requires certain details concerning revenue from transportation transactions under proposed Subparts B, C, and G of Part 284. The Commission is considering whether to revise FERC Form No. 2.

[140] State of Michigan/Michigan PSC and El Paso Natural Gas Co.

[141] National Fuel Gas Distribution Corp. and National Fuel Gas Supply Corp.

[142] State of Michigan/Michigan PSC.

[143] *E.g.*, Seagull Energy Corp. and Natural Gas Pipeline Co. of America.

[144] Texas Gas Transmission Corp.

Section IV. B. Take-or-Pay/Producer Abandonment Policy Statement

[1] Section 2.76 was promulgated in the Commission's Statement of Policy and Interpretative Rule issued April 10, 1985, 50 FR 16,076 (Apr. 24, 1985) (to be codified at 18 CFR § 2.76) (Docket No. PL85–1–000) (Policy Statement).

[2] *E.g.*, Columbia HNG-InterNorth, ANR Pipeline, INGAA, El Paso Natural Gas Co., Tetco, Texas Gas Transmission Co., Transcontinental Gas Pipeline Corp., Southern, and N.W. Central.

[3] ANR Production, Coastal Oil & Gas Corp., Pennzoil, Indicated Producers, Tenneco, and Texaco.

[4] *E.g.*, Amoco.

[5] *E.g.*, New York Public Service Commission, CPUC, and American Gas Association.

[6] Illinois Commerce Commission.

[7] Iowa State Commerce Commission.

[8] *E.g.*, Amoco, Tenneco, DuPont, Mesa Petroleum Co., Oklahoma Independent Petroleum Association, Consolidated, Columbia, HNG-InterNorth, ANR Pipeline, NGSA, Texaco, Inc., Mobil, United Distribution Companies, NSP Cos., Connecticut Utilities, DOE, C/LEC, Great Lakes, and APGA.

[9] INGAA, Minnesota Department of Public Service, *et al.*, NGSA, AGD, and Missouri PSC.

[10] ANR Pipeline, Tennessee, DOMAC, ANR Production, Indicated Producer, Elizabethtown, Coastal, Amoco, HNG–InterNorth, Process Gas, Oklahoma Industrial Petroleum Association, Columbia, and Mobil.

[11] DuPont, Texaco, and Indicated Producers.

[12] Process Gas Consumers Group.

[13] Amoco.

[14] ANR Pipeline.

[15] Process Gas Consumers Group, Mountain Fuel Resources, NI–Gas, Utah Division of Public Utilities, and Columbia Gas Distribution Cos.

[16] Panhandle Eastern Pipe Line Co., Northern Natural, and Trunkline Gas Co.

[17] Maryland People's Counsel, Texas Gas Transmission, Commonwealth, Utah Division of Public Utilities, APGA, and Pogo Producing Co.

[18] Elizabethtown, Tenneco, Maryland People's Counsel, Commonwealth, Louisville Gas, and Electric, and Pogo Producing Co.

[19] American Paper Institute, APGA, Northwest Pipeline, NI–Gas, Utah Division of Public Utilities, Air Products, ANR Pipeline, HNG–InterNorth, Texas Gas, Maryland People's Counsel, Texaco, Mountain Fuel Resources, AGA, Natural, Owens Corning, Tetco, Missouri PUC, Panhandle/Trunkline TIPRO, Indicated Producers, Mesa Petroleum Co., AGD, Cascade Natural Gas Corp., UGI Corp., Process Gas, *et al.*, Air Products, Department of Energy, Pennzoil, and Michigan/Michigan PSC.

[20] Panhandle/Trunkline, Columbia, Department of Energy, N.W. Central, United Gas Pipe Line, HNG–InterNorth, Natural Gas, AGA, Texas Gas, Consumers Power Co., Columbia Distribution Cos., Great Lakes, Process, *et al.*, Commonwealth Gas, Illinois Commerce Commission, APGA, AGD, Piedmont Natural Gas., Mich Con, and NI–Gas.

[21] Natural Gas, East Tennessee Group, Elizabethtown, Commonwealth, Columbia, N.W. Central, New England Energy Group, Peoples Gas/North Shore, and Laclede.

[22] *E.g.*, INGAA, Tenneco and Panhandle Eastern Pipeline Co.

[23] *E.g.*, Petition for Rulemaking in the Matter of Take-or-Pay Clauses in Producer/Pipeline Contracts, Docket No. RM83–46–000; Petition Requesting Re-Evaluation of Policy Requiring Rate Base Treatment of Prepayments Made Under Take-or-Pay Contracts, Docket No. RM83–54–000; Petition for Declaratory Order and Expedited Rulemaking in the Matter of Take-or-Pay Provisions in Producer/Pipeline Contracts, Docket No. RM83–55–000; Petition for Rulemaking in the Matter of Reformation of Take-or-Pay Clauses, Docket No. RM84–17–000.

[24] *E.g.*, INGAA.

[25] *See supra* note 1.

[26] *See also*, Mississippi River Transmission Corp., 30 FERC ¶ 61,155 (1985); Sunray Mid-Continent Oil Co. v. FPC, 364 U.S. 137 (1960), Policy Statement, 50 FR at 16079; Tenneco Oil Co. *et al.*, 28 FERC ¶ 61,383 *order on reh'g*, 29 FERC ¶ 61,334 (1984).

[27] Policy Statement, 50 FR at 16080 (to be codified at 18 CFR 2.76(e)).

[28] These orders required the presiding judge to: (1) Conduct the hearing provided by the order on an expedited basis, (2) set a deadline for closing the hearing record approximately 40 days after issuance of the order, and (3) issue the initial decision not later than 60 days after the record was closed.

[29] *See supra*, notes 25 and 26.

[30] *See e.g.*, Tenneco Oil Co. *et al.*, 28 FERC ¶ 61,383, *order on reh'g*, 29 FERC ¶ 61,334 (1984); Columbia Gas Transmission Corp. et al., 25 FERC ¶ 61,220 (1983) (certification Columbia SMP). *See also*, Mesa Petroleum Co., 28 FERC ¶ 61,081 (1984).

[31] *E.g.*, Northern Natural Gas (HNG-InterNorth), Seagull Energy Corp., Mountain Fuel Resources, Inc., and Michigan Consolidated Gas Co.

[32] *E.g.*, Maurice L. Brown.

[33] Natural Gas Supply Association.

[34] Columbia Gas Transmission Corp.

[35] 15 U.S.C. 3312(d) and 3318 (1982).

The rule provides, as proposed, for high cost, but still regulated, gas to be included in Block 2. Gas in the high cost categories specified by the NGPA were allowed incentive prices in order to accelerate new gas discoveries, encourage development of supply sources that are expensive to bring into production, avoid underrecovery of marginal wells, or encourage the flow of intrastate gas into the intersate market. High cost gas includes:

Section 102(d) gas: gas produced from old leases on the Outer Continental Shelf (OCS) from reservoirs which were not discovered before July 27, 1976;

Section 103(c) gas: gas which still includes gas from new onshore production wells that (1) was committed or dedicated to interstate commerce on April 20, 1977, and uncommitted gas produced from wells less than 5,000 feet;

Section 105 gas: gas subject to intrastate contracts on the date of enactment of the NGPA;

Section 106(b) gas: gas subject to intrastate rollover contracts on the date of enactment of the NGPA;

Section 107(c)(5) gas: gas that was not produced under the conditions described in sections 107(c)(1)–(4); and

Section 108 gas: gas produced from stripper wells.

[36] Tenneco Oil Co., *supra*, note 26.

[37] Application of Getty Oil for permission to abandon sale of Gas AR LA Gas Co., filed October 3, 1983. Cities Service Oil & Gas Corp., application for limited-term partial abandonment and cancellation of service under FERC Gas Rate Schedule 42.

[38] *E.g.*, Coastal Oil and Gas.

[39] *E.g.*, Sabine Corporation.

[40] *E.g.*, Indicated Producers, Texaco, Amoco, Dupont, Department of Energy (DOE), and INGAA.

Section IV. C. Optional Expedited Certificate

[1] 15 U.S.C. 717f (1982).

[2] Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Commodity Bill Provisions, 49 FR 22778 (1984), 3 FERC Stat. & Reg. ¶ 30,571, Docket No. RM 83–71–000, affirmed in part and remanded in part, Wisconsin Gas Company v. FERC, No. 1358 (D.C. Cir., August 20, 1985); 18 CFR 154.111 (1985).

[3] *Cf.* Maryland People's Counsel v. FERC, No. 85–1029 (D.C. Cir. August 6, 1985). (In this case the court ruled that the Commission's special marketing programs were unduly discriminatory because they allowed pipelines to insulate their core markets (the high priority markets served by LDCs) from competition where cheaper SMP gas was available to LDCs.

[4] Subpart E is specifically designed to prevent pipelines, who must assume the economic risks in order to qualify for an expedited certificate, from shifting costs among their customers if the project is not successful. Since LDC rates are not subject to federal jurisdiction, the final rule does not

address cost allocations among LDCs customers.

[5] Natural Gas Pipeline Company of America, 30 FERC ¶ 61,017 (1985), *reh'g denied*, 32 FERC ¶ (1985).

[6] 15 U.S.C. 717f(g) (1982).

Section V. Administrative Findings and Notices

[1] 5 U.S.C. 601–612 (1982).

[2] *Id.* 603(a).

[3] *Id.* 553.

[4] *Id.* 605(b).

[5] *See* Section III. Response to General Comments and Review of Alternatives.

[6] Petroleum Marketers Association of America (quoting remarks of Senator Culver) (emphasis in original removed).

[7] Construction Work in Progress for Public Utilities; Inclusion of Costs in Rate Base, 48 FR 24323 (June 1, 1983) (Docket No. RM81–38–000, Order No. 298), *rehearing granted in part and denied in part*, 48 FR 46012 (Oct. 11, 1983); Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Commodity Bill Provisions, 49 FR 22778 (June 1, 1984) (Docket No. RM83–71–000, Order No. 380), *reh'g denied*, 49 FR 31259 (Aug. 6, 1984).

[8] *See, e.g.*, 47 FR 5215 (Feb. 4, 1982) (final rule of Securities and Exchange Commission).

[9] Mid-Tex Electric Cooperative, Inc., *et al.* v. FERC, Nos. 83–2058, *et al.* (decided Sept. 24, 1984). Slip op. at 26–31 (No RFA analysis is necessary when the 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).

[10] *See* Congressional Findings and Declaration of Purpose, section 2, Pub. L. No. 96–354, codified at 5 U.S.C. 601, note (1982).

[11] For a discussion of the legislative history, *see* Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Commodity Bill Provisions, *supra*, note 7, 49 FR at 22791.

[12] These procedures are set forth as general statements of policy. *See* new §§ 2.76 and 2.77.

[13] Transactions under new § 284.221–.223 (Subpart G) are not subject to new § 284.11 because any facilities that might be constructed to implement such transactions must be authorized under Subparts E or F of Part 157. Other environmental procedures, including § 157.206(d), will apply in that event. Any construction or abandonment of facilities by local distribution companies that is incidental to services under new § 284.224 is subject to state or local regulation.

[14] H.R. Rep. No. 95–543, 95th Cong., 1st Session 45 (1977). *See* 123 Cong. Rec. 31163, 31165 (September 27, 1977).

[15] 5 U.S.C. 553(d) (1982). *See* Attorney General's Manual on the APA, at 37 (1947). (The purpose of the exception to the delayed effective date for a rule that relieves a restriction "would appear to be that the person affected by such rules are benefitted by them and therefore need no time to conform their conduct so as to avoid the legal consequences.

[16] *See* 28 FERC ¶ 61,383 (1984), *order on rehearing*, 29 FERC ¶ 61,334, and Order No. 234–B, 48 FR 34,872 (Aug. 1, 1983) (codified at 18 CFR 157.209(e) (1985)). Under these programs, producers are permitted to sell gas committed to a particular pipeline to another purchaser, while crediting the volume of such sale to the pipeline's high-priced purchase obligations. Similarly, these programs expanded an interstate pipeline's authority to transport gas for end users, including those who use gas as a boiler fuel of violation." *Id.*

[17] Maryland People's Counsel v. FERC, 761 F.2d 768 (D.C. Cir. 1985) (MPC I); Maryland People's Counsel v. FERC, 761 F.2d 780 (D.C. Cir. 1985) (MPC II); Maryland People's Counsel v. FERC, No. 85–1029 (D.C. Cir. Aug. 6, 1985) (MPC III).

[18] 44 U.S.C. 3501–3520 (1982).

[19] 5 CFR 1320.13 (1985).

PART 2—[AMENDED]

1. The authority citation for Part 2 is revised to read as follows:

Authority: Department of Energy Organization Act, 42 U.S.C. 7101–7352 (1982); Exec. Order No. 12,009, 3 CFR Part 142 (1978); Federal Power Act, 16 U.S.C. 791a–828c (1982); Natural Gas Act, 15 U.S.C. 717–717w (1982); Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432 (1982); Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601–2645 (1982); and the National Environmental Policy Act, 16 U.S.C. 4321–4361 (1978), unless otherwise indicated.

2. In § 2.76, paragraph (e) is revised to read as follows:

§ 2.76 Regulatory treatment of payments made in lieu of take-or-pay obligations.

* * * * *

(e) *Certificate amendments and abandonment.* With regard to natural gas the sale of which is subject to the Commission's jurisdiction under the Natural Gas Act, if any payments referred to under paragraph (a) of this section are accompanied by a change in or a termination of, the first seller's contractual obligation to provide natural gas service, the Commission will, as a general policy under sections 7(c) and 7(b) of the Natural Gas Act, expeditiously grant any certificate amendments or abandonment authorizations, required to effectuate such contractual or service modifications.

In cases where a producer abandonment application is based on payments made pursuant to this policy statement, the interstate pipeline making the payments will be deemed to have waived any right to oppose the abandonment.

3. Part 2 is amended by adding new § 2.77 to read as follows:

§ 2.77 Policy on expedited producer abandonment.

(a) *Situations in which expedited producer abandonment will be appropriate.* Abandonment, including partial or temporary abandonments, of service by a producer will be reviewed on an expedited case-by-case basis and will be granted where permitted by the public convenience and necessity, in cases where:

(1) The producer is subject to substantially reduced takes without payment; or

(2) The parties have entered into a take-or-pay buy-out pursuant to § 2.76.

(b) *Procedures.* Certificate and abandonment applications related to this policy statement will, as a general policy, be considered on an expedited basis under existing administrative procedures as follows:

(1) Applications will be noticed promptly and a period not to exceed 15 days will be provided for comments or interventions.

(2) In cases where the applications are unopposed, as a matter of policy they will be promptly granted by the Director, Office of Pipeline and Producer Regulation, pursuant to delegation of authority contained in 18 CFR 375.307 (1985).

(3) In cases where certificate or abandonment applications are opposed, the Commission will consider the objections and rule on the applications if possible or, if necessary will set the applications for expedited hearing. The Commission will require that initial decisions be issued not more than 60 days following the close of the record and will endeavor to issue a final decision within 60 days following issuance of the initial decision.

(4) Parties requesting expedited consideration under these procedures should include in their application a request for expedition and a reference to Docket No. RM85–1–000.

4. The authority citation for Part 157 is revised to read as follows:

Authority: Natural Gas Act, 15 U.S.C. 717–717w (1982); Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432 (1982); Department of Energy Organization Act, 42 U.S.C. 7107–7352 (1982); Executive Order No. 12,009, 3 CFR Part 142 (1978).

5. The table of contents for Part 157 is amended by revising Subpart E to read as follows:

PART 157—APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND FOR ORDERS PERMITTING AND APPROVING ABANDONMENT UNDER SECTION 7 OF THE NATURAL GAS ACT

* * * * *

Subpart E—Optional Certificate and Abandonment Procedures for New Service Under Section 7 of the Natural Gas Act

* * * * *

6. In Part 157, Subpart E is revised to read as follows:

Subpart E—Optional Certificate and Abandonment Procedures for Applications for New Service Under Section 7 of the Natural Gas Act

§ 157.100 General.

This subpart establishes optional procedures whereby any eligible applicant may obtain, for the purpose of providing new service, a certificate authorizing the following activities subject to the Commission's jurisdiction:

(a) The transportation of natural gas;

(b) Sales of natural gas;

(c) The construction and operation of natural gas facilities;

(d) The acquisition and operation of natural gas facilities; and

(e) Conditional pre-granted abandonment of such activities and facilities upon termination of its contractual obligations to provide the services.

§ 157.101 Definitions.

(a) *Statutory terms.* Any term defined under the Natural Gas Policy Act of 1978 (NGPA) means the same under this subpart as under the NGPA.

(b) *Subpart E definitions.* For purposes of this subpart:

(1) "Eligible applicant" means any natural gas company or person that will be a natural gas company upon completion of any proposed construction or extension of natural gas facilities.

(2) "New service" means a service for which the applicant for a certificate under this subpart does not have certificate authority. If a contract for service provided under a certificate issued pursuant to this subpart or Subpart A of this Part is renegotiated to provide for an increase in existing service or an additional kind of service, only the additional increment of service or the different service qualifies as "new service."

(3) "Qualifying facility" means a facility or a portion of a facility that will be used solely to provide new service.

§ 157.102 Contents of application and other pleadings.

(a) *General contents.* (1) Any application under this subpart must contain all information necessary to advise the Commission fully concerning the transportation, sales, and other services, and facilities, construction, extension, or acquisition and operation for which a certificate and conditional pre-granted abandonment authorization is requested.

(2) Except as otherwise provided in paragraph (b) of this section, any application under this subpart must conform to the requirements of Subpart A of this part. Section 157.11 does not apply to applications under this subpart.

(b) *Specific contents.* (1) Any application under this subpart must contain:

(i) A statement plainly requesting that the application be considered under the optional procedures of this subpart;

(ii) A statement that the applicant agrees to comply with all terms and conditions specified in § 157.103 of this chapter;

(iii) All exhibits required under § 157.14, except for the information required by § 157.14(a) (10), (11) and (18);

(iv) If the proposed new service would be provided to a customer that is located in the service area of a local distribution company, a statement that the applicant has served a copy of this application on that local distribution company;

(v) An environmental report, as specified in Appendix B to Part 2 of this chapter; and

(vi) A statement of the rates to be charged for the proposed new service, including *pro forma* copies of the rate schedule to be included in the effective tariff, a statement explaining fully how the proposed rate was derived, showing clearly whether the proposed rate results from negotiation, cost-of-service determination, competitive factors or others, and explaining the bases for the findings and conclusions of any related studies. Any rate filed under this paragraph for new service must comply with the conditions set forth in § 157.103.

(2) Any person filing a petition to intervene, notice of intervention, or protest in a proceeding initiated by a certificate application under this subpart must:

(i) Comply with § 157.10; and

(ii) Provide in its filing a statement of all genuine issues of fact raised by such person, identifying those alleged to be material to a determination of whether the applicant's requested certificate is or will be required by the present or future public convenience and necessity.

(c) *Transportation for others.* If the application requests a certificate to provide transportation service under this subpart, the applicant must state that it has filed for and will accept a blanket transportation certificate under § 284.221 of this chapter, identify the docket number assigned to that filing, and state that it will comply with the conditions in Subpart A of Part 284.

§ 157.103 Terms and conditions; other requirements.

(a) *Non-exclusivity of certificates issued under this subpart.* A certificate issued pursuant to this subpart must be non-exclusive and must provide that it in no way prejudices any application for any other certificate under the Natural Gas Act or for authorization under the Natural Gas Policy Act.

(b) *Certificate limited to qualifying facilities and new service.* A certificate issued under this subpart provides only for authorization to construct or acquire and operate qualifying facilities and to provide new service.

(c) *Allocation of joint costs.* To the extent the service proposed will utilize existing facilities, the cost of those facilities will be allocated among the services provided under this subpart and other services provided.

(d) *Rates.*—(1) *General.* Any rate filed for new service under this subpart must comply with the conditions of this paragraph.

(2) *Rate objectives.* Maximum rates for both peak and off-peak periods must be designed, to the maximum extent possible, to achieve the following three objectives:

(i) Rates for service during peak periods should ration capacity;

(ii) Rates for firm service during off-peak periods and for interruptible service during all periods should maximize through-put; and

(iii) The certificate holder's revenue requirement allocated to firm and interruptible services should be attained by providing the projected units of service in peak and off-peak periods at the maximum rate for each service.

(3) *Volumetric rates.* Except for a reservation charge for firm transportation service consistent with the conditions in § 284.8(d), any rate filed for new service must be a one-part rate that recovers the costs allocated to the new service to the extent that the projected units of that service are actually purchased and may not include a demand charge, a minimum bill or minimum take provision or any other provision that has the effect of guaranteeing revenue.

(4) *Based on projected units of service.* Any rate filed for new service must be designed to recover costs on the basis of projected units of service. The units projected for the new service in the initial rates filed under this subpart may be increased in a subsequent rate filing but may not be decreased.

(5) *Differentiation due to time and distance.* Any rate filed for new service must reasonably reflect any material variation in the cost of providing the service due to:

(i) Whether the new service is provided during a peak or an off-peak period; and

(ii) The distance over which the new service is provided.

(6) *Cost basis for rates.*

(i) Any maximum rate filed for new service must be designed to recover, on a unit basis, solely those costs which are properly allocated to that service.

(ii) Any minimum rate for new service must be based on the average variable costs which are properly allocated to that service.

(7) *Rate flexibility.*

(i) Any rate schedule filed for new service must state a maximum rate and a minimum rate.

(ii) The certificate holder may charge an individual customer for new service any rate that is neither greater than the maximum rate nor less than the minimum rate on file for that service.

(iii) The certificate holder may not file a revised or new rate designed to recover costs not recovered under rates previously in effect.

(iv) If, during any billing period, a certificate holder charges a rate or collects a reservation fee that is less than the maximum rate or fee that could be charged, the certificate holder must, within 45 days of the close of the billing period, file a report with the Commission identifying:

(A) The maximum rate or fee and the rate or fee actually charged during the billing period;

(B) The customer; and

(C) Any corporate affiliation between the customer and the certificate holder.

(8) *Prohibitions against cost shifting.* No costs originally allocated to a new service may subsequently be allocated to any other services without a filing under § 154.63 of this part and a determination by the Commission that the costs sought to be reallocated are in fact being incurred for the benefit of the other services.

(e) *No revenue guarantees for new sales service.* No demand charge, reservation fee, minimum bill provision, minimum take provision, or any other provision that has effect of guaranteeing revenue may be imposed for firm or interruptible sales service provided under this subpart.

(f) *Conditional pre-granted abandonment authority.*

(1) Subject to paragraph (f)(2) and (f)(3) of this section, if requested by the applicant in its application, any order issuing a certificate under this subpart must provide conditional pre-granted authority to abandon the proposed new service and qualifying facilities at the expiration of the contracts under-lying the new service.

(2) At least forty-five days prior to the expiration of any contractual agreement with a customer to provide new service, a certificate holder that intends to abandon any part of the new service upon expiration of the contractual agreement for that service must provide the customer and the Commission with written notice of the proposed abandonment.

(3) A customer receiving notice of a proposed abandonment of new service to it may file a protest under § 157.106 of this subpart.

(g) *Flexible receipt point authority.* (1) A certificate holder authorized to transport gas under a certificate issued pursuant to this subpart may at the request of the shipper and without prior notice:

(i) Reduce or discontinue receipts of natural gas at a particular point from a supplier, and

(ii) Commence or increase receipts at a particular point from that supplier or any other supplier. The total natural gas volumes received by the interstate pipeline following any such reassignment must not exceed the total volume of natural gas that the certificate holder is authorized under the certificate issued pursuant to this subpart to transport on behalf of the shipper.

(2) The receipt points to which natural gas volumes may be reassigned under this paragraph include eligible facilities under § 157.208 of this part which are authorized to be constructed and operated pursuant to a certificate issued under Subpart F of this part.

(h) *Flexible delivery point authority.* (1) A certificate holder authorized to transport gas under a certificate issued pursuant to this subpart may at the request of the shipper and without prior notice:

(i) Reduce or discontinue deliveries of natural gas to a particular delivery point; and

(ii) Commence or increase deliveries to a particular delivery point.

(2) The total natural gas volumes delivered by the certificate holder following any such reassignment must not exceed the total amount of natural gas that the certificate holder is authorized under the certificate issued pursuant to this section to transport on behalf of the shipper.

(3) The delivery points to which natural gas volumes may be reassigned under this paragraph include facilities authorized to be constructed and operated pursuant to a certificate issued under Subpart F of this part.

(i) *Environmental compliance.* Any certificate issued under this subpart is subject to the terms and conditions of § 157.206(d) of this chapter.

(j) *Commencement of new service.* Any authorized construction, extension, or acquisition of qualifying facilities must be completed and in actual operation by the applicant and any authorized operation, service, or sale must be actually undertaken and regularly performed by the applicant (within a period of time to be specified by the Commission in each order) from the issue date of the order issuing the certificate. The certificate holder may apply to the Director of the Office of Pipeline and Producer Regulation for an extension of this deadline.

§ 157.104 Hearings.

(a) *General.* The Commission will schedule each application for public hearing at the earliest possible date giving due consideration to statutory requirements and other matters pending, with notice thereof as provided by § 157.9 and § 385.2009 of this chapter.

(b) *Shortened procedure.* If no protest or petition to intervene raises a genuine issue of material fact, the Commission may upon request of the applicant dispose of an application in accordance with the provisions of § 385.802 of this chapter.

(c) *Presumption.* If an application complies fully with the requirements of § 157.102 and § 157.103, it is presumed, subject to rebuttal that:

(1) The applicant is qualified to perfrom all the activities for which certificate authorization is requested;

(2) The applicant is willing and able to perform acts and provide service, as proposed, and to comply with the Natural Gas Act and any applicable regulations thereunder; and

(3) The proposed new service is or will be required by the present or future public convenience and necessity.

§ 157.105 Issuance of certificate.

A certificate requested under this subpart will be issued if:

(a) The application for the certificate complies fully with §§ 157.102 and 157.103; and

(b) The presumptions established under § 157.104 are not rebutted.

§ 157.106 Protests to abandonment of new service.

(a) *Notice by certificate holder under § 157.103(f).* Any authority pre-granted to a certicate holder to abandon any new service or qualifying facilities authorized by a certificate issued under this subpart upon the expiration of any contract for such new service, is conditional and subject to protest by any customer to which the new service is provided.

(b) *Protest procedure.* (1) If a new service customer received notice of a proposed abandonment from a certificate holder in accordance with § 157.103(f), the customer may, within 30 days prior to such expiration date, file a petition under § 385.207 of this chapter to protest the abandonment and request the Commission to direct the certificate holder to continue the new service in accordance with the expired contractual agreement.

(2) The Commission may require the certificate holder to continue to provide the new service described in the abandonment notice under § 157.103(f) where the Commission determines that:

(i) Continuation of the new service is necessary because the customer is unable, after having made all reasonable efforts, to arrange for alternative service, and

(ii) The customer will pay the rate on file for the new service.

7. Section 157.201 is amended by removing the word "transportation," from paragraph (a) and by revising paragraph (c) to read as follows:

§ 157.201 Applicability.

* * * * *

(c) *Cross-reference.* The procedures applicable to transportation by interstate pipelines under blanket certificates are set forth in Subpart G of Part 284 of this chapter.

* * * * *

8. In § 157.202, paragraph (b)(2)(i) is revised to read as follows:

§ 157.202 Definitions.

* * * * *

(b) *Subpart F definitions.* For purposes of this subpart:

* * * * *

(2)(i) "Eligible facility" means, except as provided in paragraph (b)(2)(ii) of this section, any facility subject to the Natural Gas Act jurisdiction of the Commission that is necessary to provide service within existing certificated volumes, or any gas supply facility. Eligible facility includes any facility needed by the certificate holder to receive gas from a supplier and interconnecting points between transporters that transport natural gas under § 284.221 of this chapter.

* * * * *

§ 157.203 [Amended]

9. In § 157.203, paragraph (b) is amended by removing the term "157.209(a)," and paragraph (c) is amended by removing the term "157.209(b),".

§ 157.204 [Amended]

10. In § 157.204, paragraph (d)(4) is amended by removing the term "157.209,".

11. In § 157.205, the initial sentence of paragraph (a) is revised, new paragraph (b)(6) is added, and paragraph (h) is revised to read as follows:

§ 157.205 Notice procedure.

(a) *Applicability.* No activity described in §§ 157.208(b), 157.210, 157.211(a)(2), 157.212, 157.213(b), 157.214, 157.216(b) or 284.223(b) is authorized by a blanket certificate granted under this subpart or by Part 284, unless, prior to undertaking such activitiy:

* * * * *

(b)(6) Identities and docket numbers of other applications related to the transaction. All related filings must be made within 10 days of the first filing. Otherwise, the applications on file will be rejected under paragraph (c) of this section without prejudice to refiling when all parties are ready to proceed.

* * * * *

(h) *Final authorization.* (1) If no protest is filed within the time allowed by the Secretary, the certificate holder is authorized to conduct the activity under its blanket certificate, effective on the day after time expires for filing protests and interventions unless, during that time, the certificate holder withdraws its application in accordance with § 385.216 of this chapter.

(2) If any protest is filed within the time allowed for protest and interventions and is subsequently withdrawn under paragraph (g) of this section, the certificate holder is authorized to conduct the activity under its blanket certificate, effective upon the day after the withdrawal of all protests, unless the certificate holder withdraws its application in accordance with § 385.216 of this chapter prior to that date.

12. In § 157.206, the initial sentence and paragraph (h) are revised to read as follows:

§ 157.206 Standard conditions.

Any activity authorized under a blanket certificate issued under this subpart is subject to the following conditions:

* * * * *

(h) *Treatment of revenues.* (1) Except as provided in paragraph (h)(2) and (3) of this section, all revenues received for storage services authorized under § 157.213 or for sales for resale authorized under § 157.210 in excess of an allowance of one cent per MMBtu shall be credited to Account No. 191 and flowed back to the certificate holder's customers.

(2) A certificate holder is not required to credit revenues to Account No. 191 pursuant to paragraph (h)(1) of this section:

(i) If representative levels of revenues attributable to such services have been credited in arriving at a test period cost of service; or

(ii) If representative levels of volumes for such services have been included in billing determinants for the purposes of establishing rates.

(3) The certificate holder may elect to forego the one cent per MMBtu allowance provided in paragraph (h)(1) of this section. If the certificate holder so elects, it is not required to credit to Account No. 191 any amount which, upon application, is demonstrated to represent the out-of-pocket expenses of the certificate holder in connection with a transaction authorized under this subpart.

13. Section 157.207 is revised to read as follows:

§ 157.207 General reporting requirements.

On or before May 1, of each year, the certificate holder must file an annual report signed under oath by a senior official of the company, that lists for the previous calendar year:

(a) For each new facility authorized as by § 157.208, the information specified in § 157.208(e);

(b) For each sales tap authorized under § 157.211(a)(1), the information required by § 157.211(c);

(c) For each storage service authorized under § 157.213(a), the information specified in § 157.213(c);

(d) For each storage project tested or developed under § 157.215, the information specified in § 157.215(b)(1);

(e) For each abandonment authorized under § 157.216(a), the information specified in § 157.216(d);

(f) For each change in rate schedule authorized under § 157.217, the information specified in § 157.217(b);

(g) For each change in customer name authorized under § 157.218, the information specified in § 157.218(b); and

(h) If any activity required to be reported under this section was not undertaken, a statement to that effect.

§ 157.209 [Removed]

14. Section 157.209 is removed.

15. Section 157.211 is revised to read as follows:

§ 157.211 Sales taps.

(a) *Construction and operation.*—(1) *Automatic authorization.* The certificate holder may construct and operate sales taps for the delivery of gas to an end-user, if:

(i) The natural gas is ultimately delivered to, and consumed by, a right-of-way grantor; and

(ii) Not more than 200 MMBtu of natural gas per day are to be delivered to the right-of-way grantor.

(2) *Prior notice.* Subject to the notice procedure of § 157.205, the certificate holder may construct and operate sales taps for service to end-users other than a right-of-way grantor, if:

(i) The natural gas is ultimately consumed by an end-user that is, or will be, served directly or indirectly from the general system supply of the certificate holder, or the natural gas is being delivered to a shipper for whom the certificate holder is, or will be, authorized to transport gas;

(ii) The volumes delivered are within the certificated entitlements of the customer; and

(iii) The certificate holder's tariffs do not prohibit the addition of new delivery points.

(b) *Contents of request.* In addition to the requirements of § 157.205(b), requests for activities authorized under paragraph (a)(2) must contain:

(1) The name of any distributor or the end-user and the location of all proposed sales taps;

(2) The authority for the current service to the distributor or end-user;

(3) The quantity of gas to be delivered through the proposed facility;

(4) The rate or rate schedules applicable to the service made through the proposed tap; and

(5) A description, with supporting data, of the impact of the service rendered through the proposed sales tap upon the certificate holder's peak day and annual deliveries.

(c) *Reporting requirements.* As part of the certificate holder's annual report of projects authorized under paragraph (a)(1) of this section, the certificate holder must report:

(1) The name of the end-user;

(2) The maximum daily volumes to be sold; and

(3) The actual cost of the sales tap and date placed in service.

(d) *Indirect customers.* The authorization in paragraphs (a) and (b) of this section applies irrespective of whether the certificate holder sells the natural gas directly to the end-user or the natural gas is delivered to the end-user for the account of a local distribution company.

Appendices I and II [Amended]

16. In Appendices I and II to Part 157, the initial sentence is amended by removing the term "Subpart F of Part 157" and inserting in its place the term "Subparts E or F of Part 157 and to any other service subject to § 157.206(d)".

PART 250—[AMENDED]

17. The authority citation for Part 250 is revised to read as follows:

Authority: Department of Energy Organization Act, 42 U.S.C. 7101–7352 (1982); Executive Order 12,009, 3 CFR Part 142 (1978); Natural Gas Act, 15 U.S.C. 717–717w (1982); Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432 (1982).

18. Part 250 is amended by adding a new § 250.15 to read as follows:

§ 250.15 Form of Self-Implementing Transportation Filing.

[FERC Format No. 549–ST]

Self-Implementing Transportation by Interstate, Intrastate, and Hinshaw Pipelines and by Local Distribution Companies Under Natural Gas Act Blanket Certificates and Under the Natural Gas Policy Act of 1978 and Related Authorities

1. Type of Report (check one):
☐ Initial ☐ Subsequent*

2. Applicable Regulation Section (check up to two):
☐ 284.106(a) ☐ 284.106(b)*
☐ 284.222
☐ 284.126(a) ☐ 284.126(b)*
☐ 284.224
☐ 284.223(f)(1) ☐ 284.223(f)(2)

*Report only the changes with respect to information filed in the initial report. Complete only items 1 through 5 and item 8 for identification purposes.

3. Reporting Company: ______

4. ST Docket No. (subsequent report only): ST______

5. Report Date: ______

6. Date Received by Commission (leave blank): ______

7. Affiliation of Reporting Company, if any, with other entities involved in the transaction (284.106 and 284.222 initial filings only):

______

8. Communications concerning this transaction should be addressed to:
Name: ______
Title: ______
Mailing Address: ______
Phone Number: ______

9. General description of applicant's existing operations (initial reports under 284.106(a), 284.126(a), 284.222, and 284.224):

______

10. Description of the Transportation (including, but not limited to):

(a) Identity and type of the parties to the transaction:
(i) Intrastate Pipeline recipient of transportation service:
(ii) Local Distribution Company recipient of transportation service:
(iii) Interstate Pipeline recipient of transportation service:
(iv) End User:
(b) Commencement date: ______
(c) Projected termination date: ______

[NOTE: Section 284.223 transactions are limited to a single 120-day term]

(d) Estimated total quantity to be transported: ______ MMBtu
(e) Estimated maximum daily quantity: ______ MMBtu
(f) Points between which gas is transported: ______
(g) The location (state) of the original source of the gas: ______
(h) The location (state) of the ultimate delivery point of the gas: ______
(i) Rate to be charged: ______ ¢/MMBtu

(INTRASTATE PIPELINES ONLY)

(i) If the rate is pursuant to § 284.123(b)(1)(i) (i.e., an appropriate state regulatory agency approved rate for city gate service), an explanation of how the rate is computed. Attach necessary supporting information as justification:

(ii) If the rate is pursuant to § 284.123(b)(1)(ii), a statement of the basis for determining the rate schedule used was for service comparable to that being described herein (citation to an appropriate SA docket approved rate). Attach necessary supporting information as justification:

(iii) If the rate is pursuant to § 284.123(b)(2) (e.g., a FERC approved rate), a statement to that effect. Attach necessary supporting information as justification:

11. The undersigned certifies that the contract provides that the transportation arrangement is subject to the provisions of this subpart.

12. Intrastate Pipelines only:

The undersigned certifies that the appropriate state regulatory agency has been notified that the Commission has presumed that all revenues received by an intrastate pipeline in connection with the transportation arrangement authorized under § 284.122 and computed in accordance with § 284.123(b), have been or will be taken into account by the appropriate state regulatory agency for purposes of establishing transportation rates charged by the intrastate pipeline for service to intrastate customers:

______
Name ______
Title ______
Address ______
Phone Number ______

OATH STATEMENT

______, being duly sworn on his/her oath, deposes and says that he/she has read the foregoing filing and that the statements contained therein are true and correct to the best of his/her knowledge, information and belief.

______
Name ______

Title ______

Subscribed and sworn to before me this ______ day of ______, 198—.

______

Name ______

Title ______

My Commission Expires ______

Instructions for Filing Self-Implementing Transportation Reports

[FERC Format No. 549-ST]

General Information

I. Purpose

The report is the primary source of specific data on self-implementing natural gas transportations. The information is necessary to assure that a transaction is in compliance with the Commission's regulations. The standardized format minimizes industry filing burden and facilitates both staff review of the transactions and the application of automatic data processing techniques. This format does not in any way modify existing reporting requirements as provided by the Commission's Regulations, nor does it relieve any respondent from filing additional information necessary to support the reporting elements.

II. Who Must File

Any interstate or intrastate pipeline, Hinshaw company, or local distribution company undertaking a transportation transaction under 18 CFR Part 284.

III. When to File

Initial reports are to be filed within thirty (30) days after commencing a covered transportation. Subsequent reports are to be filed within thirty (30) days of the change being reported.

IV. What to File

Each reporting company must submit an original and five copies of the applicable report specified in Part 284, and the necessary support for the required reporting elements. If a reporting company is unable to supply a data element, it should attach an explanation.

V. Where to Submit

1. Submit an original and five copies of these reports to:

Office of the Secretary, Federal Energy Regulatory Commission, 825 N. Capitol Street NE., Washington, DC 20426.

2. Hand deliveries of an original and five copies may be made to:

Office of the Secretary, Federal Energy Regulatory Commission, Room 3110, 825 N. Capitol Street NE., Washington, DC 20426.

General Instructions

The attached reporting format is to be used to make initial and subsequent reports covering the following types of transactions under Part 284:

1. Interstate pipelines transporting natural gas on behalf of other interstate pipelines, intrastate pipelines, or local distribution companies (LDCs) under either Subpart B of Part 284 (§ 284.102) or Subpart G (§ 284.222). Note that reports under § 284.222 covering blankets certificate transportation for other interstate pipelines must include all data elements required by § 294.106.

2. Intrastate pipelines (or persons holding blankets certificates) transporting natural gas on behalf of interstate pipelines or local distribution companies served by an interstate pipeline under Subpart C of Part 284 (§ 284.122) or Subpart G (§ 284.224). Note that reports under § 284.224 covering blanket certificate transportation must include all data elements required by § 284.126.

3. Interstate pipelines transporting natural gas for any end user under a blanket certificate (§ 284.223).

Definitions

1. "Comparable Service" means for service by interstate pipelines, a transaction utilizing similar parts of the company's system for a similar number of miles, etc.; and for service by intrastate pipelines, "comparable service" has been determined to refer to city-gate service.

2. "Hinshaw Pipeline" means a person not subject to the jurisdiction of the Commission, by reason of section 1(c) of the Natural Gas Act. A Hinshaw Pipeline or LDC with a blanket certificate is authorized to engage in the transportation of natural gas in the same manner that intrastate pipelines are authorized by Subpart C of Part 284.

3. "LDC" means a local distribution company as defined in Section 2(17) of the NGPA (including Hinshaw Pipelines).

4. "Parties" means all persons who either sell, transport, or take title to gas, on whose behalf the service is rendered, or who receive gas in a transaction which is the subject of the filing made under the applicable subpart.

5. "Representative Levels" means representative levels of volumes or revenues used in setting test period, cost-based rates, and approved by the Commission in a company's currently applicable rate case.

6. "SA" means a Staff Adjustment pursuant to section 502(c) of the NGPA requesting an adjustment from the provisions of § 284.123. Once approved by the Commission the SA would allow the intrastate pipeline to have its rates designed by an appropriate state regulatory agency.

For any other definitions needed in completing these reports, refer to the Commission's regulations in 18 CFR, §§ 157.201 through 157.204 and §§ 157.206 and 157.208; and in §§ 284.1 through 284.126 and §§ 284.221 through 284.224.

Specific Instructions

Although this format is provided to expedite the submittal and processing of reports, it is not conclusive as to the level of detail necessary in all cases. Reporting companies are encouraged to attach additional supporting information as justification as deemed necessary.

The format begins with "applicable regulation section" check off boxes. These items help the Commission identify the type of report that is being filed. This format can only be used to satisfy the filing requirements for the sections of the regulations listed by its check off boxes.

Note that in the case of a blanket certificate holder operating under §284.222, § 284.223, or § 284.224, check the box next to one of those sections as well as the box next to the specific reporting requirement that is incorporated by reference. For example, an interstate pipeline transporting gas under the blanket certificate authority of § 284.222 must file an initial report specified in § 284.106(a). In such a case, the §284.222 box should be checked along with the § 284.106(a) box.

Every interstate pipeline transporting natural gas must have an approved tariff on file with the Commission prior to commencing such transportation.

Every interstate pipeline transporting natural gas must make a rate election at the commencement of a transaction. Different information is required under each alternative. Below is a summary of the rate election options available to intrastate pipelines or persons holding blanket certificates issued pursuant to § 284.224.

§ 284.123(b)(1)(i)—A rate derived from a city gate sales tariff on file with an appropriate state regulatory agency, i.e., sales less gas costs.

§ 284.123(b)(1)(ii)—A rate determined by FERC in an approved Staff adjustment under NGPA section 502(c) to be for comparable service, such rate then being approved by the appropriate state regulatory agency.

§ 284.123(b)(2)—A cost of service based rate requested of and approved by FERC. This rate application must be filed prior to or upon commencement of the specific transportation service and must include a full cost of service, with workpapers and a system map clearly delineating the facilities to be used in the specific transaction. The information should illustrate that the proposed rate is "fair and equitable".

19. The authority citation for Part 284 continues to read as follows:

Authority: Natural Gas Act, 15 U.S.C. 717–717w (1982); Natural Gas Policy Act of 1978, 15 U.S.C. 3301–3432 (1982); Department of Energy Organization Act, 42 U.S.C. 7101–7352 (1982); Executive Order No. 12,009, 3 CFR Part 142 (1978).

20. The table of contents for Part 284 is amended by revising the title of Subpart A and adding under Subpart A new §§ 284.7 284.8, 284.9, 284.10, 284.11, and 284.12, removing §§ 284.103, 284.104, 284.107 and 284.127, removing and reserving Subpart F, revising the title of Subpart G and the titles of §§ 284.221 and 284.222, and by adding new §§ 284.223 and 284.224 to read as follows:

PART 284—CERTAIN SALES AND TRANSPORTATION OF NATURAL GAS UNDER THE NATURAL GAS ACT AND THE NATURAL GAS POLICY ACT OF 1978 AND RELATED AUTHORITIES

Subpart A—General Provisions and Conditions

SUBPART F—[Reserved]

* * * * *

Subpart G—Blanket Certificates Authorizing Certain Transportation by Interstate Pipelines on Behalf of Others and Services by Local Distribution Companies

§ 284.4 [Amended]

21. In § 284.4, the designation "(a)" is removed from the first paragraph and paragraph (b) is removed.

22. Part 284 is amended by adding new §§ 284.7, 284.8, 284.9, 284.10, 284.11 and 284.12 to read as follows:

§ 284.7 Rates.

(a) *Applicability.* Any rate charged for transportation service under Subparts B, G and H of this part must be established under a rate schedule that is filed with the Commission prior to commencement of such service and that conforms to the requirements of this section.

(b) *Interim rates for Part 284 transactions.*

(1) Any person providing transportation service under Subpart B, G or H of this part may charge an interim rate for that service until an appropriate rate is established in accordance with this section, if the interim rate is a one part rate filed and included in an appropriate rate schedule on file with the Commission and effective prior to November 1, 1985, for transportation authorized under this part or § 157.209, as effective prior to November 1, 1985, and provided such person complies with paragraph (b)(2) of this section.

(2) Any person offering a transportation service subject to this section must file rates in accordance with paragraph (a) of this section to be effective not later than July 1, 1986. Any interim rate under this paragraph may be charged only until new transportation rates under this section are effective.

(c) *Rate objectives.* Maximum rates for both peak and offpeak periods must be designed to achieve the following three objectives:

(1) Rates for service during peak periods should ration capacity;

(2) Rates for firm service during off-peak periods and for interruptible service during all periods should maximize throughput; and

(3) The pipeline's revenue requirement allocated to firm and interruptible services should be attained by providing the projected units of service in peak and off-peak periods at the maximum rate for each service.

(d) *Rate design.*—(1) *Volumetric rates.* Except as provided in § 284.8(d), any rate filed for service subject to this section must be a one-part rate that recovers the costs allocated to the service to the extent that the projected units of that service are actually purchased and may not include a demand charge, a minimum bill or minimum take provision or any other provision that has the effect of guaranteeing revenue. Such rate must separately identify cost components attributable to transportation, storage, and gathering costs.

(2) *Based on projected units of service.* Any rate filed for service subject to this section must be designed to recover costs on the basis of projected units of service. The fixed costs allocated to capacity reservations, as determined in accordance with § 284.8(d), should be used along with the projected nominations accepted by the pipeline to compute the unit reservation fee. The remaining fixed costs and all variable costs should be used to determine the volumetric rate computed on the basis of projected volumes to be transported. The units projected for the service in rates filed under this section may be changed only in a subsequent rate filing under Section 4 of the Natural Gas Act.

(3) *Differentiation due to time and distance.* Any rate filed for service subject to this section must reasonably reflect any material variation in the cost of providing the service due to:

(i) Whether the service is provided during a peak or an off-peak period; and

(ii) The distance over which the transportation is provided.

(4) *Cost basis for rates.*

(i) Any maximum rate filed under this section must be designed to recover on a unit basis, solely those costs which are properly allocated to the service to which the rate applies.

(ii) Any minimum rate filed under this section must be based on the average variable costs which are properly allocated to the service to which the rate applies.

(5) *Rate flexibility.*

(i) Any rate schedule filed under this section must state a maximum rate and a minimum rate.

(ii) The pipeline may charge an individual customer any rate that is neither greater than the maximum rate nor less than the minimum rate on file for that service.

(iii) The pipeline may not file a revised or new rate designed to recover costs not recovered under rates previously in effect.

(iv) If, during any billing period, a pipeline charges a rate or collects a reservation fee that is less than the maximum rate or fee, the pipeline must, within 45 days of the close of the billing period, file a report with the Commission identifying:

(A) The maximum rate or fee and the rate or fee actually charged during the billing period;

(B) The shipper; and

(C) Any corporate affiliation between the shipper and the transporting pipeline.

§ 284.8 Firm transportation service.

(a) *Firm transportation availability.* (1) An interstate pipeline that provides transportation service under Subpart B, G or H must offer such transportation service on a firm basis.

(2) An intrastate pipeline that provides transportation service under Subpart C may offer such transportation service on a firm basis.

(3) "Service on a firm basis" means that the service is not subject to a prior claim by another customer or another class of service and receives the same priority as any other class of firm service.

(b) *Non-discriminatory access.* An interstate pipeline or intrastate pipeline that offers transportation service on a firm basis under Subpart B, C, G or H must provide such service without undue discrimination, or preference, including undue discrimination or preference in the quality of service provided, the duration of service, the categories, prices, or volumes of natural gas to be transported, customer classification, or undue discrimination or preference of any kind.

(c) *Reasonable operational conditions.* Consistent with paragraph (b) of this section, a pipeline may impose reasonable operational conditions on any service provided under this part. Such conditions must be filed by the pipeline as part of its transportation tariff.

(d) *Reservation fee.* Where the customer purchases firm service, a pipeline may impose a reservation fee or charge on a shipper as a condition for providing such service. The reservation fee may not recover any variable costs or any fixed costs in excess of those costs that would be recovered by using the same ratemaking methodology used for determining the demand charge in the pipeline's sales rates. Except as provided in this paragraph, the pipeline may not include in a rate for any transportation service provided under Subpart B, C, G or H any minimum bill or minimum take provision, or any other provision that has the effect of guaranteeing revenue.

(e) *Limitation.* A person providing service under Subpart B, C, G or H of this part is not required to provide any requested transportation service for which capacity is not available or that would require the construction or acquisition of any new facilities.

§ 284.9 Interruptible transportation service.

(a) *Interruptible transportation availability.* (1) An interstate pipeline that provides firm transportation under Subpart B, G or H must also offer transportation service on an interruptible basis under that subpart or subparts.

(2) An intrastate pipeline that provides transportation service under Subpart C may offer such transportation service on an interruptible basis.

(3) "Service on an interruptible basis" means that the capacity used to provide the service is subject to a prior claim by another customer or another class of service and receives a lower priority than such other classes of service.

(b) *Non-discriminatory access.* An interstate or intrastate pipeline that offers interruptible service under Subpart B, C, G or H must provide such service without undue discrimination, or preference, including undue discrimination or preference in the quality of service provided, the duration of service, the categories, prices, or volumes of natural gas to be transported, customer classification, or undue discrimination or preference of any kind.

(c) *Reasonable operational conditions.* Consistent with paragraph (b) of this section, a pipeline may impose reasonable operational conditions on any service provided under this part. Such conditions must be filed by the pipeline as part of its transportation tariff.

(d) *Reservation fee.* No reservation fee may be imposed for interruptible service. A pipeline's rate for any transportation service provided under this section may not include any minimum bill provision, minimum take provision, or any other provision that has the effect of guaranteeing revenue.

(e) *Limitation.* A person providing service under Subparts B, C, G or H of this part is not required to provide any requested transportation service for which capacity is not available or that would require the construction or acquisition of any new facilities.

§ 284.10 Reductions in firm sales entitlements and conversions to firm transportation.

(a) *Agreement to offer reduction and conversion options.* An interstate pipeline that, beginning December 15, 1985:

(1) Commences a new transportation arrangement under authority of § 284.102 or § 284.243 of this chapter; or

(2) Accepts a certificate issued under § 284.221 of this chapter

is deemed to have agreed to offer its firm sales customers the options set out in paragraphs (c) and (d) of this section.

(b) *Definition.* For purposes of this section, "eligible firm sales service agreement" means an agreement, between an interstate pipeline subject to this section and a customer, that was entered into before the date the pipeline accepted a certificate issued under § 284.221 of this chapter or began transporting natural gas under authority of § 284.102 or § 284.243 of this chapter, as those sections were revised effective November 1, 1985.

(c) *Option to reduce certain firm purchase obligations.*—(1) *Customer option.* An interstate pipeline subject to this section agrees to offer each firm sales customer the option to reduce the level of the customer's firm sales entitlements under any eligible firm sales service agreement with that pipeline.

(2) *Notice.* Unless the pipeline agrees otherwise, a customer that wishes to exercise its option under this paragraph must provide the pipeline written notice, not later than 150 days before the proposed reduction, of the level of the reduction. The pipeline may establish a single date during each calendar year for such reductions to take effect.

(3) *Level of reduction.*—(i) In any 12-month period beginning February 1, 1986, a customer of a pipeline subject to this section may elect to reduce, by up to 25 percent, the level of its firm sales entitlements under any eligible firm sales service agreement with that pipeline.

(ii) Beginning February 1, 1986, a pipeline subject to this section may, at any time, permit a firm sales customer to reduce its firm sales entitlements by more than 25 percent.

(4) *Effect of reduction on minimum bills.* If a customer reduces its firm sales entitlements under this paragraph, any minimum commodity bill that requires the customer to pay the fixed cost component of a certain percentage of the customer's firm sales entitlements must be reduced by an amount proportionate to the reduction in the firm sales entitlements.

(d) *Option to convert to firm transportation.*—(1) *Customer option.* An interstate pipeline subject to this section agrees to offer each firm sales customer the option, under this paragraph, to convert a portion of its firm sales entitlement under each eligible firm sales service agreement to a volumetrically equal amount of firm transportation service.

(2) *Notice.* Unless the pipeline agrees otherwise, a customer that wishes to exercise its option under this paragraph must provide the pipeline written notice, not later than 60 days before the proposed conversion.

(3) *Level of conversion.*—(i) In any 12-month period beginning February 1, 1986, a customer of a pipeline subject to this section may convert to firm transportation up to 25 percent of the level of its firm sales entitlements under any eligible firm sales service agreement with that pipeline.

(ii) Beginning February 1, 1986, a pipeline subject to this section may, at any time, permit a firm sales customer to convert more than 25 percent of its firm sales entitlements to firm transportation.

(4) *Reservation fee.* Where a customer exercises its option under this paragraph to convert to firm transportation service, the pipeline may impose a reservation fee as provided in § 284.8(d) of this subpart.

(5) *Effect of conversion on minimum bills.* If a customer converts under this paragraph any portion of its firm sales entitlements from a pipeline, each unit of firm transportation service purchased must be credited to any minimum commodity bill obligation that the customer may have under its firm sales service agreements with that pipeline.

(e) *Limitation.* Reductions of firm sales entitlements under paragraph (c) of this section and conversions of firm sales entitlements under paragraph (d) of this section may not, in combination, affect more than 25 percent of a customer's eligible firm sales service agreements in any 12-month period, without the consent of the pipeline.

(f) *Abandonment.*—(1) If a firm sales customer exercises an option under paragraph (c) or (d) of this section, the pipeline may file under §157.18 of this chapter to abandon sales service to the extent of the reduction or conversion.

(2) Exercise by a customer of an option under paragraph (c) or (d) of this section constitutes consent by that customer to the proposed abandonment under this paragraph.

(3) Abandonment of a sales service under this paragraph is deemed permitted by the present or future public convenience and necessity.

(g) *Rate adjustments.* If a customer's firm sales entitlement in its eligible firm sales service agreements is changed under this section, the pipeline must file appropriate adjustments to its rates.

§ 284.11 Environmental Compliance.

Any authorization granted under Subparts B, C and H of this part that involves construction or abandonment with removal of facilities is subject to the terms and conditions of § 157.206(d) of this chapter.

§ 284.12 Filing of Capacity.

Each interstate pipeline that provides transportation subject to the provisions of Subpart A of this part must make an annual filing by May 1 of each year showing the estimated peak day capacity of the pipeline's system under reasonably representative operating assumptions and the respective assignments of that capacity to the various firm services provided by the pipeline.

23. Section 284.102 is revised to read as follows:

§ 284.102 Transportation by interstate pipelines.

(a) Subject to the provisions of this subpart and the conditions of Subpart A of this part, any interstate pipeline is authorized without prior Commission approval, to transport natural gas on behalf of:

(1) Any intrastate pipeline; or

(2) Any local distribution company.

(b) Any rates charged for transportation under this subpart may not exceed the just and reasonable rates established under Subpart A of this Part.

(c) Any interstate pipeline that engages in transportation arrangements under this subpart must file reports in accordance with § 284.106 of this chapter.

§§ 284.103 and 284.104 [Removed]

24. Sections 284.103 and 284.104 are removed.

25. Section 284.105 is revised to read as follows:

§ 284.105 Effectiveness of existing transportation arrangements.

(a) Any transportation service authorized under this subpart before November 1, 1985, may be continued under the terms and conditions that applied prior to November 1, 1985, with the exception of the requirements of §§ 284.7 and 284.106, until the earlier of:

(1) The expiration of the original or extended term of any transportation agreement as it was in effect on the date of issuance of this order; or

(2) October 31, 1987.

(b) Effective November 1, 1985, the reporting requirements of § 284.106 apply to all transportation authorized under this subpart which commenced either prior to, or subsequent to, November 1, 1985.

26. Section 284.106 is revised to read as follows:

§ 284.106 Reporting requirements.

(a) *Initial full report.* Within thirty days after commencing transportation under § 284.102, an interstate pipeline must file with the Commission an initial full report, signed under oath by a senior official of the company, consisting of an original and five conformed copies, containing the following information:

(1) The identity of the interstate pipeline and its affiliation, if any, with the other entities involved in the transaction and the identity, title, mailing address, and phone number of the person or persons with whom to communicate about the transportation arrangement:

(2) A general description of the interstate pipeline's existing operations;

(3) A description of the transportation including:

(i) The identity of the parties;

(ii) The dates of commencement and projected termination of the service;

(iii) The estimated total and maximum daily quantities of natural gas to be transported by the interstate pipeline;

(iv) The points between which the natural gas is to be transported by the interstate pipeline;

(v) The location (*i.e.*, state) of the original source and the location (*i.e.*, state) of the ultimate delivery point of the gas; and

(vi) A statement that the contract provides that the transportation arrangement is subject to the provisions of this subpart.

(b) *Subsequent reports.*—(1) An interstate pipeline that files an initial report under paragraph (a) of this section must amend that report to reflect any material change in the pertinent transportation arrangement.

(2) Any changes in the initial report required by this paragraph must be filed with the Commission within thirty days of the related changed circumstances, and must be signed under oath by a senior official of the company, and consist of an original and five conformed copies.

(c) *Annual report.* Not later than May 1 of each year, an interstate pipeline must file with the Commission an annual report that contains, for each docketed transportation service provided during the preceding calendar year under § 284.102, the following information:

(1) The docket number assigned to the transaction;

(2) Total volumes transported for the transaction; and

(3) Total revenues received for the transaction.

(d) *Notification of termination.* Not later than thirty days after the termination of any transportation arrangement under § 284.102, the interstate pipeline must file with the Commission an original and five conformed copies of a statement including the following information:

(1) The docket number assigned to the transaction and the date the transaction was terminated;

(2) The total volumes transported under the arrangement;

(3) The total revenues received; and

(4) A statement certifying that the service was provided under the terms and conditions previously reported in that docket.

(e) *Filing fees.* Each initial full report required by paragraph (a) of this section must be accompanied by the fee prescribed in § 381.404 of this chapter or by a petition for waiver under § 381.106 of this chapter.

(f) *Reporting format.* Each initial report filed under paragraph (a) of this section and each subsequent report filed under paragraph (b) of this section must utilize FERC Format No. 549–ST.

§ 284.107 [Removed]

27. Section 284.107 is removed.

28. Section 284.122 is revised to read as follows:

§ 284.122 Transportation by intrastate pipelines.

(a) Subject to the provisions of this subpart and the applicable conditions of Subpart A of this part, any intrastate pipeline may, without prior Commission approval, transport natural gas on behalf of:

(1) Any interstate pipeline; or

(2) Any local distribution company served by an interstate pipeline.

(b) No rate charged for transportation authorized under this subpart may exceed a fair and equitable rate under § 284.123.

(c) Any intrastate pipeline engaged in transportation arrangements authorized under this section must file reports as required by § 284.126.

29. In § 284.123, the initial sentence of paragraph (b) is revised to read as follows:

§ 284.123 Rates and changes.

* * * * *

(b) *Election of rates.* Subject to the conditions in §§ 284.8 and 284.9 of this chapter, an intrastate pipeline may elect to: * * *

* * * * *

30. Section 284.125 is revised to read as follows:

§ 284.125 Effectiveness of existing transportation services.

(a) Any transportation service authorized under this subpart before November 1, 1985, may be continued under the terms and conditions that applied prior to November 1, 1985, with the exception of reporting requirements, until the earlier of:

(1) The expiration of the original term of any transportation agreement as it was in effect on the date of issuance of this order.

(2) October 31, 1987.

(b) Effective November 1, 1985, the reporting requirements of § 284.126 apply to all transportation authorized under this subpart which commenced either prior to, or subsequent to, November 1, 1985.

31. Section 284.126 is revised to read as follows:

§ 284.126 Reporting requirements.

(a) *Initial full report.* Within thirty days after commencing transportion under by this subpart, an intrastate pipeline must file with the Commission and the appropriate state regulatory agency an initial full report, signed under oath by a senior official of the company, consisting of an original and five conformed copies to the Commission, containing the following information:

(1) The identity of the intrastate pipeline and the identity, title, mailing address, and phone number of the person or persons with whom to communicate about the transportation arrangement;

(2) A general description of the intrastate pipeline's existing operations;

(3) A description of the transportation including:

(i) The identity of the parties;

(ii) The dates of commencement and projected termination of the service;

(iii) The estimated total and maximum daily quantities of natural gas to be transported by the intrastate pipeline;

(iv) The points between which the natural gas is to be transported by the intrastate pipeline;

(v) The location (*i.e.*, state) of the original source and the location (*i.e.*, state) of the ultimate delivery point of the gas; and

(vi) The rate to be charged.

(4) A statement of the basis upon which the intrastate pipeline determined that the service provided is comparable to service provided for under that rate schedule, if the intrastate pipeline is charging a rate under § 284.123(b)(1)(ii) of this chapter; and

(5) A statement that:

(i) The appropriate state regulatory agency has been notified that the Commission presumes that all revenues received by an intrastate pipeline under rates for transportation under § 284.122 established under § 284.123(b)(1) of this chapter, have been or will be taken into account by the appropriate state regulatory agency for purposes of establishing transportation rates charged by that intrastate pipeline for service to intrastate customers; and

(ii) Any contract for the transportation arrangement provides that it is subject to this subpart.

(b) *Subsequent reports.* (1) An intrastate pipeline that files an initial report under paragraph (a) of this section must amend that report to reflect any material change with pertinent transportation arrangement.

(2) Any changes in the initial report required by this paragraph must be filed with the Commission and the appropriate state regulatory agency within 30 days of the material change, and must be signed under oath by a senior official of the company, and consist of an original and five conformed copies to the Commission.

(c) *Annual report.* Not later than May 1 of each year, each intrastate pipeline must file an annual report with the Commission and the appropriate state regulatory agency that contains, for each docketed transportation service provided during the preceding calendar year under § 284.122, the following information:

(1) The docket number assigned to the transaction;

(2) Total volumes transported for the transaction; and

(3) Total revenues received for the transaction.

(d) *Notification of termination.* Not later than thirty days after the termination of any transportation arrangement authorized under § 284.122, the intrastate pipeline must file with the Commission and with the appropriate state regulatory agency a statement, consisting of an original and five conformed copies to the Commission, including the following information:

(1) The docket number assigned to the transaction and the date the transaction was terminated;

(2) The total volumes transported under the arrangement;

(3) The total revenues received; and

(4) A statement certifying that the service was provided under the terms and conditions previously reported in that docket.

(e) *Filing fees.* Each initial report required by paragraph (a) of this section must be accompanied by the fee set forth in § 381.404 of this chapter, or a petition for waiver under § 381.106 of this chapter.

(f) *Reporting format.* Each initial report filed under paragraph (a) of this section and each subsequent report filed under paragraph (b) of this section must utilize FERC Format No. 549–ST.

§ 284.127 [Removed]

32. Section 284.127 is removed.

§§ 284.200–284.208 [Removed]

33. Subpart F (§§ 284.200–284.208) is removed.

34. The title of Subpart G of Part 284 is revised to read as follows:

Subpart G—Blanket Certificates Authorizing Certain Transportation by Interstate Pipelines on Behalf of Others and Services by Local Distribution Companies

35. Section 284.221 is revised to read as follows:

§ 284.221 General rule; transportation by interstate pipelines on behalf of others.

(a) *Blanket certificate.* Any interstate pipeline may apply under this section for a single blanket certificate authorizing the transportation of natural gas on behalf of others in accordance with this subpart. A certificate of public convenience and necessity under this section is granted pursuant to section 7 of the Natural Gas Act.

(b) *Application procedure.* (1) An application for a blanket certificate under this section must include:

(i) The name of the interstate pipeline; and

(ii) A statement by the interstate pipeline that it will comply with the conditions in paragraph (c) of this section.

(2) Upon receipt of an application under this section, the Commission will conduct a hearing pursuant to section 7(c) of the Natural Gas Act and § 157.11 of this chapter and, if required by the public convenience and necessity, will issue to the interstate pipeline a blanket certificate authorizing such pipeline company to transport natural gas, as provided under this subpart.

(c) *General conditions.* Any blanket certificate under this subpart is subject to the conditions of Subpart A of this part.

(d) *Pre-grant of abandonment.* Pursuant to section 7(b) of the Natural Gas Act abandonment of transportation services is authorized upon the expiration of the contractual term of each individual transportation arrangement authorized under a certificate granted under this section.

(e) *Availability of regular certificates.* This subpart does not preclude an interstate pipeline from applying for an individual certificate of public convenience and necessity for any particular transportation service.

(f) *Cross references.* (1) Any local distribution company served by an interstate pipeline may apply for a blanket certificate to perform certain services under § 284.224 of this chapter.

(2) Any interstate pipeline may apply under Subpart F of Part 157 of this chapter for a blanket certificate to construct or acquire and operate certain natural gas facilities that are necessary to provide transportation under § 284.222 or § 284.223.

(3) Section 157.208 of this chapter provides automatic authorization for the construction, acquisition, operation, and miscellaneous rearrangement of certain eligible facilities, as defined in § 157.202 of this chapter, subject to limits specified in § 157.208(d) of this chapter and § 284.11.

(4) Authorization for sales taps is subject to the prior notice procedures under §§ 157.211(b) and 157.205.

(g) *Flexible receipt point authority.*—(1) An interstate pipeline authorized to transport gas under a certificate granted under this section may, at the request of the shipper and without prior notice:

(i) Reduce or discontinue receipts of natural gas at a particular receipt point from a supplier; and

(ii) Commence or increase receipts at a particular receipt point from that supplier or any other supplier.

(2) The total natural gas volumes received by the interstate pipeline following any such reassignment under this paragraph must not exceed the total volume of natural gas that the interstate pipeline may transport on behalf of the shipper under a certificate granted under this section.

(3) The receipt points to which natural gas volumes may be reassigned under this paragraph include eligible facilities under § 157.208 which are authorized to be constructed and operated pursuant to a certificate issued under Subpart F of Part 157 of this chapter.

(h) *Flexible delivery point authority.*—(1) An interstate pipeline authorized to transport gas under a certificate issued pursuant to this section may at the request of the shipper and without prior notice:

(i) Reduce or discontinue deliveries of natural gas to a particular delivery point; and

(ii) Commence or increase deliveries at a particular delivery point.

(2) The total natural gas volumes delivered by the interstate pipeline following any such reassignment must not exceed the total amount of natural gas that the interstate pipeline is authorized under a certificate issued pursuant to this section to transport on behalf of the shipper.

(3) The delivery points to which natural gas volumes may be reassigned under this paragraph include facilities authorized to be constructed and operated only under §§ 157.211 and 157.212 and the prior notice conditions of § 157.205 of this chapter.

36. Part 284 is amended by redesignating § 284.222 as new § 284.224, adding new § 284.222 and new § 284.223 and revising paragraphs (b), (d)(1), (e)(1), and (g) of redesignated § 284.224 to read as follows:

§ 284.222 Transportation by interstate pipelines on behalf of other interstate pipelines.

An interstate pipeline issued a certificate under § 284.221 may transport natural gas on behalf of another interstate pipeline subject to the same terms and conditions, rates and charges, and reporting requirements as apply to transactions authorized under Subpart B of this part.

§ 284.223 Transportation by interstate pipelines on behalf of shippers other than interstate pipelines.

(a) *Automatic authorization.*—(1) An interstate pipeline issued a certificate under § 284.221 may for one period that may not exceed 120 days, transport any natural gas for any shipper for any end-use by that shipper or any other person without prior notice to the Commission.

(2) If an interstate pipeline and a shipper at any time conducted a transportation arrangement under paragraph (a)(1) of this section or previously-effective §157.209, an additional 120-day transportation authority is permitted only if, after the commencement of the previous 120-day transportation term and prior to the commencement of the new 120-day transportation term under this subparagraph, the transportation arrangement was authorized under the prior notice procedures of § 157.205 of this chapter.

(b) *Prior notice.* Subject to the prior notice requirements of § 157.205 of this chapter, an interstate pipeline issued a certificate under § 284.221 may transport any natural gas for any shipper for any end-use for any duration by that shipper or any other person.

(c) *Contents of prior notice filings under § 284.223.* In addition to the requirements of § 157.205(b) of this Chapter, prior notice filing under § 284.223 for transportation under paragraph (b) of this section must contain:

(1) The name of the shipper;

(2) The volumes of gas to be transported on a peak day, on an average day, and on an annual basis;

(3) A copy of the executed transportation agreement;

(4) A separate clear description of any agency relationship under which a local distribution company or affiliate of the shipper will receive natural gas on behalf of the shipper, unless such agency relationship is clearly described in the executed transportation agreement;

(5) A statement of the projected costs of any facilities that will be constructed in order to provide the transportation service, as well as any other facilities that will be utilized together with an identification of the location of such facilities; and

(6) If the interstate pipeline has transported for the same shipper under the 120-day automatic authorization provisions of paragraph (a) of this section, the docket numbers under which the pipeline or any person acting on its behalf made any filings required with respect to such transportation.

(d) *Fees.* When filed with the Commission, each initial report required by paragraph (f)(1) of this section must be accompanied by the fee set forth in § 381.404 of this chapter or a petition for waiver pursuant to § 381.106 of this chapter.

(e) *Reporting format.* Each initial report filed under paragraph (f)(1) of this section and each subsequent report filed under paragraph (f)(2) of this section must utilize FERC Format No. 549–ST.

(f) *Reporting requirements.*—(1) *Initial full report.* Within thirty days after commencing transportation authorized by paragraph (a) of this section, an interstate pipeline must file with the Commission an initial full report, signed under oath by a senior official of the company, consisting of an original and five conformed copies containing a description of the transportation service, including:

(i) The identities of the parties;

(ii) The dates of commencement and projected termination of the service;

(iii) The estimated total and maximum daily quantities of natural gas to be transported by the interstate pipeline;

(iv) The points between which the natural gas is to be transported by the interstate pipeline; and

(v) The location (*i.e.,* state) of the original source and the location (*i.e.,* state) of the ultimate deliver point of the gas.

(2) *Subsequent reports.* (i) An interstate pipeline that files an initial report under paragraph (f)(1) of this section must amend that report to reflect any material change in the pertinent transportation arrangement.

(ii) Any changes in the initial report required by this paragraph must be filed with the Commission within thirty days of the related changed circumstances, and must be signed under oath by a senior official of the company, and consist of an original and five conformed copies.

(3) *Annual report.* Not later than May 1 of each year, each interstate pipeline must file with the Commission an annual report that contains, for each docketed transportation service provided during the preceding calendar year under authority of paragraph (a) and (b) of this section, the following information:

(i) The docket number assigned to the transaction;

(ii) Total volumes transported for the transaction; and

(iii) Total revenues received for the transaction.

(4) *Notification of termination.* Not later than thirty days after the termination of any transportation arrangement under § 284.223(a), the interstate pipeline company must file with the Commission an original and five conformed copies of a statement including the following information:

(i) The docket number assigned to the transaction and the date the transaction was terminated;

(ii) The total volumes transported under the arrangement;

(iii) The total revenues received; and

(iv) A statement certifying that the service was provided under the terms and conditions previously reported in this docket.

(g) *Transitional rule for transportation arrangements.*—(1) In the case of transportation authorized under § 157.209(a)(1) which commenced prior to November 1, 1985, such transportation is deemed to be authorized under this section for the full term originally certificated subject to the provisions of § 284.7 of this chapter. In all other respects, the terms and conditions existing prior to November 1, 1985, shall continue for this period.

(2) Except as provided in paragraph (3) of this section, a transportation service authorized under § 157.209(e) prior to November 1, 1985, is authorized under this section for the full term of the underlying agreement if:

(i) The interstate pipeline company files before November 1, 1985, a statement of notification that it will, beginning November 1, 1985, comply with §§ 284.8(b) and 284.9(b) and § 284.7; and

(ii) The existing transportation service was—

(A) Subject to the notice and protest procedures of § 157.205 and the application was not protested or any protest was withdrawn; or

(B) Authorized on a self-implementing basis pursuant to § 157.209(e)(1) for 120 days, and time remains in that 120-day term past October 31, 1985.

(3) Authorization for transportation service under paragraph (g)(2) of this section:

(i) Ceases on December 15, 1985, unless the pipeline files for a blanket certificate under § 284.221 before that date; and

(ii) Is subject to compliance with the requirements of § 284.8(b), § 284.9(b), as appropriate, and § 284.7.

(4) Effective November 1, 1985, the reporting requirements of § 284.223(f) apply to all transportation authorized under this subpart which commenced either prior to, or subsequent to, November 1, 1985.

§ 284.224 Certain transportation, sales, and assignments by local distribution companies.

* * * * *

(b) *Blanket certificate.*—(1) Any local distribution company served by an interstate pipeline or any Hinshaw pipeline may apply for a blanket certificate under this section.

(2) Upon application for a certificate under this section, a hearing will be conducted under section 7(c) of the Natural Gas Act, § 157.11 of this chapter, and Subpart H of Part 385 of this chapter.

(3) The Commission will grant a blanket certificate to such local distribution company or Hinshaw pipeline under this section, if required by the present or future public convenience and necessity. Such certificate will authorize the local distribution company to engage in the sale, transportation, or assignment of natural gas that is subject to the Commission's jurisdiction under the Natural Gas Act, to the same extent that and in the same manner that intrastate pipelines are authorized to engage in such activities by Subparts C, D, and E of this part, except as otherwise provided in paragraph (e)(2) of this section.

* * * * *

(d) *Effect of certificate.* (1) Any certificate granted under this section will authorize the certificate holder to engage in transactions of the type authorized by Subparts C, D, and E of this part.

* * * * *

(e) *General conditions.* (1) Except as provided in paragraph (e)(2) of this section, any transaction authorized under a blanket certificate is subject to the same rates and charges, terms and conditions, and reporting requirements that apply to a transaction authorized for an intrastate pipeline under Subparts C, D, and E of this part.

* * * * *

(g) *Hinshaw pipeline without blanket certificate.* A Hinshaw pipeline that does not obtain a blanket certificate under this section is not authorized to sell, assign, or transport natural gas as an intrastate pipeline actions by Subparts C, D, and E of this part.

* * * * *

37. Section 284.243 is revised to read as follows:

§ 284.243 Statement of policy.

(a) *Interstate pipelines.* Any interstate pipeline, or eligible distributor acting on behalf of an interstate pipeline, may file an application under § 284.244 for covered transportation under either section 7(c) of the Natural Gas Act or section 311(a)(1) of the Natural Gas Policy Act (NGPA). The Commisson will consider such applications on a priority basis. Covered transportation is subject to the terms and conditions under § 284.245.

(b) *Interstate pipelines.* Any intrastate pipeline may, without application or prior Commission approval, transport natural gas for ultimate delivery into the service area of an eligible distributor under section 311(a)(2) of the NGPA, subject to the conditions applicable to transportation by interstate pipelines under section 311 of the NGPA and under Subparts A and C of this part.

38. In § 284.244, the initial sentence and paragraphs (a) and (b) are revised to read as follows:

§ 284.244 Application requirements for interstate pipelines.

An application by an interstate pipeline for covered transportation must include the following:

(a) A stated preference for authorization under either section 7(c) of the Natural Gas Act or section 311(a)(1) of the NGPA. If section 7(c) authorization is preferred, the application must also comply with Part 157. If section 311(a)(1) authorization is preferred, the application must comply with the requirements of Subpart B of this part.

(b) A statement that all of the natural gas transported under this subpart, other than normal compressor fuel and loss allowance, will ultimately enter the eligible distributor's service area.

* * * * *

39. In § 284.245, paragraph (a) is revised, paragraphs (b) and (c) are removed, and a new paragraph (b) is added to read as follows:

§ 284.245 Terms and conditions.

(a) *Interstate pipelines.* (1) *General.* Covered transporation by an interstate pipeline authorized under section 7(c) of the Natural Gas Act or under section 311(a)(1) of the NGPA, is subject to the terms and conditions, rates and charges, and reporting requirements of Subparts A and B of this part that apply to transportation by interstate pipelines under section 311 of the NGPA.

(2) *Natural gas supply emergency.* If the President declares a natural gas supply emergency under secton 301 of the NGPA in the United States or in a region served by the interstate pipeline, the authorization of the covered transportation may be suspended or terminated by order of the Commission.

(b) *Intrastate pipelines.* Any intrastate pipeline may, without application or prior Commission approval, transport natural gas under § 284.243 for ultimate delivery into the service area of an eligible distributor under section 311(a)(2) of the NGPA, subject to the conditions applicable to transportation by intrastate pipelines under section 311 of the NGPA and under Subparts A and C of this part.

40. The authority for Part 375 is revised to read as follows:

Advisory: Department of Energy Organization Act (42 U.S.C. 7101–7352), E.O. 12009, 3 CFR, 1977 Comp., p. 142; Administrative Procedure Act (5 U.S.C. 553); Federal Power Act (16 U.S.C. 791–828c), as amended; Natural Gas Act (15 U.S.C. 717–717w), as amended; Natural Gas Policy Act of 1978 (15 U.S.C. 3301 et seq.); Public Utilities Regulatory Policies Act of 1978 (16 U.S.C. 2601 et seq.) unless otherwise noted.

40a. Section 375.307(a)(15) is amended by adding before the term "Subpart F of Part 157," the phrase "Subpart G of Part 284 and".

41. In § 375.307, new paragraphs (v) and (w) are added to read as follows:

§ 375.307 Delegation to the Director of the Office of Pipeline and Producer Regulation.

* * * * *

(v) Grant any producer's uncontested application for abandonment, in accordance with § 2.77 of this chapter.

(w) Pass upon any uncontested application for a blanket certificate under § 284.221 of this chapter.

42. The authority for part 381 continues to read as follows:

Authority: Department of Energy Organization Act (42 U.S.C. 7101–7352), E.O. 12009, 3 CFR, 1977 Comp., p. 142; Federal Power Act (16 U.S.C. 791–828c), as amended; Natural Gas Act (15 U.S.C. 717–717w), as amended; Natural Gas Policy Act of 1978 (15 U.S.C. 3301 et seq.); Public Utilities Regulatory Policies Act of 1978 (16 U.S.C. 2601 et seq.); Independent Offices Appropriations Act (31 U.S.C. 9701 (1982)); Interstate Commerce Act (49 U.S.C. 1–27), unless otherwise noted.

43. Section 381.404 is revised to read as follows:

§ 381.404 Initial or extension reports for Title III transactions.

The fee established for an initial or extension report is $800. Such fee must be submitted in accordance with Subpart A of this part and §§ 284.106(e), 284.126(e), 284.148(e), 284.165(d), and 284.223(d).

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federal register

Friday
October 18, 1985

Part IX

Office of Management and Budget

Cumulative Report on Rescissions and Deferrals; Notice

OFFICE OF MANAGEMENT AND BUDGET

Cumulative Report on Rescissions and Deferrals

October 1, 1985.

This report is submitted in fulfillment of the requirements of section 1014(e) of the Impoundment Control Act of 1974 (Pub. L. 93–344). Section 1014(e) provides for a monthly report listing all budget authority for this fiscal year for which, as of the first day of the month, a special message has been transmitted to the Congress.

This report gives the status as of October 1, 1985, of 23 deferrals contained in the first special message of FY 1986. There were no rescissions proposed. This message was transmitted to the Congress on October 1, 1985.

Rescissions (Table A and Attachment A)

As of October 1, 1985, there were no rescission proposals pending before the Congress.

Deferrals (Table B and Attachment B)

As of October 1, 1985, $1,614.4 million in 1986 budget authority was being deferred from obligation. Attachment B shows the history and status of each deferral reported during FY 1986.

Information From Special Messages

The special message containing information on the deferrals covered by this cumulative report is printed in the **Federal Register** listed below: Vol. 50, FR p. 41100, Tuesday, October 8, 1985

James C. Miller III,

Director.

BILLING CODE 3110-01-M

TABLE A

STATUS OF 1986 RESCISSIONS

	Amount (In millions of dollars)
Rescissions proposed by the President	0
Accepted by the Congress	0
Rejected by the Congress	0
Pending before the Congress	0

****

TABLE B

STATUS OF 1986 DEFERRALS

	Amount (In millions of dollars)
Deferrals proposed by the President	$1,628.8
Routine Executive releases through October 1, 1985	-14.3
Overturned by the Congress	0
Currently before the Congress	$1,614.4

Attachments

Attachment A - Status of Rescissions - Fiscal Year 1986

As of October 1, 1985 Amounts in Thousands of Dollars Agency/Bureau/Account	Rescission Number	Amount Previously Considered by Congress	Amount Currently before Congress	Date of Message	Amount Rescinded	Amount Made Available	Date Made Available	Congressional Action
None.								

Attachment B - Status of Deferrals - Fiscal Year 1986

As of October 1, 1985 Amounts in Thousands of Dollars Agency/Bureau/Account	Deferral Number	Amount Transmitted Original Request	Amount Transmitted Subsequent Change	Date of Message	Cumulative OMB/Agency Releases	Congres-sionally Required Releases	Congres-sional Action	Cumulative Adjustments	Amount Deferred as of 10-1-85
FUNDS APPROPRIATED TO THE PRESIDENT									
Appalachian Regional Development Programs									
Appalachian regional development programs...	D86-1	10,000		10-1-85					10,000
DEPARTMENT OF AGRICULTURE									
Forest Service									
Expenses, brush disposal....................	D86-2	77,913		10-1-85					77,913
Timber salvage sales........................	D86-3	22,854		10-1-85					22,854
DEPARTMENT OF DEFENSE - MILITARY									
Military Construction									
Military construction, all services.........	D86-4	353,079		10-1-85	5,298				347,781
DEPARTMENT OF DEFENSE - CIVIL									
Wildlife Conservation, Military Reservations									
Wildlife conservation.......................	D86-5	1,168		10-1-85					1,168

Attachment B - Status of Deferrals - Fiscal Year 1986

As of October 1, 1985 Amounts in Thousands of Dollars Agency/Bureau/Account	Deferral Number	Amount Transmitted Original Request	Amount Transmitted Subsequent Change	Date of Message	Cumulative OMB/Agency Releases	Congressionally Required Releases	Congressional Action	Cumulative Adjustments	Amount Deferred as of 10-1-85
DEPARTMENT OF ENERGY									
Energy Programs									
Fossil energy research and development......	D86-6	9,247		10-1-85					9,247
Fossil energy construction..................	D86-7	7,038		10-1-85					7,038
Naval petroleum and oil shale reserves......	D86-8	155,668		10-1-85					155,668
Energy conservation.........................	D86-9	9,880		10-1-85					9,880
SPR petroleum account.......................	D86-10	536,958		10-1-85					536,958
Alternative fuels production................	D86-11	1,149		10-1-85					1,149
Power Marketing Administration									
Southeastern Power Administration,									
Operation and maintenance..................	D86-12	25,344		10-1-85	536				24,808
Southwestern Power Administration,									
Operation and maintenance..................	D86-13	5,000		10-1-85					5,000
Western Area Power Administration,									
Construction, rehabilitation, operation									
and maintenance........................	D86-14	27,095		10-1-85					27,095
Departmental Administration									
Departmental administration.................	D86-15	8,501		10-1-85	8,501				0
DEPARTMENT OF HEALTH AND HUMAN SERVICES									
Office of Assistant Secretary for Health									
Scientific activities overseas									
(special foreign currency program)........	D86-16	3,000		10-1-85					3,000
DEPARTMENT OF JUSTICE									
Bureau of Prisons									
Buildings and facilities....................	D86-17	20,000		10-1-85					20,000
Office of Justice Programs									
Crime victims fund..........................	D86-18	100,000		10-1-85					100,000

Attachment B - Status of Deferrals - Fiscal Year 1986

As of October 1, 1985 Amounts in Thousands of Dollars Agency/Bureau/Account	Deferral Number	Amount Transmitted Original Request	Amount Transmitted Subsequent Change	Date of Message	Cumulative OMB/Agency Releases	Congressionally Required Releases	Congressional Action	Cumulative Adjustments	Amount Deferred as of 10-1-85
DEPARTMENT OF STATE									
Bureau of Refugee Programs									
United States emergency refugee and migration assistance fund, executive	D86-19	18,082		10-1-85					18,082
Other									
Assistance for implementation of a Contadora agreement	D86-20	2,000		10-1-85					2,000
DEPARTMENT OF TRANSPORTATION									
Urban Mass Transportation Administration									
Discretionary grants	D86-21	223,600		10-1-85					223,600
OTHER INDEPENDENT AGENCIES									
Pennsylvania Avenue Development Corporation									
Land acquisition and development fund	D86-22	10,947		10-1-85					10,947
Railroad Retirement Board									
Milwaukee railroad restructuring, administration	D86-23	243		10-1-85					243
TOTAL, DEFERRALS		1,628,765	0		14,335	0		0	1,614,430

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