DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 154, 161, 250, and 284

[Docket Nos. RM98–10–001, RM98–10–004, RM98–12–001, RM98–12–004; Order No. 637–A]

Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services

Issued May 19, 2000.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule; order on rehearing.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing an order addressing the requests for rehearing of Order No. 637 [65 FR 10156, Feb. 25, 2000]. Order No. 637 revised Commission regulations to enhance the competitiveness and efficiency of the interstate pipeline grid. The order revised Commission pricing policies by waiving price ceilings for short-term released capacity for a two year period and, permitting pipelines to file for peak/off-peak and term differentiated rate structures. It also effected changes in regulations relating to scheduling procedures, capacity segmentation, pipeline imbalance processes and penalties, pipeline reporting requirements, and the right of first refusal. The rehearing order largely denies rehearing on these issues, but grants rehearing, in part, to make clarifying adjustments to the regulations regarding penalties, reporting requirements, and the right of first refusal.

DATES: The amendments to the regulations will become effective July 5, 2000.

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SUPPLEMENTARY INFORMATION:

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Before Commissioners: James J. Hoecker, Chairman; William L. Massey, Linda Breathitt, and Curt Hebert, Jr.

Order on Rehearing

In Order No. 637, issued on February 9, 2000, the Federal Energy Regulatory Commission (Commission) issued a final rule that amended Part 284 of the Commission's open access regulations to improve the efficiency of the market and to provide captive customers with the opportunity to reduce their cost of holding long-term pipeline capacity while continuing to protect against the exercise of market power.[1] In addition, the Commission instituted a new effort to monitor the changes taking place in the market so that the Commission can be prepared to continue its reexamination of its current regulatory framework to better meet the challenges posed by the growing competitive market. Specifically, the final rule made the following changes in the Commission's regulatory model:

- The rule grants a waiver for a limited period of the price ceilings for short-term released capacity to enhance the efficiency of the market while continuing regulation of pipeline rates and services to provide protection against the exercise of market power.
- The rule revises the Commission's regulatory approach to pipeline pricing by permitting pipelines to propose peak/off-peak and term differentiated rate structures. Peak/off-peak rates can better accommodate rate regulation to the seasonal demands of the market, while term differentiated rates can be used to better allocate the underlying risk of contracting to both shippers and pipelines.
- The rule improves the competitiveness and efficiency of the interstate pipeline grid by changing regulations relating to scheduling procedures, capacity segmentation, and pipeline penalties.
- The rule narrows the right of first refusal to remove economic biases in the current rule, while still protecting captive customers' ability to resubscribe to long-term capacity.
- The rule improves reporting requirements to provide more transparent pricing information and to permit more effective monitoring for the exercise of market power and undue discrimination.

Fifty-one requests for rehearing and clarification were filed, covering all the major elements of the rule.[2] As discussed below, the Commission largely denies rehearing, but grants rehearing, in part, to make clarifying adjustments to the regulations regarding penalties and reporting requirements. It also grants rehearing to clarify that shippers with a multi-year contract for a service that is not available for 12 consecutive months are eligible to exercise the right of first refusal.

I. Adjustments to Rate Policies

A. Removal of the Rate Ceiling for Capacity Release Transactions

In Order No. 637, the Commission removed the rate ceiling for short-term (less than one year) capacity release transactions for a two-year period ending September 30, 2002. In determining that the removal of the rate ceiling for short-term capacity release transactions was warranted, the Commission examined the interaction of its cost-of-service regulations with the actual way in which gas markets operate today. Based on this analysis of the market, the Commission concluded that the rate ceiling should be removed because cost-of-service rate regulation is not well suited to the short-term capacity market, the rate ceiling interfered with the efficient operation of the market, removal of the rate ceiling for short-term capacity would have little effect on the prices paid for capacity during peak periods, since shippers can avoid ceiling by making bundled sales, and removal of the ceiling would provide short-term shippers with an additional transportation option. The Commission found that protection against the exercise of market power in the short-term capacity release market could be achieved in ways other than

[1] Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services, 63 FR 10156 (Feb. 25, 2000), III FERC Stats. & Regs. Regulations Preambles ¶ 31,091 (Feb. 9, 2000).

[2] The appendix lists those filing for rehearing and clarification.

direct price regulation, including competition from other sellers of released capacity, improved reporting, monitoring and complaint procedures, and the maintenance of Commission regulation of pipeline capacity. In order to review the effects of this change in regulatory philosophy, the Commission limited the removal of the price ceiling to a two-year period so that the Commission and the industry could obtain more complete information about how the change would actually affect prices.

Requests for rehearing have been filed challenging the Commission's determination to grant a waiver of the price ceiling for short-term capacity release transactions.[3] In addition, several pipelines request rehearing of the determination not to remove rate ceilings on their short-term capacity.[4] As discussed below, the Commission is denying rehearing with respect to the waiver of the price ceiling [5] and is denying the request to apply the waiver to pipeline services. Others requested rehearing or clarification regarding the way in which the regulation would be applied. The Commission will address those requests.

1. Removal of the Price Ceiling

The requests for rehearing contend that the removal of the rate ceiling for short-term capacity release transactions permits unjust and unreasonable rates, because the Commission has not put forward sufficient proof that the market for capacity release transactions is competitive. They maintain that the Commission improperly found that short-term shippers were entitled to less protection against market power than long-term shippers. They argue that the Commission legally is permitted to relax rate regulation for short-term shippers only when the Commission has conducted a market-by-market analysis to show that there are sufficient alternative sources of supply, so the resulting rates can be considered just and reasonable.[6] They maintain the Commission has not conducted the market analysis of competition that it previously required in order to demonstrate a lack of market power and that reporting requirements and complaints are not an adequate basis to police market power abuses. The rehearing requests further maintain that the Commission failed to take into account the ability of pipelines to use their affiliates to purchase capacity, in order to capture the profits from above maximum rate capacity sales.[7]

Those seeking rehearing also argue that the Commission cannot base its determination to release the rate ceiling on the evidence showing that releasing shippers can avoid maximum rate regulation by making bundled gas sales [8] with transportation values that exceed the maximum rate. They maintain that the Commission should not be permitted to justify the removal of the rate ceiling on its own failure to make the capacity release system work and its continued tolerance of the bundled sales market.

Under section 4 of the Natural Gas Act (NGA), the Commission's responsibility is to ensure that rates are just and reasonable. To be sure, that responsibility entails an examination of the potential for the exercise of market power.[9] But rate regulation cannot perfectly emulate the prices produced by a competitive market and rate regulation frequently reflects a balance between the potential for exercise of market power and the need to promote allocative or productive efficiency or achieve other regulatory goals.[10] The Commission's current regulatory framework, for instance, has long permitted some exercise of market power by pipelines through selective discounting below the maximum rate. The justification for permitting this exercise of market power is to enhance efficiency by increasing throughput and to benefit those captive customers with long-term contracts by reducing, in the pipeline's rate case, the amount of the fixed costs that otherwise would be recovered through the rates paid by those captive customers.[11]

In this instance, the Commission has reviewed its regulations in light of the actual workings of the gas market. Based on this analysis, the Commission decided to make an incremental change to its current regulatory framework by creating a two-year waiver of price ceilings only for short-term capacity release transactions in the secondary market, while retaining rate regulation for primary capacity available from the pipeline as well as long-term capacity release transactions. The Commission determined that cost-of-service rate ceilings for short-term capacity release transactions do not approximate competitive prices. It further found that maintenance of the rate ceiling reduces efficiency, inhibits capacity trading and reduces the dissemination of accurate pricing information, limits shippers' capacity options, and inequitably allocates the cost of capacity between long-term and short-term shippers. Rather than continuing a traditional approach to regulation, the Commission has opted for a different regulatory approach which first, seeks to reduce the potential for the exercise of market power and second, employs contemporaneous reporting and monitoring along with case-specific enforcement mechanisms to identify and correct exercises of market power. The Commission will discuss below the various factors that led it to the conclusion that, on balance, removal of the price ceiling for short-term capacity release transactions will result in just and reasonable rates for all shippers and will respond to the rehearing requests in each of these areas.

a. Cost-of-Service Ratemaking. The Commission found in Order No. 637 that cost-of-service ratemaking is not well suited to the short-term capacity release market. The purpose of regulating a pipeline's rates is to try to capture the productive efficiency of a natural monopoly while imposing limits on the monopolist's ability to exercise market power. To achieve this goal, cost-of-service ratemaking limits a pipeline's rates to an amount sufficient to recover its revenue requirement. Cost-of-service regulation inhibits the exercise of the pipeline's market power because the pipeline's rates are limited, eliminating a monopolist's incentive to

[3] Rehearing Requests of Amoco, IPAA, Indicated Shippers, NGSA, NWIGU, National Association of Gas Consumers, Process Gas Consumers.

[4] Rehearing requests of CNG, Great Lakes, Kinder-Morgan, Koch, Williams.

[5] On April 20, 2000, Indicated Shippers and Independent Petroleum Association of America requested rehearing of the Commission's decision to deny their request for a stay of the price cap waiver. That request too is denied.

[6] Rehearing Requests by Amoco, IPAA, Indicated Shippers, NGSA, NWIGU, Process Gas Consumers.

[7] Rehearing Requests by Amoco, IPAA, Indicated Shippers, Ohio Oil and Gas Association, Process Gas Consumers.

[8] The rehearing requests refer to the bundled sales market as the gray market.

[9] *FPC* v. *Hope Natural Gas Co.,* 320 U.S. 591, 610 (1944); *Associated Gas Distributors* v. *FERC,* 824 F.2d 981, 995 (D.C. Cir. 1987), *cert. denied,* 485 U.S. 1006 (1988).

[10] *See Environmental Action* v. *FERC,* 996 F.2d 401 (D.C. Cir. 1993) (recognizing the need to balance efficiency gains from unfettered trading with the need to protect against the exercise of market power). *See also* Permian Basin Area Rate Cases, 390 U.S. 747, 792 (1968) (need to balance interests of investors and the protection of the public interest); *FPC* v. *Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) (ratemaking involves the balancing of investor and consumer interests).

[11] *Associated Gas Distributors* v. *FERC,* 824 F.2d 981, 1010–1012 (D.C. Cir. 1987) (selective discounting permitted to benefit captive customers by contributing to payment of fixed costs), *cert. denied,* 485 U.S. 1006 (1988); *United Distribution Companies* v. *FERC,* 88 F.3d 1105, 1141–42 (D.C. Cir. 1996) (affirming Commission's determination to permit selective discounting and not requiring pipelines to discount); 1 A. Kahn, the Economics of Regulation 131–33 (1970) (price discrimination one solution to problems of natural monopoly and declining costs).

withhold capacity (by not constructing facilities) in order to raise prices through the creation of scarcity. This rationale for limiting rates for pipelines, however, has little applicability to the secondary market where releasing shippers do not control the amount of long-term capacity that will be built.

In addition, the static annual rates produced by cost-of-service ratemaking bear no relationship to competitive rates that would be established in the short-term market, particularly during peak periods. The evidence cited in Order No. 637 showing the implicit value of transportation in the bundled sales market demonstrates the variability of transportation value in the short-term market and the divergence between transportation value and cost-of-service rates. In short, traditional methods of cost-of-service regulation cannot come close to emulating the variability of short-term market prices.

The rehearing requests do not dispute that the cost-of-service ratemaking method is ill-suited to the short-term capacity release market, and they do not challenge the Commission's conclusion that no method of cost-of-service rate regulation could emulate the prices a competitive market would produce. Indeed, they recognize that during peak periods, transportation prices in a competitive market could exceed the cost-of-service maximum rate.[12] Despite the recognized infirmities of cost-of service regulation as applied to the short-term capacity release market, the rehearing requests contend that the Commission has no choice other than to continue to use this method of regulation unless it conducts a market analysis showing that each market performs competitively. As explained below, the Commission has concluded that the removal of cost-of-service regulation for short-term capacity release transactions is warranted without a full market-by-market analysis.

b. Bundled Sales and Transportation. In today's gas market, shippers can effectively bundle gas and transportation to make gas sales in downstream markets. During peak periods, when transportation values exceed maximum ceiling rates, firm shippers can avoid the ceiling rates by making bundled sales at delivery points, rather than releasing the transportation capacity independently. As a consequence, the Commission concluded that the price ceiling does not limit the prices paid by shippers in the short-term capacity release market as much as it limits their transportation options. Due to the price ceiling, many shippers without firm transportation are limited to purchasing gas through a bundled sales transaction or simply taking gas from the pipeline system and incurring overrun and scheduling penalties. The price ceiling in effect denies these shippers the option of obtaining transportation capacity (without gas) during peak periods.

The rehearing requests recognize the existence of the bundled sales market and do not challenge the fact that the value of transportation in bundled sales transactions can exceed the maximum rate derived from cost-of-service regulation. Some suggest that the bundled sales market is not a factor at upstream pooling points in the production area, constraint points, or at interconnects, although they do not explain why bundled sales cannot be made at such points.[13] In fact, comments in this proceeding indicate that production area pricing is governed by the same basis differentials as downstream markets.[14] Those requesting rehearing instead argue that the Commission should not allow its failure to ''make the capacity release system work, and continued tolerance of the grey market'' [15] justify the removal of the price ceilings in the short-term capacity release market.

The capacity release system was intended to provide an efficient method by which shippers could reallocate transportation capacity to other shippers in a way that is fair, open, and transparent and that would provide good market information about the value of pipeline capacity. But the short-term rate ceiling prevents the capacity release system from fulfilling these goals during peak periods precisely because releasing shippers seek to avoid the rate cap by ignoring the capacity release market and bundling the transportation with downstream sales. Removal of the rate ceiling on short-term capacity release transactions, therefore, will make the capacity release system more, not less, viable. It will also serve to make capacity transactions during peak periods more transparent, providing good information to all shippers about the market value of transportation.

Nor do those seeking rehearing suggest how the Commission could regulate the bundled sales market in ways that would not reduce the efficiency of that market and that would be consistent with Congress's deregulation of gas sales.[16] For the Commission to ignore the bundled sales market, as the rehearing requests suggest, is to take a panglossian perspective, rather than seeing the market as it really exists. The Commission has concluded that its regulation will be far more effective if it recognizes how business is really done and seeks to impose regulatory controls that are consistent with that market, rather than continuing to use regulatory methods that are ineffective and reduce efficiency. Given the ability of shippers to make bundled sales without rate ceilings, removal of the rate ceiling for capacity release transactions will have little adverse effect on the transportation costs consumers will pay. Rather, lifting of the price ceiling adds another capacity option to the market that can increase efficiency and the transparency of transactions, and thereby, result in lower effective transportation rates.

c. *Promotion of Greater Efficiency.* Even if the bundled sales market were not effective as a substitute for releasing capacity, the Commission found in Order No. 637 that the price ceiling on capacity release transactions inhibits the efficient allocation of capacity and harms short-term shippers. The price ceiling in the long-term market serves to protect customers by reducing the pipeline's ability to exercise market power either by withholding capacity to raise price or by price discriminating and, as a consequence, creates the incentive for pipelines to add capacity when demand increases. The pipelines have an incentive to increase capacity, because adding capacity is the only way the pipeline can increase long-term revenue. In the short-term capacity release market, however, a rate ceiling does not provide comparable protection.

Shippers without firm capacity are always at risk of being unable to obtain capacity, because the services on which they rely, pipeline interruptible or released capacity, may not be available during peak periods, or may be available only in limited quantities. Given the limited amount of capacity available during peak periods, a rate ceiling is of little or no benefit to a short-term shipper; capping the price the shipper can pay provides no protection to a

[12] Rehearing Request of Process Gas Consumers, at 30.

[13] Rehearing Requests of Amoco, IPAA, Indicated Shippers, NGSA.

[14] Comments by Koch, at 41–42 (on a production area pipeline, ''the value of transportation services (both firm and interruptible) is driven primarily by the basis differentials that are present across its system'').

[15] Rehearing Request of IPAA, at 16. For the same point, see Rehearing Requests by Amoco, Indicated Shippers, NGSA, Process Gas Consumers.

[16] Natural Gas Wellhead Decontrol Act of 1989, Pub. L. No. 101–60, 103 Stat. 157 (1989); Natural Gas Policy Act, § 601(a)(1), 15 U.S.C. 3431 (Commission jurisdiction does not apply to first sales of domestic gas).

shipper that, as a result of that ceiling, cannot obtain the capacity it needs. The rate ceiling creates an inefficient allocation system which operates to prevent the shipper most valuing the capacity from being able to obtain it. For example, the rate ceiling results in arbitrary allocations of capacity based on queue positions or on a *pro rata* allocation, in which the shipper most needing the capacity may be unable to obtain any capacity or the amount of capacity it needs. Indeed, the removal of the rate ceiling benefits short-term shippers because the shipper placing a high value on the capacity has greater assurance of obtaining the capacity it needs than it does under a price cap where that shipper may be unable to obtain any capacity.[17] The rate ceiling could have the further effect of actually reducing the amount of released capacity available, because price ceilings may make the release of capacity uneconomic for some shippers.

Those requesting rehearing do not contest that the use of price ceilings during peak periods can result in an inefficient allocation of capacity. Instead, Indicated Shippers maintain that the Commission's assertion that removing price ceilings could induce releasing shippers to release additional capacity is completely speculative. But the Commission's conclusion was not speculation; it was based on sound economic theory.[18] A releasing shipper will hold onto its capacity if the amount it receives for the release is less than its opportunity cost, the value to the shipper of the next best use of its capacity. Thus, a releasing shipper, subject to a rate ceiling, will hold onto capacity if the amount it will receive is less than the cost to it of using an alternative fuel or storage, or the cost of reducing its use of gas through conservation. However, if the releasing shipper can obtain the market value for its capacity and that value exceeds the value of its next best alternative, it will choose to release that capacity, thereby adding to the amount of released capacity to the market. The effect of increasing the amount of released capacity available in the market will be to reduce the price for transportation, because, as the supply of transportation increases, but the demand for transportation remains the same, the price of transportation will decrease.

Indicated Shippers also contends that in light of pipelines' ability to file for peak and off-peak rates, the Commission has not explained why additional action is needed to aid long-term shippers in defraying the cost of their reservation charges. In the first place, the purpose of removing the rate ceiling was not simply to permit firm shippers a greater opportunity to defray the cost of their reservation charges (although that was one goal). An equally important purpose was to help foster an efficient trading market in which capacity would be sold to the shipper placing the highest value on obtaining transportation service. Particularly during peak periods when capacity is most constrained, an efficient market is needed so that a market clearing price will provide for the efficient allocation of capacity. While permitting pipelines to file for peak and off-peak rates will enable pipelines to file for rate structures more in line with the value of transportation capacity, the development of peak and off-peak rates that remain within a pipeline's cost-of-service may not come close to duplicating the rates, particular during peak periods, that a competitive market would require to clear efficiently. As the data cited in Order No. 637 with respect to the value of transportation demonstrates, during peak demand periods the value of transportation in an efficient market rises dramatically for short periods to levels that would exceed the rates that pipelines could establish through proposals for cost-of-service peak/off-peak rates.[19] For instance, during some peak winter periods, the value of transportation was 8–13 times greater than the applicable maximum rate for short periods of time, but during other winter periods with differing demand conditions the peak period rates were only 1½ to 2 times the maximum rate. Pipelines would not propose revenue neutral cost-of-service peak rates coming close to the higher levels that occur during peak constraint periods, because they could never be sure how frequently those demand conditions would occur and if they established peak winter rates at that level, their off-peak rates would be so low that in many cases, they would be unable to recover their cost-of-service. Moreover, even if pipelines could propose peak rates high enough to cover market prices during maximum constraint periods, those rates would be far too high for the same time period when demand conditions are not as severe. While cost-of-service peak and off-peak pricing has a legitimate purpose in the world of cost-of-service ratemaking, these rates likely will not approximate the efficient rates that a competitive market needs to clear during peak periods. In order to create such a efficient market, cost-of-service peak and off-peak rates are not sufficient and removal of the rate ceiling for capacity release transactions (with the protections adopted by the Commission) is necessary to permit efficient pricing.

d. Equitable Allocation of Capacity Costs. The Commission found in Order No. 637 that the price ceiling can result in an inequitable distribution of costs between long-term firm capacity holders and short-term shippers. Indicated Shippers maintain that the Commission has no foundation for finding that higher rates during peak periods are needed to reapportion cost responsibility between short-term and long-term shippers. They argue that the Commission failed to take any steps in Order No. 637 to ensure that capacity is not withheld during off-peak periods and, therefore, they maintain market power may be exercised during off-peak periods.

Prior to Order No. 636, and the institution of capacity release, pipelines were the only source of interruptible capacity during off-peak periods. Pipelines could discount selectively, charging maximum rates to customers with more inelastic demand and charging discounted rates to customers with alternatives, such as dual fuel capability. The pipelines' ability to selectively discount benefitted the long-term firm capacity holders, because the greater contribution to cost recovery provided by interruptible service would reduce firm shippers' rates.

The institution of capacity release in Order No. 636, along with flexible receipt and delivery points, placed competitive pressure on the pipelines' interruptible service, because a shipper in the short-term market was given the choice of obtaining capacity from a number of releasers, rather than being limited to pipeline interruptible service. In fact, during the Order No. 636 proceedings, pipelines were concerned that competition from capacity release would so reduce the level and prices for interruptible service that they would be unable to recover the costs allocated to

[17] Those short-term shippers who currently have a high place on the pipeline's queue may prefer the current system, because they can obtain capacity at a cheap regulated rate and use it to effect a bundled sale at market prices reflecting a higher market value. But this is a selective benefit to certain shippers not a benefit to the market as a whole.

[18] *Associated Gas Distributors* v. *FERC,* 824 F.2d 981, 1008–09 (D.C. Cir. 1987) (agency can rely upon generally accepted economic theory even without factual evidence to support proposition that increased competition will lead to lower prices), *cert, denied,* 485 U.S. 1006 (1988); *Environmental Action* v. *FERC,* 939 F.2d 1057, 1064 (D.C. Cir. 1991) (agency entitled to rely upon predictions about the market it regulates).

[19] Order No. 637, 65 FR at 10196, 10174–79, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091, at 31,271–74 (figures 6 and 7).

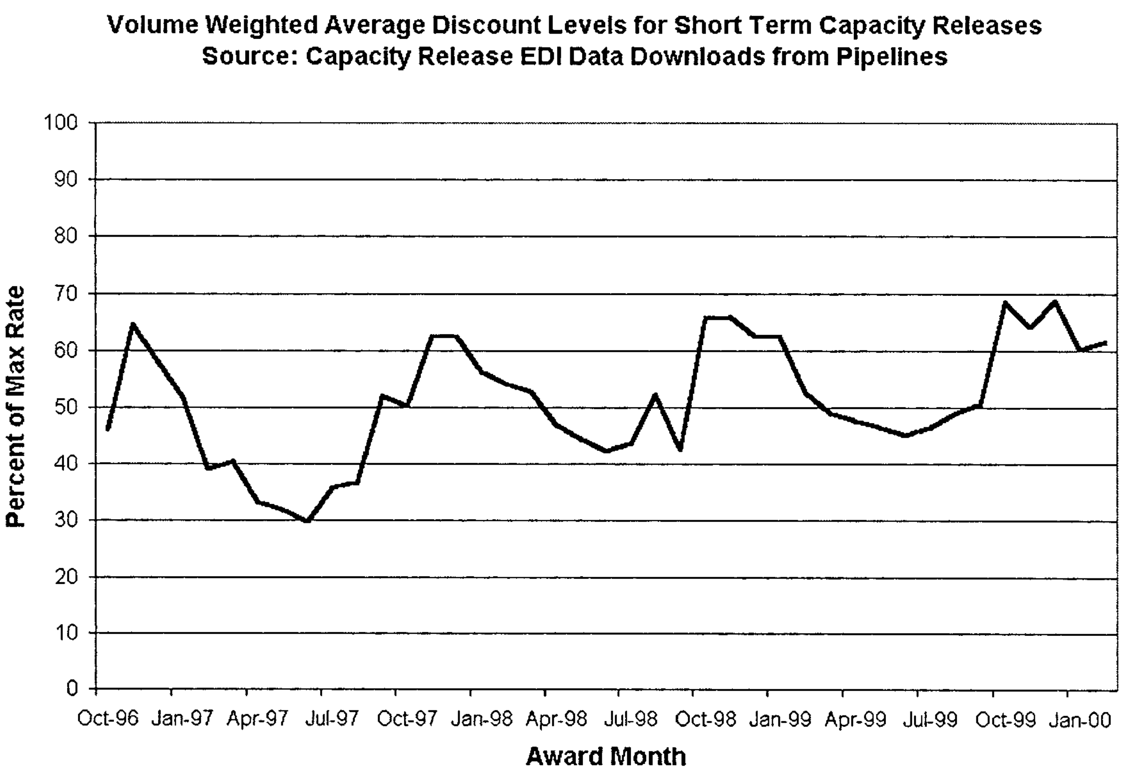
interruptible service.[20] Accordingly, in restructuring proceedings, pipelines reduced the cost responsibility for interruptible service, and increased firm shippers' rates. After the institution of capacity release, firm shippers could reduce their costs of holding pipeline capacity by releasing the capacity they held as well as receiving interruptible revenue credits to the extent the pipeline was able to sell interruptible service above the costs allocated to that service.[21]

With the advent of capacity release, however, the rates for capacity release and pipeline interruptible service have fallen well below maximum tariff rates, particularly during off-peak periods, as would be expected from the addition of numerous firm shippers who are now competing with the pipeline to sell capacity during off-peak periods. This is well documented. Numerous commenters made the point that competition from capacity release transactions has depressed short-term rates, particularly during off-peak periods, and has hurt long-term shippers by requiring them to bear a greater proportion of capacity costs.[22]

Studies support the finding that short-term rates have fallen well below maximum rates. One study, using data from the period 1992–1998, has shown that the average rates for released capacity range from 31% to 76% of maximum rates in 17 pipeline corridors, with only 5 of the corridors exceeding an average rate of 60%.[23] Commission data from capacity release and interruptible transactions also support the conclusion that short-term rates fall well below maximum tariff rates. The following graphs show the average prices of capacity release transactions and discounted pipeline interruptible transportation from October 1996 to February 2000, as a percentage of the applicable maximum tariff rate.[24]

The average capacity release rate for all pipelines in the sample ranges from 30% to 70% of the pipeline's maximum rate, with the lowest average in the off-peak winter months. Off-peak rates during the summer months were below 50% of the maximum rate in all three off-peak periods.

Figure 1 –Capacity Release Transactions as Percentage of Maximum Rate (Oct. 1996-Feb. 2000)



[20] Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Order No. 636–A, 57 FR 36128 (Aug. 12, 1992), FERC Stats. & Regs. Regulations Preambles [Jan. 1991–June 1996] ¶ 30,950, at 30,562–63 (Aug. 3, 1992).

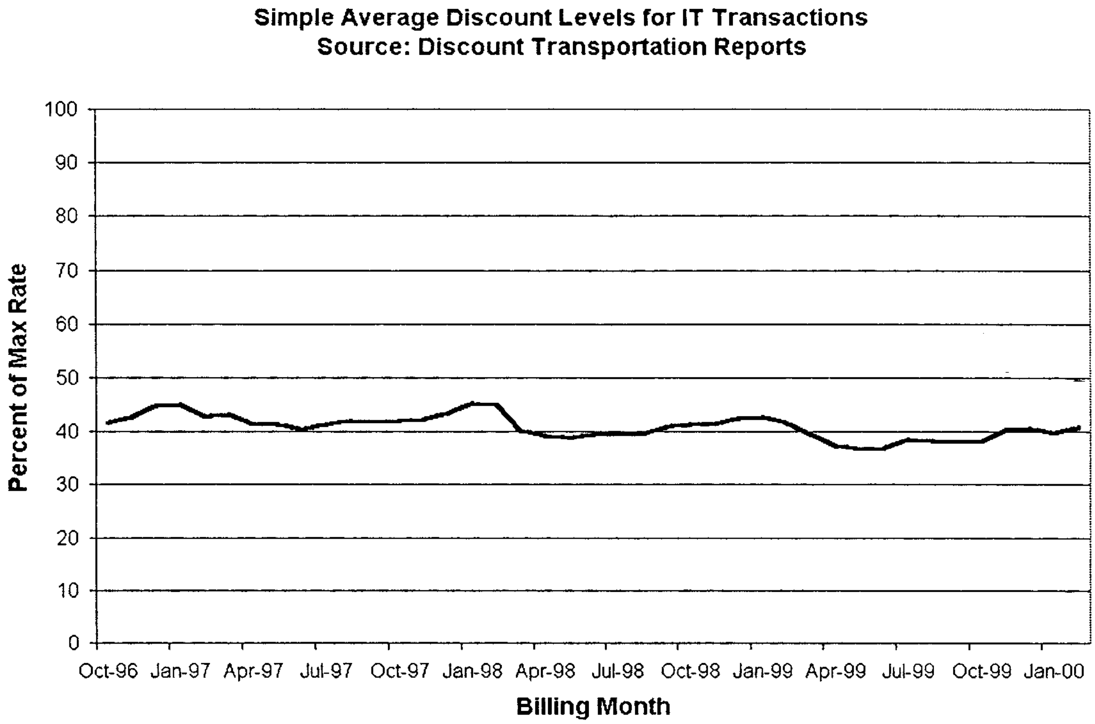
[21] *Id.*

[22] Associated Gas Distributors v. FERC, 824 F.2d 981, 1008–1009 (D.C. Cir. 1987) (agencies do not need to conduct experiments to verify predictions that competition will lower prices), *cert. denied,* 485 U.S. 1006 (1988). Comments of AGA I, Arkansas PSC, Consolidated Edison, Enron Pipelines, Illinois Commerce Commission, INGAA, NARUC, NASUCA, Nisource, Pennsylvania/Ohio Consumer Advocates, Pennsylvania PUC, Philadelphia Gas Works, Piedmont/UGI, PSC of Wisconsin, PUC of Ohio, and Washington Gas Light.

[23] Henning & Sloan, Analysis of Short-Term Natural Gas Markets, 41–45 (Energy and Environmental Analysis, Inc., November 1998) (the authors conclude that these percentages are somewhat overstated insofar as they reflect maximum rate transactions mandated by state unbundling programs).

[24] The data are derived from capacity release data downloaded from 33 pipeline Internet sites, and the discount reports filed by the pipelines with the Commission.

Figure 2 –Interruptible Transportation Rates as Percentage of Maximum Rate (Oct. 1996-Feb. 2000)



For discounted interruptible transportation, the average rate ranged from the mid-30% to mid-40% of maximum rates.[25] Removal of the rate ceiling, therefore, removes a regulatory bias in the current system and will help to create a more equitable distribution of capacity costs between short and long-term customers, just as selective discounting did before the advent of capacity release. Prior to capacity release, pipeline sales of interruptible transportation reduced the cost responsibility of long-term shippers, because the revenue from interruptible transportation lowered the amount of costs allocated to long-term firm shippers. Shippers with inelastic demand buying short-term interruptible transportation service were more likely to pay maximum rates, because they had fewer capacity alternatives. With the advent of capacity release, however, the prices for released capacity during the off-peak periods are well below maximum rates and the rate ceiling prevents long-term shippers from recovering the value of capacity during peak periods. Similarly, pipeline interruptible transportation recovers less of the cost-of-service than it did before, so long-term shippers are required to shoulder a higher level of cost responsibility than they did prior to the institution of capacity release.

Removal of the rate ceiling on capacity release transactions, therefore, will help restore the previous balance between the cost responsibility of long and short-term shippers, but in a way consistent with prices in a competitive market. Short-term shippers will continue to benefit from lower rates during off-peak periods, but will now face more appropriate market rates during peak periods. By the same token, long-term customers, which can recover only a small portion of their capacity costs through capacity release during off-peak periods, will be able to recover a greater proportion of those costs during peak periods. As a result of removing the rate ceiling, short-term shippers will pay their fair share of capacity costs through the release market to reflect their peak period use and long-term captive customers will benefit by being better able to defray their costs of holding capacity by selling released capacity.

e. Protection Against the Exercise of Market Power. In Order No. 637, the Commission concluded that maximum rate regulation may not be appropriate for regulating the short-term capacity release market, that there are a number of factors which inhibit the ability of releasing shippers to exercise market power, and that the Commission can assure just and reasonable rates through indirect methods. Competition among capacity releasers—enhanced by the Commission's regulations providing for flexible receipt and delivery point rights and capacity segmentation—provides protection against the exercise of market power. This protection is supplemented by public reporting of pricing, along with complaint procedures that permit the Commission to monitor and respond to complaints about the exercise of market power. In addition, the Commission is maintaining regulatory protections against market power abuse, including the retention of the Commission's current posting and bidding requirements for capacity release transactions, the maintenance of

[25] The purpose of these data is to compare the rates for capacity release and interruptible service to the maximum tariff rate. Due to differences in the way in which capacity release and interruptible transportation are reported, one can draw no conclusion about whether the average rates for capacity release are higher or lower than the rates for interruptible service. The average capacity release rates include deals at the maximum tariff rate, but the average discounted interruptible rate does not include maximum rate transactions because prior to Order No. 637, pipelines did not include maximum rate interruptible transactions in their discount reports. In addition, the capacity release transactions are weighted by the volume of the contract demand involved, while the interruptible transactions are simple averages, because interruptible shippers do not have a contract demand. They can ship only as much gas as the pipeline has available.

rate regulation on primary pipeline capacity and on long-term capacity release transactions, and the regulation of pipeline penalty levels to establish an effective ceiling price for release transactions.

The crux of the arguments presented by those seeking rehearing is that regardless of the limits of maximum rate regulation and the inefficiencies created by such rate regulation for the short-term capacity release market, the Commission legally must continue to apply cost-based ceiling rates in the short-term capacity release market unless it conducts a detailed market study showing that there are a sufficient number of competing suppliers of capacity to ensure the market is competitive. They maintain that without such a market-by-market study, removal of rate ceilings is not permissible. The Commission does not view its authority to choose appropriate regulatory methods for implementing the Natural Gas Act to be so limited. The Commission will discuss below its legal authority to remove rate ceilings and the protections against the exercise of market power that will continue to exist.

(1) Legal Justification

The courts have long recognized that the Commission is not ''bound to the use of any single formula or combination of formulas in determining rates.'' [26] ''Under the statutory standard of 'just and reasonable,' it is the result reached not the method employed which is controlling.'' [27] The courts have recognized that the Commission's ratemaking function rates requires a balancing of interests.[28]

They further recognize that the Commission's ratemaking function requires the making of ''pragmatic adjustments which may be called for by particular circumstances.'' [29] The Court, for example, recognized the difficulties the Commission faced in regulating individual producer prices and permitted the Commission to depart from individual producer cost-of-service ratemaking to the use of area and national rates.[30] The Court also has found that the Commission has the authority to depart from cost-of-service ratemaking for some classes of customers and to rely upon methods of indirect regulation to keep rates within just and reasonable levels.[31]

In Order No. 637, the Commission examined the available methods of direct rate regulation as well as the operation of the gas marketplace, and concluded that direct rate regulation of the short-term release market did more harm than good, since shippers can avoid rate regulation in the short-term capacity release market by making bundled sales and because regulation of short-term rates results in market inefficiency, findings the rehearing requests do not significantly challenge. In this context, the Commission determined that its existing methods of rate regulation needed to be changed to better comport with the actual operation of the market.[32] To respond to the changes in the market, the Commission undertook a limited program to improve the efficiency of the short-term capacity release market in which rate regulation was relaxed for a short period only for short-term capacity release transactions. In place of direct rate regulation, the Commission is relying on a combination of other factors to ensure rates remain just and reasonable, including competition among releasing shippers, regulatory changes to enhance competition, posting requirements to increase transparency, monitoring and enforcement, and the continuation of regulation on pipeline capacity. The Commission limited the program to a two-year period, which enables the Commission to gather data on market performance which otherwise would be unavailable.

The setting of just and reasonable rates is intended to establish a reasonable balance between the interests of pipelines and consumers.[33] In this rule, the Commission has retained cost-of-service regulation for pipelines to assure just and reasonable prices for primary pipeline capacity. Since firm shippers can make bundled sales without rate ceilings, the current price ceiling on capacity release transactions in the secondary market has little impact on final consumer prices and, in fact, as explained earlier, lifting the rate ceiling may help to reduce such prices by increasing the efficiency and transparency of the market. With the market and regulatory protections against market power, the lifting of the rate ceiling for short-term capacity release transactions is consistent with the Commission's statutory authority because it will have limited effect on consumer prices and provides protection against unjust and unreasonable prices.

The cases principally cited in the rehearing requests do not preclude the approach adopted by the Commission in Order No. 637.[34] First, these cases concern the lifting of price ceilings for primary capacity from a pipeline or regulated utility, not, as is the case here, with the relaxation of rate regulation only in the secondary market, with rate regulation maintained for primary pipeline capacity. Second, they do not indicate, as the rehearing requests contend, that a competitive market analysis is a prerequisite for relaxing cost-of-service rate regulation in the secondary market.

Farmers Union did not require a detailed market-by-market study before relaxing cost-of-service rate regulation. In *Farmers Union,* the Court found that the Commission had not justified relaxation of cost-based regulation of oil pipeline companies, because the Commission had not shown how its overall regulatory program would ensure that pipeline rates remained within the zone of reasonableness. But *Farmers Union* focused on balancing the financial interests of the oil pipelines and the relevant public interest and did not focus on regulation of the secondary or resale market. Even so, *Farmers*

[26] *FPC* v. *Hope Natural Gas Co.,* 320 U.S. 591, 602 (1944); *Elizabethtown Gas Company* v. *FERC,* 10 F.3d 866, 870 (D.C. Cir. 1993); *Farmers Union Central Exchange* v. *FERC,* 734 F.2d 1486, 1501 (D.C. Cir. 1984).

[27] Hope, 320 U.S. 591, 602.

[28] Permian Basin Area Rate Cases, 390 U.S. 747, 792 (1968) (need to balance interests of investors and the protection of the public interest); *FPC* v. *Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) (ratemaking involves the balancing of investor and consumer interests); *Farmers Union Central Exchange* v. *FERC,* 734 F.2d 1486, 1502 (D.C. Cir. 1984) (balance of financial interest of regulated company and public interests).

[29] Permian Basin Area Rate Cases, 390 U.S. 747, 777 (1968). *See FPC* v. *Natural Gas Pipeline Co.,* 315 U.S. 575, 586 (1942); Hope, 320 U.S. 591, 602.

[30] Permian Basin Area Rate Cases, 390 U.S. 747 (1968) (permitting area rates); *Mobil Oil Exploration & Producing Southeast, Inc.* v. *United Distribution Companies,* 498 U.S. 211 (1991) (permitting the collapse of prior vintage rates into a single national ceiling rate equal to the highest pre-existing ceiling rate).

[31] *FPC* v. *Texaco,* 417 U.S. 380 (1974) (authority to assure just and reasonable rates through indirect regulation as opposed to direct price regulation); Permian Basin Area Rate Cases, 390 U.S. 747, 787 (1968) (Commission empowered to prescribe different requriements for different classes of persons or matters).

[32] Permian Basin Area Rate Cases, 390 U.S. 747, 785, 790 (1968) (Commission permitted to adopt policies needed to respond to demands of changing circumstances).

[33] Hope, 320 U.S. 591, at 603 (ratemaking involves a balance of investor and consumer interests); *Tejas Power Corporation* v. *FERC*, 908 F.2d 998 (D.C. Cir. 1990) (Commission must protect interest of consumers); *Farmers Union Central Exchange, Inc.* v. *FERC*, 734 F.2d 1486, 1502 (D.C. Cir. 1984) (strike a fair balance between financial interests of the regulated company and public interest).

[34] The cases principally cited in the rehearing requests are *Farmers Union Central Exchange* v. *FERC*, 734 F.2d 1486, 1509–10 (D.C. Cir. 1984), *Elizabeth Gas Company* v. *FERC*, 10 F.3d 866 (D.C. Cir. 1993), *Environmental Action* v. *FERC*, 996 F.2d 401 (D.C. Cir. 1993).

Union recognized that the Commission was not confined to cost-of-service ratemaking (734 F.2d 1486, at 1501), that non-cost factors could play an important role in determining whether rates are just and reasonable (734 F.2d 1486, at 1502), that changing circumstances can justify an agency in taking a new approach to the determination of just and reasonable rates (734 F.2d 1486, at 1503), and that rate regulation can be relaxed if the regulatory scheme itself acts as a monitor to maintain rates in the zone of reasonableness or to act as a check on rates if they are not (734 F.2d 1486, at 1509). The court concluded that ''moving from heavy to lighthanded regulation ''can be justified by a showing that under current circumstances, the goals and purposes of the statute will be accomplished through substantially less regulatory oversight.'' [35]

In Order No. 637, the Commission, satisfied the *Farmers Union* criteria. It described in detail the non-cost factors and industry changes that justified the relaxation of cost-of-service regulation for short-term capacity release transactions. It demonstrated how the regulatory scheme, including competition, monitoring, complaint procedures, mitigation measures, such as the capacity auction, and the continuation of regulation for primary pipeline services, would act as a check to ensure that rates remain just and reasonable. For instance, unlike *Farmers Union,* where the Court found the Commission had failed to document how market forces would limit rates to just and reasonable levels, [36] the record shows that competition from multiple firm shippers has successfully reduced rates, particularly during off-peak periods, to well below the maximum regulated rate. The Commission found that, given the interaction of all these factors, the goals and purposes of the NGA would be accomplished through relaxation of cost-of-service rates for the short-term capacity release market and greater reliance on other regulatory initiatives for controlling the potential exercise of market power.

Elizabethtown was the next case in which the court considered relaxation of a cost-of-service ratemaking. In *Elizabethtown,* the court affirmed the Commission's determination to replace cost-of-service ratemaking for pipeline gas sales with market based pricing, rejecting the contention that the Commission is required under the NGA to base rates on historic cost-of-service ratemaking principles. The court recognized that the use of the Commission's section 5 authority, either upon the Commission's own motion or that of a complaint, can assure that negotiated rates remain just and reasonable. [37] As the rehearing requests note, in *Elizabethtown,* the Commission relied on a market study as part of its conclusion that market-based rates were just and reasonable, but the court did not suggest that such a market study was a necessary requirement for permitting market-based rates if other factors would keep rates within a just and reasonable range.

Environmental Action continued the movement toward the use of lighter handed regulation when needed to achieve other statutory goals. In *Environmental Action,* the Court approved a relaxation of cost-of-service rate regulation for an electric power pool in order to promote more effective capacity trading, even though the Commission did not conduct a detailed market analysis of competition. *Environmental Action* admittedly is different than the Commission's action in this proceeding, because while the Commission in *Environmental Action* did not rely upon company-by-company cost-of-service analysis to design rates, it maintained a cost based rate ceiling based on the hypothetical cost of the average company for firm energy, the most valuable and expensive service offered in the power pool. The Court found that the Commission could relax rate regulation because the Commission had struck a reasonable balance between promoting efficiency through capacity trading and relying on competition and price disclosure as a means of protecting against price gouging and the exercise of market power.[38] In *Environmental Action,* the Court further found that the benefits of free and open trading justified a risk of price discrimination against the most captive members of the pricing pool. Similarly, the benefits of more efficient and effective capacity trading in this instance outweigh any limited potential for the exercise of market power during the few periods in which transportation value exceeds maximum rates.

In *Environmental Action,* the Commission did impose a high ceiling rate as further protection against the exercise of market power by the utilities in the pricing pool. But *Environmental Action* involved a lifting of rate ceilings for all transactions, including those made by the utilities. In Order No. 637, in contrast, the Commission has lifted the price ceiling only for short-term capacity release transactions, while retaining cost-based regulation for pipeline services and long-term capacity release transactions. The evidence showing large and sudden increases in transportation values during peak periods demonstrates that the Commission could not design a cost-based short-term rate ceiling that would emulate short-term market prices and that would not interfere with the efficiency of the capacity release market, particularly during peak periods when an efficient market is most needed. In order to come close to replicating market prices during peak periods, any short-term rate ceiling would have to be so high as to provide little protection to any shipper. Rather than using a high and artificial price ceiling as back-up protection, as in *Environmental Action,* the Commission in this rule retained cost-based regulation of pipeline capacity as back-up protection. This approach provides better protection to short-term shippers than an artificial price ceiling without compromising the efficiency of capacity trading as a price ceiling would.

The rehearing requests further contend that the Commission ignored its own precedent in not conducting a detailed market analysis before permitting releasing shippers to charge market based rates. [39] The prior proceedings were in a different posture from this rulemaking because the proceedings cited all included applications by pipelines to remove cost-of-service regulation from their services. Moreover, while the Commission has found that a market power study is one method for permitting market based rates,[40] it did not indicate that it was the exclusive method or that other regulatory steps could not also be justified. In this rulemaking, the Commission examined all relevant market factors and fully explained why continuation of cost-of-service rate ceilings for capacity release

[35] 734 F.2d 1486, at 1510.

[36] 734 F.2d 1486, at 1508.

[37] 10 F.3d 866, 870.

[38] 996 F.2d 401, 410.

[39] The rehearing requests cite, *e.g.,* Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines, 61 FR 4633 (Feb. 7, 1996), 74 FERC ¶ 61,076 (1996), Koch Gateway Pipeline Company, 85 FERC ¶ 61,013 (1998), *reh'g denied,* 89 FERC ¶ 61,046 (1999); Secondary Market Transactions on Interstate Natural Gas Pipelines, Notice of Proposed Rulemaking, 61 FR 41046 (Aug. 7, 1996) FERC Stats. & Regs. Proposed Regulations [1988–1998] ¶ 32,520 (July 31, 1996) (final rule never issued); Proposed Experimental Pilot Program to Relax the Price Cap for Secondary Market Transactions, 76 FERC ¶ 61,120 (1996) (program terminated).

[40] Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines, 74 FERC ¶ 61,076 (1996).

transactions no longer meets the needs of the market and that a more flexible approach, relying on competition and other regulatory controls, was necessary.

Indicated Shippers maintain that the Commission's relaxation of price ceilings in this case is inconsistent with its policy with respect to electric transmission service where Indicated Shippers maintain the Commission continues to regulate on a cost-of-service basis. In fact, however, the Commission has not limited pricing for short-term electric transmission service to embedded cost-of-service rates. As the Commission has done in this rule, the Commission has recognized that neither historic nor incremental costs are an appropriate ceiling for short-term electric transmission services and has permitted utilities to sell short-term transmission services at the higher of embedded or opportunity cost without a price cap. [41] With respect to reassignments of electric transmission capacity of one year or less, the Commission has similarly found that reassignments can be made at the reassignor's opportunity cost without an embedded cost or incremental price cap.[42] In this rule, the Commission followed essentially the same policy it has applied to electric regulation by removing embedded cost price ceilings for short-term capacity releases, so that releasing shippers can effectively obtain the opportunity costs for capacity. A releasing shipper will be able to sell its capacity for a rate that exceeds the value to the shipper of the next best use of its capacity. A combination of competition and other regulatory controls protect against short-term capacity release rates becoming unjust and unreasonable.

Those requesting rehearing further contest what they term the Commission's determination that shippers in the short-term capacity release market are not entitled to protection. They maintain that short-term shippers may be captive to particular pipelines and that, in any event, all shippers are entitled to protection under the Natural Gas Act.

In Order No. 637, the Commission recognized that its principal responsibility is to protect captive customers holding long-term contracts.[43] Short-term customers, even if connected to only one pipeline, are not captive since given the nature of interruptible and short-term release services they do not have to pay for service when they want to use alternatives and have no guarantee that the pipeline will provide service when they want it. Prior to Order No. 636, the use of 100% load factor interruptible rates and selective discounting, maximized the revenue from short-term shippers and reduced the costs borne by captive firm customers. [44] Lifting of the price ceiling for short-term capacity release transactions restores the balance between short and long-term shippers, but in a way more consonant with competitive pricing. Short-term shippers that currently pay lower prices during off-peak periods as a result of competition created by capacity release will now face appropriate rates for peak period capacity when capacity is most in demand and prices in a competitive market would be higher to properly allocate the capacity. At the same time, this will enable releasing shippers to derive greater revenue for short-term releases during peak periods to help offset the low rates they receive during off-peak periods.

The Commission did not find, as the rehearing requests suggest, that short-term shippers are not entitled to any protection. It found only that just and reasonable regulation of customers in the short-term market needs to be tailored to the realities of that market.[45] Short-term customers, by the very nature of the service for which they are contracting, expressly take the risk that they may have to forgo the use of gas entirely if short-term capacity is not available when they need it. As the country learned very well during the period of price controls on interstate gas, customers receive little benefit from regulated prices if they are unable to acquire the gas or transportation service when they need it. Short-term customers will receive more protection if they can obtain capacity when they need it, even by paying higher prices, than if they are unable to obtain the capacity they need when they are willing to pay the market price for such capacity. Short-term customers desiring greater price security can purchase long-term capacity at a regulated rate from the pipeline. Even if capacity is not immediately available, the pipeline has the incentive to construct new capacity when shippers are willing to pay for the cost of construction, and the Commission is committed to reviewing closely a pipeline's decision to refuse to construct capacity when the customer is willing to pay the costs.

In short, the static cost-of-service rate regulation that the Commission has applied to long-term capacity commitments is not applicable to short-term released capacity. The Commission, therefore, has decided to try a more flexible regulatory approach to the short-term release market that does not rely upon artificial pricing ceilings, but instead relies on competition and other regulatory controls to minimize the ability to exercise market power as well as relying on enforcement proceedings to control the abuse of market power if it should occur. Such a regulatory approach is better geared to the needs of the short-term market than the maintenance of static, regulated prices that bear little relationship to market realities, that distort shipper's options, and that contribute to a less efficient market.

The Commission will discuss below the protections against the exercise of market power that justify the removal of the rate ceiling for short-term capacity release transactions.

(2) Protections Against the Exercise of Market Power

Competition from Releasing Shippers, Monitoring, and Enforcement. The availability of capacity from alternative firm capacity holders, as well as the pipeline, constitutes a strong protection against the exercise of market power by any one holder of firm capacity. Capacity release has become an ever more vibrant part of the gas marketplace since Order No. 636. By permitting releasing shippers to use secondary points and to segment their capacity, capacity buyers have the ability to choose among numerous alternative suppliers of capacity. Indeed, as shown above,[46] competition in the capacity release markets already has been successful in keeping, on average, the rates for released capacity below the

[41] Florida Power & Light Company, 66 FERC ¶ 61,227, at 61,527 (1994), on *reh'g* 70 FERC ¶ 61,158 (1995). Opportunity costs reflect the cost to the utility of its next best alternative sale.

[42] California Independent System Operator Corporation, 89 FERC ¶ 61,153, at 61,436 (1999).

[43] *United Distribution Companies* v. *FERC*, 88 F.3d 1105, 1123 (D.C. Cir. 1996) (Commission's prime constituency is captive customers vulnerable to the pipeline's market power). *See Maryland People's Counsel* v. *FERC*, 761 F.2d 780, 781 (D.C. Cir. 1985); *FPC* v. *Hope Natural Gas Co.,* 320 U.S. 591, 610 (1944); *Associated Gas Distributors* v. *FERC*, 824 F.2d 981, 995 (D.C. Cir. 1987), *cert. denied,* 485 U.S. 1006 (1988).

[44] *See Associated Gas Distributors* v. *FERC,* 824 F.2d 981, 1011 (D.C. Cir. 1987) (selective discounting benefits captive customers by making a contribution to fixed costs); *Mobil Oil Co.* v. *FERC*, 886 F.2d 1023 (8th Cir. 1989) (100% load factor interruptible rates ensure that interruptible service pays the cost of providing that service); *Elizabethtown Gas. Co.* v. *FERC,* 10 F.3d 866, 871–72 (D.C. Cir. 1993) (affirming use of 100% load factor interruptible rates); *Orange and Rockland Utilities, Inc.* v. *FERC*, 905 F.2d 425, 427–29 (D.C. Cir. 1990) (affirming use of 100% load factor interruptible rates).

[45] Permian Basin Area Rate Cases, 390 U.S. 747, 787 (1968) (Commission empowered to prescribe different requirements for different classes of persons or matters).

[46] *See* Figure 1, at 20.

maximum rates during both peak and off-peak periods, demonstrating that competition will significantly limit releasing shippers' ability to exercise market power during peak periods even without a price ceiling. Further, the data cited in Order No. 637 from the bundled sales market show that in a market without price ceilings, competition has generally maintained the value of transportation at rates below the current maximum ceiling rate.[47] The data show that the only time rates increase above the cost-based maximum ceiling rate is during peak demand periods, when higher prices are needed to effectively allocate capacity.[48] Thus, the evidence does not provide a basis for the fear of those seeking rehearing that removal of price ceilings will lead to the ability of shippers to sustain price increases above cost-based rates.

The competition among multiple capacity holders and the pipelines to sell capacity has, at the very least, significantly lessened the potential for the exercise of market power by releasing shippers, so that case-by-case review of allegations of market power is appropriate and far less disruptive to the overall workings of the market than application of static cost-based regulation that does not comport with the way in which short-term markets operate. The Commission has revised its reporting and internal monitoring capability as well as its complaint procedures to better enable it and the industry to monitor the marketplace and conduct case-by-case review of allegations of abuses of market power in the release market.

Regulated Pipeline Alternatives. In this rule, the Commission only took an interim step to improve efficiency by removing the rate ceiling for short-term capacity release transactions. It decided not to change the existing regulation of pipelines to provide additional protection against the exercise of market power in the short-term capacity release market. Market power can be exercised in two basic ways, through withholding of capacity and price discrimination. Firm shippers cannot successfully withhold capacity from the market, because any capacity they do not use is available from the pipeline as interruptible service at a cost-based rate. Shippers also can purchase long-term firm capacity from the pipeline at a regulated rate. In addition, the Commission continues to regulate pipeline penalty levels in the short-term market which effectively establishes a rate ceiling for capacity release transactions. A shipper will not pay more for capacity than the penalty it would pay if it simply shipped gas in excess of its contract rights.

In traditional market analysis, one looks at the number and market shares of potential alternative suppliers and other factors such as barriers to entry to determine whether competition between those suppliers is sufficient to prevent explicit or tacit collusion to reduce output in order to raise price.[49] If a large enough number of firms are in competition for buyers' business, buyers, when faced with an effort to raise price by any one firm, will have alternative suppliers who have an incentive to increase their own sales (and hence total output) by charging a lower price. While the Commission has used competitive market analysis to determine whether to permit market-based rates, such an analysis is time consuming, difficult and is not subject to slide rule precision. Disputes frequently arise over issues, such as product and geographic market definition, the existence of barriers to entry, and the number and market positions of alternative suppliers needed to protect against market power. When the Commission previously instituted a pilot program attempting to use market analysis to relax price ceilings in the short-term market, disputes over all these issues arose.[50]

While market analysis looks principally at market structure and barriers to entry in an attempt to discern whether firms will have incentives to reduce output to raise price, the Commission's regulations protect against the exercise of market power by directly limiting the withholding of available transportation capacity through the requirement that pipelines sell all available capacity at a regulated rate. There is only a fixed amount of capacity in the short-term capacity market. Any capacity not sold or used by a firm shipper is, by definition, available from the pipeline as interruptible or short-term firm capacity. In these circumstances, if firm shippers attempt to exercise market power by raising price above the regulated rate, buyers can acquire the capacity from the pipeline at the regulated rate. Because no capacity can be withheld from the market above the regulated maximum rate and buyers can always obtain capacity from the pipeline on a non-discriminatory basis, market power cannot be exercised when rates exceed the cost-of-service price ceiling, and consequently the resulting price is the competitive price needed to equate supply and demand and allocate the available capacity. The requirement that a pipeline sell its capacity at the regulated maximum rate prevents tacit collusion between the pipeline and the shipper to withhold capacity to raise price above the ceiling rate, and effectively limits the releasing shipper's ability to exercise market power at prices above the ceiling rate.

Short-Term Pipeline Capacity. Those requesting rehearing contend that maintenance of rate regulation for pipeline interruptible capacity is insufficient to restrain market power in the capacity release market because pipeline interruptible capacity is not an adequate substitute for firm released capacity given its lower priority.[51] In many cases, releasing shippers impose recall rights on released capacity, so it is, in effect, an interruptible service. Moreover, pipeline interruptible capacity does not need to be identical to released capacity to be a good substitute, sufficient to restrain the exercise of market power.[52] In this case, there is, in effect, only one product, pipeline capacity, and several ways to obtain it, firm released capacity, short-term firm and interruptible capacity from the pipeline. These methods of obtaining capacity directly compete with each other: any firm capacity not released is available as interruptible transportation from the pipeline. Even though interruptible capacity is of lower priority than firm released capacity, the requirement that the pipeline sell all of its interruptible transportation at the maximum rate inhibits a releasing shipper's ability to exercise market power, because the releasing shipper cannot withhold capacity from the market. If the releasing shipper does not

[47] Order No. 637, 65 FR at 10174–80, figures 5–7, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091, at 31,271–74, figures 5–7.

[48] Figure 7, for example, shows that the value of transportation during January 2,000 rose only during the time period when temperatures turned colder. Order No. 637, 65 FR at 10178–79, figure 7, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091, at 31,273–74, figure 7.

[49] Department of Justice-Federal Trade Commission, Horizontal Merger Guidelines, ¶ 0.1 (small number of firms can approximate the performance of a monopolist, by either explicitly or implicitly coordinating their actions).

[50] Compare Secondary Market Transactions on Interstate Natural Gas Pipelines, 77 FERC ¶ 61,183 (1996) *with* Transwestern Pipeline Company, 78 FERC ¶ 61,200 (1997) (disputes over whether market power can be exercised over single lateral on pipeline).

[51] Rehearing Requests by Amoco, Indicated Shippers, NGSA.

[52] Department of Justice—Federal Trade Commission, Horizontal Merger Guidelines, ¶ 1.11 (inquiry is whether alternative products would inhibit the ability of a monopolist of a single product to sustain a price rise); *U.S.* v. *E.I. Dupont De Nemours & Co.,* 351 U.S. 377 (1956) (product market determined by cross-elasticity of demand between different products).

use its capacity (attempts to withhold capacity), that capacity becomes available as interruptible service which the pipeline must sell at a just and reasonable rate. The pipeline also is required to sell short-term firm service to the extent all of its firm service is not fully subscribed. Since the pipeline is required to sell all of its available capacity at the maximum rate, it cannot collude with the releasing shipper to withhold capacity from the market.

Long-Term Pipeline Capacity. Amoco and Indicated Shippers maintain that the ability to purchase long-term capacity from the pipeline at just and reasonable rates is not a reasonable protection against market power. They maintain that the pipeline may not have long-term capacity available and that short-term prices may only be high on a sporadic basis, not sufficient to induce the pipeline to build additional capacity.

Maintaining cost-of-service regulation on long-term pipeline capacity provides protection against the exercise of market power by releasing shippers in the short-term market in two ways. On pipelines with unsubscribed firm capacity, the availability of capacity from the pipeline provides an alternative, at a regulated rate, to buying short-term capacity from releasing shippers. Even when pipelines are fully subscribed, the pipelines' ability to construct additional capacity will discipline the ability of releasing shippers to sustain rates in the short-term market above the marginal cost of construction. If prices in the short-term capacity release market generate revenues that would be above the cost of constructing new capacity, the pipeline can capture such potential profits only by adding capacity to serve the demand.[53] The pipelines' ability and incentive to undertake such construction reduces the incentive for releasing shippers' to attempt to raise prices above the marginal cost of new construction. In many cases, capacity can be added quickly simply by adding compression to the system.

The rehearing requests suggest that short-term prices may only sporadically exceed the maximum rate so that the rise in price is not sufficient to attract new pipeline investment. But if prices rise only sporadically, the price change is most likely due to an increase in demand relative to supply, creating scarcity rents, rather than the sustained exercise of market power. In any event, the sporadic nature of such increases suggests that, even if market power is present, any harm from removing the rate ceiling would be relatively minor, since it would occur only during those short periods when prices exceed the maximum rate. Any possible harm from short-term higher prices is outweighed by the greater efficiency created by a more effective capacity trading market that would permit those short-term shippers who most urgently need capacity during peak periods to have a better opportunity to obtain capacity. As discussed above, if short-term prices rise frequently enough to make the construction of additional pipeline capacity profitable, the pipeline will have the incentive to build that capacity, which provides short-term shippers with an additional capacity option.

Process Gas Consumers suggest that long-term capacity may not be a viable alternative for industrial firms because, unlike marketers and LDCs, who are in the gas business, industrial firms' principal business is not gas and their ability to purchase long-term transportation contracts is often inhibited by business planning cycles of five years or less. But those are the kinds of choices shippers have to make as the gas market becomes more competitive. If shippers want price security, they need to share the risks of new construction with the pipelines; they cannot require that pipelines fully absorb all those risks. Shippers that are unwilling to undertake that commitment can purchase gas from marketers or can choose to participate in the short-term market, with full recognition of the price fluctuations inherent in that choice. Moreover, the point here is not that any one class of customer would or would not subscribe to new construction. If short-term prices produce revenues high higher than the cost of new construction, the pipeline has the incentive to construct new capacity to capture additional revenue, and shippers who see the profit potential in obtaining that capacity will subscribe, because they can resell that capacity for more than it costs them.

Process Gas Consumers also argue that the Commission has failed to give sufficient credence to its contention that LDCs control access to the points behind their citygates and, therefore, can obviate any benefits of competitive access to that point. It contends that in the past, the Commission proposed to require that LDCs provide open access service before they could benefit from removal of the price ceilings.[54] It further contends that alternative capacity suppliers may not be meaningful alternatives to obtaining capacity from the LDC, because using secondary receipt and delivery points is not the equivalent of using primary points.

In the first place, as shown in Order No. 637, over 80% of all industrial sales are now unbundled and unbundling programs are accelerating.[55] Thus, the need for the Commission to impose its own requirements for open access service has diminished. Second, the ability of an LDC to exercise market power over pipeline capacity is limited because, if it tries to withhold capacity, that capacity becomes available from other releasing shippers or from the pipeline at a regulated rate. If an LDC holding primary firm rights attempts to exercise market power by withholding capacity, that would make the use of its points available to shippers buying capacity from other releasing shippers or from the pipeline.[56] If Process Gas Consumers is arguing that LDCs can exercise market power over their intrastate facilities by refusing to schedule gas for a shipper behind the city-gate, state regulatory agencies have primary responsibility for policing LDC activity over their own facilities. Moreover, any refusal by an LDC to schedule gas on behalf of a shipper would be readily apparent and, if such an abuse relates to interstate transportation, the Commission can remedy such problems through individual case procedures. There is no need to retain the price ceiling for the entire class of LDC shippers based only on speculation about whether some LDCs will refuse to schedule capacity when any such abuses can be addressed in individual cases.

The National Association of Gas Consumers maintains that lifting of the price ceiling could lead to speculative pricing. As explained in Order No. 637, however, high prices during peak periods are a legitimate reaction to supply and demand forces. As long as capacity is not being withheld from the market, high prices during peak periods are the competitive response to market conditions and will result in a more

[53] The pipeline cannot recover any of the potential profit by raising price because its rates are capped.

[54] Process Gas Consumers cites to Secondary Market Transactions on Interstate Natural Gas Pipelines, Proposed Experimental Pilot Program to Relax the Price Cap for Secondary Market Transactions, 76 FERC ¶ 61,120 (1996).

[55] Order No. 637, 65 FR at 10158–60, 101–68 III FERC Stats. & Regs. Regulations Preambles ¶ 31,091, at 31,251–52, 31,261.

[56] For example, if one capacity holder has firm primary point capacity of 100 MMBtu and does not use 50 MMBtu of that capacity, other shippers can schedule delivereis to the same point using secondary delivery point rights or interruptible service. This makes it difficult for the shipper holding the primary delivery point rights to withhold capacity.

efficient allocation of capacity to those valuing it the most. Indeed, it is the current price regulated system that can create the more inefficient system and be the most harmful to gas consumers, because regulated rates during peak periods may prevent those shippers who most need capacity to serve their customers from obtaining capacity when they need it most. As shown by the period of rate regulation of wellhead prices, the maintenance of regulated rates that do not fit with market conditions can harm consumers by distorting price signals and thereby inhibiting the efficient allocation of resources. In any event, removal of rate regulation for capacity release transactions will have limited effect on pricing behavior, since there is no rate ceiling for bundled gas transactions and firms can speculate in the gas market. Rather than exacerbating pricing problems during peak periods, the lifting of rate ceilings on capacity release transactions should help to provide shippers with more options for dealing with those problems.

Amoco and Indicated Shippers maintain that the Commission has not provided adequate protection against capacity withholding when the market rate falls below the regulated maximum rate for pipeline capacity. They argue that at rates below the maximum rate, the pipeline is under no obligation to sell all available capacity which could permit capacity withholding.

This complaint is unrelated to the regulatory changes in Order No. 637. The Commission made no regulatory changes with respect to its policy regarding pipeline and release rates that are below the maximum rate. As shown above, the competition between firm shippers and the pipelines already has significantly limited the ability of releasing shippers to withhold capacity and to selectively discount during the off-peak period when rates are below the maximum rate. Moreover, Commission policy since Order No. 636 has been to permit pipelines and releasing shippers to refuse to discount.[57] The Commission has not changed that policy here. The regulatory changes in this rule, therefore, result in no additional harm to short-term shippers when rates are below the maximum rate and promise greater efficiency and options for shippers during peak periods.

Mitigation Measures. Amoco, IPAA, and Indicated Shippers contend the Commission erred when it relaxed price ceilings, because it failed to adopt further measures to mitigate the exercise of market power. Amoco contends the fundamental error in Order No. 637 was the failure to require an auction, as proposed in the NOPR, to ensure capacity is allocated in an unbiased manner to promote competition while mitigating market power. Indicated Shippers contend the Commission erred by not eliminating the exemption from the posting and bidding requirements for pre-arranged deals for greater than one month at or above the maximum lawful rate and by not revising its regulations to restrict releasing shippers' ability to impose recall conditions. AGA and a number of LDCs also request clarification as to whether the exemption for releases at the maximum rate continues to apply.[58]

With respect to Amoco's argument, the Commission, in fact, will continue to require bidding for capacity release transactions, which is, in effect, a form of capacity auction. Since Order No. 636, the Commission has required posting and bidding for capacity release transactions as protection against the potential for undue discrimination and the exercise of market power in the capacity release market.[59] Under Commission regulations, all capacity releases for more than 31 days and all rollovers of releases of 31 days or less are subject to the bidding process. In Order No. 636, the Commission permitted an exemption from the bidding process for short-term releases of less than a month, because of a concern at that time that the pipeline's auction process could be too administratively cumbersome for short-term transactions.[60]

As explained in Order No. 637, electronic commerce is growing, particularly in the gas industry, and may well represent the future, but the comments in this rulemaking, including comments by those seeking rehearing,[61] maintain that the electronic capabilities of some pipelines today still do not permit a mandatory requirement for a daily auction and that a daily auction might well create administrative difficulties of its own. Although the Commission strongly encourages both pipelines and third parties to begin gaining experience with the use of electronic auctions as a means of allocating available capacity, the Commission determined, based on the rulemaking comments, that it was not the time to impose an across-the-board requirement for a mandatory daily auction. Nonetheless, the pre-existing posting and bidding requirements for capacity release will continue to promote fair and equitable capacity allocation and inhibit the exercise of market power, because any transactions of longer than a month are subject to the auction and transactions of less than a month (while initially exempt) will be subject to the auction if they are continued or rolled over.

Indicated Shippers contend the Commission should have eliminated the provision (contained in the current regulations) that exempts from the bidding requirements pre-arranged capacity release transactions at the maximum rate. Indicated Shippers argue that maintaining this exemption prevents non-affiliate replacement shippers from fairly competing in an open capacity market. AGA and a number of LDCs contend in their clarification requests that the exemption from posting and bidding for releases at the maximum rate continues to apply.[62]

Although there is apparently confusion on this point, the Commission did eliminate this exemption in Order No. 637. Section 284.8(h) of the regulations contains an exemption from the posting and bidding requirements for capacity release transactions at the "maximum tariff rate applicable to the release." [63] Since the maximum tariff rate is no longer applicable to short-term capacity release transactions, the exemption does not apply as long as the rate ceilings are waived. Nevertheless, to ensure the regulations are clear, the Commission will add the following to section 284.8 (i) of the regulations: "The provision of paragraph (h)(1) of this section providing an exemption from the posting and bidding requirements for transactions at the applicable maximum tariff rate for pipeline services will not apply as long as the waiver of the rate ceiling is in effect." Section 284.8 (i)

[57] Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Order No. 636–A, 57 FR 36128 (Aug. 12, 1992), FERC Stats. & Regs. Regulations Preambles [Jan. 1991–June 1996] ¶ 30,950, at 30,629 (Aug. 3, 1992) (pipelines are not required to discount or accept bids at less than the maximum rate), 636–B, 61 FERC ¶ 61,272, at 62,027–28 (pipelines not required to discount transportation rate), *aff'd, United Distribution Companies* v. *FERC,* 88 F.3d 1105, 1141–42 (D.C. Cir. 1996).

[58] Atlanta Gas Light, UGI, Keyspan, and Washington Gas also request clarification of this point.

[59] 18 CFR 284.8.

[60] 18 CFR 284.8(h); Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Order No. 636–A, 57 FR 36128 (Aug. 12, 1992), FERC Stats. & Regs. Regulations Preambles [Jan. 1991–June 1996] ¶ 30,950, at 30,553–54 (Aug. 3, 1992).

[61] Comments by Process Gas Consumers.

[62] Atlanta Gas Light, UGI, Keyspan, and Washington Gas also request clarification of this point.

[63] 18 CFR 284.8(h).

already contains a provision specifying that posting and bidding will apply to any rollovers or continuations of capacity release deals of 31 days or less.[64]

Thus, under the Commission regulations, all capacity release transactions of more than 31 days will be subject to the posting and bidding requirements. For transactions of 31 days or less, shippers can enter into prearranged deals that are not subject to the posting and bidding requirements. But all rollovers or continuation of such deals will be subject to posting and bidding.[65]

UGI and Atlanta Gas Light seek rehearing of the decision to eliminate the maximum rate exemption from the posting and bidding requirements, claiming that continuing the exemption is important to their retail unbundling initiatives at the state level.

In Order No. 637, the Commission specifically continued the existing posting and bidding requirements for capacity release transactions to ensure that capacity is equally available to all shippers and to protect against undue discrimination and the exercise of market power.[66] Permitting releases at or above the maximum rate to be exempt from the posting and bidding requirements would defeat the very purpose of requiring posting and bidding by enabling releasing shippers to consummate pre-arranged transactions with certain shippers without giving other shippers an opportunity to compete for the capacity. The original justification for exempting pre-arranged deals at the maximum rate was that, as long as a rate ceiling was in effect, no other shipper could beat the pre-arranged deal and bidding and posting requirements would be superfluous.[67] When the maximum rate ceiling is lifted, posting and bidding becomes necessary to protect against undue discrimination and to ensure that capacity is properly allocated to the shipper placing the greatest value on the capacity.

The imposition of posting and bidding will not prevent LDCs from entering into pre-arranged deals under state unbundling programs, as the clarification and rehearing requests suggest. LDCs can still enter into pre-arranged transactions of less than one year and the pre-arranged shipper is guaranteed to receive the capacity as long as it is willing to match the highest rate bid for that capacity. LDCs also can enter into pre-arranged deals exempt from the posting and bidding requirements by entering into a pre-arranged release for one year or more at the maximum rate.

In individual cases where an LDC considers a further exemption from the posting and bidding requirement essential to further a state retail unbundling program, it may request the Commission to waive the regulation, permitting the LDC to consummate pre-arranged deals at the pipeline's maximum tariff rate without having those transactions subject to competitive posting and bidding. If the LDC seeks such a waiver, it must be prepared to have all of its capacity release transactions and any re-releases of that capacity limited to the applicable maximum rate for pipeline capacity. The LDC should not be able to sell to some shippers without a rate ceiling, protecting other favored shippers from the bidding process. All such waiver applications must either be filed jointly with the appropriate state regulatory authority or must include a verified statement by that authority stating why the request is necessary to promote a legitimate state goal.

Indicated Shippers also contend the Commission should eliminate the right of releasing shippers to impose recall conditions on releases.[68] They maintain that releasing shippers can abuse their recall rights by recalling the capacity from third parties and then reselling it at higher prices, while not recalling capacity from affiliates. The Commission sees no basis for prohibiting releasing shippers from imposing recall rights. Recall rights add capacity to the release market by enabling shippers to release capacity when they do not need it, and then recall the capacity when necessary for their needs. Without the ability to impose recall rights, releasing shippers may be reluctant to release capacity out of concern that weather patterns will change. If replacement shippers are concerned about abuse of the recall process in the scenario envisaged by Indicated Shippers, they can refuse to enter into recallable release transactions unless the releasing shipper guarantees that, if a recall is exercised, it will not be able to resell that capacity. Allegations concerning abuse of recall conditions also can be examined by the Commission through the complaint process.

Potential Affiliate Abuse: Amoco, Process Gas Consumers, NGSA, and Ohio Oil and Gas Association contend that removing the price ceiling for released capacity provides an opportunity for affiliate abuse because it creates an incentive for the pipeline corporate entity to transfer capacity from the pipeline to its affiliate, which is not subject to the price ceiling.

Pipelines cannot simply transfer capacity to an affiliate. Pipelines are required to allocate their capacity on a non-discriminatory basis and must sell the capacity to the shipper bidding the highest net present value for the capacity. Thus, if unaffiliated shippers project that profits can be made by selling short-term capacity above the price ceiling, they can bid against the affiliate to obtain capacity from the pipeline.[69]

Moreover, as the Commission explained in Order No. 637, the removal of the rate ceiling effects little change from the market today because pipeline affiliates are currently able to make bundled gas sales where the transportation component of the transaction is not subject to the rate ceiling. Removal of the rate ceiling, coupled with the reporting requirements, therefore, may make these transactions more transparent, because affiliates will have a greater incentive to release transportation and pipelines must post such transactions. The rate ceiling on pipeline capacity also will continue to protect against the exercise

[64] 18 CFR 284.8(i) provides that any rollovers or extensions are subject to the posting and bidding requirements.

[65] Under section 284.8(h)(2), a shipper can enter into another short-term (31 days or less) release to the same replacement shipper without posting and bidding if 28 days have passed since the previous release to that shipper.

[66] Order No. 637, 65 FR at 10182, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091, at 31,279. *See* Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Order No. 636–A, 57 FR 36128 (Aug. 12, 1992), FERC Stats. & Regs. Regulations Preambles [Jan. 1991–June 1996] ¶ 30,950 at 30,555 (Aug. 3, 1992) (posting and bidding needed to give all parties an opportunity to obtain capacity by bidding the highest rate).

[67] Release of Firm Capacity on Interstate Natural Gas Pipelines, Order No. 577, 60 FR 16979 (Apr. 4, 1995), FERC Stats. & Regs. Regulations Preambles [Jan. 1991–June 1996] ¶ 31,017, at 31,316 (Mar. 29, 1995) (''when the pre-arranged deal is at the maximum rate, no other shipper can make a better bid for that capacity'').

[68] A recall condition is a term in the release that enables the releasing shipper to use the capacity in certain circumstances, for example, if the temperature drops to a point where the releasing shipper needs the capacity to serve its own customers.

[69] There may be little incentive for the affiliate to inflate the net present value of its bid, for example, by increasing the contract duration. The unaffiliated shipper would be willing to bid a net present value up to its expectation of the value of the capacity. If the affiliate obtains the capacity by bidding a higher net present value, the corporate entity loses the opportunity to obtain the revenue the unaffiliated shipper would have paid. As long as the expected future value of the capacity does not exceed the amount bid by the unaffiliated shipper, the corporate entity cannot expect to recoup the revenue it would have received from the unaffiliated shipper.

of market power in the event capacity is held by a pipeline affiliate. The pipeline affiliate, like any other firm shipper, will be unable to withhold capacity and exercise market power because, if the affiliate refuses to sell released capacity, buyers can obtain that capacity as interruptible transportation at a just and reasonable rate from the pipeline.

Amoco suggests that a pipeline and an affiliate or partner could conspire to withhold capacity through a number of artifices: nominating gas into the pipeline but not delivering it; purchasing park and loan services at a low rate; moving gas to market area storage or line pack; or having the affiliate use the unreliability of interruptible service as a threat to induce the buyer to purchase released capacity at a higher than competitive price. NGSA similarly contends that a firm shipper can create artificial periods of peak demand by nominating, but not using just enough capacity to drive up demand for capacity while decreasing the availability of interruptible transportation.

All of these techniques would be costly to implement, costs which would limit the incentive to attempt them. The pipeline's sale of parking and loan service at a lower than market rate costs the pipeline the opportunity cost of selling that service to someone else. Nominating gas, but not taking delivery, could result in scheduling or imbalance penalties, and to the extent that capacity is not used, the pipeline would still have the obligation to sell the unused capacity as interruptible or short-term firm service. Moving gas to storage or line pack when it is not truly needed results in costs to the shipper for the gas and transportation and the consequent reduction in storage and line pack flexibility. No protection against market power can be considered absolute; even the market analysis advocated by those seeking rehearing cannot perfectly predict whether market power may be exercised. But the benefits of removing the rate ceiling here outweigh the limited potential for the exercise of market power inherent in these scenarios. Further, the Commission stands ready to investigate complaints about such abusive practices.

In Order No. 637, the Commission recognized that affiliate transactions could be troublesome in one respect: where the affiliate holds large quantities of pipeline capacity and the pipeline determines not to construct new capacity in order to increase scarcity rents for the affiliate.[70] The Commission found that this situation exists today, with affiliates able to make bundled sales to reap scarcity rents, but there seems little indication that profits from scarcity exceed those that can be earned by the pipeline from new construction, since pipeline construction applications have not noticeably declined. Because of the possibility of such affiliate abuse, however, the Commission will be particularly sensitive to complaints that pipelines, on which affiliates hold large blocks of capacity, are refusing to undertake construction projects when demand exists and will be prepared to take remedial measures in cases where such concerns are established.

Process Gas Consumers and NGSA maintain that the Commission's reliance on historic construction information ignores the current trend toward greater concentration in the industry and the concentration of pipeline capacity in the hands of affiliates. As a result, NGSA contends that the Commission should condition the removal of the price ceiling for pipeline affiliates on the pipeline's including a tariff provision requiring it to put in interconnections and to construct capacity when requested by customers willing to pay the costs of construction.

NGSA's concern with interconnections already has been addressed by the Commission. The Commission's policy requires pipelines to provide interconnects to any shipper that constructs, or pays for construction of, the facilities needed for the interconnection, as long as the interconnection does not adversely affect pipeline operations, violate applicable environmental or safety regulations, or violate right-of-way agreements.[71] With respect to refusals to build additional mainline capacity, the Commission can take remedial action when warranted. Among the potential remedies that could be considered would be limiting the rates at which the affiliate can release capacity, limiting the amount of capacity the affiliate can hold, prohibiting the affiliate from holding capacity on its related pipeline, or, as NGSA suggests, conditioning the affiliate's continued right to exceed the price ceiling on the pipeline's agreement to construct capacity for which the shipper is willing to pay.

More Limited Experiment. Recognizing the value of experimental programs, Process Gas Consumers contends that if the Commission chooses to proceed with an experiment in lifting price ceilings, it should narrow the scope of the experiment to select markets where competition appears to be the most robust and to place some form of ceiling on the prices that can be charged.

The Commission sees little value in further limiting the scope of the waiver. First, as discussed above, the Commission has concluded that there are sufficient protections to go forward with the relaxation of the price ceiling for short-term capacity release transactions in all markets. Second, the Commission finds that limiting the program in these ways will eliminate information that is needed to evaluate the effects of price cap removal and is otherwise infeasible. The impact of removing price ceilings will occur principally in markets where, due to weather conditions, demand increases and capacity becomes scarce. Such markets cannot be anticipated in advance, so that a geographic or other limitation may yield little useful information by the end of the two-year period. Limiting the waiver only to those markets that are already presumed to be competitive similarly will provide little information on how markets across the board behave. Such a limitation would be tantamount to conducting an experiment with only a control group, excluding those markets whose performance is most important to monitor. To evaluate the waiver, the Commission needs to be able to examine the effects of removing the price ceiling on all markets, both those which may appear competitive and those with higher concentration ratios.

2. Price Ceiling for Pipeline Capacity

CNG, Great Lakes, Kinder-Morgan, Koch, and Williams contend the Commission erred in not removing rate regulation for pipeline short-term services. They maintain that if the market is workably competitive enough to permit lifting of the price ceiling for capacity release transactions, it also should be sufficiently competitive to lift the price ceiling for pipeline short-term services. Kinder-Morgan and Koch maintain the regulation of pipeline services is not justified as a protection against withholding of capacity by releasing shippers because firm shippers can manipulate the nomination process to withhold capacity.

The Commission in this rule determined to make only incremental changes in its regulatory policies to promote efficiency, establishing an ongoing process to consider whether more fundamental changes should be adopted. Since unbundling, the regulation of pipeline services has been the basic protection against the potential exercise of market power over

[70] Order No. 637, 54 FR at 10186, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091, at 31,287.

[71] Panhandle Eastern Pipe Line Company, 91 FERC ¶ 61,037 (2000).

transportation service, and in making incremental changes to its current regulatory system, the Commission chose not to disturb this traditional protection. The Commission, therefore, waived the price ceiling only for capacity release transactions, as urged by a number of commenters, including pipelines, who contended that removal of rate ceilings for capacity release transactions is a first step toward the goal of revising regulatory policy to enhance efficiency.[72]

In addition, pipelines do have avenues for lifting price ceilings for their short-term services. In Order No. 637, the Commission stated that pipelines could lift price ceilings for their capacity if they implement an auction process that protects against the exercise of market power. They also can file for market based rates under the Commission's Alternative Rate Design Policy if they can demonstrate that sufficient competition exists in the short-term market so that the removal of rate regulation for all short-term services will not permit the exercise of market power.

3. Implementation of the Waiver

Several rehearing requests seek rehearing or clarification regarding the way in which the waiver of the rate ceiling for short-term release transactions will be applied.

a. Refund Requirement. IPAA and Indicated Shippers contend that the Commission should impose a refund requirement in the event the Commission or a reviewing court concludes the removal of rate ceilings for short-term released capacity is unlawful. The imposition of a refund requirement would run counter to the purpose of waiving the rate ceiling. One of the reasons for lifting the rate ceiling was to give releasing shippers an incentive to move transactions from the opaque bundled sales market to the transparent capacity release market, so that the Commission can obtain useful data about the effect of lifting the price cap during the two-year waiver period. If releasing shippers know they are subject to a potential refund requirement, they will be less likely to use capacity release as opposed to making bundled sales.[73] Moreover, an across-the-board refund condition is not necessary because, should the Commission determine in an individual case that a releasing shipper has abused its market power, the Commission has the authority under section 16 of the NGA to take appropriate remedial action that can include remedies to prevent unjust enrichment.[74]

b. Compliance with Reporting Requirements. NGSA and Indicated Shippers contend the Commission erred in lifting the price ceiling before pipelines comply with the tariff and reporting requirements established in Order No. 637. They contend that the tariff changes, such as enhancing segmentation, and the reporting requirements are intended to enhance competition and permit better monitoring of the marketplace, and, accordingly, they maintain the waiver of the rate ceiling should be postponed until these enhancements are in place.

The Commission finds no reason to delay removal of the price ceiling to await pipeline compliance with other aspects of Order No. 637, particularly given the efficiency benefits identified in Order No. 637 that open capacity trading will bring. The revised reporting requirements primarily are to obtain more information about pipeline capacity and to make the reporting of pipeline transactions conform with the existing reporting requirements for capacity release transactions. The reporting requirements related to capacity release transactions essentially are the same as they were before, and will provide information about capacity release transactions sufficient to permit the industry and the Commission to monitor these transactions. Although the compliance filings with respect to segmentation are designed to improve the current system, many pipelines already permit segmentation on their systems and the rule contains sufficient other protections against the exercise of market power that implementation of the rate ceiling waiver need not wait for implementation of enhanced segmentation.

c. Tariff Requirement. Process Gas Consumers maintains the Commission's relaxation of the price cap violates section 4 of the NGA under the principles established in *Maislin Industries, U.S., Inc.* v. *Primary Steel, Inc.*,[75] because the rates for capacity release transactions will not be on file prior to the rate being collected. The Commission finds no violation of the requirements of section 4 of the NGA. Unlike Maislin, which involved a statute providing for common carriage, section 4 of the Natural Gas Act envisions that individualized contracts will be used to establish rates for the sale of gas,[76] and such contracts can become effective even before the rates are filed with the Commission.[77]

The Commission is complying with the filing and notice requirements of section 4 by requiring the pipelines to file tariffs setting forth the conditions of capacity release and specifying that the rates for capacity release transactions will be established by contract between the releasing and replacement shippers. The Commission further is satisfying these requirements by requiring the posting of the rates on Internet web sites no later than the first nomination for service under an agreement.[78] Section 4 of the NGA provides that the Commission can establish the ''rules and regulations'' for how rate schedules will be filed, and that the Commission can waive the advance 30 day filing requirement and, in so doing, specify ''the time when they shall take effect and the manner in which they shall be filed and published.'' [79] Using modern electronic methods to provide fast and effective dissemination of rates to the public using computers satisfies the statutory goal of open posting of rates.

d. Effective Date. Columbia Gas and Enron request clarification that the removal of the price ceiling does not take effect until the Commission has accepted tariff changes to remove pipeline tariff provisions inconsistent with the removal of the price ceiling. The Commission denies the request. Under Order No. 637, the rate ceiling was removed from capacity release transactions on the day the regulation (section 284.8 (i)) became effective, March 26, 2000. To reduce the tariff-filing burden on pipelines, the Commission provided them with a period of up to 180 days to remove potentially inconsistent tariff provisions, but that grace period did not change the effective date of the regulation.

[72] See Comments of AGA and INGAA.

[73] As pointed out in Order No. 637, a shipper may be willing to release its capacity where the price it can obtain for the released capacity exceeds the cost of its alternatives, such as using an alternative fuel or LNG. Order No. 637, 65 FR at 10181, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091, at 31,277. If the releasing shipper is not certain that it will be permitted to retain funds above the maximum rate, it may be less likely to release the capacity or may decide to make a bundled sale instead.

[74] 15 U.S.C. 717o; *Mesa Petroleum Co.* v. *FERC*, 441 F.2d 182, 186–88 (5th Cir. 1971); *Coastal Oil & Gas Corporation* v. *FERC*, 782 F.2d 1249 (5th Cir. 1986).

[75] 497 U.S. 116 (1990).

[76] *United Gas Pipe Line Co.* v. *Mobile Gas Service Corp.*, 350 U.S. 332 (1955).

[77] *Columbia Gas Transmission Corp.* v. *FERC*, 895 F.2d 791 (D.C. Cir. 1990), *City of Piqua* v. *FERC*, 610 F.2d 950 (D.C. Cir. 1979) (individual contracts can take effect even prior to filing with the Commission).

[78] As discussed below, the Commission is granting rehearing and revising its transactional reporting regulations to require posting no later than the first nomination for service.

[79] 15 U.S.C. 717c (c)–(d).

B. Peak and Off-Peak Rates

Order No. 637 provides that pipelines may institute value-based peak/off-peak rates for all short-term services as one possible method of promoting allocative efficiency that is consistent with the goal of protecting customers from monopoly power.[80] Short-term services are defined to include short-term firm and interruptible service and multi-year seasonal contracts. Implementation of peak/off-peak rates can promote several important policy goals. Specifically, peak/off-peak rates could remove one of the biases favoring short-term contracts, reduce the need for discounts and reliance on discount adjustments, and increase efficiency in short-term markets by allowing prices to better reflect demand during peak periods. Order No. 637 provides that in implementing peak/off-peak rates, the pipeline must stay within its annual revenue requirement and, thus, any increases in rates at peak must be offset by decreases in off-peak rates.

The discussion of peak/off-peak rates in Order No. 637 was a statement of policy and not a rule that imposed any requirements on pipelines or changed current Commission regulations. As the Commission explained, the current regulations [81] and Commission precedent already recognized that peak/off-peak rates have a role in the ratemaking process.[82]

The policies adopted in Order No. 637 are intended to facilitate the implementation of peak/off-peak rates with a flexible policy that will permit the use of a wide variety of peak/off-peak rate methods. As the Commission explained, there is more than one reasonable way to implement peak/off-peak rates based on value of service concepts, and some methods may work better for certain systems than others. Therefore, the Commission did not adopt any one method of developing peak/off-peak rates, but left the details of the implementation of peak/off-peak rates to individual pipelines.

Order No. 637 permits pipelines to implement peak/off-peak rates through limited section 4 *pro forma* tariff filings subject to several conditions.[83] First, if the pipeline seeks to implement seasonal rates in a limited section 4 filing, it must include in its proposal a revenue sharing mechanism that will provide for at least an equal sharing of any increased revenues with its long-term customers. In addition, Order No. 637 provides that after 12 months experience with peak/off-peak rates, the pipeline must prepare a cost and revenue study and file the study with the Commission within 15 months. Based on the cost and revenue study, the Commission will determine whether any rate adjustments are necessary to the long-term rates, and may order such adjustments prospectively.

AGA, Keyspan, New England, UGI, Amoco, IPAA, Indicated Shippers, Process Gas Consumers, NGSA, NAGC, NASUCA, INGAA, CNG, Coastal Companies, Columbia, Enron, Kinder Morgan, Koch, and The Williams Companies (TWC) seek rehearing or clarification of this portion of Order No. 637. Indicated Shippers argue that the Commission's policy statement fails to comply with the Administrative Procedure Act. Several shipper groups argue that the Commission should require pipelines to implement peak/off-peak rates in a full section 4 proceeding, while the pipelines argue that the limited section 4 procedures established by the Commission are too burdensome. The LDCs ask the Commission to clarify the application of peak/off-peak rates to captive customers.

1. Compliance With the Administrative Procedure Act

Indicated Shippers argue that insofar as Order No. 637 establishes specific mechanisms for the implementation of peak/off-peak rates, it is not a policy statement, but is a substantive rule, and that the Commission erred in promulgating this final rule without complying with the notice and comment requirements of the Administrative Procedure Act (APA).[84] Indicated Shippers state that the Commission's statement that peak/off-peak rates are allowable under the Commission's regulations may qualify as a policy statement or interpretive rule that is exempt from the notice and comment requirements of the APA,[85] but mechanisms applicable to the filings to implement peak/off-peak rates are substantive requirements of general applicability that must be subject to notice and comment.

Indicated Shippers argue that under the APA, a policy statement is ''only supposed to indicate an agency's inclination or leaning, [and is] not in any way binding on the agency.'' [86] Indicated Shippers argue that the *pro forma* tariff filing, the revenue-sharing mechanism, and the cost and revenue study, do not meet the criteria for a policy statement because they are binding on the agency and the pipelines. Further, Indicated Shippers argue that the Commission has created new rights and duties for pipelines choosing to implement peak and off-peak rates. According to Indicated Shippers, Order No. 637 creates new rights because pipelines and long-term shippers will reap the benefits of sharing increased revenues from short-term shippers; it creates new duties because it imposes on the pipeline an obligation to perform a cost and revenue study.

Further, Indicated Shippers state that the *pro forma* tariff filing and the revenue sharing mechanism fundamentally change the allocation of costs between short-term and long-term shippers, effectively increase pipeline rates, and allow pipelines to retain 50 percent of the increased rates even though this increases their allowable rate of return. Indicated Shippers argue that none of these mechanisms were mentioned in the NOPR, and therefore the parties did not have an opportunity to comment on them. Indicated Shippers argue that the Commission must provide another notice and comment period on the mechanisms identified in the Rule, including the *pro forma* tariff filing, the revenue crediting mechanism, and the cost and revenue study.

As explained in Order No. 637, peak/off-peak rates are currently available as a ratemaking methodology under the Commission's regulations and prior decisions. Nothing in Order No. 637 imposes any requirements on the pipelines—the decision to implement peak/off-peak rates is entirely voluntary—or changes Commission regulations. Thus, Order No. 637 does not promulgate substantive rules that establish a ''standard course of action which has the force of law.'' [87] The Commission did not establish a method of developing peak/off-peak rates, but left this and other issues such as the revenue sharing mechanism to be resolved in the individual proceedings. The Commission did give guidance and direction on how peak/off-peak rates could be implemented in the individual

[80] Order No. 637 at 93–106.

[81] The Commission cited 18 CFR 284.7(c)(3)(i).

[82] The Commission cited the Rate Design Policy Statement, 47 FERC ¶ 61,295 at 62,054 (1989).

[83] Order No. 637 provides that the *pro forma* filing would be noticed with comments due in 21 days, rather than the 12 days permitted for tariff filings, and the Commission would act on the proposal within 60 days.

[84] 5 U.S.C. 553(b)(3), (c).

[85] The notice and comment requirements of the APA are not applicable to ''interpretive rules, general statements of agency policy, or rules of agency organization, procedure, or practice. * * *'' 5 U.S.C. 553(b)(3)(A).

[86] Indicated Shippers cite, *inter alia, Hudson* v. *FAA,* 192 F.3d 1031, 1034 (D.C. Cir. 1999).

[87] *Pacific Gas and Electric Co.* v. *FERC,* 506 F.2d 33, 38 (D.C. Cir. 1974).

cases and therefore is properly considered a policy statement.

Indicated Shippers recognize that the discussion of peak/off-peak rates as a voluntary method of promoting allocative efficiency is properly considered a policy statement, but attempt to distinguish the revenue sharing mechanism as a separate matter that creates new rights and duties. However, the revenue sharing mechanism does not create a ''right'' to additional revenues. As the Commission explained in Order No. 637, the voluntary implementation of peak/off-peak rates, as currently permitted under Commission policy, could lead to increased revenues.[88] The Commission has found here, as a matter of policy, that a revenue sharing mechanism is necessary to provide for an equitable division of those revenues as part of the implementation of peak/off-peak rates in a limited section 4 filing.

The Commission has the discretion to direct the conduct of its proceedings. It is within that discretion for the Commission to conclude that it will use a limited section 4 rather than a full section 4 proceeding to implement peak rates and to require pipelines to submit a cost and revenue study.

In any event, Indicated Shippers and the other petitioners have had an opportunity to submit their views on the use of a *pro forma* tariff filing, the revenue sharing mechanism, and the cost and revenue study. These issues and the petitioners' substantive arguments about the appropriate mechanisms for implementing peak/off-peak rates are fully discussed below. Thus, the parties have been given a full opportunity to comment on the use of peak/off-peak rates and the appropriate method for implementing these rates. Nothing more could be accomplished through an additional notice and comment period.

2. Implementation Procedures

Since the implementation of peak/off-peak rates is likely to result in a revenue increase for the pipeline if all other rates remain the same, traditionally, the Commission would require the pipeline to file a general section 4 rate case to implement peak/off-peak rates. However, as the Commission explained in Order No. 637,[89] the traditional methods are ill-suited to this context because the rate methodology relies on a historical test period to project future throughput for each service, and there is no historical experience with peak/off-peak pricing. The Commission also pointed out that using general rate cases to implement peak/off-peak rates could be time consuming. Moreover, because the seasonal rate will be derived from the annual revenue requirement, there should be no factual issues involved in computing the rate that would require investigation or analysis. Therefore, the Commission concluded that pipelines may implement peak-off peak rates in a limited section 4 proceeding, subject to the conditions that the pipeline implement as part of its filing a revenue sharing mechanism and file a cost and revenue study within 15 months of the implementation of peak/off-peak rates.

a. The Option of a Limited Section 4 Filing. Indicated Shippers, IPAA, and NGSA argue that the Commission has not justified use of a *pro forma* tariff filing to implement peak/off-peak rates, and that peak/off-peak rates must be implemented in a full section 4 proceeding. They argue that the concerns that lead the Commission to require that term-differentiated rates must be implemented in a full section 4 proceeding apply to peak/off-peak rates as well. They assert that in both cases the change in rate method will affect other elements that affect the rates of all shippers, and in each case, the change will have an effect on throughput, demand units, discount levels and pipeline revenues. INGAA, on the other hand, asserts that arguments that rates for short-term services must be established in a full section 4 rate case fail to consider that implementation through a settlement or *pro forma* filing will reduce the level of discount adjustments in future rate cases, and that the possibility of sharing revenues will benefit long-term customers immediately.

A limited section 4 filing with the safeguards imposed by the Commission is an appropriate vehicle for implementing peak/off-peak rates. As the Commission explained in Order No. 637, the peak/off-peak rates will be derived from the pipeline's annual revenue requirement, and there should be no factual issues involved in computing the rates that require investigation or analysis in a full section 4 proceeding. Under the current method, the pipelines' rates have been derived by recovering the annual revenue requirement uniformly throughout the year. With peak/off-peak rates, the rates will be derived from the annual revenue requirement using one of several methods of measuring value at peak and off-peak. This does not require an investigation of all the pipeline's costs and rates in a full section 4 proceeding. Moreover, a meaningful review of rates under the current methodology requires one year of historical experience. The process here permits the pipeline to get that experience and then allows the Commission to review the results with a cost and revenue study, making any necessary prospective adjustments.

Moreover, a meaningful review of rates under the current methodology requires one year of historical experience in order to predict future costs and volumes. The limited section 4 process adopted by the Commission obtains the data from that experience and permits the Commission to review the results with a cost and revenue study, allowing prospective adjustments. The use of a limited section 4 proceeding to implement peak/off-peak rates is similar to a situation where a pipeline initiates new services and the Commission permits implementation of the new services in a limited section 4 proceeding in part because there is no historical experience available.[90]

Indicated Shippers, IPAA, and NGSA also argue that implementation of peak/off-peak rates should be conditioned on a pipeline filing a full section 4 proceeding in the future. Indicated Shippers and NGSA state that because some pipeline rates are already stale, implementation of seasonal rates increases the need or rate review. NGSA states that revenue crediting is not a long-term fix for pipeline rates, and only through a requirement that a pipeline at least periodically submit a rate case can the Commission fulfill its responsibility to ensure cost-based rates that approximate a pipeline's cost-based revenue requirement.

Under section 4 of the NGA, the Commission is required to ensure that rate changes proposed by the pipelines are just and reasonable, and under section 5, if the Commission finds after a hearing that the existing rate is unjust or unreasonable, it must establish the just and reasonable rate for the future. The Commission's authority under these two sections provides adequate means for ensuring that pipeline rates are just and reasonable. A requirement that pipelines file periodic rate cases is not part of the statutory scheme. The Commission imposed a three-year review requirement as part of its purchased gas adjustment (PGA) scheme—in exchange for the benefit of being able to track changes in purchased

[88] The Commission explained that because the price cap would be higher in the peak, and the pipeline might see little reduction in off-peak revenues because market prices are usually below the maximim rate, this could lead to increased reveues.

[89] Order No. 637 at 104.

[90] See Mojave Pipeline Co., 79 FERC ¶61,347 at 62,482 (1997).

gas costs which were then rapidly increasing, the pipelines agreed to a reexamination of all their costs and revenues at three year intervals. Seasonal rates are not analogous to the implementation of the PGA. Seasonal rates do not change the pipeline's existing cost of service or revenue requirement; rather they constitute a change in rate design used to recover the pipeline's existing cost of service. Thus, they are more analogous to the Commission's direction to the pipelines in Order No. 636 to implement the SFV rate design, and the court upheld the Commission's decision not to require periodic rate review in that context.[91] The authority provided the Commission under sections 4 and 5 of the NGA is adequate to enable the Commission to fulfill its responsibility to ensure that rates are just and reasonable, and a mandatory periodic rate review is not necessary at this time. Under the procedures established by the Commission, the cost and revenue study will provide a basis for determining whether the rates are stale, and, if so, the Commission would institute a section 5 proceeding to address the issue.

Indicated Shippers also argue that the *pro forma* tariff procedures would shift the burden of proof to ratepayers and eliminate the refund provision. Indicated Shippers state that under the *pro forma* procedures established by the Commission, the pipeline would have the burden of proof only with respect to whether the particular method proposed by the pipeline is just and reasonable, and that if ratepayers want to challenge aspects of the rates filed other than the peak/off-peak method itself, then such issues must be raised in a section 5 proceeding. Indicated Shippers give an example of an argument that the peak/off-peak rates will reduce the pipeline's need to discount and therefore the design units should be increased, and assert that the burden of proof would be on the shipper and not the pipeline under the procedure established by the Commission.

Order No. 637 specifically provides that the pipeline will have the burden of proving that its proposed method of implementing peak/off-peak rates is just and reasonable. As discussed above, the Commission has determined that, if the pipeline meets the conditions set forth in Order No. 637, it may implement peak/off-peak rates through a limited section 4 proceeding. Therefore, the pipeline's burden will be limited to showing that its proposed method is just and reasonable. The specific issues involved in this determination will be established in the individual cases. The pipeline will have the burden of proof regarding any changes it proposes in the limited section 4 proceeding. Because the tariff filing is *pro forma*, any other issues raised under section 5 can be resolved before the tariff sheets go into effect, so there should be no issue of refunds.

Order No. 637 provides that under the *pro forma* filing procedure, the filing would be noticed with comments due in 21 days, rather than the 12 days permitted for tariff filings, and the Commission would take action within 60 days. Several petitioners ask the Commission to modify its time table for processing *pro forma* tariff filings. UGI asserts that given the complexity of the filings, the current schedule is too compressed and asks the Commission to modify the schedule to allow 30 days for comment and 120 days for Commission action. Process Gas Consumers ask the Commission to give parties 45 days to comment and the Commission 90 days to act on the filing in order to provide time for a technical conference in each case. Process Gas Consumers state that the Commission should require a technical conference to give the parties a chance to raise concerns and possibly resolve issues prior to the filing of substantive comments.

The Commission has extended the comment period from the 12 days permitted for a tariff filing to 21 days to provide the parties with an additional time to analyze the pipeline's proposals. This extended period should be adequate to enable the parties to analyze and present their views on the pipeline's proposals. If adjustments are necessary, or if it appears that a technical conference would be beneficial in a particular case, the Commission can address these concerns in the individual proceedings.

b. Revenue Sharing. The implementation of peak/off-peak rates could lead to higher pipeline revenues from short-term services since a pipeline could reduce off-peak period price caps so that they would be close to recent discount history, and correspondingly increase peak period price caps. The Commission indicated in Order No. 637 that the process for implementing peak/off-peak rates must take into account any increased revenues. Therefore, if the pipeline seeks to implement seasonal rates in a limited section 4 filing, it must include in its proposal a revenue sharing mechanism that will provide for at least an equal sharing of any increased revenues with its long-term customers. Order No. 637 indicated the Commission's view that the revenue sharing should be limited to long-term customers and explained that under the current cost-of-service rate methodology, underpricing short-term peak capacity results in long-term customers paying higher rates because a greater share of the pipeline's costs is recovered from long-term customers.

Indicated Shippers argue that the revenue sharing mechanism is unjust and unreasonable and will result in a windfall to the pipelines, and further that it will serve as a disincentive for the pipelines to file section 4 rate cases. Indicated Shippers and NGSA argue that the Commission provided no basis for permitting pipelines to retain up to 50 percent of the excess revenues, and NGSA states that Order No. 637 is internally inconsistent because, on the one hand it justifies seasonal rates by stating that the pipeline's overall recovery will be limited to their cost-based annual revenue requirement, and on the other hand, permits the pipelines to retain up to 50 percent of the excess revenues. Indicated Shippers and NGSA assert there is no need to give pipelines an incentive to file seasonal rates since pipelines have proposed and want seasonal rates. NGSA and NASUCA argue that the Commission has given no justification for departing from the 90/10 split it used in restructuring.

Kinder Morgan, on the other hand, argues that the level of revenue sharing should be fully subject to negotiation and not limited by any predetermined rules such as a minimum level of revenue sharing.

The Commission has not required a 50/50 sharing of excess revenues, but indicated that the pipeline should include in its filing a mechanism that will provide for at least an equal sharing of any increased revenues with its customers. The Commission and the parties can work out the details of the revenue crediting mechanism in individual pipeline proceedings. In particular, the Commission suggested that the pipelines and their customers try to negotiate an equitable sharing mechanism pending the filing of the cost and revenue study required by Order No. 637. As the Commission explained in Order No. 637, the revenue sharing method should be fair to the pipelines and the customers, and pipelines are encouraged to work with their customers to develop a method that has wide support. When the pipeline files its cost and revenue study, the Commission can determine whether any changes to the long-term customers' rates are necessary. In the interim, a

[91] *UDC* v. *FERC,* 88 F.3d 1105, 1176 (D.C. Cir. 1996).

revenue sharing mechanism agreed upon by the parties provides an equitable temporary solution. Indicated Shippers and NGSA also argue that excess revenues should be shared by all customers, not just long-term customers. Indicated Shippers assert that the Commission's concerns for long-term shippers are misplaced because the Commission considered only the risks of long-term service without considering the benefits of long-term service that makes it superior to short-term service. Indicated Shippers state that on many fully-subscribed pipelines, short-term service is the only service available.

Further, Indicated Shippers state that in the past where increased revenues attributable to increased demand units are to be credited to shippers, the Commission has held that revenues should be credited to all shippers.[92] Indicated Shippers quote the Commission's rationale for deciding that IT revenues should be credited to all shippers:

> Since the purpose of interruptible revenue credits was to protect the pipeline's customers from too low an allocation to interruptible service, it follows that the customers who receive the credits should be the customers harmed by the erroneously low allocation. An allocation of too little costs to interruptible services cause both the firm and interruptible maximum rates to be too high.[93]

Indicated Shippers argue that the same reasoning applies in the present case, and that to the extent that pre-existing short-term rates were designed on the basis of fewer demand units than will arise upon the adoption of peak/off-peak rates, both the existing long-term and short-term rates are too high. Accordingly, Indicated Shippers argue, all shippers should be eligible to share in the increased revenues attributable to peak/off-peak rates, and the only customer excluded should be discount shippers whose discounts more than offset the understatement of design units underlying existing rates.[94]

NGSA similarly argues it is appropriate to credit excess revenues to all shippers because, until a pipeline's next rate case, revenue crediting acts as a substitute for adopting new discount adjustments (*i.e.*, lowering maximum rates), which will benefit all shippers, both short-term and long-term. Further, NGSA states that the Commission should not allow any credit to be paid to any pipeline affiliate.

NASUCA, on the other hand, argues that all revenues should be credited back to long-term firm shippers. NASUCA asserts that since the Commission has not departed from SFV, long-term shippers pay all the pipeline's fixed costs, and therefore they should receive the revenue offset.

It is appropriate to limit the revenue sharing to long-term customers. Crediting of excess revenues from peak/off-peak rates is not analogous to crediting of IT revenues during restructuring. In the case of IT revenues, as Indicated Shippers point out, the crediting was intended to protect the pipeline's customers that would be harmed by too low an allocation to interruptible service. Too low an allocation to interruptible service would result in all the customers' rates being too high. That is because the maximum interruptible rate was a load factor derivative of the firm rate, and not a rate separately designed based on the costs allocated to interruptible service. Here, in contrast, a primary purpose of peak/off-peak rates is to lower the share of the pipeline's costs that are paid by long term shippers as a result of short-term shippers obtaining peak service at less than the market rate for that service. In these circumstances, a credit to long-term customers only is appropriate.

Amoco and Dynegy ask the Commission to clarify that pipelines will not share revenues under this requirement with affiliates, negotiated rate customers, or customers receiving a discount. At present, the Commission is not persuaded that affiliates that are long-term customers should be treated any differently from other long-term firm customers for purposes of revenue crediting. However, the parties may address this issue in the individual proceedings. Also, as an initial matter, the Commission believes that it may be appropriate for customers receiving a discount to share in any revenues to the extent that the credit would reduce their rate below the discount level. However, this issue may also be addressed in the individual proceedings. On the other hand, negotiated rate shippers have already negotiated the rate they will pay, and therefore will not share in the revenues.

Koch asks the Commission to clarify that in a situation where the pipeline offers both seasonal and non-seasonal rates, and the revenues generated from the seasonal services are greater than the costs allocated to those services, but the total revenues from both seasonal and non-seasonal services are less than the costs allocated to both the services, the pipeline should not be required to share a portion of the excess revenues from its seasonal services with its long-term shippers. Koch states that in this example the pipeline has not earned its revenue requirement, and if revenue sharing were required, the pipeline would be in a worse position than if it had not offered the seasonal service. Koch asks the Commission to clarify that the revenue sharing mechanism applies only when the revenues collected from all of its transportation services exceed the total revenue requirement.

Order No. 637 stated that the pipeline is not required to share revenues if there are none, and that a pipeline will not be required to share excess revenues if it demonstrates that its total revenues from peak/off-peak rates were less than the costs allocated to the relevant services in its last rate case.[95] The appropriate method for determining the level of revenues to be credited can be decided in the individual proceedings.

c. Cost and Revenue Study. A pipeline that implements peak/off-peak rates through a limited section 4 proceeding after 12 months of experience with peak/off-peak rates, will need to prepare a cost and revenue study and file the study pursuant to the format prescribed in § 154.313 of the Commission's regulations within 15 months of implementing peak/off-peak rates. Based on the results of the study, the Commission will determine whether any rate adjustments are necessary to the long-term rates and, if so, order adjustments prospectively.

Process Gas Consumers agree that the cost and revenue study is a necessary part of the implementation of seasonal rates, but ask the Commission to clarify that interested parties may participate in the review process involving the study, and that the parties must have access to the information used by the pipeline to compile its study, and be privy to data requested by Staff in its review of the study. In addition, Process Gas Consumers request the Commission to clarify that pipelines must eliminate the discount adjustment as part of their individual cost/revenue study.

The Commission clarifies that interested parties may participate in the review process of the cost and revenue study. Procedures can be adopted in the individual cases to provide that these parties have access to the information necessary for their participation. A pipeline is not required to eliminate its discount adjustment at the time it files the cost and revenue study, but the issue of whether a change should be

[92] Indicated Shippers cite Transcontinental Gas Pipeline Corp., 78 FERC ¶ 61,057 (1997); Transcontinental Gas Pipeline Corp., 79 FERC ¶ 61,325 (1997).

[93] Transcontinental Gas Pipe Line Corp., 78 FERC at 61,209.

[94] Indicated Shippers cite Transcontinental Gas Pipeline Co., 78 FERC at 61,209.

[95] Order No. 637 at 106.

made in the pipeline's discount adjustment may be considered in the individual proceedings.

INGAA, CNG, Coastal Companies, Columbia, Enron, Koch, Kinder Morgan, and TWC argue that the cost revenue study would be overly burdensome to the pipelines and should either be eliminated or strictly limited to costs and revenues associated with peak/off-peak rates. These petitioners assert that the requirement for this study could discourage pipelines from filing for peak/off-peak rates. If the study is retained, the pipelines argue that the Commission should not require a full cost and revenue study, but should limit its scope to a review of the revenues associated with the new services compared to revenues from standard rates, as well as data regarding revenue crediting. They assert that the filing should not be an occasion to examine the pipeline's costs or long-term rates that are unaffected by the peak/off-peak initiative.

The Commission does not intend to discourage pipelines from using peak/off-peak rates, and has structured the implementation process so that pipelines are not required to file a full section 4 proceeding in order to implement peak/off-peak rates. If the pipeline uses the limited section 4 procedure, it will be necessary to assure that the pipeline does not overrecover its cost of service. In order to make this determination, the Commission will look at all the services offered by the pipeline, including the interplay of short-term and long-term services, and therefore a cost and revenue study as provided by section 154.313 of the Commission's regulations is appropriate.

Coastal Companies state that if the Commission continues to require a cost and revenue study, it should not require that it be filed within 15 months if the pipeline files a rate case in that period and seeks in the rate case to implement peak/off-peak rate. The Commission clarifies that the requirement to file a cost and revenue study applies if the pipeline chooses to implement peak/off peak rates through the pro forma filing procedures outlined in Order No. 637, not if the pipeline implements peak/off-peak rates in a general section 4 rate proceeding.

Koch states that requiring the filing of the cost and revenue study after 15 months would not be effective given what the Commission is trying to determine, and that it would be more appropriate for this study to be made after two winters as the Commission required with regard to the capacity release proposal. In addition, Koch states that pipelines should be able to offset over-recoveries received in one year against under-recoveries in another year. The Commission has determined that requiring the study after one year of experience strikes the appropriate balance between the need to obtain useful representative information and acting expeditiously.

3. Peak/Off-Peak Rates for Multi-Year Seasonal Contracts

AGA, Keyspan, NAGC, and New England urge the Commission to rule on rehearing that pipelines cannot implement value-based seasonal rates for multi-year seasonal services purchased by customers without meaningful alternatives. These petitioners assert that the Commission's finding that multi-year seasonal contracts are more like short-term contracts is unsupported with regard to essential multi-year services purchased by captive customers. These petitioners argue, as they do with regard to the applicability of the right of first refusal (ROFR) to these contracts, that the services provided under many of these seasonal contracts, often storage and related transportation, are available from the pipeline only for specific months,[96] and are not offered for a full year. They assert that these long-term contracts for seasonal service are not the product of negotiations in which the LDCs used leverage to avoid purchasing services on an annual basis. Instead, they assert, the pipelines offered the services for limited periods of the year, and the LDCs are dependent on these contracts to meet their peak demands.

These petitioners argue that since one of the benefits of seasonal rates cited by the Commission is that they will reduce costs to captive customers, the Commission should not let them be a vehicle to shift costs to captive customers. These petitioners assert that the rates for their seasonal long-term contracts were established in section 4 proceedings and already recover the full cost of providing the service. Keyspan argues that it would be unlawful to change these rates in a limited section 4 proceeding.

As also discussed below with regard to the ROFR, some multi-year seasonal contracts of captive LDC's have characteristics that are more similar to long-term service than to short-term contracts. These captive customers contract with the pipelines for the peaking service necessary for the LDCs to serve their customers during the winter heating season over a period of years. These services, often storage and related transportation, are offered by the pipeline only on a partial year basis, and the LDCs take the services on the basis that they are offered by the pipeline. In these circumstances, the shippers are different from non-captive shippers taking short-term service at peak periods with no long-term contractual relationship with the pipeline. It was not the Commission's intent that the limited section 4 filings would result in increased costs to long-term captive customers, and the mechanisms for implementing peak rates on the individual pipelines must be consistent with the Commission's goals. Issues concerning the appropriate allocation of costs to long-term peak/off-peak are more appropriately addressed in a general section 4 rate case.

4. Other Matters

a. Resolution by Settlement. INGAA and Kinder Morgan ask the Commission to clarify that peak/off peak and term-differentiated rates may be implemented through settlements, and that nothing in Order No. 637 affects the ability of pipelines and their customers to negotiate peak/off-peak and term differentiated rates that do not interfere with existing settlement provisions. Kinder Morgan asks the Commission to clarify that peak/off-peak and term-differentiated rates may be implemented through settlements that can deviate from the conditions set forth in Order No. 637. The Commission clarifies that its discussion of peak/off-peak rates and term-differentiated rates does not limit the parties' ability to settle rate cases.

b. Future Discounts. Koch asks the Commission to clarify whether offering peak/off-peak rates will affect its ability to seek a discount adjustment in its next rate case. Koch states that it does not appear that peak/off-peak rates would have a positive effect on revenues or reduce the annual level of discounting on its system. If Koch decides not to implement seasonal rates and that choice will reduce its ability to use a discount adjustment in future rates cases, then Koch needs to factor that risk into its decision, since the discount adjustment is critically important to Koch's long-term financial viability. Koch is concerned that the election not to implement seasonal rates will bar it from seeking a discount adjustment in future rate cases.

The Commission clarifies that implementation of peak/off-peak rates is voluntary on the part of the pipeline. A pipeline's decision not to implement peak/off-peak rates will not affect the

[96] AGA gives several examples of such service, *e.g.*, Transco's Southern Expansion Service which is available only from November through March.

pipeline's ability to seek a discount adjustment in its next rate case.

C. Term Differentiated Rates

Term-differentiated rates, *i.e.*, rates that differentiate among shippers based on the length of their contract, should be available to the pipeline as one of several methods that could be used to price capacity more efficiently. In Order No. 637, the Commission explained that term-differentiated rates would match price more closely with risk-adjusted value, and could result in a rate structure that prices capacity held for a longer term at a lower rate than capacity held for a shorter term.[97] As explained in Order No. 637, term-differentiated rates would more accurately reflect in the price of service the relative levels of risk that pipelines must face when selling service for a shorter period than for a longer period, as well as the higher risks that customers face when they purchase service for a longer period of time.

The Commission in Order No. 637 also explained that like peak/off-peak rates, term-differentiated rates would be cost-based, just and reasonable rates because the Commission will limit the rates in the aggregate to produce the pipeline's annual revenue requirement. The Commission recognized that there are various methods that could be used to develop reasonable term differentiated rates, and some methods might be more appropriate on certain pipelines than on others. Therefore, the Commission did not adopt a generic formula for implementation of term-differentiated rates, but indicated that it would allow the pipelines and the customers to work out the details of the methodologies in specific rate proceedings.

Order No. 637 also provides that a pipeline may propose term-differentiated rates just for long-term services or for both short and long-term services. Because the use of term-differentiated rates for short-term services may enhance the potential for price discrimination, particularly during off-peak periods, by increasing the rate caps that would apply to short-term service acquired in off-peak periods, the Commission made clear that a pipeline proposing term-differentiated rates for short-term services will need to explain fully the basis and justification for the price differentials. Further, because term-differentiated rates have a much greater potential for affecting the rates of all customers than peak/off-peak rates,[98] the Commission required that the general reallocation of revenue responsibility among customer classes must be done through rate changes for all customers simultaneously in the section 4 rate filing in which the pipeline seeks to implement term-differentiated rates. Requests for rehearing or clarification of this portion of Order No. 637 were filed by Amoco, Keyspan, Process Gas Consumers, INGAA, CNG, Coastal Companies, Kinder Morgan and Koch. The requests for rehearing are discussed below.

Process Gas Consumers argue that the Commission violated its own rules and acted arbitrarily and capriciously in granting pipelines permission to file for term-differentiated rates without undertaking further generic review and definition of the proper principles to guide the filings. Process Gas Consumers state that the Commission's regulations preclude pipelines from differentiating among shippers based upon contract term. Process Gas Consumers quote 18 CFR 284.7(b)(1) and 284.9(b) which provide that pipelines offering Part 284 firm and interruptible service must ''provide such service without undue discrimination, or preference in the quality of service provided, *the duration of the service*, the categories, prices, or volumes of natural gas to be transported, customer classification, or undue discrimination or preference of any kind.'' (emphasis added by Process Gas Consumers). Process Gas Consumers argue that term-differentiated rates would differentiate among shippers taking the same service based upon their duration of service, and that this is prohibited by the regulations. Further, Process Gas Consumers argue that under the current regulations the Commission has not permitted such a rate design change[99] and has failed to explain its reasons for departing from the regulations.

The portions of the regulations quoted by Process Gas Consumers do not prohibit charging a different rate for contracts of differing lengths. Instead, they provide that a pipeline cannot engage in undue discrimination in certain areas, including duration of service. Thus, if the capacity is available, and the shipper requests service at the maximum rate, then the pipeline must provide the service without regard to the length of the service requested. Moreover, charging a different rate for long-term service than for short-term service does not constitute undue discrimination because the different characteristics of long-term and short-term service justify rate differentials. As explained in Order No. 637, a shorter term contract is riskier for the pipeline, and a higher rate would compensate the pipeline for this additional risk. A shorter term contract provides greater flexibility and less risk to the shipper, and a higher rate would recognize and require payment for these benefits.

Process Gas Consumers argue that the Commission should reverse its decision and initiate further generic proceedings to provide guidance as to the proper boundaries for term-differentiated rates. Process Gas Consumers argue that the Commission's decision to shift the evolution of term-differentiated rates to individual pipeline cases does not constitute reasoned decisionmaking or a fair procedural setting for this evolution. Process Gas Consumers argue that while the Commission can set policy in individual cases, it may not encourage a departure from its current regulations without guidance or further regulatory action. Industrial argue that the Commission's decision to proceed in this fashion fails to protect consumers from the unjust and unreasonable rates and discriminatory behavior that Order No. 637's encouragement of term-differentiated rates invites.

As explained above, the Commission does not accept the premise of Process Gas Consumers' argument, *i.e.*, that term differentiated rates are unjust, unreasonable, and discriminatory. Moreover, as Process Gas Consumers recognize, the Commission can develop policy in adjudications as well as in rulemakings. As the Commission explained, there are a number of methods that could be used to develop reasonable term-differentiated rates, and some methods might be more appropriate on certain pipelines than on others. In these circumstances, it is preferable to allow the pipelines and the customers to work out the details of the methodologies in specific rate proceedings, rather than to try to discuss and analyze all of the possibilities in a generic proceeding. However, this does not mean that there are no parameters or standards that a proposal must meet, or that individual adjudications will not protect consumers from unjust and unreasonable rates and discriminatory behavior. All methods for developing term-differentiated rates must meet the NGA requirements that rates must be just and reasonable and not unduly discriminatory. These standards can more easily be applied to specific

[97] Order No. 637 at 107.

[98] Term-differentiated rates would raise the maximum tariff rates for some customers, and there should be a decrease in the maximum tariff rates for long-term customers.

[99] Process Gas Consumers cites ANR Pipeline Co., 82 FERC ¶ 61,145 at 61,535 (1998).

pipeline proposals in a section 4 proceeding than to theoretical generic principles.

Further, Process Gas Consumers argue, without guidance in a generic proceeding, the Commission risks substantial harm to the development of dynamic markets that depend on short-term transactions. Process Gas Consumers provides a list of types of proposals that should be prohibited by the Commission, *e.g.,* proposals that would allow pipelines to exercise market power over short-term market participants, proposals for ''outrageously high'' one-day rates. However, the Commission will assure in the individual section 4 proceedings that the specific proposal will not have adverse market consequences and that the rates proposed are not unreasonable. Process Gas Consumers have provided no reason why shippers cannot be protected and just and reasonable rates developed in individual section 4 proceedings.

INGAA, CNG, Coastal Companies, Kinder Morgan, and Koch argue that the Commission should not require pipelines to file a general section 4 rate case to implement term-differentiated rates. They argue that the procedures established by the Commission for implementing peak/off-peak rates are also appropriate here. They argue that the requirement of a full section 4 proceeding will make term-differentiated rates less attractive to pipelines and the option may go unused.

The Commission has attempted to balance the desire for expeditious implementation of the voluntary rate options with the need to assure that the statutory standards are met. While the Commission has concluded that a limited section 4 proceeding can accommodate both considerations in the implementation of peak/off-peak rates, the Commission has concluded for the reasons set forth in Order No. 637, that term-differentiated rates must be proposed in a section 4 proceeding. This does not necessarily mean that the proceeding must be lengthy and time-consuming or involve a full evidentiary hearing, and the parties may use that forum to develop a mutually agreeable method of implementing term-differentiated rates. Properly designing term-differentiated rates could be very complicated and would affect all the pipeline's rates to ensure that rates stay within the pipeline's revenue requirement. This cannot be done in a limited section 4 proceeding. The Commission does not intend to discourage pipelines from proposing term-differentiated rates, but has determined that a section 4 proceeding is necessary.

Amoco argues that the Commission erred in failing to limit a pipeline's rate flexibility options to either seasonal rates or term-differentiated rates, but not both in the short-term market. Amoco argues that pipelines should not be permitted to superimpose term-differentiated rates on seasonal rates, such that the maximum short-term rate would exceed the expected seasonal market value, else the result would be to effectuate market-based rates without a showing of a lack of market power. Amoco argues that this would eliminate the primary market mitigation mechanism relied on by the Commission in permitting market-based capacity release rates, *i.e.,* that just and reasonable cost-based pipeline rates will serve as a good alternative to unregulated capacity release rates.

Further, Amoco argues that term-differentiated rates are intended to adjust rates on the basis of demonstrable term risk, and this rationale does not apply in the short-term market where implementation of seasonal rates will allow pipelines to structure their rates to capture seasonal value differences within a cost of service framework. Amoco argues that there should be an absolute prohibition against term-differentiated rates for short-term contracts.

As the Commission acknowledged in Order No. 637, the use of term-differentiated rates for short-term services may enhance the potential for price discrimination, particularly during off-peak periods, by increasing the rate caps that would apply to short-term service acquired in off-peak periods. The Commission made clear that these proposals will be carefully scrutinized, and a pipeline proposing term-differentiated rates for short-term services will need to explain fully the basis and justification for the price differentials. If the pipeline chooses to implement both peak rates and term-differentiated rates, the proposal will be implemented in a full section 4 proceeding and the Commission and the parties will be able to address the impacts of the proposal. The Commission will not preclude a pipelines from proposing both rate methodologies.

Amoco also states that the Commission should clarify that term-differentiated rates should be designed only within rate of return ''zone of reasonableness'' parameters to reflect the differential risk associated with varying contract durations. For example, Amoco states that if a ROE zone of reasonableness ranges from 10% to 14%, a longer term contract of 10 years or longer would have a 10% ROE imputed and a short term contract of one year would have a 14% ROE imputed. Otherwise, Amoco argues, pipelines can use their market power to coerce captive customers into purchasing capacity either at excessive rates or for excessive terms. Amoco's suggestion may be one reasonable method of designing term-differentiated rates which can be considered in the individual proceedings, but the Commission will not limit the parties to this one method. Pipelines and their customers may devise other methods that protect shippers from unreasonable rates or contract terms.

Amoco is also concerned about affiliate abuse which it says is increased in the term-differentiated rate structure. Amoco states that there must be limitations on the imputed contract term available for an affiliate. The Commission will not establish a limit on the contract term available for affiliates, but this is an issue that the parties may address in a section 4 proceeding.

Keyspan asks the Commission to clarify that pipelines that are subject to Commission-approved settlements that prohibit increases to rates for seasonal services for some period are not entitled to increase those seasonal rates until the specified period in the settlement expires, and that pipelines cannot implement term-differentiated rates during rate moratorium period. INGAA asks the Commission to clarify that nothing in Order No. 637 affects the ability of pipelines and their customers to negotiate term-differentiated rates that do not interfere with existing settlements. The Commission cannot rule on specific settlement provisions, but the Commission clarifies that parties continue to be bound by their settlements, and nothing in Order No. 637 changes existing settlements. Further, nothing in this rule limits the parties' ability to negotiate future settlements.

Keyspan also asks the Commission to clarify that any term-differentiated rates proposed by the pipelines must differentiate on the basis of the contract term regardless of the remaining life of the contract, *i.e.*, if a pipeline has different rates for contracts of ten, five, and three years, a customer with three years remaining on a ten-year contract should be charged the ten-year rate for the remaining three years. The Commission clarifies that its intent was to have a long-term rate apply to a long-term contract for the duration of that contract, and not to have that contract charged a shorter-term rate in the later years of the contract.

D. Voluntary Auctions

Recognizing the increasing use of electronic commerce to create efficient markets, the Commission in Order No. 637 encouraged both pipelines and third parties to develop capacity auctions, and provided basic principles for the design of transparent, verifiable, and non-discriminatory auctions. The Commission also indicated that an appropriately designed auction may be a means by which a pipeline could sell all or some of its capacity without a price cap so long as the auction was designed in such a way as to protect against the pipeline's ability to withhold capacity and exercise market power. The Commission set out some general criteria for accomplishing these goals, one of which was a statement that all capacity available at the time of the auction would have to be included in the auction.

Koch requests clarification that a pipeline can engage in limited auctions without a price ceiling by auctioning only capacity between select points in the auctions. Koch claims that such an auction would prevent the exercise of market power because the pipeline would be unable to withhold any capacity between the designated points.

While the Commission would have to examine any such auction proposal in detail before it could determine whether it would adequately protect against the exercise of market power, Koch's proposal for selective auctions does not appear sufficient. Under Koch's proposal, the pipeline could select only capacity between certain points to include in the auction at a particular time, while reserving the right to sell capacity between those points outside the auction process at other times as well as to sell capacity between other points outside of the auction process. In a fair auction process, the pipeline should not be able to choose the auction format only for those markets or at those times where it could benefit, while reserving its right to selectively discount at other times or for other markets.

Process Gas Consumers contends the Commission should not permit market-based rates through auctions, or at least should provide detailed guidance in advance about the showing the seller of capacity must make to justify the lifting of price caps. They further seek clarification concerning the process to be used by a pipeline to propose an auction, particularly about the rights of shippers to participate in that process, clarification that auctions can only take place upon reasonable notice and during normal business hours, and clarification that combined gas and capacity auctions by third parties would be subject to Commission regulation.

Auctions can be methods by which pipelines can sell capacity without a rate ceiling if the auction format adequately protects against the exercise of market power by preventing withholding of available capacity and price discrimination. There may be many different ways of achieving this result, and the Commission cannot specify in advance all the necessary criteria. Given the Commission's and the industry's lack of experience with auctions, it is important to encourage innovation in auction design, rather than having the Commission insist on a design that may not be the most effective or efficient. One of the Commission's principles for a fair auction design is that such an auction must be open to all potential bidders on a non-discriminatory basis, which would include notice of when the auctions will take place. But the Commission will not generically require that all auctions take place during normal business hours, as requested by Process Gas Consumers. Given the intra-day nomination schedule adopted by the Commission, some auction designs may want to include after hour auctions. Questions concerning the timing of auctions must be evaluated in individual applications.

Pipelines contemplating proposing auctions would be well advised to review their plans with their customers as a way of resolving potential problems and creating a more efficient design prior to filing the proposal with the Commission. Shippers, of course will have to the right to fully participate in any auction proceeding initiated by a pipeline filing.

The Commission has authority to regulate the reallocation by shippers of transportation capacity.[100] Depending on how an auction is organized, and whether waiver of Commission regulatory requirements is requested, Commission regulatory oversight may or may not be necessary. Third-parties currently can auction released capacity without regulatory oversight by the Commission as long as the results of those auctions comply with the Commission's capacity release regulations, particularly the requirement for posting and bidding on Internet sites authorized by pipelines. In these cases, the third-party auctions are merely ways for shippers to enter into pre-arranged releases of capacity.[101] As long as those pre-arranged releases comply with Commission requirements, i.e., are transmitted to the pipeline for posting on pipeline Internet sites and bidding (when necessary) is allowed, no further oversight is needed.[102]

Some third parties indicated in their comments that compliance with some of the Commission's existing regulations can impede the development of third-party auctions. For instance, the requirement that certain transactions must be posted on pipeline Internet sites was identified as a barrier to third-party auctions because it would require a double posting of capacity (once in the auction and once on the pipeline's Internet site) and would render the results of the auction less certain. In those cases in which a shipper or third-party finds that a current Commission regulatory requirement impedes the development of an efficient auction, the Commission encourages shippers or third-parties to propose an alternate method for satisfying the goal of the requirement. For example, to satisfy the requirement that prices be disclosed on a pipeline's Internet web site, the pipeline could be required to maintain a link on its web site to the web site of the third-party auctioneer. The Commission cannot proscribe, in the abstract, criteria for such proposals. Third-parties should have the freedom to develop and propose innovative solutions to such problems.

II. Improvements to Competition Across the Pipeline Grid

A. Scheduling Equality

In Order No. 637, the Commission adopted the proposal set forth in the NOPR to amend the Commission's regulations to include a new section 284.12(c)(1)(ii) to require pipelines to provide purchasers of released capacity the same ability to submit a nomination at the first available opportunity after consummation of the deal as shippers purchasing capacity from the pipeline. This will enable shippers to acquire released capacity at any of the nomination or intra-day nomination times, and nominate gas coincident with their acquisition of capacity. By enabling released capacity to compete on a comparable basis with pipeline capacity, the new section of the

[100] *United Distribution Cos.* v. *FERC,* 88 F.3d 1105, 1151–54 (D.C. Cir. 1996).

[101] Pipelines can, and have, used third-parties to satisfy the posting and bidding obligations for their systems. Third-parties, in this context, refer to parties conducting auctions not under the auspices of the pipeline.

[102] For example, third-party auctions for short-term released capacity (31 days or less) can be conducted without complying with the requirements for posting and bidding on pipeline Internet sites, because short-term releases are exempt from the Commission's posting and bidding requirements.

regulations will foster a more competitive short-term market. Also, in Order No. 637, the Commission explained the basis for its policy that the shipper must have title to the gas being transported, and concluded that no changes in this policy are appropriate at this time. Niagara Mohawk, NGSA, Scana Energy Marketing, Tejas, TWC, and Williston seek clarification or rehearing of this portion of Order No. 637.

Williston seeks rehearing of the Commission's regulation requiring nominations for capacity release transactions to be on an equal footing with shippers purchasing capacity directly from the pipeline. Williston argues that there must be differences in the nomination and scheduling of capacity release and the nomination and scheduling of pipeline capacity because additional time is required to evaluate capacity release transactions due to possible conditions the releasing shipper may impose on the acquiring shipper. Williston states that the time required by the pipeline to evaluate such conditions and the potential operational impact requires that the existing timing difference in the nomination and scheduling process.

Williston does not explain what conditions and operational considerations could need to be evaluated. The replacement shipper will take the service under the same contract, subject to the same conditions as the releasing shipper and, therefore, will have the same operational impact on the system. There should be no change in conditions or impact for the pipeline to evaluate.

In addition, Williston asserts that the provision of such a service will not be cost effective on its system because Williston would be required to expend significant money and manhours on new electronic contracting software. Williston states that it has had 13 capacity releases in the last three years, and this number of releases does not justify the Commission's imposition of this requirement on Williston. Williston argues that the offering of nomination opportunities for capacity release equal to nomination opportunities for shippers purchasing capacity should be on a best efforts or optional basis on pipelines with significant capacity release.

As explained in Order No. 637, the Commission adopted the new regulation requiring equality in scheduling in order to enable released capacity to compete on a comparable basis with pipeline capacity. This furthers the Commission's goal of enhancing competition and improving efficiency across the grid. In order for the requirement to have this effect it must apply to all pipelines and all capacity release transactions.

Scana seeks clarification, or in the alternative, rehearing, that the pipelines must provide replacement shippers with the same no-notice scheduling rights as held by releasing shippers. Scana asserts that some pipelines have placed restrictions in their tariffs on the release of no-notice transportation, such that a shipper may release no-notice transportation, but the replacement shipper receives FT capacity without no-notice scheduling rights. Scana further asserts that other pipelines do not restrict release of no-notice service, but instead impose artificial restrictions on the scheduling flexibility after release. Scana argues that, consistent with the Commission's purpose of achieving scheduling equality between releasing and replacement shippers, the Commission must clarify that Order No. 637's mandate for scheduling equality among releasing and replacement shippers is intended to cover no-notice scheduling rights and contingency ranking.

The Commission has held that the pipeline must permit shippers to release their no-notice service as no-notice service.[103] Further, if the pipeline permits shippers to receive no-notice service at flexible delivery points, it must permit the no-notice shipper to release that capacity with similar flexible delivery points.[104] However, if the pipeline does not permit its no-notice shippers flexible delivery point rights, it is not required to provide flexible delivery points to the replacement shipper. There should be no operational reason why the pipeline should limit the release of no-notice service or place restrictions on the released service that do not apply to the releasing shipper. Since the shipper releasing the no-notice capacity is not able to use it, the pipeline will not be providing any more no-notice service than it contracted to provide.

TWC and Tejas ask the Commission to clarify the relationship between new section 284.12(c)(1)(ii) and the approved GISB Standards, including the GISB Standard timelines for capacity release as set forth in GISB Standard 5.3.2. The Commission clarifies that new section 284.12(c)(1)(ii) supplants GISB Standard 5.3.2, to the extent that they are inconsistent. Thus, the capacity release nomination requirements are contained in the new regulation, and GISB Standard 5.3.2 now applies only to the bidding process. It is not necessary for the Commission to delay implementation of its new nomination requirements until GISB acts to amend section 5.3.2.

Tejas quotes the discussion in Order No. 637 as providing that under new regulation § 284.12(c)(1)(ii), the pipeline must ''approve'' a contract within an hour. Tejas asks the Commission to clarify whether the Commission means ''issuance'' or ''approval,'' and whether issuance or approval of the contract means that it has been executed by both parties.

The text of the regulation states that the pipeline must ''issue'' the contract within an hour and the Commission clarifies that the requirement is to issue the contract, rather than approve the contract. Issuance of the contract does not mean that it has been executed by both parties.

Tejas also observes that GISB Standard 5.3.2 defines short-term releases as those with a duration of less than 5 months, and in Order No. 637, the Commission defines short-term releases as those extending for less than one year. Tejas asks the Commission to clarify which of the two definitions will apply to short-term releases.

The bidding requirements of GISB Standard 5.3.2 apply to capacity releases of more than five months. In Order No. 637, the Commission waived, for a two year period, the rate ceiling for capacity releases of less than one year. Neither of these provisions defines a short-term release for other purposes, and they are not inconsistent.

NGSA states that although the Commission established scheduling equality between capacity release shippers and others holding firm capacity, and recognized the efficacy of master agreements in achieving scheduling equality, it did not require use of a master agreement. NGSA asserts that master agreements are the only means to achieve scheduling equality, and therefore the Commission should require them.

The Commission recognizes that master agreements are a good way to achieve scheduling equality, but as explained in Order No. 637, there are other methods as well. The Commission will not mandate any one method, but will leave this to be resolved by the pipelines and shippers.

Finally, Niagara Mohawk requests that the Commission clarify that it will be receptive to requests for waiver of the shipper must have title policy where the applicant demonstrates that the waiver

[103] Order No. 636–B, 61 FERC ¶ 61,272 at 62,009–10 (1992); Questar Pipeline Co., 62 FERC ¶ 61,192 at 62,298 (1993).

[104] **Editor's Note:** No text in footnote 104.

will not result in undue discrimination or the inefficient allocation of capacity. Parties may apply for a waiver of the policy and, as in the past, the Commission will consider the waiver based on the specific circumstances of the request.[105]

B. Segmentation and Flexible Point Rights

In Order No. 636, the Commission established two related policies—flexible point rights and segmentation—that were designed to provide firm shippers with the flexibility to use their capacity and to enhance competition between shippers and between shippers and the pipeline.[106] Flexible point rights refer to the rights of firm shippers to change receipt or delivery points so they can receive and deliver gas to any point within the firm capacity rights for which they pay. Segmentation refers to the ability of firm capacity holders to subdivide their capacity into segments and to use the segments for different capacity transactions.

The requirement to permit segmentation originally was not included in the Commission's regulations, but was implemented through pipeline restructuring filings. The Commission found that capacity segmentation was not being implemented uniformly across the pipeline grid. Some pipelines did not permit segmentation at all, others placed restrictions on the ability to segment for release, and others did not permit shippers to segment capacity for their own use.

In Order No. 637, the Commission responded to the inconsistent application of segmentation rights by adopting a regulation requiring pipelines to permit a shipper ''to make use of the firm capacity for which it has contracted by segmenting that capacity into separate parts for its own use or for the purpose of releasing that capacity to replacement shippers to the extent such segmentation is operationally feasible.'' [107] Each pipeline is required to make a *pro forma* tariff filing demonstrating how it intends to comply with the regulation, by revising its tariff, explaining why its existing tariff meets the requirements, or explaining why the operational configuration of its system does not permit segmentation.

In Order No. 637, the Commission also concluded that no regulatory changes were needed to be made with respect to the relative scheduling priorities of shippers using secondary points depending on whether they were shipping within or outside their capacity path.[108]

Rehearing and clarification requests were filed with respect to both the segmentation and path priority determinations.

1. Segmentation

Rehearing and clarification requests were received regarding the adoption of the segmentation regulation and the requirements of the regulation. In addition, rehearing and clarification requests were filed concerning the extent to which earlier Commission policies will apply to segmented releases and the manner in which pipelines are to implement the requirement. These are discussed below.

a. Adoption and Requirements of the Regulation. Legal Justification. Koch maintains the Commission's generic segmentation policy violates sections 4 and 5 of the NGA. It contends the requirement violates section 5, because the Commission has not found that an existing tariff provision is unlawful and that the Commission-imposed modification of the tariff is just and reasonable. Koch maintains the Commission's action in requiring a pipeline compliance filing is not justifiable under section 4 of the NGA, because Koch has not voluntarily submitted a proposed tariff change and the Commission cannot under section 4 place the burden on the pipeline of justifying that segmentation is inappropriate.

The Commission's action is an appropriate use of its authority under section 5 of the NGA. In Order No. 637, the Commission made a generic determination that the failure of a pipeline to permit segmentation would be unjust and unreasonable if the pipeline could operationally permit segmentation.[109] Under Order No. 636, the firm transportation capacity held by shippers was to include the same flexibility the pipeline enjoyed when it provided bundled sales service, and the ability to use capacity flexibly, through the use of flexible point rights and segmentation, was part of the flexibility enjoyed by pipelines. Further, as the Commission found in Order No. 637, segmentation increases the number of capacity alternatives and so improves competition, and also is important in facilitating the development of market centers and liquid gas trading points.[110] Based on these findings, the Commission determined that pipelines that operationally can permit segmentation, but do not, would be acting in an unjust and unreasonable manner.

While Order No. 637 announced the Commission's segmentation policy, it did not make a section 5 determination that any particular pipeline's tariff is, in fact, unjust and unreasonable. Any such determination will be made in the individual pipeline compliance proceedings. The Commission had reason to believe, based on the comments and its own analysis of pipeline tariffs, that some pipelines are not permitting shippers to segment capacity, both for the shipper's own use and for capacity release transactions, to the extent operationally feasible on their systems. The Commission, therefore, required pipelines to make *pro forma* filings to establish whether their current tariffs are just and reasonable. The requirement for pipelines to make *pro forma* compliance filings is not, as Koch characterizes it, a requirement that pipelines make a section 4 filing. Rather, the *pro forma* filings require the pipelines to show why their existing tariffs should not be considered unjust and unreasonable. If the Commission finds changes are warranted, it will be acting under section 5 to implement such changes.

Non-Operational Barriers to Segmentation. CNG and Columbia Gas contend the inquiry into segmentation should not be limited to whether segmentation is ''operationally feasible,'' because non-operational problems, such as rate design, administrative complexity, or potential legal barriers can inhibit the ability of a pipeline to offer segmentation. They maintain that such problems can be particularly difficult for reticulated pipelines where shipper paths are not easily defined. CNG contends that such changes can be made only through a full section 4 rate filing that would include the identification of multiple paths, a redesign of services, and an elimination

[105] *See, e.g.,* Baltimore Gas and Electric Co., 88 FERC ¶ 61,133, *reh'g denied,* 89 FERC ¶ 61,150 (1999).

[106] Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Order No. 636, 57 FR 13267 (Apr. 16, 1992), FERC Stats. & Regs. Regulations Preambles [Jan. 1991–June 1996] ¶ 30,939, at 30,428, 30,420–21 (Apr. 8, 1992), Order No. 636–A, 57 FR 36128 (Aug. 12, 1992), FERC Stats. & Regs. Regulations Preambles [Jan. 1991–June 1996] ¶ 30,950, at 30,559 n.151 (Aug. 3, 1992), Order No. 636–B, 61 FERC ¶ 61,272, at 61,997 (1992).

[107] Order No. 637, 65 FR at 10195, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091, at 31,303–304; 18 CFR 284.7(e).

[108] Order No. 637, 65 FR at 10196, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091, at 31,304.

[109] *Wisconsin Gas Co.* v. *FERC,* 770 F.2d 1144, 1166–67 (D.C. Cir. 1985) (Commission can make generalized determinations that particular practices are unjust and unreasonable through rulemaking).

[110] Order No. 637, 65 FR at 10195, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091, at 31,303–304.

of postage stamp (one rate for the entire system) rate structures.

The Commission will not eliminate the ''operationally feasible'' requirement from the regulation. The goal in permitting shippers to segment capacity is to enable firm shippers to use the capacity for which they have contracted as flexibly as possible without infringing on the legitimate rights of other shippers. In the case of a reticulated pipeline charging a postage stamp rate, firm shippers are paying for the use of the entire pipeline in their rates. The pipeline, therefore, has the obligation to optimize the system so that firm shippers can make the most effective use of the capacity for which they pay. On reticulated pipelines with postage stamp rate structures, where shippers have no specifically defined paths, the pipeline should permit firm shippers to use all points on the system and to use or release segments of capacity between any two points, while continuing to use other segments of capacity.

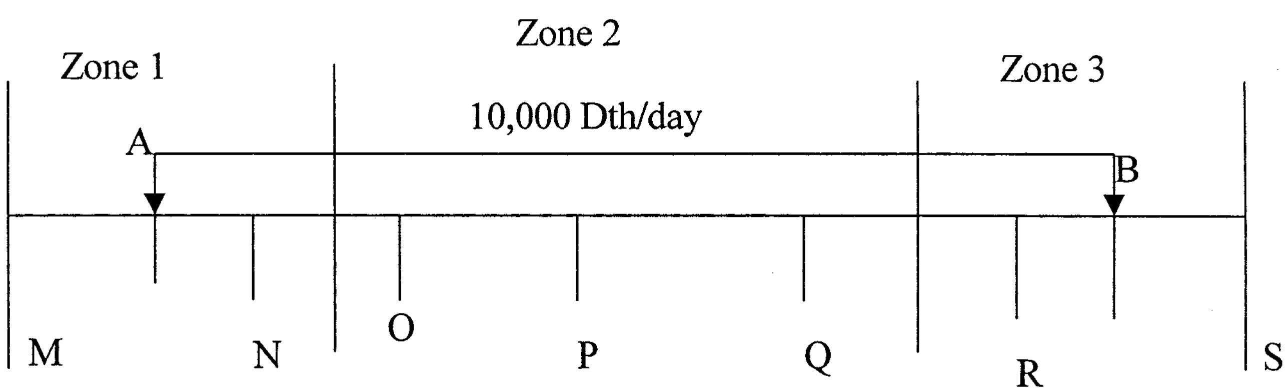
The Commission recognizes that permitting segmentation on a reticulated pipeline can result in operational difficulties if replacement shippers flow gas at different points than the existing shippers. But that is not a reason for the pipeline to refuse to provide the ability to segment. Instead, the pipeline needs to optimize its system to provide maximum segmentation rights while devising appropriate mechanisms to ensure operational stability. Displacement pipelines with postage stamp rate structures have been able to permit segmentation with operational rules to protect system integrity.[111]

On reticulated systems with zone rates, segmentation can be limited to the zones for which the shipper pays. If a pipeline currently using a postage stamp rate structure finds that providing segmentation or defining capacity paths would be more feasible with a redesign of its rates, the pipeline can make a section 4 filing to establish rates that it considers more consonant with segmentation.

b. Compliance Filings and Implementation. Overlapping capacity segments. Coastal, INGAA, Kinder Morgan, and Williston request clarification that the Commission will adhere to its current policy of not permitting shippers to use segmentation to release overlapping capacity segments.[112] National Fuel Distribution also seeks clarification that shippers can segment capacity at market centers or other non-physical transaction points on the pipeline's system.

Capacity segmentation refers to the ability of shippers to divide their capacity into individual segments with each segment equal to the contract demand of the original contract. As a general matter, pipelines are not required to permit segmentation in a situation where the nominations by a shipper or a combination of releasing and replacement shippers exceed the contract demand of the underlying contract on any segment. The Commission further clarifies, as National Fuel Distribution requests, that shippers can divide their capacity through segmented releases at any transaction points on the pipeline system, including virtual transaction points, such as paper pooling points, as well as at physical interconnect points, such as market centers.

To help avoid inconsistent application of the Commission's flexible receipt and delivery point policy and the segmentation policy, the following example will provide clarification as to how those policies should operate. In this example, a shipper has a contract for 10,000 Dth per day from receipt point at A to delivery point B.



The shipper has the flexibility to segment capacity throughout zones 1–3 (point M through point S), so long as the combined nominations of it and replacement shippers do not exceed the mainline contract demand of 10,000 Dth. The shipper has the right to segment outside of its path because it is paying the full rates for zones 1–3 and, therefore, has the right to use all points within the zones for which it pays. Thus, the shipper could nominate and ship 10,000 Dth from point M to point P, while at the same time nominate and ship another 10,000 Dth from point P to point S. But the shipper could not nominate 10,000 Dth from point M to point Q and nominate 10,000 Dth from point P to point S, because that would result in 20,000 Dth nominated in segment P–Q.

The shipper also could release 10,000 Dth of capacity from point P to point B, while retaining 10,000 Dth of capacity from point A to point P for its own use. The releasing shipper could then nominate and ship 10,000 Dth from point A to point P, while the replacement shipper could nominate and ship 10,000 Dth from point P to point B.

Segmentation would also permit the releasing and replacement shippers to use overlapping segments so long as their combined nominations in a segment do not exceed 10,000 Dth. For instance, the releasing shipper could nominate and ship 5,000 Dth from point A to point Q, while the replacement

[111] *See* Northwest Pipeline Corporation, 69 FERC ¶ 61,171, at 61,677 (1994), 71 FERC ¶ 61,315, at 61,224 (1995) (providing operational controls for segmented releases that jeopardize system integrity).

[112] Citing Tennessee Gas Pipeline Company, 85 FERC ¶ 61,052 (1998), *reh'g denied,* 86 FERC ¶ 61,290 (1999); Texas Gas Transmission Corporation, 89 FERC ¶ 61,096 (1999).

shipper nominates and ships 5,000 Dth from point O to point B even though the segments overlap in segment O–Q. Both nominations would be accepted because the combined nomination over segment O–Q would not exceed 10,000 Dth. However, if both shippers sought to nominate the full 10,000 Dth in one or more pipeline segments, the pipeline could limit the nominations to 10,000 Dth in those segments. The pipeline should have a default tariff provision detailing how nominations from releasing and replacement shippers will be handled in the event that they exceed the contract demand, and releasing shippers also can include provisions for handling overlapping nominations in their release conditions.[113]

Both the releasing and replacement shippers also would retain the flexibility to use their capacity fully to make backhauls. Thus, the shipper could deliver 10,000 Dth from point A to point B using forward haul capacity and 10,000 Dth from point S to point B using a backhaul, because there is no overlap over the mainline.

This may require a change by some pipelines with respect to their tariffs regarding backhauls. The Commission's policy on the use of forwardhauls and backhauls to the same point in excess of contract demand has been in the process of change. While the Commission found in 1997 that a shipper cannot use the same delivery point for a forwardhaul and backhaul in excess of contract demand,[114] the Commission recently found that a forwardhaul and backhaul to a series of 23 meter stations considered as a single point for nomination purposes did not result in a capacity overlap even though the total amount received by the shipper exceeded contract demand.[115] In order to promote shippers' ability to use their capacity as flexibly as possible, the Commission has determined that prior restrictions on shippers' use of forwardhauls and backhauls to the same point should not be followed. Shippers' segmentation rights should not depend upon metaphysical distinctions between delivery to a single point or to two points adjacent to each other. In both situations, shippers should be permitted to use a forwardhaul and a backhaul to deliver gas as long as the mainline contract demand is not exceeded and they can take delivery of the gas.

Segmentation and primary point rights. Several rehearing requests relate to the relation between segmentation and primary point rights. El Paso and Enron maintain segmentation should be considered separately from primary point rights and should not result in shippers being able to use segmentation to increase primary point rights beyond those covered in their contracts. Kinder Morgan claims that if shippers change their primary point rights in segmenting capacity for their own use, the shippers do not have the right to revert to their original primary points without the consent of the pipeline. Kinder Morgan and INGAA seek clarification that pipelines can resell capacity at primary points vacated by releasing or replacement shippers. In contrast, National Fuel Distribution maintains that shippers should be permitted to segment capacity and retain their primary priority in both segments.

The Commission cannot clarify the role of primary receipt points on a generic basis, but will need to examine the issues raised in the pipelines' compliance filings. In Order No. 637, the Commission explained that in the past it had adopted different policies on the issue of whether pipelines could restrict replacement shippers' ability to choose new primary points depending on whether pipelines had historic tariff provisions that limited primary point rights to the same level as the shipper's mainline contract demand.[116] Although the Commission accepted tariff filings during Order No. 636 that continued historic limitations on the number of primary receipt and delivery points, the Commission questioned whether it continued to be appropriate for pipelines to limit receipt and delivery point quantities to the shipper's contract demand.[117] The Commission concluded that a pipeline's overly restrictive allocation of primary point rights to existing shippers could restrict the ability of shippers to use their capacity flexibly. But the Commission did not impose a blanket prohibition on all limits to a firm shipper's ability to choose primary receipt and delivery points. The Commission recognized that pipelines might need to impose some restrictions on primary point rights, as appropriate to the circumstances of their systems, to prevent hoarding of capacity by some shippers to the detriment of others.[118] Moreover, even when the Commission did permit continuation of tariff provisions that limited primary point rights to contract demand, the Commission adopted a policy (*Texas Eastern/El Paso* policy) which permitted both releasing and replacement shippers in segmented releases to choose separate primary point rights that did not exceed each shipper's contract demand.[119]

Permitting flexibility in the selection of primary points in segmented releases can be important to creating effective competition between pipeline services and released capacity. If replacement shippers were limited to the use of segmented points on a secondary basis, as some of the rehearing requests suggest, the pipeline would still retain the right to sell that receipt point on a primary basis. The ability to sell points on a primary basis would provide the pipeline with a competitive advantage over segmented release transactions. In order to equalize competition between pipeline and released capacity, pipelines need to permit shippers greater flexibility in selecting primary points than they have in the past.

Because the Commission has not reviewed receipt and delivery point restrictions since Order No. 636 and restrictions on segmentation and point rights can limit effective competition, pipelines should not be able to continue to rely upon their historic tariff practices dating back to the days of merchant service, but need to justify restrictions on shippers' ability to use additional primary points in segmented transactions and any deviation from the *Texas Eastern/El Paso* policy.[120] For example, on a fully subscribed pipeline where receipt point capacity exceeds mainline capacity fivefold, the pipeline can seemingly permit shippers to select primary receipt point rights well in excess of their mainline contract

[113] *See* Texas Gas Transmission Corporation, 89 FERC ¶ 61,096, at 61,274 (1999).

[114] Iroquois Gas Transmission System, L.P., 78 FERC ¶ 61,135 (1997) (shipper cannot use same delivery point for forwardhaul and backhaul in excess of contract demand).

[115] Transcontinental Gas Pipe Line Corporation, 91 FERC ¶ 61,031 (2000) (using forwardhaul and backhaul to series of delivery points does not result in an overlap).

[116] Order No. 637, 65 FR at 10194, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091, at 31,301–302. *Compare* Transwestern Pipeline Company, 62 FERC ¶ 61,090, at 61,659, 63 FERC ¶ 61,138, at 61,911–12 (1993); El Paso Natural Gas Company, 62 FERC ¶ 61,311, at 62,982–83 (1993) (permitting pipelines to continue historic limitations on primary receipt point rights) with Northwest Pipeline Corporation, 63 FERC ¶ 61,124, at 61,806–08 (1993) (not permitting the pipeline to add such restrictions).

[117] El Paso Natural Gas Company, 62 FERC ¶ 61,311, at 62,982–83 (1993); Transwestern Pipeline Company, 62 FERC ¶ 61,090, at 61,659, 63 FERC ¶ 61,138, at 61,911–12 (1993).

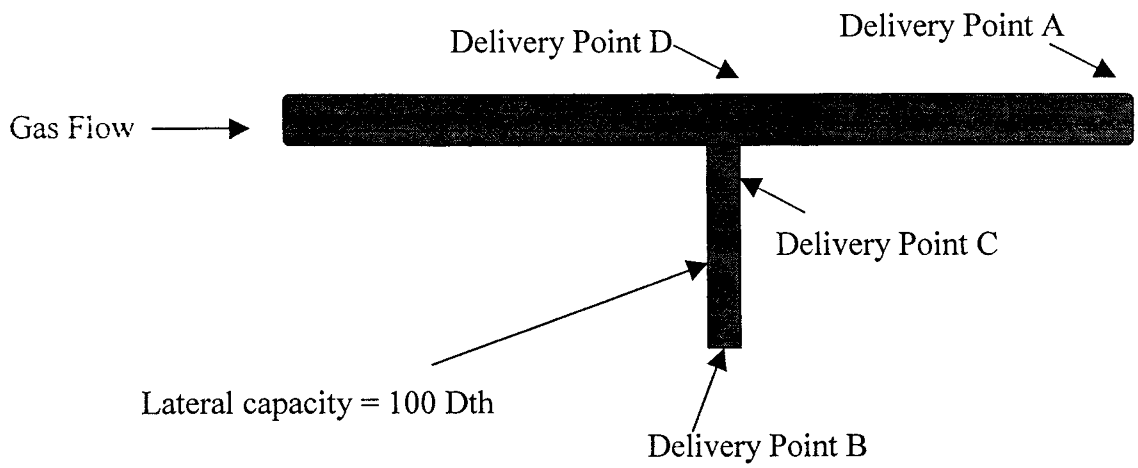
[118] *See* El Paso Natural Gas Company, 62 FERC ¶ 61,311, at 62,982–83 (1993) (pipelines could propose methods for limiting the potential for hoarding).

[119] Order No. 637, 65 FR at 10194, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091, at 31,301–302; Texas Eastern Transmission Corporation, 63 FERC ¶ 61,100, at 61,452 (1993); El Paso Natural Gas Company, 62 FERC ¶ 61,311, at 62,991. *See also* Transwestern Pipeline Company, 61 FERC ¶ 61,332, at 62,232 (1992).

[120] Order No. 637, 65 FR at 10195–96, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091, at 31,304.

demand, since the pipeline has no capacity left to sell and, therefore, needs to reserve no receipt point capacity in order to sell unsubscribed capacity.[121]

El Paso contends that providing shippers with the right to select multiple delivery point rights along a path could detrimentally affect the rights of existing shippers. It provides an example in which a lateral off the mainline can support only 100 Dth of capacity and a shipper at the terminus of the lateral (Delivery Point B) already has primary point capacity of 100 Dth on the lateral. El Paso maintains that if another shipper with a primary delivery point (Delivery Point A) can subscribe to an upstream point on the lateral (Delivery Point C) on a primary basis, the downstream shipper on the lateral could lose its primary point priority.



This argument misapprehends Commission policy. The new shipper could not obtain a primary delivery point at Delivery Point C, because no capacity on the lateral is available at that point; the lateral capacity is fully subscribed. In order for shippers to obtain primary points, the mainline capacity to that point must be available. Thus, the shipper with a primary delivery point at Delivery Point A could obtain another primary delivery point at Delivery Point D, because the shipper has sufficient mainline capacity to deliver to that point. As pointed out previously, the selection of this new delivery point would not increase the shipper's mainline contract demand. It would only permit the shipper to choose to deliver to Delivery Point A or Delivery Point D on a primary basis.

The resolution of issues relating to the allocation of primary point rights in segmented transactions will have to be addressed in each pipeline's compliance filing. Pipelines will have to include justifications, based on the operational characteristics of their systems, for restrictions on the extent to which shippers and replacement shippers can change primary points or can revert back to the original points at the end of a release or segmented transaction.

Point discounts. Kinder Morgan and Koch request clarification that in implementing segmentation, the Commission will continue its current policy under which discounts granted with respect to specific points do not apply when the shippers change points. They contend that if a shipper seeks to use different points as part of a segmentation transaction, the shipper will not be entitled to continue its discount.

This issue also needs to be considered in the pipelines' compliance filings. In the restructuring proceedings to implement Order No. 636, the Commission's policy was to permit pipelines to limit a shipper's discount to particular receipt and delivery points. A shipper with a discount contract to particular points would be subject to the pipeline's maximum rate if it, or a replacement shipper, chose to exercise its right to use flexible receipt or delivery points.[122] The justification for this policy was that market conditions may vary on a pipeline, and the pipeline, therefore, should be permitted to structure its discounts to meet the prevailing market conditions.

The Commission still recognizes that pipelines may have underutilized segments of their pipelines for which they may need to offer discounts in order to increase throughput and that such discounts should not necessarily entitle shippers to move gas in more highly utilized portions of the pipeline, where the pipeline can obtain the maximum rate for transportation service. This would occur particularly on pipelines with postage stamp rate systems where the same maximum rate applies throughout the system, even though utilization patterns may differ across the system, as well as for pipelines with large zones where utilization may differ within a zone.[123] What is less clear, however, is whether the Commission's previous policy should continue to be applied for segmented transactions that occur within the path of the shipper's transportation contract. Once the pipeline has decided that a discount is needed to stimulate throughput in a section of the pipeline, that shipper should be permitted to use flexible point rights and segment capacity along that capacity path without incurring additional charges.[124] The Commission recognizes that not all pipelines follow straight-line paths and, therefore, in order for some pipelines to implement segmentation, restrictions on segmentation for discounted contracts may be necessary. These issues should

[121] Even if the pipeline is not fully subscribed, it could protect its ability to sell available mainline capacity by reserving an appropriate percentage of the receipt or delivery point capacity to be associated with the unsubscribed mainline capacity.

[122] El Paso Natural Gas Company, 62 FERC ¶ 61,311, at 62,990–91 (1993); ANR Pipeline Company, 62 FERC ¶ 61,079, at 61,562–63 (1993).

[123] *See* Questar Pipeline Company, 69 FERC ¶ 61,119 (1994) (applying policy to a postage stamp system).

[124] On a long-line pipeline, for instance, once the pipeline has discounted transportation to a downstream delivery point, it has foreclosed the possibility of selling that same capacity at a higher rate to an upstream delivery point. The discount, therefore, should apply to all transactions within the capacity path.

be addressed in the pipeline's compliance filings.

c. Implementation. El Paso requests clarification that the ability of shippers to segment through the nomination process applies only to shippers segmenting for their own use, not to shippers seeking to make a segmented capacity release transaction. El Paso maintains that allowing capacity release transactions through the nomination process would by-pass the bidding and posting procedures that apply to capacity release transactions. The Commission agrees that shippers subject to the posting and bidding requirements for capacity release transactions cannot avoid those requirements by designating a transaction as a segmented transaction.

El Paso and Kinder Morgan ask clarification concerning the implementation of the requirement that shippers be given the ability to segment capacity for their own use through the nomination process, without having to use the capacity release process to effectuate segmentation. El Paso asks that pipelines be able to implement shipper segmentation in different ways depending on the configuration of their existing computer system. Kinder Morgan asks that it be permitted to continue to use its capacity release mechanism to effectuate shipper segmentation for its own use until it can revise its computer systems to accommodate this process through the nomination process.

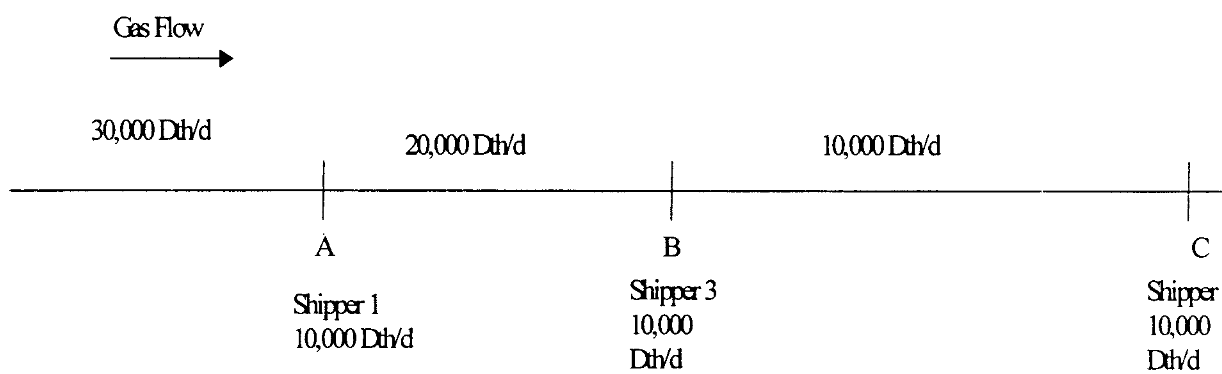
The Commission will expect pipelines to permit shippers to schedule segmented transactions for their own use in as efficient manner as possible through the nomination process and to revise their computer systems to permit such nominations as soon as is feasible. Until such computer revisions are made, pipelines should permit segmented transactions in the most efficient method feasible given their current computer configurations.

2. Mainline Priority at Secondary Points Within the Path

In Order No. 637, the Commission did not adopt a specific policy with respect to assigning priority over mainline capacity among shippers using secondary points when they pay the same rate for transportation within a zone.[125] Dynegy, National Energy Marketers, and NGSA contend the Commission should accord a higher priority to shippers seeking to use mainline capacity to reach secondary points within their capacity path than shippers seeking to use mainline capacity outside of their path. Dynegy and National Energy Marketers contend that according a shipper using a secondary point within its path a higher priority would help alleviate confusion with respect to state unbundling programs in which state officials are requiring marketers to hold primary firm capacity, rather than permitting them to use secondary capacity, because of concerns about reliability. Giving greater priority to shippers within their primary path, they assert, will alleviate the concerns about the reliability of secondary point transactions during constraint periods when pipelines limit deliveries. Dynegy maintains that, under the current system, it can often effectuate a delivery, but at a higher cost, by scheduling primary firm capacity and then purchasing an interruptible back-haul service to reach the secondary upstream point.

The Commission's goal in expanding segmentation and flexible point rights is to strengthen competition in the transportation market. As pointed out in Order No. 637, capacity allocation is most efficient when capacity is allocated to the shipper placing the highest value on obtaining the capacity. In order to provide for efficient allocation of capacity, shippers must have rights to capacity and be able to trade capacity so that the party placing the highest value can obtain it.[126]

In the situation presented by the rehearing requests, two shippers paying the same rate for capacity in a zone seek to use a secondary delivery point which is upstream of one shipper and downstream of the other. In the example below, shippers 1 and 2 pay the same rate for 10,000 Dth/d of capacity in the zone, with primary points at A and C respectively, and both shippers seek to deliver gas to point B. The pipeline is sized such that 30,000 Dth/d can be delivered to point A, 20,000 Dth/d to point B, and 10,000 Dth/d to point C.



The Commission's prior policy was to allocate mainline capacity using secondary points on a *pro rata* basis among shippers seeking to use those secondary points,[127] although some pipelines had been permitted to implement a within-the-path allocation methodology.[128] The justification for *pro rata* allocation was that two customers paying the same rate should receive the same priority of service to secondary points.

The Commission, however, is concerned that providing all shippers in a zone with equal scheduling rights to secondary points does not provide for the most efficient use of mainline capacity or promote capacity release

[125] Order No. 637, 65 FR at 10196–97, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091, at 31,304–306.

[126] *See* R. Posner, Economic Analysis of Law, § 3.1, at 28 (2d ed. 1977) (exclusive property rights are necessary to promote trading).

[127] *See* Tennessee Gas Pipeline Company, 71 FERC ¶ 61,399, at 62,577 (1995) (cases cited therein).

[128] *See* Panhandle Eastern Pipe Line Company, 78 FERC ¶ 61,202, at 61,870–71 (1997) (conditionally accepting within the path allocation); Northwest Pipeline Corporation, 67 FERC ¶ 61,095 (1994) (priority given to shippers moving within primary path).

because it creates uncertainty as to how much mainline capacity any shipper seeking to use secondary points will receive. Under *pro rata* allocation, neither shipper 1 nor shipper 2 has guaranteed rights to the mainline capacity for purposes of making deliveries to point B and, therefore, neither can trade those rights In addition, a shipper holding primary point capacity at point B (shipper 3) has a competitive advantage over either shipper 1 or shipper 2 in selling its capacity, since it can guarantee mainline capacity to point B and neither of the other two shippers can make a similar guarantee. As Dynegy and NEM point out, some state unbundling programs require shippers to obtain primary point capacity from the shipper at B in order to ensure that deliveries can be made.

The Commission, therefore, has determined to change its allocation policy to the within-the-path approach in order to improve competition. Under the within-the-path allocation approach, shipper 2 would have a higher priority than shipper 1 to use mainline capacity to reach secondary points within its capacity path. By using within-the-path priority, shipper 2 has a firm right to mainline capacity to delivery point B and, therefore, becomes a more effective competitor to the shipper holding primary point capacity at point B. Shippers needing capacity to point B now have a choice of buying mainline capacity from shipper 2 or shipper 3. Under this policy, shipper 2 would have primary mainline rights to ship to or beyond point B, but would have secondary rights to make deliveries at point B (unless shipper 2 is permitted to select B as an additional primary point as discussed previously).[129]

The Commission recognizes that because the pipeline in the example has a large rate zone that is not divided at constraint points, shipper 1 (the upstream shipper) pays the same rate as shipper 2 and receives less valuable rights under the within-the-path allocation. But it is not possible to allocate mainline capacity downstream of point A to shipper 1, because shipper 2 (with primary point rights at C) could preempt shipper 1's use of any capacity beyond point A by shipping gas to its primary point at C. Thus, the only method of creating tradable capacity rights is to give shipper 2 priority rights to all capacity upstream of its delivery point at C.[130]

The Commission therefore finds that the use of within-the-path priority better promotes efficient allocation of capacity and improves competition as compared with *pro rata* allocation and, accordingly, each pipeline must use the within-the-path allocation method in its compliance filing, unless it can demonstrate that such an approach is operationally infeasible or leads to anticompetitive outcomes on its system. The Commission encourages pipelines to look closely at their zone boundaries and to develop more efficient methods of allocating capacity based on price, so that capacity initially is allocated to the shipper placing the highest value on obtaining that capacity.

C. Imbalance Services, Operational Flow Orders and Penalties

In Order No. 637, the Commission determined that while OFOs and penalties can be important tools to correct and deter shipper behavior that threatens the reliability of the pipeline system, the current system of OFOs and penalties is not the most efficient system of maintaining pipeline reliability in the short-term market. The manner in which pipelines impose OFOs and penalties often restricts shippers' abilities to effectively use their transportation capacity. For example, OFOs can limit the ability of shippers to respond to prices in the market, undermining the fluidity of the commodity market.

The Commission also determined that Commission-authorized penalties provide an opportunity for shippers to engage in a form of penalty arbitrage, both across pipeline systems, and within a single pipeline system. Arbitrage activity imposes higher costs on all shippers on the system, and at peak, also may imperil systemwide reliability and trigger OFOs and emergency penalties. Further, many pipelines have responded to arbitrage on their systems by imposing stricter imbalance tolerances and higher penalties, which, in turn, often operate to limit and distort market forces.

Given the existence of arbitrage on and across pipeline systems, the Commission concluded that shippers are using penalties as a means to indirectly gain flexibility with respect to obtaining gas supplies and transportation capacity. Therefore, because the penalty system encourages shippers to engage in behavior that may be harmful to the system as a way to obtain needed flexibility, the Commission shifted its policy away from one that fosters the use of OFOs and penalties, to a ''service-oriented'' policy that gives shippers other options to obtain flexibility and relies on penalties only when necessary to protect system integrity. Specifically, Order No. 637 established three general policies designed to help give shippers positive incentives to use the pipeline appropriately to avoid the need for penalties and OFOs.

First, Order No. 637 required pipelines to provide separate imbalance management services, like park and loan service, to give shippers flexibility, directly.[131] The Commission explained that the imbalance management services, together with the provision of greater information about the imbalance status of shippers and the system, will give shippers a greater ability to remain in balance in the first instance, and thereby avoid penalties.

Second, Order No. 637 required pipelines to establish incentives and procedures to minimize the use of OFOs.[132] The Commission required each pipeline to revise its tariff to include a number of pipeline specific standards for the issuance of OFOs.

Third, Order No. 637 required pipelines to include in their tariffs only those penalty structures and levels that are necessary and appropriate to protect the system.[133] The Commission also required pipelines to credit the revenues from penalties and OFOs to shippers to eliminate the pipelines' financial incentive to impose penalties and OFOs.

Finally, Order No. 637 required each pipeline to either propose in its compliance filing *pro forma* changes to its tariff to implement the new requirements, or explain how its existing tariff and operating practices are already consistent with the new requirements.

The rehearing applicants seek rehearing and/or clarification of various aspects of each of the three new provisions. However, the petitioners do

[129] Shipper 2's ability to deliver gas using point B as a delivery point would depend on whether it has capacity on the downstream side of point B to take gas from the system. Providing for such take-away rights at city-gate points would be within the province of the state regulatory authority regulating the LDC at that point. With respect to priority at pipeline interconnects, the Commission, in Order No. 637, stated that such priority would be determined by pipeline confirmation rules, but that a shipper that has obtained firm capacity on both sides of the interconnect generally should have priority over a shipper that is using interruptible transportation on one of the pipelines, regardless of whether the firm shipper is using a secondary or primary point. *See* Order No. 637, 65 FR at 10197, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091, at 31,306–7.

[130] Under within-the-path allocation, if shipper 1 values the capacity to point B more than shipper 2, it can purchase the capacity from shipper 2. This would ensure that the capacity is allocated efficiently to the highest valued user.

[131] 18 CFR 284.12(c)(2)(iii).

[132] 18 CFR 284.12(c)(2)(iv).

[133] 18 CFR 284.12(c)(2)(v).

not oppose the core requirement that pipelines provide imbalance management services, but primarily seek rehearing of the new OFO and penalty provisions. Below, the Commission further details each of the new provisions and addresses the rehearing arguments related to each.

1. Imbalance Management

New section 284.12(c)(2)(iii) is an important component of the Commission's new policy focus to use positive incentives to achieve shipper behavior, rather than penalties or OFOs. In that section, the Commission established the policy that pipelines must provide to shippers, to the extent operationally practicable, imbalance management services, such as park and loan service, swing on storage service, or imbalance netting and trading. Pipelines will be permitted to retain the revenues from the new imbalance management services initiated between rate cases. As part of this requirement to provide imbalance management services, the Commission encouraged pipelines to design imbalance management services that would give shippers a built-in incentive to utilize the service, and to develop financial inducements for shippers to remain in balance or avoid behavior that is harmful to the system. In addition, the Commission stated in Order No. 637 that pipelines will not be permitted to implement the new imbalance services until they also implement imbalance netting and trading on their systems.

Rehearing requests were filed concerning the retention by pipelines of the revenue from imbalance management services between rate cases, and the applicability of the imbalance management service requirement to pipelines that do not impose imbalance penalties or OFOs. A number of requests for clarification of the requirement to offer imbalance management services were also filed. These are discussed below.

a. Retention of Imbalance Management Service Revenue Between Rate Cases. NASUCA and Penn./Ohio Advocate jointly, and Amoco argue that the Commission erred by allowing pipelines to retain the revenues from the new imbalance management services between rate cases. They argue that, since pipelines control the timing of rate cases and have no obligation to file a rate case, this policy could provide the pipeline with windfall profits at the expense of long-term shippers who pay 100 percent of the costs of the facilities used to provide those services.

NASUCA and Penn./Ohio Advocate argue that the Commission's general policy of permitting retention of revenues between rate cases should not apply here because the new services are being required as a remedy to existing unreasonable practices and procedures (*i.e.* gaming on pipeline systems), and pipelines should not be able to retain the benefits from such remedies. NASUCA and Penn./Ohio Advocate request that the Commission require pipelines to credit all of the imbalance management service revenues to firm shippers. Alternatively, they propose that the revenues be shared between the pipeline and long-term firm shippers, perhaps providing pipelines with a 10 percent share to encourage the pipelines to provide the services.

Amoco argues that if a pipeline's penalty free imbalance tolerance is set at an unreasonably low level, the retention of the imbalance management services revenues could result in significant windfalls. Amoco requests that pipelines not be permitted to retain imbalance service revenues, but be required to implement either an annual rate recalculation or a tracker mechanism to ensure that the pipeline does not overrecover its costs. Amoco also seeks clarification that pipelines will not be permitted to reduce or eliminate existing imbalance tolerance levels to levels that effectively force utilization of the new services.

As the Commission stated in Order No. 637, "[i]n order to give pipelines an incentive to develop these new imbalance management services, the Commission is not changing its current policy that pipelines may retain the revenues from a new service initiated between rate cases." [134] The Commission has decided not to change that policy in the context of the new imbalance management services being required here.

In requiring that pipelines offer imbalance management services to the extent operationally practicable, the Commission's goal, as stated in Order No. 637, is for pipelines to provide as many different imbalance management services as the pipeline can operationally, and to develop innovative imbalance management services that might not currently exist. It is important for pipelines to have an incentive to develop, create, and offer such new imbalance management services. The pipelines' retention of 100 percent of the revenues between rate cases provides an incentive for pipelines to offer imbalance management services and ensures that the use of imbalance management services will supplant the need for penalties. Allowing pipelines to retain only a *de minimus* share of the revenues will not provide an adequate incentive to develop and provide the services.

In response to Amoco's concern, pipelines will not be permitted to arbitrarily reduce or eliminate imbalance tolerance levels and increase penalty levels in an effort to force shippers to use imbalance management services, since the Commission is requiring pipelines to implement and justify reasonable tolerance and penalty levels. All such proposed changes will be reviewed by the Commission comprehensively along with all of the pipeline's imbalance management services to ensure that the impact of the services and penalties work together to achieve the Commission's policy objectives.

b. Who Must Comply. Michigan Gas Storage argues that the Commission should not require pipelines that do not impose OFOs or collect imbalance penalties to provide imbalance management services or information on shippers' and the systems' imbalance status.[135] Michigan Gas Storage asserts that because the purpose of requiring imbalance management services is to minimize the imposition of OFOs and penalties, there would be no apparent purpose served by requiring pipelines that neither impose OFOs or collect imbalance penalties to provide imbalance management services or imbalance status information.

The Commission agrees with Michigan Gas Storage that if a pipeline's tariff does not include OFO provisions and imbalance penalty provisions, it need not provide imbalance management services or information on imbalance status. The Commission's goal in requiring pipelines to provide imbalance management services and greater information regarding imbalances is to enable shippers to avoid imbalances so that they will not incur penalties or be subject to an OFO. If a pipeline has no authority to issue OFOs or to assess penalties for either imbalances or OFO violations, then a shipper has no need for imbalance management services, and there is no need to require pipelines to offer such services. Pipelines that do not impose OFOs or collect penalties apparently do not have problems with shipper imbalances.

Accordingly, the Commission will amend the first sentence of section

[134] Order No. 637, 54 FR at 10199, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091 at 31,310.

[135] In new section 281.12(c)(2)(v), concerning penalties, pipelines are required to provide shippers with information on their imbalance and overrun status.

284.12(c)(iii) to state: ''A pipeline with imbalance penalty provisions in its tariff must provide, to the extent operationally practicable, parking and lending or other services that facilitate the ability of its shippers to manage transportation imbalances.'' Similarly, the Commission will amend the last sentence of section 284.12(c)(v) to provide: ''A pipeline with penalty provisions in its tariff must provide to shippers, on a timely basis, as much information as possible about the imbalance and overrun status of each shipper and the imbalance of the pipeline's system.'' However, if a pipeline that does not have such provisions in its tariff at any time decides to include OFO or imbalance penalty provisions in its tariff, then such pipeline must comply with sections 284.12(c)(iii) and (v).

c. Requests for Clarification. (1) Imbalance Netting and Trading. In Order No. 637, the Commission stated the following with respect to imbalance netting and trading:

> However, pipelines will not be permitted to implement the new imbalance services until they also implement imbalance netting and trading on their systems. Pipelines should not expect shippers to purchase new services until the shippers can determine whether imbalance trading will be adequate for their needs. Thus, the implementation of the new imbalance management services must coincide with the implementation of imbalance netting and trading. Since GISB has already approved business practice standards for netting and trading, pipelines should be able to implement imbalance netting and trading at the same time that they implement the new imbalance management services.[136]

Northern Distributor Group (NDG) requests clarification in two respects of the Commission's directive in Order No. 637 that pipelines implement imbalance netting and trading at the same time that they implement the new imbalance management services. First, NDG asserts that it is unclear whether the Commission established the Order No. 637 compliance filing date as the date certain by which pipelines must implement imbalance netting and trading, or whether the pipeline's obligation to implement imbalance netting and trading is dependent on whether the pipeline chooses to implement imbalance management services. NDG requests the Commission to clarify that regardless of whether a pipeline chooses to offer new imbalance management services on its designated compliance date, it must nevertheless offer imbalance netting and trading on that date. Second, NDG seeks clarification that a pipeline's implementation of imbalance netting and trading must be consistent with the GISB-approved netting and trading business practices.

In Order No. 637, the Commission determined that pipelines would be required to offer their shippers imbalance services. The Commission, however, determined that it would be unreasonable to expect shippers to purchase the new services unless the shippers first had an opportunity to evaluate whether imbalance trading would be sufficient for their needs. The Commission, therefore, imposed a moratorium on approving pipeline filings to establish imbalance services unless the pipeline has, or has proposed, an imbalance trading mechanism.

With respect to the pipeline's obligations to make compliance filings under Order No. 637, all pipelines are required to make *pro forma* compliance filings to establish the imbalance services they propose to comply with the Commission's regulation. Those services, however, will not be implemented until the Commission has reviewed the proposal and established an effective date. The Commission will not do so unless the pipeline has a pre-existing imbalance trading mechanism or one that will take effect at the same time as the imbalance services.

The Northern Distributor Group requests clarification as to when pipelines will be required to implement imbalance trading. In Order No. 587–G,[137] the Commission adopted a regulation requiring pipelines to implement imbalance trading, but deferred implementation of this regulation until GISB has developed the necessary standards. Although GISB initially had projected that such standards could be developed by June 30, 1998,[138] it has taken far longer to develop the necessary standards. GISB's Executive Committee has approved business practice standards for imbalance trading and GISB has now established an Expedited Data Development Subcommittee to develop the standards relating to the use of EDI for communication.[139] The Commission fully expects those standards to be approved quickly and, at that point, all pipelines will be obliged to implement those standards expeditiously. At the time when the imbalance trading standards are implemented, pipelines will be required to implement the imbalance services.

For a pipeline that wishes to implement imbalance services and imbalance trading at an earlier date, the pipeline should comply with the business practice standards already passed by GISB's Executive Committee. But the pipelines need only provide for imbalance trading on their Internet web sites. They do not need to establish EDI communication until GISB has approved the relevant technical standards for EDI.

(2) Third-Party Imbalance Management Services. New section 284.12(c)(iii) requiring pipelines to offer imbalance management services to its shippers also requires pipelines to provide their shippers with the opportunity to obtain imbalance management services from third-party providers. In describing section 284.12(c)(iii) in Order No. 637, the Commission stated that ''under this policy, pipelines will not be permitted to give undue preference to their own storage or balancing services over such services that are provided by a third party.''[140] The Commission then stated, ''The Commission is requiring pipelines to include these imbalance management services as part of their tariffs.''[141]

Koch is confused by the latter sentence quoted above. Koch states that if the Commission is requiring pipelines to permit third parties, within the scope of the pipeline's existing tariff provisions, to provide imbalance services, then it has no objection to the proposed changes. However, Koch objects if the Commission is requiring Koch to draft tariff provisions to implement services that third parties want to have included in Koch's tariff or to allow third parties the right to seek changes to Koch's tariff, outside the statutory requirements of section 5.

The Commission's intent was to require pipelines to include their own imbalance management services as part of their tariffs, not the third party's imbalance management service. However, the Commission expects the pipelines' tariffs to be crafted so that the pipeline will not unduly discriminate against shippers using other providers, or give undue preference to its own imbalance management services. For

[136] Order No. 637, 54 FR at 10199, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091 at 31,311.

[137] Standards for Business Practices of Interstate Natural Gas Pipelines, Order No. 584–G, 63 FR 20072 (Apr. 23, 1998), III FERC Stats. & Regs. Regulations Preambles ¶ 31,062 (Apr. 16, 1998).

[138] Standards for Business Practices of Interstate Natural Gas Pipelines, Order No. 587–G, 63 FR 20072, 20081 (Apr. 23, 1998), III FERC Stats. & Regs. Regulations Preambles ¶ 31,062, at 30, 677 (Apr. 16, 1998).

[139] Http://www.gisb.org/edd.htm (announcing formation of Expedited Data Development Subcommittee).

[140] Order No. 637, 54 FR at 10199, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091 at 31,310.

[141] *Id.*

example, the pipeline's tariff should not contain unnecessary restrictions that prevent third-party imbalance providers from competing with the pipeline.

Both Koch and Kinder-Morgan request clarification with respect to how imbalance management services by third parties will be provided and whether such third-party providers will be subject to the Commission's NGA jurisdiction. They request the Commission to clarify that the third-party providers will be subject to the same statutory requirements and standards for providing services in interstate commerce that pipelines are subject to, such as open-access requirements or the requirements of Order No. 497. Otherwise, argues Kinder-Morgan, pipelines will be at a significant competitive disadvantage. Kinder-Morgan argues that to the extent third-party services are provided, a number of conditions must apply.[142] In addition, Kinder-Morgan requests the Commission to identify who will be responsible if third-party providers of imbalance services fail to provide the necessary balancing, and that it should not be the pipeline that is the ''balancer of last resort.'' [143]

To the extent that the third-party providers are performing the interstate transportation of natural gas, as defined in the NGA, in their provision of imbalance management services, they will be engaging in a jurisdictional activity. However, a third-party provider may be able to provide imbalance management services that do not involve the interstate transportation of gas. Whether a third-party provider is performing jurisdictional transportation service is dependent on the characteristics of the particular imbalance management service being provided. For example, an imbalance management service provided by a third-party may consist simply of the sale of gas to make up an underdelivery. To the extent that the gas sale is a first sale, it would not be jurisdictional, and for jurisdictional gas sales, the Commission has already granted a blanket certificate to make sales for resale at negotiated rates.[144]

The Commission will not require that the conditions which Kinder-Morgan lists be attached to the provision of third-party imbalance management services. However, in their compliance filings, pipelines may include proposed tariff provisions for coordinating with third-party providers of imbalance services if such requirements are needed for operational purposes. Further, in the event a pipeline faces sufficient competition for imbalance management services from third party providers, the pipeline may be able to justify a request for market-based rates for that service.

(3) Clarification of Specific Phrases and Terms. Under section 284.12(c)(2)(iii), a pipeline must provide imbalance management services ''to the extent operationally practicable.'' Amoco requests the Commission to clarify that phrase. Amoco argues that under such discretionary language, a pipeline could refuse to comply on the basis of an assertion that such services are not operationally practicable. Amoco asserts that either the burden of proof should be placed on the pipeline to support such a claim, or the language should be eliminated.

The Commission agrees with Amoco that the burden of proof is on the pipeline to support a claim of operational impracticability. The pipeline must provide sufficient evidence demonstrating why the provision of imbalance management services is ''operationally impracticable.''

IMGA states its belief that Order No. 637 intended the term ''imbalance'' to apply to both physical and scheduling imbalances,[145] and requests the Commission to clarify that the use of the term ''imbalance'' throughout Order No. 637 encompasses both physical and scheduling imbalances. If the Commission did not intend for the term ''imbalances'' to refer to both types of imbalances, IMGA requests the Commission to indicate which type of imbalance it meant each time the Commission used the term in the preamble of Order No. 637. The Commission confirms that the term ''imbalance'' was intended to apply to both physical and scheduling imbalances.

2. Operational Flow Orders

In Order No. 637, the Commission found that the imposition of OFOs ''may severely restrict the purchase and transportation alternatives available to a customer during peak periods, precisely when such alternatives are critically needed to enhance the opportunities of a shipper to purchase such services at the lowest competitive prices.'' [146] Thus, new section 284.12(c)(2)(iv) establishes the principle that a pipeline must take ''all reasonable actions to minimize the issuance and adverse impacts of operational flow orders (OFOs) or other measures taken to respond to adverse operational events on its system.''

To implement this principle, the Commission required pipelines to revise their tariffs to adopt objective standards and procedures for the use of OFOs. Specifically, the Commission required each pipeline's tariff to: (1) State clear, individualized standards, based on objective operational conditions, for when OFOs begin and end; (2) require the pipeline to post information about the status of operational variables that determine when an OFO will begin and end, (3) state the steps and order of operational remedies that will be followed before an OFO is issued; (4) set forth standards for different levels or degrees of severity of OFOs to correspond to different degrees of system emergencies the pipeline may confront; and (5) establish reporting requirements that provide information after OFOs are issued on the factors that caused the OFO to be issued and then lifted.

On rehearing, only Koch and Kinder-Morgan take issue with OFO requirements imposed by Order No. 637. These arguments are discussed below.

a. Legal Authority and Need for OFO Standards and Procedures. Koch and Kinder-Morgan argue that the OFO provisions (as well as the penalty provisions discussed in the next section) violate section 5 of the NGA because the Commission has not made the requisite finding under section 5 that the existing OFO procedures are unjust, unreasonable, and unduly discriminatory. They assert that the Commission has departed without justification from the existing OFO policy established in Order No. 636 that OFOs are appropriate tools to deter harmful shipper conduct, and therefore, necessary for the pipeline to ensure system integrity in an open-access environment. Specifically, Koch and Kinder-Morgan assert that there is no record evidence supporting the Commission's finding that OFOs inhibit shipper flexibility, interfere with the fluidity of the commodity market, are a source of revenue, or are issued too frequently. Koch also disputes the Commission's decision to require all pipelines to revise their OFO

[142] Kinder-Morgan states that such conditions include, for example, Commission approval of the service prior to commencement, contractual privity between the third-party provider and the pipeline, and the availability of bi-directional flow at the delivery and/or receipt points involved. Request for Rehearing of Kinder-Morgan at 22.

[143] *Id.* at 23.

[144] 18 CFR 284.402 (1999).

[145] IMGA cites the Commission's discussion in Order No. 637 defining penalties as including penalties for physical and scheduling imbalances at 54 FR at 10197, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091 at 31,317. IMGA Request for Rehearing at 10.

[146] Order No. 637, 54 FR at 10200, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091 at 31,312.

procedures and standards instead of targeting only pipelines that are in fact issuing unnecessary OFOs. In addition, Keyspan requests clarification that if a pipeline proposes no change in its compliance filing, the Commission will act to make changes only when it is able to make the required section 5 findings.

In requiring pipelines to take actions to minimize the use and adverse impacts of OFOs, and to include objective pipeline-specific standards for the use of OFOs, the goal of the Commission is to enable pipelines to continue to use OFOs to protect pipeline integrity, without unnecessarily limiting or restricting competition in the market. The intent of the Commission is not to ban or restrict the use of OFOs so that pipelines may not impose OFOs when they are necessary to ensure system reliability. Rather, the new OFO policy and tariff requirements are designed to address the manner or way in which OFOs are being designed and imposed. The Commission seeks to ensure that they are being imposed only to the extent necessary to protect system reliability, and thus, that shippers are not needlessly restricted. In other words, the Commission is seeking ways for pipelines to use the proper mix of OFOs and positive financial incentives so that shippers can have as much flexibility as possible without causing operational problems that threaten reliability.

Therefore, the Commission has not departed from its existing policy that OFOs are appropriate tools for ensuring system integrity and reliability, and consequently need not find under section 5 that OFOs, *per* se, are unjust and unreasonable. Rather, the Commission has made a generic determination that the manner in which a pipeline imposes OFOs, or a pipeline's existing procedures or guidelines for its use of OFOs, may be unjust and unreasonable if the pipeline's issuance of an OFO unnecessarily restricts shippers' flexibility or is not well-defined, or if the OFOs are issued too frequently or stay in effect too long for the purpose of maintaining system reliability.

The Commission's findings that some pipelines are issuing OFOs that may be unnecessary for system reliability purposes, and that the manner in which some pipelines impose OFOs may unnecessarily restrict shipper flexibility, are based on adequate evidence. The Commission concluded from the comments to the NOPR,[147] and the Commission staff's own independent analysis of pipeline OFO tariff provisions, as well as the record in the cases cited in Order No. 637,[148] that the design and imposition of OFOs are not always tailored to ensure OFOs are imposed to preserve the integrity of system operations. For instance, the comments, tariff provisions, and cases revealed that OFO tariff provisions are not well defined, permit OFOs to be issued too frequently and to stay in effect too long, and do not give adequate warnings to shippers. All of this evidence provided the Commission with a reasonable basis upon which to require all pipelines to make a *pro forma* tariff filing to rejustify their current OFO provisions as just and reasonable.

Thus, the Commission has not yet made a section 5 determination that any particular pipeline's tariff regarding OFOs is, in fact, unjust and unreasonable. Any such section 5 determination will be made in the individual pipeline compliance filings. Such filings give individual pipelines, like Koch, the opportunity to show why their existing tariffs should not be considered unjust and unreasonable and that their tariffs are already in compliance with Order No. 637. In response to Keyspan, if the Commission finds that changes in a particular pipeline's tariff are warranted, the Commission will act under section 5 to implement such changes. Accordingly, the new OFO regulation does not violate section 5 of the NGA, and the Commission has acted within its authority.

b. The Reasonableness of the OFO Standards and Procedures. Kinder-Morgan and Koch argue that the Commission has not imposed a just and reasonable remedy to the allegedly unlawful existing OFO procedures. They argue that the new OFO procedures take away the pipelines' ability to manage their systems and jeopardize the provision of reliable service to customers. Kinder Morgan asserts that in situations where OFOs are issued, the concern should be whether deliveries to all customers can be maintained, not whether one shipper is unable to reduce its gas prices by a few pennies.

As the Commission stated above, the new OFO policy and requirement to establish OFO standards does not ban the use of OFOs and thereby remove pipelines' ability to control their systems. The Commission agrees that the reliability of service to all customers should be of greater concern than the reduction in one shipper's flexibility, where system reliability is a genuine or legitimate concern.

Kinder Morgan specifically argues the requirement, that pipelines set forth clear pipeline-specific standards based on objective operational conditions for when OFOs will begin and end, unduly constrains pipelines because it assumes both static conditions and perfect foresight. Kinder-Morgan asserts that operating conditions change over time, and the pipeline cannot predict all possible operating conditions that would justify issuance of an OFO. Kinder-Morgan also maintains the OFO tool should not be restricted because OFOs are particularly important to pipelines that have no storage or only limited storage, since they have no ability to absorb imbalances and counteract adverse operating conditions. Similarly, Koch requests clarification that the OFO policy to be implemented will be tailored specifically to meet Koch's operational needs, rather than those of some other pipeline.

Kinder-Morgan misinterprets what the Commission is requiring. The Commission expects pipelines to formulate the pipeline-specific OFO standards based on their reasonable expectation of potential operating conditions. The Commission is not prohibiting a pipeline from issuing an OFO until a particular predesignated operating condition actually occurs. The pipelines may build flexibility into the standards and procedures so that OFOs may be issued based on expectations or in anticipation of particular operating conditions. This flexibility is only limited by the need to draft standards that will give shippers clear notice of the instances when an OFO could be issued. The particular OFO standards applicable to each pipeline can be developed in the individual compliance filing proceedings, where the reasonableness of the standards can be determined in the context of the pipeline's complete imbalance management, penalty and OFO scheme. Further, the Commission clarifies that it is not requiring a set of rigid OFO standards invariant to the particular needs of individual pipelines. The Commission will permit considerable variation in the tariff provisions to enable pipelines to tailor OFO standards to fit the operational parameters of their

[147] *E.g.*, Comments of Shell Energy Services Company, L.L.C. at 17, Florida Cities at 7–8, and American Forest & Paper Association at 43.

[148] *See, e.g.*, NorAm Gas Transmission Company, 79 FERC ¶ 61,126, at 61,546–47 (1997); Southern Natural Gas Company, 80 FERC ¶ 61,233, at 61,890 (1997) Northern Natural Gas Company, 77 FERC ¶ 61,282 (1997); Panhandle Eastern Pipe Line Company, 78 FERC ¶ 61,202 (1997); Northwest Pipeline Company, 71 FERC ¶ 61,315 (1995). The Commission determined the validity of the claims made in these cases by conducting its own analysis of the pipelines' tariffs.

particular systems, such as the lack of storage facilities.

3. Penalties

New section 284.12(c)(2)(v) establishes three key principles. First, it provides that ''[a] pipeline may include in its tariff transportation penalties only to the extent necessary to prevent the impairment of reliable service.'' The Commission recognized in Order No. 637 that unnecessarily high penalties have been imposed in the past, and that the penalties on some pipelines are at the same level during peak and non-peak periods, when the potential for the impairment of reliability may differ. The Commission stated that ''[n]on-critical day penalties, or penalties imposed during off-peak periods, may not be the most appropriate and effective to protect system operations.'' [149] Therefore, the Commission explained that it is requiring pipelines to narrowly design penalties to deter only conduct that is actually harmful to the system. The Commission directed all pipelines in their compliance filings to either explain or justify their current penalty levels and structures under this standard, or revise them to be consistent with this principle.

The second principle established by this regulation is that pipelines must credit to firm shippers all revenues from all penalties, net of costs, including imbalance, overrun, cash-out, and OFO penalties. The Commission determined that the elimination of the pipelines' economic incentive to use and impose penalties was necessary to shift pipelines to the use of non-penalty mechanism to solve and prevent operational problems. The Commission did not prescribe on a generic basis the details of the revenue crediting mechanism, including which shippers will receive the penalty revenue credits, but instead will permit each pipeline to formulate an appropriate method for implementing penalty revenue crediting on its system. However, the Commission did indicate that, ideally, penalty revenues should be credited only to non-offending shippers.

The third principle established by the new regulation is pipelines must provide to shippers, on a timely basis, as much information as possible about the imbalance and overrun status of each shipper and the imbalance of its system as a whole.

On rehearing, the petitioners argue that the new penalty policy violates section 5 of the NGA and is unsupported by concerns regarding penalty arbitrage, restrictions on shipper flexibility, and penalties being a source of revenue. The rehearing applicants also argue that the Commission erred by limiting the use of penalties ''only to the extent necessary to prevent the impairment of reliable service,'' and by requiring the crediting of penalty revenues. In addition, several applicants request clarification of the revenue crediting requirement and what constitutes a penalty. Finally, one petitioner requests the Commission to implement a ''no-harm, no-foul'' policy.

a. Legal Authority and Need for New Penalty Policy. As they argue with respect to OFOs, Kinder-Morgan and Koch argue that the new penalty provision violates section 5 of the NGA because the Commission has not found existing penalties unjust and unreasonable. They assert that the Commission has departed without justification from the existing policy that recognizes that penalties are an appropriate tool to deter shipper misconduct. Kinder-Morgan and Koch argue that the Commission's findings that penalties encourage arbitrage and are a source of revenue are unsupported, and do not justify the Commission's remedy of limiting or eliminating the use of penalties.

The Commission acknowledges that penalties are an appropriate tool to protect system reliability. In Order No. 637, the Commission did not find the use of penalties, *per se,* to be an inappropriate method of protecting system integrity. The Commission did find, however, that (a) penalties, as currently designed and applied, are not always being used to ensure system reliability, and (b) penalties may not be the most appropriate way to preserve system reliability. The Commission found that there could be other ways for pipelines to ensure reliability, that did not involve the use of a negative deterrent.

Specifically, the Commission determined that the use of imbalance management services would be a better way to keep shippers from engaging in behavior that could adversely affect system reliability, especially since penalties provide the opportunity for arbitrage behavior. Thus, the Commission shifted its policy away from penalties and towards imbalance management services. Yet, the Commission nevertheless recognized that penalties could still be a valid mechanism to ensure system integrity, if penalty levels and structures were better designed to meet that purpose. Therefore, the Commission did not ''eliminate penalties altogether,'' as Kinder-Morgan seems to believe, but rather, redefined their role. Thus, the new penalty policy does not violate section 5 of the NGA because the Commission has not abandoned its existing penalty policy recognizing penalties as an important tool to protect system reliability; the Commission has shifted its policy focus to place less reliance on penalties.

The Commission's determinations that changes to the design and application of pipelines' penalty levels and structures are necessary, and the penalty system may not be the best way to ensure system reliability, are adequately supported. The fact that arbitrage is occurring and that penalties provide the opportunity for shippers to engage in arbitrage is well documented by a number of cases in which pipelines sought higher overrun and imbalance penalties and lower tolerances specifically in response to arbitrage activity on their systems.[150] The Commission agrees with Kinder-Morgan that the existence of arbitrage does not justify the elimination of penalties; the Commission is not eliminating penalties. However, the fact that arbitrage is occurring not only across pipeline systems but within pipeline systems demands that pipelines revise the level and structure of their penalty provisions to minimize the opportunity for arbitrage. For example, as the Commission stated in Order No. 637, pipelines may be able to change their imbalance cash-out procedures or methods to eliminate the incentives for shippers to borrow gas from the pipeline because the cash-out price is less than the market price for gas.[151]

The Commission also determined after review of the comments to the NOPR that high penalties and low or no tolerances can operate to restrict shipper flexibility and distort market forces and are not effective in deterring harmful conduct and protecting system reliability.[152] Further, the penalty tariff

[149] Order No. 637, 54 FR at 10201, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091 at 31,314

[150] *E.g.,* Northern Natural Gas Company, 77 FERC ¶61,282 at 62,236 (1997); Panhandle Eastern Pipe Line Company, 78 FERC ¶61,202 at 61,876–77 (1997), *reh'g denied,* 82 FERC ¶61,163 (1998); and Williams Natural Gas Company, 78 FERC ¶61,342 (1997).

[151] Order No. 637, 54 FR at 10201, III FERC Stats. & Regs. Regulations Preambles ¶31,091 at 31,314–15.

[152] *E.g.,* Comments of Dynegy, Chapter 6 and Appendix B; Comments of Proliance Energy, LLC at 4–5. In Appendix B of Dynegy's comments, Dynegy provided a review of the significant penalty cases in the recent past, and its assessment of current penalty and OFO tariff provisions. In one of the cases cited by Dynegy, Williams Natural Gas Company, 78 FERC ¶61,342 at 62,462 (1997), the parties argued that the high contract overrun penalties being sought would prompt responsible shippers to oversubscribe to transportation capacity solely to provide a safety margin, rather than deter harmful conduct.

provisions proposed by the pipelines in the penalty cases cited above, led the Commission to conclude that penalty provisions needed to be better crafted and defined, and better tailored to address potential harm to system reliability.

Thus, as the Commission similarly explained with respect to the new OFO policy, *supra*, the Commission has not yet made a section 5 determination that any particular pipeline's penalty provisions is, in fact, unjust and unreasonable. Any section 5 determination will be made in the individual pipeline compliance filings, and such determinations will be made on specific findings that the existing penalty provisions are unjust and unreasonable, and the replacement provisions are just and reasonable.

b. Limitation of Penalties Only to the Extent Necessary to Prevent the Impairment Of Reliable Service. Kinder-Morgan and CNGT object to the Commission's limitation on the use of penalties ''only to the extent necessary to prevent the impairment of reliable service.'' [153] CNGT argues that the limitation allowing penalties only to the extent necessary to prevent the impairment of reliable service is overly restrictive because system reliability is only one purpose of penalties. CNGT argues that penalties also serve to enforce contractual rights, obligations, and limitations, and to discourage penalty arbitrage.

Further, Kinder-Morgan and Keyspan raise questions about whether the requirement that penalties must be necessary to prevent the impairment of reliable service prohibits pipelines from issuing penalties during non-critical periods. Kinder-Morgan takes issue with what it believes is the Commission's assumption underlying this provision— that penalties simply are ''not required.'' [154] Kinder-Morgan argues that pipelines may need penalties to maintain system integrity during non-critical periods, as well as during critical periods. Conversely, the Industrials request the Commission to require pipelines to use a ''no harm/no foul'' mechanism, unless the pipeline is operationally constrained from doing so.

The Commission denies the requests to change the requirement that penalties be justified solely on the basis of system reliability. The pipelines themselves recognize that ''the fundamental purpose of penalties and OFOs is to protect the reliability of service to all shippers * * * '' [155] It was precisely this purpose that the Commission recognized in Order No. 636, when it permitted pipelines to develop and utilize OFOs and penalties as system management tools. Thus, the requirement that pipelines impose penalties ''only to the extent necessary to prevent the impairment of reliable service'' simply reflects a formalized requirement that pipelines use penalties exclusively for their intended purpose. The Commission is not permitting pipelines to impose penalties for other purposes, such as the enforcement of contractual obligations, where unrelated to system reliability. The Commission has determined that shippers should be given the flexibility to exceed contractual limitations, unless such action jeopardizes system reliability and integrity. For example, if a shipper overruns its contractual entitlement, and its action does not affect the reliability of the pipeline's service, there is no reason for the pipeline to charge a penalty. Of course, however, the pipeline may charge the shipper for the additional transportation service.

The question whether penalties may be imposed during non-critical periods needs to be determined in the pipelines' compliance filing proceedings and cannot be decided in the abstract. Contrary to Kinder-Morgan's statement, the Commission did not find that penalties are ''not required.'' [156] The Commission reiterates that penalties may be required, especially during critical periods when system reliability is most in jeopardy. With respect to penalties during non-critical periods, the Commission stated, ''[u]nder the regulations adopted in this rule, pipelines will only be able to impose penalties to the extent necessary. This requirement may result in *either* no penalties for non-critical days or higher tolerances and lower penalties for non-critical as opposed to critical days.'' [157] The Commission will examine such issues in the individual compliance filing proceedings, where the Commission can evaluate how the proposed imbalance management services, OFO provisions, and penalty structures all work together, as an overall program of system management.

c. Crediting of Penalty Revenues. Only Koch and CNGT seek rehearing of the Commission's decision to require pipelines to credit penalty and OFO revenues, net of costs, to shippers. Koch argues that crediting the penalty and OFO revenues weakens the deterrent function of penalties, which are designed and have been implemented to deter abusive shipper behavior. Koch maintains that there is nothing inherently wrong with shippers being punished for their inappropriate actions. Koch asserts that requiring the penalty revenue to go back to the shippers, offending or not, is unwarranted because they have not assumed any of the risks that warrants receipt of such compensation. Koch states that penalties are designed to compensate pipelines for the risks they face from a shipper that is outside the parameter of the pipeline's tariff. Koch also claims that the Commission's concern about penalties being profit centers for pipelines is not applicable on all pipelines. Koch states that it has received virtually no penalty revenue since its Order No. 636 tariff became effective.

CNGT seeks rehearing of the requirement to credit penalty revenues if the Commission continues to strictly limit penalties to reliability needs.

The goal of the Commission's new policy on penalties is to encourage pipelines to rely less on penalties and more on non-penalty mechanisms to manage their systems, such as imbalance management services, and to design and impose only necessary and appropriate penalties. Allowing pipelines to retain the revenues from penalties provides pipelines with a financial incentive to impose penalties where they may not be required to ensure system reliability, or to set penalties at inappropriate levels. It also can discourage pipelines from developing the other, non-penalty mechanisms that might give shippers positive incentives to control their imbalances. Therefore, the Commission must require the crediting of penalty and OFO revenue to eliminate the financial incentive that retention of penalty revenue provides the pipeline. Only by removing this incentive will pipelines begin to rely on other management techniques and use penalties less. Thus, the Commission

[154] Request for Rehearing of Kinder-Morgan at 11, quoting Order No. 637, 54 FR at 10201, III FERC Stats. & Regs. Regulations Preambles ¶31,091 at 31,314.

[155] Request for Rehearing of Kinder-Morgan at 8.

[156] Kinder-Morgan relies on the following statement by the Commission, but misinterprets it:

[155] Request for Rehearing of Kinder-Morgan at 8.

[156] Kinder-Morgan relies on the following statement by the Commission, but misinterprets it: ''First, penalties are not required, but to the extent that a pipeline assesses penalties, they must be limited to only those transportation situations that are necessary and appropriate to protect against system reliability problems.'' Order No. 637, 54 FR at 10201, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091 at 31,314. This first clause of the statement was intended to clarify that the Commission was not requiring pipelines to include penalties in their tariffs or to impose penalties on their shippers, and was not an affirmative finding on the merits that penalties are not required.

[157] Order No. 637, 54 FR at 10202, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091 at 31,317 (emphasis added).

reemphasizes that the crediting of penalty and OFO revenues to firm shippers is necessary to eliminate the pipelines' incentive to utilize penalties.

The Commission recognizes that penalties serve a deterrent function. The deterrent function is a legitimate function where the penalty is narrowly designed to protect the integrity of the system. The crediting of penalty revenues arguably will weaken the deterrent function, as Koch maintains, only to the extent significant revenue is credited back to the offending shippers. While the Commission is not requiring that the revenue be credited exclusively to non-offending shippers, the Commission's objective is that where possible, pipelines should credit the revenue only to non-offending shippers.[158] Further, while Koch is correct that there is nothing inherently wrong with using a punishment such as a penalty as a deterrent, the Commission has determined that a more effective and less restrictive way for pipelines to maintain control of their systems is for pipelines to rely on services and incentives that enable and encourage shippers to behave appropriately without the threat of punishment.

Several pipelines request clarification of the revenue crediting requirement. Coastal requests the Commission to clarify that a pipeline's responsibility to credit penalty revenues is net of any costs incurred (i.e. demand credits to customers whose service was curtailed) or revenues foregone by pipeline as a result of the actions which resulted in penalty being assessed. Similarly, Tejas requests the Commission to clarify that OBA charges may be netted against any penalty revenue. In addition, Paiute requests clarification that under the cost netting exclusion, it will be permitted to retain scheduling penalty revenues that it assesses to its shippers during Northwest Pipeline Corporation's Declared Entitlement Periods because the Northwest penalties assessed Paiute during Declared Entitlement Periods represent a cost to Paiute. Finally, Enron requests clarification that the revenue crediting mechanisms take into account penalty revenues included in developing underlying rates. Enron maintains that until a pipeline's next general rate case, crediting should only be required with respect to net penalty proceeds that exceed any amounts included in developing existing rates (whether through an allocation or though the inclusion of representative penalty levels). Otherwise, states Enron, the double counting of penalty revenues would result.

These issues may depend on the facts of individual cases. Pipelines that seek to net out costs incurred as a result of a shipper's actions that caused the penalty to be assessed must demonstrate that the shipper's conduct in fact caused such costs. Similarly, pipelines seeking to offset penalty revenues included in developing underlying rates should include in their compliance filings a detailed description of how penalty revenues were included in designing their rates. The Commission will consider these matters, along with other factors, to determine the appropriate revenue crediting in each case.

Coastal requests the Commission to allow pipelines to establish a surcharge mechanism in their tariffs to impose surcharges on customers who receive penalty credits to allow the pipelines to recover those credits if additional costs are found attributable to the penalty event after the refund is made. The Commission will not allow pipelines to establish a surcharge mechanism to recoup revenue credits from firm customers to recover additional costs discovered after-the-fact. The Commission expects pipelines to build into their revenue crediting mechanisms a reasonable amount of time in which to accurately determine the true level of costs and revenues before actually crediting the revenues.

Koch asks for clarification in a number of respects on how to implement revenue crediting on its system. The Commission is not requiring any particular revenue crediting mechanism; pipelines may propose whatever implementation mechanism is best for their systems. The Commission will address any questions regarding the implementation of revenue crediting in the individual pipeline compliance proceedings.

d. Other Requests for Clarifications. A number of rehearing applicants request clarification with respect to what constitutes a ''penalty.''[159] For example, the Industrials seek clarification that Order No. 637 applies to all operational limits that have punitive or disciplinary effects and to any tariff provision that may trigger an additional charge or punitive action to shippers. Tejas seeks clarification whether a tiered cash-out program constitutes a penalty, and Koch questions whether unauthorized gas overrun charges are penalties. Keyspan requests clarification whether pipelines are required to explain all penalties, or just imbalance penalties.

The Commission considers a penalty to be any charge imposed by the pipeline on a shipper that is designed to deter shippers from engaging in certain conduct and reflects more than simply the costs incurred as a result of the conduct. Thus, the term ''penalty'' was intended to encompass more than just imbalance penalties, and includes, for example, scheduling, OFO, and unauthorized overrun penalties, as well.

While a tiered cash-out program is a penalty mechanism, a cash-out mechanism that only requires the shipper to reimburse for the cost of gas provided by the pipeline is not a penalty. However, some shippers allege that certain pipelines' cash-out mechanisms operate as penalties.[160] Therefore, the Commission expects pipelines to include in their *pro forma* compliance filings their cash-out provisions, in addition to their provisions for imbalance management services, netting and trading, OFOs and penalties. The Commission cannot evaluate the components of a pipeline's system management program, such as the cash-out mechanism, in isolation. The Commission must consider the imbalance services, and netting and trading, OFO, and penalty provisions together to evaluate how they function together in light of the pipeline's characteristics. This evaluation will occur in the individual compliance filing proceedings.

III. Reporting Requirements for Interstate Pipelines

A. Transactional Information

To equalize the reporting requirements for capacity release transactions and pipeline transactions, and to simplify the overall reporting system, Order No. 637 required pipelines to report the same transactional information about both their own firm and interruptible transactions, and their released capacity transactions, and established a single, new reporting requirement for this transactional information. Section 284.13(b)(1) requires the pipeline to post transactional information on its Internet web site contemporaneously with the execution or revision of a contract for firm service. For interruptible transportation, section 284.13(b) requires pipelines to post the information on a daily basis. Further, pipelines are required to keep this firm and interruptible transactional information available on their web sites

[158] The Commission stated in Order No. 637 that ''[i]deally, penalty revenues should be credited only to non-offending shippers.'' Order No. 637, 54 FR at 10201, III FERC Stats. & Regs. Regulations Preambles ¶ 31,091 at 31,315.

[159] Requests for Rehearing of Industrials, Keyspan, Koch, and Tejas.

[160] Request for Rehearing of Industrials at 72.

for 90 days, and to archive this information for a period of three years after the 90-day period expires.[161]

Rehearing requests have been filed concerning the new transactional reporting requirements on two main grounds '' confidentiality and burden. With respect to confidentiality, as described more fully below, the rehearing applicants, largely marketers, essentially argue that the information in the new transactional reports is commercially sensitive information, which if disclosed publicly and, particularly, contemporaneously with the transaction, will cause competitive harm to shippers. With respect to burden, the pipeline applicants maintain that the magnitude of the information required to be reported is burdensome to the pipelines. In addition, rehearing applicants seek revision or clarification of certain of the specific transactional data elements.

The reporting of detailed transactional information is necessary to provide shippers with price transparency for informed decisionmaking, and the Commission and shippers with the ability to monitor transactions for undue discrimination and preference. The need for more informed decisionmaking capabilities and the ability to monitor for undue discrimination arises because the Commission is making changes in the way it regulates the natural gas industry, fostering competition where it can and moving toward lighter-handed regulation where it can. Specifically, the Commission is removing the rate cap from short-term capacity releases, and thus will be relying on competitive forces, as well as some regulatory controls, to protect against the exercise of market power. As a result, it becomes increasingly important to provide good transactional information to facilitate competition for pipeline capacity and between pipeline capacity and released capacity, and to monitor the market for potential undue discrimination or preference.

The disclosure of greater information regarding capacity transactions is necessary to achieve these dual goals of fostering competition and market monitoring. To foster competition, it is not sufficient merely to ensure there are multiple competitors, there also needs to be good information to enable buyers to make informed choices among the competitors. As the Commission explained in Order No. 637 [162] in discussing the removal of the short-term capacity release rate ceiling:

> Difficulty in obtaining information can reduce competition because buyers may not be aware of potential alternatives and cannot compare prices between those alternatives. The reporting requirements will expand shippers' knowledge of alternative capacity offerings by providing more information about the capacity available from the pipeline as well as those shippers holding capacity that is potentially available for release. The reporting requirements further will provide shippers with more accurate information about the value of capacity over particular pipeline corridors so that shippers can make more informed choices about the prices of capacity they may wish to purchase.

In addition, requiring detailed information about pipeline transactions to be reported, where very little had previously been required, will increase and improve competition by equalizing the information available to the market for capacity release transactions and pipeline transactions. Since pipeline capacity and released capacity now compete head-to-head, shippers must have the same information about both. Further, the reporting of increased information on pipeline transactions is important to enable pipeline service pricing to discipline capacity release pricing, acting as a check on any market power in the secondary market.

Reporting of data associated with capacity transactions is also critical to monitoring the market for undue discrimination or preference. The more detailed transactional information that is made available to market participants and the Commission, the better able both shippers and the Commission will be to identify situations in which market power is being abused, and the information will enable the Commission to tailor specific remedies. Moreover, the reporting of detailed transactional information is necessary not only for the monitoring of the current market for abuses of market power, but also for the Commission to assess the need for further regulatory reforms in the future.

As discussed further below, because of the importance of detailed transactional information for market monitoring and informed decisionmaking, the Commission generally is denying the rehearing requests that object to the new transactional reporting requirements on the basis of confidentiality and burden. However, the Commission is granting rehearing of the requirement that the firm transactional data must be posted contemporaneously with contract execution. The Commission is adjusting the timing of disclosure to require firm and interruptible transactional data to be posted no later than the first nomination for service.

1. Confidentiality

a. Need for Transactional Information. Columbia Gulf argues that the Commission has not justified the need for requiring the disclosure of confidential information. Columbia Gulf asserts that the Commission's finding that disclosure of detailed transactional information is necessary to provide shippers with improved decisionmaking and monitoring abilities is unsupported.[163] Columbia Gulf also questions why the Commission is requiring the detailed transactional information in light of the fact that natural gas commodity costs are already publicly available and widely scrutinized, and the industry itself, through GISB, has already determined the information that needs to be posted.

As the Commission explained above, the reporting of detailed transactional information is necessary because the Commission is modifying its method of regulating the natural gas industry by replacing traditional regulatory controls, such as the price cap on short-term capacity releases, with competition. Thus, greater transactional information is necessary to ensure that competition flourishes, and that market power and undue discrimination remain in check in the new competitive environment. To the extent that Columbia Gulf maintains that improved decisionmaking and market monitoring can occur without requiring greater information, the Commission finds it axiomatic that greater, more complete and detailed information about transactions will greatly improve shippers' ability to make informed decisions, and both the shippers' and the Commission's ability to monitor the market.

Further, while natural gas commodity costs are publicly available, as Columbia Gulf notes, information about transportation transactions, particularly transportation prices, is necessary to effectively evaluate the information about gas prices. Finally, the Commission will not defer to GISB with respect to the information that the industry needs. GISB is not a regulatory body and the market is not self-regulating.

[161] 18 CFR 284.12(c)(3)(v).

[162] Order No. 637, 65 FR at 10184, III FERC Stats. & Regs. Regulations Preambles ¶ 30,091 at 31,283.

[163] For example, Columbia Gulf disputes the Commission's statement that ''[s]hippers need to know the price paid for capacity over a particular path to enable them to decide, for instance, how much to offer for the specific capacity they seek.'' Order No. 637, 65 FR at 10206, III FERC Stats. & Regs. Regulations Preambles ¶ 30,091, at 31,324. Request for Rehearing of Columbia Gulf at 5. Williston Basin also disputes this point. Request for Rehearing of Williston Basin at 7.

b. Competitive Harm. Several marketers and two pipelines seek rehearing of the Commission's decision to require pipelines to publicly post data about their capacity transactions, such as shipper names, individual contract numbers, and receipt and delivery points.[164] They argue that such data are confidential information, and if publicly disclosed, will create unfair competition and competitive harm.

For example, Columbia Gulf argues that marketing strategies for both pipelines and shippers would be revealed, and bundled sales activity would increase, resulting in decreased price transparency and competition. Dynegy and NEMA argue that by tracking chain of title from individual contract number and receipt and delivery points, shippers will be able to learn immediately of other shippers' supply sources and markets. They argue that the knowledge of other shippers' supply sources and markets and the rates shippers pay for transportation will enable shippers to undercut one another's transactions. Thus, Dynegy and NEMA argue that the disclosure of the transactional information will seriously threaten the continued development of competitive gas markets and pose great risks to gas marketers whose business relies on fashioning creative packages of services at competitive prices.[165]

Williston Basin argues that the posting of the transactional information will enable shippers to know their competitors' supply and markets, and what other shippers are paying, which might prevent Williston Basin from being able to negotiate the best price for the services it offers. In addition, some rehearing applicants, most notably Columbia Gulf and Williston Basin, assert that the Commission in Order No. 637 has failed to balance the benefits of disclosure of confidential information against the harm that would be caused by divulging the commercially sensitive information.

Most of the rehearing applicants objecting to the new transactional reporting requirements on the basis of confidentiality request that the Commission either exclude the commercially sensitive data from that required to be reported, allow pipelines to file the transactional information only with the Commission under protected status, or delay the posting of the information so it is not required to be posted contemporaneously with the execution of the contract.

The Commission remains unpersuaded that the information in the transactional reports is commercially sensitive data that are entitled to confidential treatment. Section 4 of the Natural Gas Act and the NGA's general statutory scheme clearly contemplates full disclosure of contractual terms and prices, as a means of preventing undue discrimination. Section 4(b) of the NGA provides that no natural-gas company may, with respect to any jurisdictional transportation or sale of natural gas, ''make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage,'' or ''maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, * * *''[166] The immediately following section, section 4(c),[167] sets forth the means for ensuring that such undue discrimination or preference does not occur:

> Under such rules and regulations as the Commission may prescribe, every natural-gas company shall file with the Commission, within such time * * * and in such form as the Commission may designate, and *shall keep open in convenient form and place for public inspection*, schedules showing all rates and charges for any transportation or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.

Although the NGA gives the Commission some discretion with respect to how to provide for the disclosure of rate schedules and contracts, clearly the public disclosure of rate schedules and related contracts, in some manner, is required.

Under new section 284.13(b) of the regulations, the Commission is requiring pipelines to post the following data: the name and identification number of the shipper receiving service under the contract, the contract number, the rate charged under each contract, the maximum rate, the duration of the contract, the receipt and delivery points and zones or segments covered by the contract, the contract quantity or volumetric quantity, special terms and conditions applicable to a capacity release and special details pertaining to a transportation contract, and whether there is an affiliate relationship between the pipeline and the shipper or between the releasing and replacement shipper. As is evident, the transactional information the Commission is requiring to be reported, and that those requesting rehearing want to remain confidential, is for the most part information that either is an inherent part of, or included in, the very transportation contracts the NGA requires to be disclosed. The affiliate relationship is the only piece of information required that may not necessarily be reflected in the contract. However, those requesting rehearing do not argue that that particular data element is commercially sensitive data.

Therefore, as the Commission held in Order No. 637, the posting of the transactional information is entirely consistent with the NGA's statutory framework intending for contracts to be publicly disclosed. Significantly, no party on rehearing has taken issue with the Commission's view of these statutory requirements.

Further, the full disclosure of all of the key contractual information—shipper name, contract number, contract quantity, rate charged, and receipt and delivery points—is consistent with the Commission's policy direction toward transparency in the market. The Commission has determined that the disclosure of information, rather than its concealment, will best help the market to function more efficiently and competitively, to the ultimate benefit of natural gas consumers.

The rehearing applicants allege that competitive harm will result, generally to individual firms, from the public disclosure of the transactional information. However, the Commission is unconvinced that the disclosure will result in competitive harm substantial enough to outweigh the pro-competitive and market monitoring purposes for which both the NGA and the Commission require the information to be disclosed.[168] The pipelines, those from whom the information would be obtained, do not explain precisely how competition will be harmed. Columbia Gulf tersely states that the marketing strategies of pipelines and shippers would be revealed. Williston Basin essentially argues that it will become

[164] Requests for Rehearing of Columbia Gulf, Dynegy, NEMA, Williston Basin, and Cibola.

[165] Request for Rehearing of Dynegy at 20 and Request for Rehearing of NEMA at 9.

[166] 15 U.S.C. 717(c) (1994).

[167] *Id.* (emphasis added).

[168] Part of the standard, as relevant here, for determining whether information is privileged or confidential employed under the Freedom of Information Act (5 U.S.C. 552), as amended by the Electronic Freedom of Information Act Amendments of 1996, 5 U.S.C.A. 552 (West Supp. 1997), and followed by the Commission when evaluating requests for confidential treatment, is whether the disclosure of the information is likely ''to cause substantial harm to the competitive position of the person from whom the information was obtained.'' *National Parks and Conservation Ass'n* v. *Morton*, 498 F.2d 765, 770 (D.C. Cir. 1974). *See* section 388.112 of the Commission's regulations, governing requests for privileged treatment. 18 CFR 388.112.

more difficult for it to negotiate the best price for its services. The marketers, Dynegy and NEMA, focus on potential competitive disadvantage from the perspective of a service provider, but do not consider the benefits that they may realize as pipeline customers from the availability of transactional information. Thus, while disclosure of the transactional information may cause some commercial disadvantage to individual entities, it will benefit the market as a whole, by improving efficiency and competition. Buyers of services need good information in order to make good choices among competing capacity offerings. Without the provision of such information, competition suffers.

Further, pipelines have been required to post for capacity release transactions virtually all of the information that they must now post regarding their own capacity transactions. However, no competitive harm has been alleged from the disclosure of the capacity release transactional data. Nor do any of the rehearing applicants argue that pipeline transactions require greater confidentiality than capacity release transactions.

The Commission recognizes that previously, during the time when pipelines were still natural gas merchants, the Commission allowed pipelines' negotiated gas sales rates to remain confidential from unregulated competitors.[169] The Commission recognized that in situations where pipelines were competing with other entities that were not required to disclose the same data, the pipelines could be commercially disadvantaged. Thus, to minimize such potential harm, the Commission made an accommodation with respect to the disclosure of the data. However, here, the Commission is requiring the disclosure of the same information for all segments of the industry. Therefore, there is no need in this instance for the Commission to make the same compromise with respect to public disclosure. Nevertheless, some of the competitive disadvantages that the rehearing applicants foresee will be tempered by the Commission's elimination, below, of the requirement that the transactional information must be posted contemporaneously with contract execution.

In sum, the Commission remains unclear precisely how either the pipelines, marketers, or the market as a whole will be substantially harmed by the disclosure of the transactional information. On the other hand, the Commission is convinced that to foster a competitive market, shippers need good information about their capacity alternatives. Accordingly, the Commission will neither eliminate any of the required information from the transactional report, nor confer confidential status on the information to be provided, on the basis of the allegations about potential competitive harm made here.

c. *Timing of the Posting of Transactional Information.* Section 284.13(b)(1) provides that pipelines must post the firm transactional information ''contemporaneously with the execution or revision of a contract for service.'' Several rehearing requests contend the Commission erred in requiring that the transactional information for firm transactions must be posted contemporaneously with contract execution.[170]

INGAA and Enron maintain that the requirement to post transactional information contemporaneously with contract execution puts pipeline services at a disadvantage compared to prearranged deals for released capacity. They point out that prearranged deals must be posted one hour prior to the first nomination deadline on the day before gas flows, well after the prearranged deals are executed.[171] Therefore, they request the transactional information required in section 284.13(b)(1) to be posted on the same timeline as prearranged deals.

Cibola, Dynegy, and NEMA contend that immediate posting, contemporaneous with contract execution, is not necessary for the purpose of monitoring for undue discrimination, and that the Commission has failed to adequately consider the adverse competitive consequences of contemporaneous reporting of firm capacity transactions. Dynegy and NEMA argue the Commission should require that the posting not occur until at least one week after service under the contract begins. Koch requests that the Commission require the transactional information to be posted within 24 hours of gas flow, consistent with Koch's current posting of discounts on its Internet website.

Conversely, Amoco argues that the Commission should reject any requests to delay the posting of the transactional information. Amoco argues that data must be filed contemporaneously with contract execution to have the desired mitigative and informational effects.

The statutory scheme of the NGA contemplates that pipelines cannot revise their rates schedules and charges until they provide the Commission with 30 days advance notice of the proposed change.[172] Most of the Commission's filing requirements reflect this statutory scheme, and require notice prior to the institution of service, rather than with respect to the execution of the contract. The Commission recognizes that contract execution may occur at a variety of different times in relation to when service takes effect. In some cases, the execution of a contract could occur significantly in advance of the commencement of service under the contract and in other cases it could occur after service commences.

To establish a consistent standard for transactional reporting, the Commission will not use the contract execution date to trigger the reporting of information. The Commission will grant rehearing and change sections 284.13(b)(1) and (2) to require the transactional information for both firm and interruptible service to be posted no later than the first nomination for service under the agreement. This modification also will minimize the potential for harm that some rehearing applicants, such as Dynegy and NEMA, have argued could result from disclosure well in advance of service.

The reporting of interruptible service needs to be somewhat different than that for firm service, because of differences in the form of contracting. Unlike firm service where the shippers' contract reflects the rate paid, shippers obtaining interruptible service frequently execute *pro forma* master contracts for interruptible service either at the maximum rate or without a specified rate. Shippers may not nominate under these master contracts for a period of time and often portions of those contracts, such as rate and other conditions, are modified by subsequent agreements between the pipeline and the shipper on a daily or monthly basis. For instance, a pipeline and shipper may agree to provide interruptible service for a particular month at discounted rate and that agreement may not be continued the next month. Therefore, with respect to interruptible service, the Commission is requiring a daily posting no later than the first nomination under an agreement for interruptible service. Any time a rate or other condition of the interruptible

[169] Natural Gas Pipeline Co. of America, 55 FERC ¶ 61,416 at 62,245–46 (1991); and El Paso Natural Gas Co., 57 FERC ¶ 61,273 at 61,881–82 (1991) (permitting negotiated gas sales rates to remain confidential from unregulated competitors in the context of gas inventory charge settlements).

[170] Requests for Rehearing of Cibola, Dynegy, NEMA, Koch, INGAA and Enron.

[171] GISB Capacity Release Standard 5.3.2 (GISB Version 1.3, July 31, 1998).

[172] 15 U.S.C. 717(c)

agreement changes the pipeline must post the change.

With these changes, the Commission will have achieved comparability between the reporting requirements for pipeline transactions and the reporting requirements for capacity release transactions, as INGAA and Enron request. The Commission is requiring the transactional reports for pipeline firm and interruptible transactions and capacity release transactions to be posted according to the same time frame previously used for capacity release service—no later than the first nomination for service.

Postponing the time for posting of firm contracts may result in somewhat later disclosure of some contractual commitments. But the effects of such a delay on shippers' ability to obtain information about available capacity will be mitigated by other reporting requirements. Under section 284.13 (d), the pipeline is required to post all available firm capacity on its system. Once the pipeline enters into a contract committing firm capacity, the pipeline must amend its posting to reflect the fact that this capacity is no longer available, even if it does not immediately disclose who the purchaser is. On balance, the Commission finds that requiring posting no later than the first nomination under the change is more consistent with its general reporting requirements, creates parity between pipeline and capacity release transactions, and will still provide the Commission and the public with sufficient information about firm pipeline contracts and capacity release transactions.

Finally, the Commission will not impose a later posting deadline for the transactional information, as some rehearing requesters have urged. First, posting no later than the deadline for service nominations is more consistent with the Commission's general regulatory scheme, as discussed above. And second, the transactional information is necessary for timely, informed decisionmaking; therefore, delaying the posting of the transactional report until after service commenced would limit the value of the transactional information for its intended purpose of current decisionmaking.

d. Consistency With Prior Policy. Columbia Gulf asserts that the new transactional reporting requirements reflect an unexplained change in Commission precedent and policy because the Commission previously concluded in Order No. 581 [173] that the same information now included in the transactional reports did not need to be included in the discount report and the Index of Customers. Columbia Gulf states that in Order No. 581 the Commission specifically found that it did not need to require pipelines to report the same level of transportation information that is posted for capacity release transactions in order to compare pipeline transactions with capacity release transactions because the benefit from such comparison would be outweighed by the risk of harm to pipelines and LDCs from the release of the commercially sensitive data. Columbia Gulf also states that in Order No. 581, the Commission determined that it could satisfy its obligations under the NGA without requiring the reporting of the additional information.

As Columbia Gulf points out, at the time of Order No. 581, in 1995, the Commission found that virtually the same transactional information (*e.g.* receipt and delivery points) did not need to be reported in the Index of Customers and discount report, because the risk of harm from the release of the information outweighed the benefit that would be obtained from the proposed use of the information. In Order No. 637, the Commission has changed its policy focus and reporting objectives from those that existed at the time of Order No. 581, and as a result, now strikes the balance differently.

One of the primary goals of the Order No. 581 rulemaking was to simplify and streamline the Commission's reporting requirements and to reduce the reporting burden on pipelines. The reporting requirements had not been updated in the ten years after the issuance of Order No. 436 in 1985, and contained numerous outdated and unnecessary provisions. Also, Order No. 581 was issued at a time when pipelines filed rate cases more frequently than they do today. The Commission's focus at the time was directed toward accumulating a large amount of information through rate case filings. Thus, the Commission determined in Order No. 581 that the inclusion of the additional information in the discount report and Index of Customers was unnecessary to further the Commission's existing regulatory policies.

However, the regulatory context of the Commission is now different than it was at the time of Order No. 581, and thus, requires different information to be reported. The Commission's waiver of the rate cap for capacity release transactions now necessitates that additional transactional information must be reported for the new purposes of facilitating informed decisionmaking and effective market monitoring. The additional information is especially necessary because pipelines now file rate cases only sporadically, if at all.

Tellingly, part of the language of Order No. 581–A relied upon and cited by Columbia Gulf, makes clear that the Commission's consideration at that time of whether to supplement the existing reporting requirements with additional information was based on industry conditions at the time: "The Commission found [in Order No. 581] that many items, such as the receipt and delivery points, extended beyond that which the Commission needs to receive from pipelines on a regular basis to regulate the natural gas industry *today.*" [174] In short, in the year 2000, the Commission has reconsidered its reporting needs and determined that better information is now needed both to promote a competitive market and to promote effective monitoring of that market.

e. Burden. Columbia Gulf argues that the transactional reporting requirements impose an undue burden on interstate pipelines. Columbia Gulf disagrees with the Commission's statement in the Final Rule that the amount of new information is "not an extensive amount of information compared to what is already provided." [175] It maintains that six new categories of information is a significant burden given that the preexisting Index of Customers required only five categories of information, and the discount report, only four categories. Columbia Gulf further asserts that the inclusion of receipt and delivery points or zones or segments in which capacity is held under contract creates an undue administrative burden on pipelines because many contracts contain multiple receipt and delivery points, which combine to create many transportation paths.

Williams and Williston Basin, also, argue that the posting of transactional information will be burdensome. Williams alleges that contrary to the Commission's finding, for some information such as the affiliate relationship between releasing and

[173] Revisions to Uniform System of Accounts, Forms, Statements, and Reporting Requirements for Natural Gas Companies, 60 Fed. Reg. 53019 (October 11, 1995), III FERC Stats. & Regs. ¶ 31,026 (1995).

[174] Revisions to Uniform System of Accounts, Forms, Statements, and Reporting Requirements for Natural Gas Companies, 61 Fed. Reg. 8860 (March 6, 1996), III FERC Stats. & Regs. ¶ 31,032 at 31,551 (1996) (emphasis added).

[175] Order No. 637, 65 FR at 10207, III FERC Stats. & Regs. Regulations Preambles ¶ 30,091, at 31,326.

replacement shippers and special details pertaining to a pipeline transportation contract, it is not just a simple matter of developing a method of displaying the data, because either the data are not routinely maintained, or are maintained manually. Williston Basin maintains that the Commission is wrong that it will not be difficult for pipelines to adapt their already existing capacity release data sets to apply to pipeline transactions. Williston Basin asserts that its capacity release data sets are not readily adaptable, but will involve extensive programming that will be an expensive and onerous task.

The new transactional reporting requirements will impose some additional burden on pipelines. While Columbia Gulf is correct that the Commission is creating new categories of information, the new information is already collected, in one form or another, by the pipeline. All of it is information that the pipeline already has in its possession, and thus, the transactional reporting requirements do not impose an additional burden on the pipelines to collect information.

Although the Commission acknowledges that the task of creating new formats for displaying the information on the pipelines' Internet web sites will be involved for some pipelines, nevertheless, it is a one-time reprogramming burden that, once completed, will enable the required data to be posted automatically. As such, the level of posting burden should not vary with the quantity of data to be posted under each data element. The Commission finds that the benefits achieved from the ongoing disclosure of the transactional information far outweigh the one-time burden of establishing the electronic reporting formats.

In addition, the interruptible transaction reporting burden should not be excessively burdensome because the Commission did not require actual transactional data to be posted daily, such as the quantity actually shipped and the receipt and delivery points actually used. The rate for interruptible service is a volumetric rate, under which a shipper may or may not ship at all. Thus, as explained more fully in the next section below, the Commission in Order No. 637 required that pipelines post only the quantity the shipper is entitled to ship, and not the amount actually flowing each time service is nominated under the interruptible service agreement. Therefore, a transaction for interruptible service on a monthly basis could be initially posted, and assuming it was not changed, could remain posted for the month without needing to be reposted on a daily basis.

f. Miscellaneous Requests for Rehearing and Clarification.

Transactional Reports for Interruptible Services: The report for interruptible transactions established by Order No. 637 requires pipelines to post on a daily basis, among other things, ''the quantity of gas the shipper is entitled to transport,'' and ''the receipt and delivery points and zones or segments covered by the contract over which the shipper is entitled to transport gas.'' [176] Great Lakes requests the Commission to require the new interruptible reporting requirements to provide for the reporting of actual service data, rather than the contractual quantities and points agreed to by the pipeline.

Great Lakes argues that the contractual data Order No. 637 requires will not provide the current pricing information that the Commission has determined shippers need. Great Lakes states that on the discount report, pipelines were only required to report discounts that were actually assessed a shipper for interruptible transportation service, and were not required to report discounts that were agreed to by the pipeline, but never utilized by the shipper. Great Lakes also argues that because interruptible contracts often list all points on the system as primary points available for interruptible service nominations by the shipper, it is not clear what maximum or charged rate to reflect on the pipeline's report. It further states that only those points where interruptible service is available on the system on a given day are actually available to that interruptible shipper.

The Commission's requirements for posting information about interruptible transactions are designed to provide information similar to that provided for firm service. For firm service, the Commission is requiring the posting of the rate the shipper pays, the volumes the shipper is eligible to ship under the contract, and the points included in the contract. The Commission is not requiring that pipelines provide actual quantities shipped or points used on a daily basis for firm transactions.

Interruptible service, by nature, is different than firm service, and the process of arranging interruptible service transactions differs from firm contracting. Interruptible shippers do not sign contracts with specific contract demand limitations, as firm shippers do. Interruptible customers frequently sign *pro forma* or master contracts with the pipelines that do not specify a rate or that permit the interruptible rate to vary and that lists all receipt and delivery points on the system. The pipeline and the shipper may then reach agreement on a monthly or daily basis as to the rate to be paid for the month and the quantity and receipt or delivery points to which that rate applies.[177] For instance, the pipeline and shipper may reach agreement that for a discount rate of $0.50/Dth the shipper can nominate up to 10,000 Dth/day between certain receipt and delivery points.

In order to create parity between the reports for firm and interruptible service, the Commission, therefore, is requiring that, for interruptible service, pipelines post on a daily basis prior to the first nomination under such an agreement, the rate the interruptible shipper is being charged, the quantities the shipper is eligible to ship, or the pipeline is willing to ship, at that rate and the receipt or delivery points between which the rate is applicable. It is the terms of the subsidiary agreement between the pipeline and the shipper, not the master contract that must be posted. Under this approach, the pipeline could post the interruptible agreement on the first of the month and simply leave that posting as long as the rate or other aspects of the agreement have not changed. But once those agreements have changed, the pipeline would have to repost the transaction.

Because the Commission is not requiring the posting of daily throughput for firm service, it has determined not to require daily posting of throughput for interruptible service. The information required under this regulation will be sufficient to enable the Commission and shippers to monitor interruptible transactions. Pipelines will be required to post interruptible transactions whenever a rate or volume commitment changes, and other shippers can use such information to determine whether there has been undue discrimination in the awarding of interruptible service.

The Commission further is revising the interruptible reporting requirements to eliminate confusion over precisely what points or rates are to be reflected on the posting. The regulation now reads ''the receipt and delivery points and zones or segments covered by the contract over which the shipper is entitled to transport gas.'' This language implies that the receipt or delivery points should be those in the master contract, rather than the points in the

[176] 18 CFR 284.13(b)(2)(iv) and (v).

[177] Many pipelines, for example, allocate interruptible capacity based on rate paid and allow interruptible shippers to increase their rate in order to obtain a greater allocation of interruptible service.

subsequent agreement to provide interruptible service. Section 284.13(b)(2)(iv) will be revised to require the posting of the receipt and delivery points over which the shipper is entitled to transport gas at the rate charged to make clear that the pipeline should post the receipt and delivery points in each individual agreement to provide interruptible service, not simply the receipt and delivery points in the master contract. It may be that some interruptible agreements permit shipment using all receipt or delivery points on the pipeline system and that is the information that should be posted. In other cases, however, interruptible transportation at a particular rate may be limited to certain receipt and delivery points in which case the posting should only include the limited points in the agreement.

Scope of the Transactional Reporting Obligation: Cibola requests clarification that the transactional reporting requirements do not apply to existing pipeline capacity transactions that have remaining terms of one year or more.[178] Cibola argues that requiring public disclosure of the price and terms of transactions negotiated at various times in the past will not serve the Commission's price transparency goals. Cibola further argues that requiring the details of existing long-term transactions to be posted will fundamentally alter the business and competitive risks that the parties understood they would face when they initially entered into the transactions.

The Commission agrees with Cibola that requiring the posting of pre-existing pipeline and capacity release transactions in the transactional reports is unnecessary, and was not the Commission's intent in Order No. 637. The transactional reporting requirement, both for pipeline and capacity release transactions, is prospective only as of the September 1, 2000 implementation date. The Commission clarifies that for all new firm contracts that are executed after September 1, 2000, and existing contracts that are revised after that date, and for interruptible transactions taking place after that date, pipelines are required to post a transactional report no later than the first nomination for service under the new or revised contract. This is consistent with the Commission's regulation requiring that transactional reports only be posted for 90 days at which point the information is archived for a three year period and made available upon request.[179]

Historical information on pipeline transactions and capacity release transactions is available through other reporting requirements. The Index of Customers provides information about existing pipeline contracts. As discussed above, historical capacity release transactions have already been posted, and the posted information is required to be made available by the pipeline.

Enron requests that the Commission clarify that the requirement that the pipeline post transactional information for revised contracts does not extend to shipper-initiated primary receipt and delivery point revisions within an effective contract.[180] Enron asserts that requiring a new posting for each point change is redundant with other reports and will clutter the web sites.

In the Commission's view, posting of primary receipt and delivery point changes is necessary so that other shippers can monitor those changes for undue preference or discrimination. Thus, the Commission will not change the requirement that amended contracts be posted.

Enron also argues that pipelines should not be required to post contracts during a pending certificate proceeding, but only for capacity that is in service.[181] Enron argues that the Commission already has established practices for requiring the disclosure of contracts in the certificate process, and that there is no benefit from requiring expansion contracts to be included in the firm transactional reports.

The Commission will not exempt expansion contracts from the transactional reporting requirement. However, since the Commission has revised the requirement that the transactional information be posted contemporaneously with contract execution to requiring posting no later than the first nomination for service, the reporting of expansion contracts should not be problematic.

Modifications to Transactional Reporting Data Elements: Kinder-Morgan requests the Commission to delete the requirement that pipelines report the contract number of each transportation transaction. Kinder-Morgan states that the contact number enables the shipper to gain access to the pipeline's system for the purpose of making nominations, raising the prospect that one party could submit nominations using the contract number of another shipper, and thereby obtain transportation using someone else's capacity. The solution here is not for the Commission to eliminate the contract number, which is necessary for analytic purposes, but for the pipelines to establish computer security measures, such as the use of PINs or some other security features to protect their internal computer systems.

Amoco requests the Commission to make three revisions to the regulatory text of section 284.13(b)(1) and (2). First, Amoco requests section 284.13(b)(1)(iii), referencing the rate charged under each contract, to be revised to state ''the rate charged under the contract and whether the rate is a negotiated rate.'' [182] Amoco maintains that the purpose of its proposed change is to put all parties on notice in future rate cases as to whether the pipeline can seek a discount adjustment regarding the transaction. Section 284.13(b)(1)(viii) requires the posting of, ''special terms and conditions applicable to a capacity release and special details pertaining to a pipeline transportation contract.'' To clarify that negotiated rates must be disclosed, the Commission is revising the regulation to include a requirement that the pipeline disclose whether the contract is a negotiated rate. Negotiated rates also will be identified in the Index of Customers.

The second change Amoco requests is that the phrase ''special terms and conditions'' in section 284.13(b)(1)(iii) be revised to read ''special terms and conditions, including all aspects in which the contract deviates from the pipeline's tariff,'' so that it will not be up to the reporting entity to decide what constitutes a special term or condition.[183] The Commission agrees that including such a change will identify any transactions that deviate from the pipeline's tariff and will revise sections 284.13(b)(1)(vii) and 284.13(b)(2)(6) to require the disclosure of all aspects in which agreements deviate from the pipeline's tariff.

Amoco's third request is to modify the language, ''special details pertaining to a pipeline transportation contract'' in section 284.13(b)(1)(viii) and the similar language in section 284.13(b)(2) governing interruptible transactional reporting, by adding the following explanatory language from the preamble of Order No. 637 to the regulatory text to eliminate any confusion: ''Under this requirement, a pipeline must report any special conditions attached to a discounted transportation contract, such as requirements for volume

[178] Request for Rehearing of Cibola at 5–7.

[179] 18 CFR 284.13(b) (90 day posting); 18 CFR 284.12(c)(3)(v) (three year archiving requirement); 18 CFR 284.12(b)(v) (Capacity Release Standard 5.3.20 provides that historical data be made available within the Commission's archival periods).

[180] Request for Rehearing of Enron at 8–9.

[181] *Id.* at 9.

[182] Request for Rehearing of Amoco at 62.

[183] *Id.*

commitments to obtain the discount.'' [184] Also, Koch requests the phrase to be limited to terms and conditions from negotiated rates contracts that are already filed with the Commission, but have not been made available by other means.

The Commission agrees with Amoco that additional clarification is worthwhile and will add the following language to the requirements to post special details pertaining to the contract, ''including conditions attached to a discounted transportation contract,'' to provide additional clarification. However, there may be other special details pertaining to the contract that would need to be posted as well. Thus, the Commission denies Koch's request to limit the special details reported to terms and conditions from negotiated rate contracts. The Commission seeks more than just conditions attached to negotiated rates contracts. For instance, a key purpose of this data element is to obtain discount conditions, and thereby correct a deficiency in the existing discount report.

Requests for Additional Data and Filing Requirements: IPAA requests the Commission to require pipelines to submit and post in addition to the data required under the new reporting requirements, information regarding the capacity actually used in each capacity release transaction. IPAA argues that for prearranged capacity release transactions to be completely transparent, shippers need enough information to determine whether even after a nomination and confirmation is made any gas actually moved. IPAA also requests that the Commission impose a transactional reporting requirement on capacity holders comparable to the pipeline's transactional reporting obligation, that would also include nominations, confirmations, and actual capacity used. IPAA asserts that the Commission must have adequate information to ensure that any available capacity is both offered and used.

The Commission does not find it necessary to report the quantity of gas moved on a daily basis under firm pipeline contracts or capacity release contracts. The Commission did not previously require detailed information about quantities nominated for capacity release transactions and it is not evident why such information is necessary to effectively monitor such transactions for undue discrimination. The information that is most important for monitoring is the rate and contract conditions upon which the shipper acquired the capacity, not whether the shipper decided to use it on a particular day. Shippers may frequently acquire capacity, but, depending on weather and other conditions, determine that they do not need to use some or all of that capacity everyday. Their decision not to use capacity they have acquired does not necessarily indicate anticompetitive activity. Given the limited value of such information, the added burden of requiring the posting is not warranted.

In addition, the Commission sees no basis for imposing a reporting obligation on capacity holders similar to the pipelines' transactional reporting requirement. Such information would largely duplicate the capacity release information that the pipelines are required to submit under the new transactional reporting requirements.

Amoco requests the Commission to require pipelines to make a simultaneous electronic filing with the Commission when they post the data on their Internet web sites. Amoco argues that this is consistent with the filing requirements of section 4(d) of the NGA, and will encourage the filing of accurate data. The Commission finds it unnecessary to require a simultaneous electronic filing with the Commission. As discussed earlier, the NGA gives the Commission discretion in determining the timing and manner for filing and notice, and the Commission has determined that the requirements of section 4 for public dissemination of rates and terms and conditions are better met by the posting of the rates and other transactional data on pipeline Internet web sites than by the filing and maintenance of the information by the Commission. Simultaneous electronic filing with the Commission is not necessary for the Commission to obtain the information it requires to monitor the market, since the Commission can download the files from the Internet postings and the pipeline's are required to maintain records of such information that the Commission may obtain if necessary.[185]

Amoco also requests certain changes to the annual Form 2 reporting. The Commission did not provide notice to the industry that Form 2 could potentially be revised. As a result, modifications to the Form 2 go beyond the scope of this rulemaking proceeding.

As stated in Order No. 637, the Commission is committed to reviewing all of its reporting requirements on an on-going basis and as part of its dialog with the industry. While the Commission cannot now see the need to expand the reporting requirements, as those requesting rehearing suggest, the Commission will be able to evaluate whether such additional information is needed as the Commission staff and the industry work with and review the information received under the current requirements.

B. Information on Market Structure

In Order No. 637 the Commission explained that information on market structure enables the Commission to know who holds or controls capacity on each portion of the pipeline system, so potential sources of capacity can be identified, and shippers and the Commission can monitor for undue discrimination or preference. To give shippers a more useful picture of market structure, Order No. 637 expanded two of the Commission's pre-existing reporting requirements that provided information on market structure—the Index of Customers and the affiliate regulations.

1. Index of Customers

Prior to Order No. 637, section 284.106(c)(3) of the regulations required pipelines to file an Index of Customers with the Commission, on the first business day of each calendar quarter, and to post the Index on their Internet web sites. The Index provides the names of shippers holding firm capacity, the amount of capacity held, the applicable rate schedule, and the contract effective and expiration dates. Order No. 637 added the following new information requirements to the existing Index of Customers: the receipt and delivery points held under the contract and the zones or segments in which the capacity is held; the common transaction point codes; the contract number; a shipper identification number, such as DUNS; an indication whether the contract includes negotiated rates; the names of any agents or asset managers that control capacity in a pipeline rate zone; and any affiliate relationship between the pipeline and the holder of capacity.

Amoco requests the Commission also to require the rate charged and the maximum contract rate to be included in the Index of Customers. Amoco argues that such information is relevant not only for the purposes of the daily transactional report, but also for the purpose of the Index of Customers.

The Commission disagrees, and will not add the maximum contract rate and actual rate charged to the Index of Customers. The purpose of the Index of Customers is to reveal the structure, or make-up, of the market for transportation capacity on a periodic

[184] *Id.*

[185] 18 CFR 284.12(c)(3)(v) (3 year archiving requirement); 18 CFR 250.16(d) (3 year requirement for maintaining discount information).

basis, to enable the Commission to assess the degree of competition on a pipeline or pipeline segments, and to detect potentially anticompetitive market dominance. Essentially, the Index of Customers shows who holds capacity on given pipeline, how much capacity is held by each shipper, where the capacity is held, the total amount of capacity held by a parent entity, and whether and the degree to which a pipeline's capacity is controlled by another entity, such as an asset manager. Price information is not directly relevant to the reason for requiring the index: to determine who and how much capacity shippers hold on the pipeline. Moreover, the rate charged and maximum contract rate are already obtained through the transactional reports.

2. Affiliate Regulations

In Order No. 637, the Commission expanded its affiliate regulations to permit monitoring and self-policing of affiliate transactions. The Commission revised section 161.3(l) of the standards of conduct for interstate pipelines specifically to require pipelines with marketing affiliates or sales operating units to post certain information concerning their affiliates on their Internet web sites, and to update the information within three business days of any change. Under new section 161.3(l)(2), pipelines must post, and update within three business days of any change, a complete list of the names of operating personnel and facilities shared by the interstate pipeline and its marketing affiliate,[186] and comprehensive organizational charts showing several different types of information.

First, the organizational charts must show the organizational structure of the parent corporation and the relative position within the corporate structure of the pipeline and all marketing affiliates.[187]

Second, the organizational charts must show business units, job titles, job descriptions, and chain of command for all positions within the pipeline, including officers and directors, with the exception of clerical, maintenance, and field positions. The job titles and descriptions must include the employee's title, duties, and an indication whether the employee is involved in transportation or gas sales. In addition, the pipeline must also include the names of supervisory employees who manage non-clerical employees involved in transportation or gas sales.[188]

Third, the organizational charts must indicate, for all employees shared by the pipeline and a marketing affiliate, the business unit or sub-unit within the marketing affiliate organizational structure in which the shared employee is located, the employee's name, the employee's job title, and job description within the marketing affiliate, and the employee's position within the chain of command of the marketing affiliate.[189]

Tejas seeks rehearing of the requirement for pipelines to post and update organizational charts showing the organizational structure of the parent corporation and the relative position within the corporate structure of the pipeline and all marketing affiliates, under section 161.3(l)(2)(ii)(A), and the business units, job titles, job descriptions, and chain of command for all positions within the pipeline, under section 161.3(l)(2)(ii)(B).[190] Tejas argues the Commission has not demonstrated that such information is needed to deter undue discrimination and preference and to help the market monitor affiliate transactions. Tejas maintains that these reporting requirements will simply clutter pipeline web sites with voluminous, irrelevant information, and will create a substantial posting and updating burden, especially for small pipelines such as Tejas.

Posting detailed organizational charts will provide shippers and the Commission with current information regarding whether pipeline personnel are separated from marketing affiliate personnel to the maximum extent practicable. Posting such information allows shippers and the Commission to monitor whether employees with access to transportation and/or non-affiliated shipper information are shared with the pipeline's marketing affiliate(s).

The Commission finds the posting of such information to be important. The requirements adopted here are similar to those adopted with respect to electric marketers and are necessary to permit monitoring of affiliate relationships. The Commission's pre-existing requirement in section 250.16(b)(1), that a pipeline maintain in its tariff a complete list of shared operating personnel and facilities, and update that list on a quarterly basis, has not been completely effective in achieving pipelines' complete disclosure of shared operating employees. Pipelines have not always disclosed the sharing of operating employees with their marketing affiliates.[191] For example, in *Kinder Morgan,* the pipeline admitted that it had not disclosed that it shared operating employees with its marketing affiliates.[192] Posting of organizational information, including job descriptions and the chain of command, will deter undue discrimination because such information permits shippers to know which employees are involved in pipeline transportation functions and have access to their commercially sensitive information. Such transparency will serve to counter the economic incentive to share information between pipelines and their marketing affiliates.[193] Moreover, the posting requirements are not onerous. The posting requirements do not apply to clerical, maintenance, and field employees because these employees would not receive information concerning the processing or administration of requests for transportation service.

Tejas argues that posting organizational charts will ''clutter'' its web site with voluminous and irrelevant information. However, electric utilities have been subject to similar posting requirements since 1997, and their web sites, for the most part, appear to be well organized and uncluttered. This appears to be an issue of web site design rather than substantive policy.

Williams requests the Commission to eliminate the organizational charts for the pipeline under section 161.3(l)(2)(ii)(B), while INGAA requests the Commission to modify that section to require pipelines to post just the title and function of non-shared employees, rather than detailed job descriptions and the employees' names. Williams and INGAA argue that the fact that the Commission has adopted a similar requirement for electric utilities is inadequate justification for imposing this reporting burden on pipelines because there are distinct and fundamental differences between the two types of utilities. They assert that pipelines do not provide a commodity

[186] 18 CFR 161(l)(2)(i).

[187] 18 CFR 161.3(l)(2)(ii)(A).

[188] 18 CFR 161.3(l)(2)(ii)(B).

[189] 18 CFR 161.3(l)(2)(ii)(C).

[190] Request for Rehearing of Tejas at 6–8. Tejas does not seek rehearing of the new posting requirements applicable to employees shared by a pipeline and a marketing affiliate in section 161.3(l)(2)(ii)(C).

[191] Kinder Morgan Interstate Gas Transmission LLC, et al., 90 FERC ¶ 61,310 (March 29, 2000) (*Kinder Morgan*) and *Amoco* v. *Natural Gas Pipeline Company of America,* 82 FERC ¶ 61,038 (1998); *reh'g denied,* 82 FERC ¶ 61,300 (1998); and *reh'g granted, in part,* 83 FERC ¶ 61,197 (1999).

[192] 90 FERC ¶ 61,310 at 62,009. Although *Kinder Morgan* concerned a settlement, the pipeline stipulated to certain facts concerning the pipeline's relations with its marketing affiliates. *See* Settlement Agreement at 6–7.

[193] *Tenneco Gas Company* v. *FERC,* 969 F.2d 1187 at 1205 (1992).

sales service similar to electric retail service, and that pipeline operations are not intertwined between a wholesale transmission service and a retail commodity service. INGAA argues that the differences between completely unbundled natural gas pipelines and vertically integrated electric utilities suggest that details about non-shared employees are unnecessary in the natural gas pipeline industry, and that, therefore, pipelines ought to be subject to less stringent reporting of non-shared employees and facilities. Williams further argues that unlike the information in paragraphs A and C of section 161.3(l)(2)(ii), the information in paragraph B does not relate to both the pipeline and its marketing affiliate, but is related solely to the pipeline.

Although it is true there is more vertical integration among electric utilities than among natural gas pipelines, it is also true that most pipelines continue to have marketing affiliates that are involved in transportation transactions on the pipelines' system. For this reason, it is important to require information to be reported on all non-clerical employees, whether shared or non-shared, so the Commission can better monitor for affiliate preferences by making its own independent determination which employees are shared and which are not shared. The posting requirements will also allow shippers to identify by name (with respect to supervisors) and job description those who have access to transportation information, enabling them to determine whether pipelines have accurately revealed shared transportation employees.

Accordingly, the posting requirements help shippers and the Commission to monitor and detect anticompetitive abuses.[194] The potential for such anticompetitive abuse continues whenever a pipeline conducts transportation transactions with its marketing affiliate(s). With the elimination of the capacity release price cap, it is especially important for the Commission to be vigilant to dealings between pipelines and their affiliates.

In addition, a number of pipelines argue that the Commission should eliminate the requirement that pipelines update the information required to be posted by section 161.3(l) within three business days of any change.[195] They assert that because growing corporations in today's business world are in constant states of evolution, three days is an inadequate amount of time in which to update the postings of the extensive and ever-changing information that is now required. They argue that the three-day updating requirement could result in daily updating, and thus, become unduly burdensome, and would be a waste of resources. CNGT and Enron add that the comparable requirements for the electric industry do not include this three-day updating requirement. Additionally, Enron urges that the updating of the information within three days of changes is an unreasonable time frame because information on corporate organizational changes is often kept confidential until employees are briefed, and once the changes are public, memoranda documenting and implementing the changes take additional time.

All of the pipelines raising this issue request that the Commission instead require the affiliate information to be updated on the first business day of each quarter. Further, CNGT and INGAA argue that if the three-day updating requirement is retained, it should be limited to the information concerning shared operating employees under section 161.3(l)(2)(ii)(C), while the information on non-shared employees required in section 161.3(l)(2)(ii)(B) should be updated quarterly.

The Commission has decided not to alter the requirement to post changes to the posted affiliate information within three business days of the change. In order to provide accurate information regarding a pipeline's management and organization for purposes of monitoring pipelines' compliance with the standards of conduct, it is essential for such information to be current. For this reason, a quarterly updating of affiliate information is inadequate.

In the Commission's view, the three-day updating requirement is not burdensome or unreasonable. In fact, the requirement to post changes three business days after they occur is less strict than the requirement for electric utilities to post changes ''as changes occur.'' [196] Enron's argument that the three-day posting requirement is burdensome was first considered and rejected in *Reporting Interstate Natural Gas Pipeline Marketing Affiliates on the Internet*[197] with regard to posting the names and addresses of marketing affiliates in existing section 161.3(l) (now section 161.3(l)(1)). In that order, the Commission agreed with Enron that the pace of markets today is brisk. However, the Commission noted that because of the dynamic nature of markets, unduly discriminatory actions must be corrected quickly if the correction is to be meaningful.[198]

Moreover, a pipeline must consider the application of the standards of conduct to a proposed organizational change before it makes such changes. Posting information regarding the transfer three days after such organizational changes have occurred is a ministerial act. However, in response to Enron, the Commission will modify the language of section 161.3(l)(1) and (2) to require that pipelines update the information ''within three business days of any change taking effect.'' This will clarify that the Commission does not intend for pipelines to post changes prior to the effective date of the change.

C. Information on Available Capacity

In Order No. 637, the Commission expanded the requirement in existing section 284.8(b)(3) of the Commission's regulations for pipelines to report information on available capacity. Under that regulation, pipelines were required to post on their Internet web sites information about the amount of operationally available capacity at receipt and delivery points, on the mainline, in storage fields, and whether the capacity is available directly from the pipeline or through capacity release.[199] In new section 284.13(d)(1), the Commission continued to require pipelines to provide this information (via posting on the pipelines' Internet web sites), and added the following information on capacity availability to the information that was already collected: the total design capacity of each point or segment on the system; the amount of capacity scheduled at each point or segment on a daily basis; and information on planned and actual service outages that would reduce the amount of capacity available. The Commission required the information on available and scheduled capacity to be posted daily, and the information on design capacity to be posted one time (and thereafter maintained on the web site), and then updated as necessary.

[194] The Standards of Conduct and posting requirements only apply if the pipeline conducts transportation transactions with its marketing affiliate(s), including those in which a marketing affiliate is involved.

[195] *See* Requests for Rehearing of CNGT, Enron, INGAA, Williams, Williston Basin, and Koch.

[196] Allegheny Power Services Corp. *et al.,* 84 FERC ¶ 61,131 at 61,714 (1998).

[197] Reporting Interstate Natural Gas Pipeline Marketing Affiliates on the Internet, III FERC Stats. & Regs. Regulations Preambles ¶ 31,064 (July 30, 1998), 63 FR 43075 (Aug. 12, 1998).

[198] III FERC Stats. & Regs. Regulations Preambles ¶ 31,064 at 30,715.

[199] 18 CFR 284.8(b)(3); 18 CFR 284.10(b)(1)(iv), Electronic Delivery Mechanism Related Standards 4.3.6; 18 CFR 284.10(b)(1)(v), Capacity Release Related Standards 5.4.13.

Service outages must posted when required.

Enron requests the Commission to eliminate the requirement that pipelines post design capacity for each point or segment.[200] Enron argues that the development and maintenance of meaningful design numbers would require the investment of a large amount of resources, and that shippers would not gain any additional useful information that they do not already receive from the posting of operationally available capacity. Enron explains that because pipelines do not operate under static conditions, the capacity of a point depends not only on the meter capacity of the point, but also on the location of other points on a lateral, the pressures at which the lateral is being operated, and the location and direction of actual gas flows. Enron states that for these reasons, GISB recently considered and declined to add design capacity to the available capacity posting.

The Commission will not eliminate the requirement that pipelines post design capacity for each point or segment. Design capacity information for points and segments will provide shippers with a picture of capacity distribution on the pipeline when operated under design conditions, and will enable shippers to better understand the relationship between design, scheduled, and operationally available capacity. The Commission recognizes that design capacity may not be available at all times due to variable operating conditions. However, the reporting of this information will provide a useful benchmark from which to evaluate operationally available capacity. Further, the Commission clarifies that it will be sufficient for pipelines to post the point and segment capacity used for system design and peak operation studies; such information should be readily available to the pipeline. Pipelines are free, however, to explain in their postings of operationally available capacity under section 284.13(d) why design capacity may not be available.

NGSA requests clarification that all information regarding capacity usage that a pipeline has access to should be made publically available on a real-time basis, whenever feasible. In particular, NGSA requests that where operationally feasible, a pipeline should report on a real-time basis for each point on its system—especially for constraint or other critical points '' the design capacity (*i.e.,* total available capacity before subscriptions) for that point, the capacity actually scheduled for that point, and actual physical flows through the point.[201] NGSA argues that only with this information can shippers know how much of unused capacity is actually unused but subscribed capacity that can be taken back by firm capacity holders at either the second or third nomination cycles. At a minimum, asserts NGSA, the Commission should require that pipelines post available design and scheduled capacity not only after the normal or ''timely'' cycle (11:30 a.m. on the day before flow day), but also after the 6:00 p.m. evening cycle, and where operationally feasible, after the two intra-day cycles. NGSA maintains that reporting available capacity only after the normal cycle is of limited value because available capacity often changes substantially as a result of the evening cycle. Amoco, however, requests that the Commission require the posting of capacity information on an ongoing basis, as the data become available to the pipeline.

The current regulations require the posting of available and scheduled capacity on a daily basis. The Commission finds merit in the argument that shippers need to know the level of available and scheduled capacity before each of the four intraday nomination opportunities in order to respond to nomination opportunities during the gas day. Therefore, the Commission will grant rehearing, and revise section 284.13(d)(1) to require that pipelines post the available and scheduled capacity information when they provide scheduling information to their shippers. This will permit the shippers to use this information to help in planning their nominations for the next nomination opportunity. Since pipelines must compute these capacity figures in the normal course of scheduling service requests for the four daily nomination cycles, there should be little additional burden in posting the data. However, the Commission will not require actual flow data to be reported because the information on available and scheduled quantities would appear sufficient to show the usage of the system. Moreover, actual flow data will not be able to help shippers nominate because it would be reported after the fact, not before nominations.

In response to NGSA and Amoco regarding the reporting of data at constraint points and bottlenecks, the Commission clarifies that under section 284.13(d)(1), pipelines are required to post information on available capacity, total design capacity, and scheduled capacity at all points, which should reasonably provide such information with respect to constraint points and bottlenecks. Pipelines, though, do not need to identify which points are constrained. However, as stated above, the Commission is not requiring the reporting of actual flow data at any point, constrained or otherwise, and denies Amoco's and NGSA's request for such flow data.

C. Implementation

The Final Rule requires pipelines to implement the new data reporting requirements by September 1, 2000. The Commission recognized in the Final Rule that the industry, through the Gas Industry Standards Board (GISB), is in the process of developing and improving standards for providing currently required information both on pipeline web sites and through downloadable file formats, using Electronic Data Interchange ASCX12 (EDI) formats.[202] The Commission further recognized that GISB will need to develop standards for the new reporting requirements (including pipeline firm and interruptible transportation transactions, design capacity, constraint information, and scheduled capacity) both for the presentation of the information on pipeline web sites, and the provision of the information in Electronic Data Interchange ASCX12 (EDI) or ASCII file formats, but that it may not be possible for GISB to complete the process of standardization in time for the September 1, 2000 implementation date.

Therefore, while the Commission encouraged GISB to work toward completing the standardization process prior to September 1, 2000, the Commission required pipelines to provide the new reporting information in non-standardized formats in the event GISB was unable to develop the datasets in time for the September 1, 2000 implementation. However, the Commission did not require that pipelines develop individual EDI file formats for the information during the period when GISB is developing the standards. Rather, the Commission required that pipelines only post the information on their web sites and provide flat ASCII file downloads for the relevant information. Pipelines, though, must continue to post the capacity release data in the existing EDI formats.

[200] Request for Rehearing of Enron at 10.

[201] Amoco, also, requests that the Commission require pipelines to post data on available capacity, as well as flow data, at constraint points and bottlenecks on the mainline.

[202] *See* Standards For Business Practices Of Interstate Natural Gas Pipelines, Order No. 587–I, 63 FR 53565, 53569–75 (Oct. 6, 1998), III FERC Stats. & Regs. Regulations Preambles ¶ 31,067, at 30,737–46 (Sept. 29, 1998).

A number of rehearing requests ask that the Commission defer the September 1, 2000 implementation date until after GISB has completed the process of establishing uniform national standards for collecting and displaying both the existing and new reporting information, so that pipelines may comply with the new reporting requirements and the GISB standards at the same time.[203] They argue that deferring the implementation of the new reporting requirements to coincide with the implementation of the GISB standards will eliminate the duplicative effort that otherwise will be required to make pipeline-specific changes to comply with Order No. 637, and then more changes to comply with the industry-wide GISB standards. They assert that requiring compliance twice will be expensive and wasteful of resources. In addition, Coastal maintains that deferring the implementation date will result in more user-friendly data presentations than will the numerous individual pipeline presentations, in various formats, developed to comply with Order No. 637.

Thus, the rehearing requesters either argue that the Commission should defer the implementation of the Order No. 637 reporting requirements until GISB publishes the uniform standards, or delay implementation until compliance with the GISB standards is possible. Some argue that the Commission should defer the implementation date until four months after the GISB standards are adopted.[204] Still others suggest that implementation should be deferred until either GISB develops the standard formats, or if GISB is unable to do so, the Commission itself develops the uniform standards.[205] In addition, Williston Basin argues that the Commission either must extend the implementation date or not require the reporting requirements to be standardized.[206]

In Order No. 637, the Commission has not required pipelines to develop EDI file formats for the new reporting requirements prior to GISB's issuance of the reporting standards. However, the Commission will not defer the implementation date for the posting of the information on pipeline web sites until after GISB acts. The information in the new reporting requirements needs to be available to the Commission and the market by September 1, 2000, to enable the Commission and market participants to begin to receive information about pipeline services prior to the start of the winter heating season.

The Commission recognizes that standardization of the reporting requirements is important to the industry, and is important to the Commission, as well. However, GISB is a private organization that is not required to act in accordance with the Commission's timetables, and thus, may not act in time to meet the Commission's implementation deadline. The Commission has minimized the potential for duplicative costs by requiring only that the information be posted on Internet web sites and in downloadable files, but not requiring pipelines to provide the data in EDI format until GISB's standardization is complete. Should GISB be unable to complete the standards necessary for posting the information on Internet web sites before September 1, 2000, the potential costs to the pipelines of having to reformat that information should not be great, particularly since they will be able to use whatever standards GISB has developed by that time. In any event, the information being required is of sufficient importance for the industry and for Commission monitoring of the market that the need for the information outweighs the costs of having to make minor changes to pipeline web sites at a later date. The Commission, therefore, will not make the implementation date dependent on GISB's actions. The Commission, however, encourages pipelines to work expeditiously with GISB to finish developing the standards in advance of the time for implementation of the Order No. 637 reporting requirements, which will eliminate any potential for duplicative development costs.

Finally, Great Lakes requests that the Commission confirm that pipelines will be able to recover the substantial costs that will be incurred in complying with the expanded reporting requirements of Order No. 637 in their next section 4 rate case. The costs may be recoverable in a rate case if they meet the Commission's standards for cost recovery. The Commission cannot make a generic ruling on this issue, since it is not aware of the nature of the costs for which recovery may be sought. The issue of the recovery of Order No. 637 compliance costs, like any other expense item, is an issue that may be raised in each pipeline's subsequent rate case, and if so, will be decided there.

IV. Other Pipeline Service Offerings

A. The Right of First Refusal

In Order No. 637, the Commission retained the right of first refusal (ROFR)[207] with the five-year matching cap, but narrowed the scope of the right. The Commission changed its policy so that in the future the right of first refusal will apply only to maximum rate contracts for 12 or more consecutive months of service. Existing discounted contracts were grandfathered so that the ROFR will apply to current discounted contracts, but will not apply when the contracts are reexecuted unless they are at the maximum rate.

The Commission also indicated that the maximum rate that a shipper must meet when exercising its right of first refusal may be, in certain limited circumstances where an incremental rate exists on the system, a rate that is higher than the historic maximum rate. Further, the Commission decided that it would not enhance the right of first refusal by allowing it to be exercised for a geographic portion of the existing contract. The Commission, however, did not change its preexisting policy that the right of first refusal can be exercised by a shipper for a volumetric portion of its capacity. The Commission also clarified that the right of first refusal as provided by the Commission's regulations, is an exercise of the Commission's authority under section 7(b) of the NGA and is not dependent on the contract between the pipeline and the shipper.

A number of parties have requested rehearing of this portion of Order No. 637.[208] As discussed below, the Commission has concluded that generally the ROFR should be limited to maximum rate contracts for 12 or more consecutive months of service, but an exception to this rule is appropriate for certain seasonal contracts. Therefore, the Commission modifies Order No. 637 to provide that the ROFR will apply to multi-year seasonal contracts at the maximum rate for services not offered by the pipeline for a full 12 months. The requests for rehearing on the other ROFR issues are denied for the reasons discussed below. The Commission also

[203] Coastal, CNGT, Enron, INGAA, Kinder-Morgan, Koch, Tejas, Williams, and Williston Basin.

[204] Request for Rehearing of Kinder Morgan at 39 and Request for Rehearing of Williams at 11.

[205] Request for Rehearing of Koch at 59 and Request for Rehearing of CNGT at 26. CNGT asserts that the Commission should establish a standardized format for the new reporting requirements by July 1, 2000, if the Commission expects pipelines to meet a September 1, 2000 deadline.

[206] Request for Rehearing of Williston Basin at 14–16.

[207] 18 CFR 284.221.

[208] Requests for rehearing on these issues were filed by AGA; APGA; Arkansas Gas Consumers; ConEd; Florida Cities; FPL Energy; Great Lakes; INGAA; Keyspan; Koch Gateway; Minnesota; New England Gas Distributors; NASUCA; National Fuel; Process Gas Consumers; Minnegasco; Texas Eastern; UGI Utilities; Washington Gas; The Williams Companies; and WDG.

clarifies Order No. 637 as provided below.

1. Contract Length

In Order No. 637, the Commission changed its policy so that in the future, the right of first refusal will apply only to maximum rate contracts for 12 or more consecutive months of service.[209] The Commission stated that it will be the term of the service, not the term of the contract, that will determine whether the right of first refusal will apply. The Commission reasoned that the purpose of the right of first refusal is to protect long-term captive customers, and that seasonal service is short-term service, even if the contract providing for the service is of a duration of more than a year. AGA, several LDCs [210] and the Minnesota Department of Commerce (Minnesota) seek rehearing on this issue.

These petitioners argue there is no record evidence to support the Commission's conclusion that all shippers taking partial year service have competitive options. They assert the fact that a contract is for less than a full year of service does not in itself imply that the customer has sufficient competitive alternatives. The petitioners maintain that the services provided under many of these contracts, often storage and related transportation, are available from the pipeline only for specific months,[211] and are not offered for a full year. For example, Keyspan states that its long-term contracts for seasonal service are not the product of negotiations in which the Keyspan companies were able to use leverage to avoid purchasing services on an annual basis. Instead, Keyspan asserts, the pipelines offered the services for limited periods of the year, and the Keyspan companies are dependent on these contracts to meet their peak demands.

In addition, Minnegasco complains that the Commission's ruling elevates the form of the contract above the substance and, as a result, there will be only one acceptable model of contracting in order for a captive customer to preserve its right of first refusal.[212] Minnegasco argues that this denies parties the contractual flexibility that is allegedly a benefit of open access.

These petitioners further argue that there is no legal justification for eliminating ROFR protection for multi-year seasonal contracts. Keyspan argues that there is nothing in section 7(b) of the NGA or the court's decision in *United Distribution Companies* v. *FERC (UDC)* [213] that permits the Commission to apply a different standard in considering the abandonment of critically needed seasonal contracts than would be applied to necessary year round contracts. New England asserts that Order No. 637 sets forth no record support for the conclusion that partial year shippers can rely on the market to protect them from the exercise of market power. New England argues that the Commission's decision is also procedurally defective because the NOPR did not contain such a proposal, and therefore interested parties did not have an opportunity to comment on the issue.

These petitioners ask the Commission to modify or clarify its ruling and provide protection for pipeline customers that have multi-year contracts for pipeline service offered for less than 12 months. AGA asks the Commission to clarify that service under rate schedules that only provide partial-year service at maximum rates have ROFR protection. Minnesota also asks the Commission to allow the ROFR to apply to multi-year seasonal contracts for shippers currently paying rates that reflect the full cost of service.[214]

The Commission will grant the clarification requested by the petitioners, and provide that the ROFR will apply to multi-year seasonal contracts at the maximum rate for services not offered by the pipeline for a full 12 months. This is consistent with the purpose of the ROFR to protect long-term captive customers at the expiration of their contracts. If a customer is paying the maximum rate under a multi-year contract for a service that is offered by the pipeline on a seasonal basis only then, as the petitioners have pointed out, it is the pipeline that has determined the duration of the service. The shipper needing the service has no alternative but to accept what the pipeline offers. In addition, the LDC petitioners state that these multi-year winter-only contracts provide firm transportation service, often from storage, at critical times during the heating season. The LDCs generally have no pipeline alternatives to this service and this service is necessary to enable them to meet their service obligations. Thus, the contracts are similar to long-term contracts because the customers contract for this peaking service over a number of years, and the customers do not have significant alternatives to these pipeline contracts. They are not similar to the typical short-term contract where the shipper is not a captive customer, has other service options, and is not subject to the pipeline's market power. In these circumstances the customer relying on the service and paying the maximum rate should have the protection of the ROFR. Long-term maximum rate contracts with increased CDs for seasons of peak demand meet the standards for ROFR protection and therefore are covered by the ROFR.

2. Discounted Contracts

In Order No. 637, the Commission narrowed the scope of the ROFR to apply only to maximum rate contracts. The Commission explained that limiting the ROFR to maximum rate contracts is consistent with the original purpose of the ROFR to protect long-term captive customers from the pipeline's monopoly power. The Commission reasoned that if a customer is truly captive and has no alternatives for service, it is likely that the contract will be at the maximum rate. The Commission stated its intent that with this modification, captive customers will still be able to receive their historical service as long as they pay the maximum rate. However, the Commission also stated that if a customer has sufficient alternatives that it can negotiate a rate below the just and reasonable maximum tariff level, it should not have the protection afforded by the right of first refusal, and the pipeline should be able to negotiate with other interested shippers. The Commission grandfathered existing discounted contracts and provided that the ROFR will apply to these contracts, but will not apply to future contracts that are not at the maximum rate. The

[209] Order No. 637 at 216–18.

[210] *E.g.,* Keyspan Brooklyn Union, National Fuel, New England Gas Distributors, and Minnegasco.

[211] AGA gives several examples of such service, *e.g.,* Transco's Southern Expansion Service which is available only from November through March.

[212] Minnegasco gives several examples: if it has two contracts with a pipeline, one for 12 consecutive months of baseload capacity each year of the multi-year contract and a second agreement with that pipeline for 5 months of winter heating capacity for each heating season of the multi-year contract, it interprets Order No. 637 as stating that the contract for the heating season capacity would not have ROFR protection. If, on the other hand, it had one contract with the pipeline for 12 consecutive months of baseload capacity, but with increased capacity for the 5-month winter period, the contract would have ROFR protection. Also, Minnegasco states, if it had a contract with a different pipeline for the increased heating season capacity, that contract would not have ROFR protection. Minnegasco asserts that these differences are of form, not substance.

[213] 88 F.3d 1105 (D.C. Cir. 1996).

[214] Minnesota states that Northern Natural Company (Northern) supplies 89 percent of Minnesota's imported gas, and that the pipeline is capacity constrained. Minnesota also states that Northern Natural was given Commission approval to implement seasonal rates that are designed to reflect the full cost of service. Docket No. RP98–203. Minnesota states that the Commission's altered ROFR policy treats Minnesota shippers holding cost-based seasonal capacity on Northern differently from Minnesota shippers holding cost-based 12-month service. (Check this).

Commission found that limiting the ROFR to maximum rate contracts strikes the appropriate balance between the need to protect captive customers and the need to better balance the risks between the shipper and the pipeline.

APGA, National Fuel, Minnegasco, WDG, Process Gas Consumers, FPL Energy, Arkansas Gas, and Enron seek rehearing on this issue. These parties argue that limiting the ROFR to maximum rate contracts is contrary to section 7(b) of the NGA and challenge the factual basis for the limitation.

The limitation of the ROFR to maximum rate contracts as provided in Order No. 637 is fully consistent with the statutory requirements and the Commission's regulatory policies. Under section 4 of the NGA, a shipper is entitled to protection from unjust and unreasonable rates, and under section 7(b) of the NGA, a shipper is entitled to protection from the pipeline's exercise of monopoly power through the refusal of service at the end of the contract term. The Commission's rate regulation assures that the rates charged by the pipeline are just and reasonable, and the ROFR protects captive customer from an exercise of the pipeline's market power at contract termination. Contrary to the suggestions of the petitioners, limiting the application of the ROFR to maximum rate contracts does not dilute either of these protections. Captive customers are guaranteed confirmed service at the just and reasonable Commission-approved tariff rate. What is not guaranteed is service below the just and reasonable rate. The limitation is consistent with the Commission's goal of promoting competition while protecting captive customers from pipeline market power, and the Commission's need to balance financial risks between pipelines and shippers.

Several petitioners argue that the Commission's decision is contrary to section 7(b) of the NGA because section 7(b) does not state that only captive or maximum rate customers are entitled to protection, and the Commission in the past has emphasized that the ROFR is intended to protect all existing customers, not just some subcategory of them.[215] Process Gas Consumers assert that in Order No. 636–C, the Commission did not limit the ROFR to captive non-discounted shippers, and that the Court in *UDC* did not limit the ROFR to captive customers and did not indicate that ''captive'' means solely maximum rate non-discounted shippers.[216] Process Gas Consumers argue that the new limitation is unjustified.

Section 7 (b) is designed to ''protect gas customers from pipeline exercise of monopoly power through refusal of service at the end of a contract period.'' [217] The ROFR, by the terms of the regulation, is available to all shippers willing to pay the maximum rate and is not limited to captive customers. The Commission's regulation protects shippers from the exercise of market power in two ways: by capping the maximum rate the pipeline can charge and by giving shippers a ROFR at contract termination.

The petitioners also argue that the Commission's conclusion that a shipper that has been able to negotiate a discount with the pipeline is not a captive customer is erroneous. They assert that pipelines give discounts to customers, including captive customers, for a variety of reasons unrelated to competition. For example, these petitioners state that a discount may be given in consideration of entering into a settlement of a rate case or a complaint proceeding, for an agreement of the shipper to shift to a less desirable or underutilized receipt point, to sign a longer contract, or to take an additional volume.[218] In these circumstances, they assert, the fact that the shipper pays a discounted rate does not mean that it is not captive or that it has market alternatives for service. Further, Process Gas Consumers point to the Alternative Rates Policy Statement, under which the Commission requires a pipeline to show that its shippers have four or five ''good alternatives'' as one aspect of demonstrating that it lacks market power,[219] and argue that a discount from one pipeline is not the same as four or five good alternatives. WDG argues that absent a finding, on a customer-specific basis, that each shipper with a discounted contract has meaningful choices at the time of the contract termination, the Commission must continue to provide such shippers with the continued protection of the ROFR.

Further, several of the petitioners argue, because a discount or negotiated rate is determined at the outset of the contract, it has no relationship to the market that the long-term shipper faces at the end of the contract. They argue that the Commission provided no reason for equating market conditions at the outset of the contract with those at the end of the contract, and that conditions could change and affect the shippers' ability to obtain capacity at the end of the contract. The petitioners assert that the Commission must make certain that a captive customer will be afforded the assurance of continued service if the customer is willing to pay the maximum rate for the service in the future, regardless of whether the customer was able to negotiate a discount in the past.

These petitioners assert that the result of the Commission's ruling is that captive customers will be forced to forgo any opportunity for a discount, and will have to pay the maximum rate in order to retain a ROFR even if the market rate on a pipeline is lower than the maximum rate. Therefore, they argue, the Commission is guaranteeing that LDCs with a supplier of last resort obligation, or those that are physically connected to only specific pipelines, will not have an opportunity to obtain a contract at the market rate.

Although the petitioners assert that pipelines give discounts for a variety of reasons, generally, discounts are given to obtain or retain load that the pipeline could not transport at the maximum rate because of competition. The Commission has held that to the extent that a pipeline was required during the test period in a section 4 rate case to give discounts either to attract or retain load, the pipeline is not required to design its rates on the assumption that the discounted volumes would flow at maximum rates.[220] The Commission has explained that discounts given to meet competition benefit all customers by

[215] Process Gas Consumers cite Order No. 636 at 30,448.

[216] Process Gas Consumers cite a portion of the Court's decision where the Court states that ''even a captive customer served by a single pipeline can exercise its right of first refusal and retain its long-term firm transportation service against rival bidders.'' *UDC* at 1140. Process Gas Consumers state that the Court's use of the word ''even'' implies that the Court was not limiting the ROFR protection to captive customers.

[217] *AGA II,* 912 F.2d at 1518.

[218] The petitioners give other examples of situations where a captive customer may receive a discounted rate. For example, APGA states that a captive customer may be given a discount where the captive customer has a non-captive retail customer; Minnegasco states that a customer may be captive for 95 percent of its load and the pipeline may be willing to negotiate a discount to retain the entire load; WDG states that a pipeline may give a discount to a captive customer in response to a perceived competitive threat from the proposed construction of a new pipeline, and defeat the introduction of the new alternative. If the existing pipeline is successful in keeping the proposed alternative from entering the market, WDG argues, the captive customer whose last contract was at a discounted rate will still be a captive; Arkansas Gas states that captive customers may receive discounts as an incentive for an industrial customer to expand its facilities, as an incentive to take service at facilities with competitve options, or to assist industrial customers during times of financial troubles in order to keep the facility viable.

[219] Process Gas Consumers cite Alternative Rates Policy Statement at 61,235.

[220] *E.g.,* Koch Gateway Pipeline Co., 74 FERC ¶ 61,088 at 61,280 (1996).

allowing a pipeline to maximize its throughput and thus spread fixed cost recovery over more units of service.[221] Thus, the customers that receive discounts under the Commission's discount policy, are generally the customers whose business would have gone to another service provider unless the pipeline granted the discount, *i.e.,* customers with alternatives. If discounts are given for other reasons,[222] for example, if a discount is given for a short-haul, then it may be that the rate for the short-haul is not properly designed. If a rate for a service is too high, the shipper can file a complaint under section 5 of the NGA. The maximum approved rate for any service is a just and reasonable rate, and no customer is harmed by paying a just and reasonable rate.

Moreover, the ROFR's protection has always been related to the customer's payment of the maximum rate as a condition to exercising the ROFR. Pipelines are never required to discount their rates, and no customer is entitled to a discount. In finding that the ROFR afforded the necessary section 7(b) protection, the court in *UDC* stated, ''[i]f the existing customer is willing to pay the maximum approved rate, then the right of first refusal mechanism ensures that the pipeline may not abandon the certificated service.'' [223] The court also observed ''[t]he 7(b) abandonment provisions protect customers against loss of service only if the customer is willing to pay the maximum rate approved in a rate proceeding.[224] Since the ROFR was first created and reviewed by the court in *UDC,* what has changed is that pipelines have been granting more discounts to long-term firm shippers in circumstances never intended under the Commission's discount policy. Many of these rate adjustments should have been handled in other ways in section 4 or 5 rate cases.

Pipelines' rates are cost-based and are capped at a maximum just and reasonable level. No shipper is harmed by paying a just and reasonable rate for the service it receives. A shipper may, of course, negotiate with the pipeline for a discounted rate. However, if the shipper has the leverage, either through the availability of alternatives to the pipeline's service or for some other reason, to obtain a discount, it should compete with other shippers for the capacity without a preference.

Thus, the limitation of the ROFR to maximum rate contracts leaves in place the basic protections afforded by the statute—the shipper is guaranteed that it will pay no more than a just and reasonable rate for the service it receives, and if the shipper pays the maximum just and reasonable rate, it is guaranteed that it can retain that service at the end of its contract. The Commission's limitation of the ROFR to maximum rate contracts is consistent with the statute and the purpose of the ROFR.

Order No. 637 also states that because the ROFR will apply only to maximum rate contracts, there will be no ROFR for negotiated rate contracts. FPL Energy argues that the Commission erred in failing to consider the impact of this ruling on pipeline laterals, and that the Commission must make an exception for this type of service. FPL Energy states that it expects to take pipeline service across laterals built by the pipeline to its electric generating plant. FPL Energy states that once such a transportation arrangement is consummated, it will be exposed to the full market power of the pipeline to which it is connected, regardless of whether the Commission considers the rate to be negotiated.

New England does not object to denial of ROFR protection to customers paying a discounted rate, but asks the Commission to clarify that a negotiated rate shipper is denied ROFR protection only if the negotiated rate is less than the tariff maximum rate.

A negotiated rate is not the equivalent of the maximum tariff rate for the service, regardless of whether the negotiated rate is higher or lower than the maximum tariff rate, and therefore the ROFR will not apply to these contracts. The Commission permits negotiated rate contracts as an alternative to service under the Commission-approved generally applicable just and reasonable tariffs, but the regulatory right of first refusal does not apply to these negotiated contracts. Shippers who are able to negotiate a rate different than the maximum tariff rate generally have alternatives to service on the pipeline. However, in any event, if a shipper wants to have the benefits of the ROFR so as to have a preference for continued service on the pipeline over other customers at the expiration of its contract, it should take its service under the maximum just and reasonable tariff rate. If the shipper negotiates its rate, then it must compete equally with other shippers for the capacity at the end of its contract. In the example given by FPL, it is not likely that there would be any other shippers bidding for service over the lateral to its electric generating plant, and the pipeline is required to provide service at the maximum rate. The shipper is therefore protected in these circumstances.

FPL asks the Commission to define several terms including ''maximum rate,'' and ''negotiated rate,'' and specify what type of contracts fall within or without the revised ROFR's protection. ''Maximum rate'' refers to the maximum tariff rate for a particular service. A ''negotiated rate'' is a rate agreed to by the pipeline and a customer under the Commission's negotiated rate policy. As explained in Order No. 637 and as modified above, the ROFR will apply to maximum rate contracts for 12 or more consecutive months of service and to multi-year seasonal contracts for services offered by the pipeline only on a seasonal basis.

Enron argues that the Commission erred in grandfathering existing discounted contracts. Enron argues that it is unnecessary to allow these shippers to exercise their ROFR because the Commission has already concluded that these shippers are not the captive customers for which the right was created. Further, Enron argues that continuation of the right, even for just a few years, keeps the pipelines from putting the capacity in the hand of shippers that value it most.[225]

The Commission's determination that the ROFR should not apply to discounted contracts is a change from the Commission's past policy. Grandfathering current contracts executed by the parties with a regulatory right of first refusal is fair, and gives the parties notice of the new limitations on the ROFR prior to re-executing their contracts. It is within the Commission's discretion to apply this policy prospectively to contracts executed after the effective date of Order No. 637, and the Commission concludes that it is a reasonable balance to grandfather existing discounted long-term contracts.

Koch agrees with the determination in Order No. 637 that the ROFR should not

[221] *Id.*

[222] *See, e.g.,* Williston Basin Interstate Pipeline Co., 85 FERC ¶ 61,247 (1998); Southern Natural Gas Co., 67 FERC ¶ 61,155 at 61,456 n.8 (1994).

[223] *UDC,* 88 F.3d at 1140.

[224] *Id.* at 1142.

[225] Enron states that pipelines with current long-term discounted contracts cannot sell the long-term capacity they expect to become available, but must stand ready to continue serving the existing shippers until they either exercise their right of first refusal or allow them to lapse. Enron states that while the discount shipper may be required to bid up to the maximum rate at the contract expiration date, it need not presently declare its intention. Enron states that a pipeline in these circumstances is precluded from offering capacity to new shippers who require a current commitment to plan for incremental gas demand, and that these shippers may look elsewhere to fill their capacity needs.

apply to discounted contracts, but seeks clarification as to the date that the regulatory right of first refusal will apply to discounted contracts. Koch suggests that the Commission clarify that any discounted contract that was entered into for a year or more after March 1, 2000 would not qualify for the right of first refusal. In response to Koch's request, the Commission clarifies that the ROFR will not apply to any discounted contracts entered into after the effective date of Order No. 637.

3. ROFR Pricing Policy

In Order No. 637, the Commission explained that, consistent with the holding in the Policy Statement concerning Certification of New Interstate Natural Gas Pipeline Facilities (Certificate Policy Statement),[226] the maximum rate that the existing shipper must meet in order to exercise its right of first refusal may be higher than its current rate in certain very limited circumstances, *i.e.,* where a shipper has a right of first refusal on a pipeline that has vintages of capacity and thus charges different prices for the same service under incremental pricing, the pipeline is full, and a competing shipper bids a rate for the capacity that is above the existing shipper's current maximum rate. In addition, in order to charge a higher rate than the previous maximum rate, the pipeline must have in place an approved mechanism for reallocating costs between the historic and incremental rates so all rates remain within the pipeline's cost of service.[227]

As the Commission explained in Order No. 637, a higher maximum rate is appropriate when the system is fully booked and there is at least one bid above the existing rate, because in those circumstances, there would be insufficient capacity to satisfy all the demands for service on the system. When insufficient capacity exists, a higher matching rate will improve the efficiency and fairness of capacity allocation, within the limits of cost of service ratemaking, by allowing new shippers who place greater value on obtaining capacity than the existing shipper to compete for the limited capacity that is available.

In Order No. 637, the Commission explained that under this pricing policy, an existing captive customer is protected against the exercise of market power by the pipeline because the pipeline cannot insist on the shipper paying a higher rate unless its expansion is fully subscribed and there is another bid for capacity at a rate above the vintage maximum rate charged the existing shipper. These conditions ensure that the pipeline is unable to use its market power over captive customers to withhold capacity from the market to raise price. Price will exceed the current maximum rate charged the existing shipper only when a higher price is needed to allocate scarce capacity.

The Commission's ROFR pricing policy was set forth in the Certificate Policy Statement. Because Order No. 637 made other changes to the ROFR mechanism, the Commission discussed the interaction of these changes with the new ROFR pricing policy. However, nothing in Order No. 637 changes anything in the Certificate Policy Statement. The Commission merely reiterated the change to the ROFR pricing policy in order to clarify how all the changes related to the ROFR work together.

AGA, APGA, ConEd, Florida Cities, Keyspan, National Fuel, New England Distributors, UGI, Process Gas Consumers, and NASUCA seek rehearing or clarification of the Commission's ruling. The petitioners generally argue that the ROFR pricing policy is inconsistent with the NGA and Commission policy and regulations. Several petitioners ask the Commission to clarify how the policy will work in specific factual situations.

a. Consistency with Statute and Regulations. Several of the petitioners argue on rehearing that charging a higher maximum rate than the shipper's previous maximum rate is unlawful under section 4 of the NGA. APGA and Keyspan argue that the increased maximum rate would be unjust and unreasonable since it would require shippers to pay for capacity that was not built to serve them and therefore, the necessary cost causation link is missing. Similarly, UGI argues that the Commission's regulations are designed to match cost recovery with cost incurrence, and that the rate that a shipper pays for retaining capacity must be related to the character and reliability of the service received, and cannot be escalated on an arbitrary basis to the value that some other shipper receives from an unrelated service. UGI asks the Commission to clarify that the maximum recourse rate that a shipper must match is a rate for a like or a comparable incremental service.[228] NASUCA argues that ROFR customers are not similarly situated to new customers because they impose no new construction demands on the system.

The higher maximum rate paid by a shipper exercising its right of first refusal is not unjust or unreasonable under section 4 of the NGA. The new maximum rate will be established by a mechanism approved by the Commission to assure a just and reasonable result. As explained in the Policy Statement, the Commission will review the proposed mechanisms and determine how well they achieve capacity pricing that permits as efficient an allocation of capacity as is possible under cost-of-service ratemaking, protection against exercise of market power by the pipeline, protection against overrecovery of the pipeline's revenue requirement, and equity of treatment between shippers with expiring contracts and new shippers seeking the same service. The Commission will assure in the individual proceedings that the pipeline has a mechanism to establish just and reasonable higher maximum rate prior to implementation.

Further, it is not the case that existing shippers do not cause the need for expansion. As the court stated in *Southeastern Michigan Gas Co.* v. *FERC*, 133 F.3d 34, 41 (D.C. Cir. 1998), ''[b]ecause every shipper is economically marginal the costs of increased demand may equitably be attributed to every user, regardless of when it first contracted with the pipeline.'' The Commission has concluded that existing shippers should not pay a rate that reflects expansion costs during the term of their contract, not because they did not cause the need for the expansion, but because these shippers sign long-term contracts with the expectation that increases in their rates will be related to the costs and usage of the system for which they subscribe. Raising the rates of these existing shippers during the term of their long-term contracts to include expansion costs reduces rate certainty and increases contractual risk, and the Commission has determined that their contracts should protect them from this risk. However, when the contracts expire and the existing shipper seeks to retain its service, it is just as much a cause of the need to expand as a new shipper seeking service for the first time. Under the Certificate Policy Statement, in order to determine whether an expansion is required, a pipeline seeking a certificate for new construction is directed to ask its current customers whether they are prepared to release their capacity. A

[226] Docket No. PL99–3–000, FERC ¶ 61,227 (1999), *reh'g,* 90 FERC ¶ 61,128 (2000).

[227] The Commission cited several examples given on rehearing of the Certificate Policy Statement of such a mechanism.

[228] UGI argues that there is no justification for a policy that requires an LDC seeking to retain its market area service to match the incremental rate paid by a power generator on a lateral line located 2000 miles upstream of the LDC's city gate.

decision on the part of the existing customers not to release their capacity is a cause of a need to expand the capacity.

The ROFR pricing policy applies where the pipeline charges different rates for the same service under incremental pricing. Therefore, as requested by UGI, the Commission clarifies that the maximum recourse rate that a shipper must match is a rate for a like or a comparable incremental service.

Several petitioners also argue that the ROFR pricing policy will result in rate discrimination. APGA states that there is no basis on which to distinguish between the circumstances of a pipeline with and without incremental rates, and the ROFR should apply to each the same way. APGA argues that the roll-up policy fosters different pricing treatment for pre-existing captive shippers on different pipelines solely as a function of whether the pipeline in question has incremental capacity and this price difference is unlawful under the section 4 NGA proscription against unduly discriminatory pricing and preferential treatment.

It has been the practice under Commission ratemaking policies to set individual pipeline rates based on each pipeline's different costs, and maximum rates have differed on pipelines as a result of these different costs. The result here is the same. APGA's argument suggests that the Commission should establish uniform national rates, but that is not required by the NGA.

New England argues that the policy is discriminatory because shippers taking the same service will have their contracts expire at different times, and shippers whose contracts expire earlier would face a rate increase while others continue to take the same service at the same rate. Similarly, Process Gas Consumers state that this approach is discriminatory because similarly situated shippers may be subjected to very different maximum rates for the same service for no reason other than the timing of their contract expiration dates and the mechanics of the process used to set the new matching rate.

It is not necessarily true that all companies should pay the same prices for the same goods or services regardless of when they contract for the goods or services, or when their contract expires. In an unregulated market, a firm may be able to lock-in a low price for goods or services when demand is weak relative to the available supply, while another firm contracting for the same goods or services at a later time when supply and demand conditions change may pay a higher price. Shippers who enter into long-term contracts are guaranteed the rate provided for by the contract, but there is no guarantee that they will have the same rate for that service after their contract expires. The courts have recognized that different contracts can justify rate differences.[229] However, once the contract expires, there is no basis for distinguishing between customers receiving the same service.

Section 4 of the NGA prohibits a pipeline from affording different treatment to similarly situated shippers on its system. When there are different rates in effect on the system for historical customers and new customers for the same service, this rate difference raises concerns about discrimination under the NGA. There is no valid economic reason why the pipeline should charge these customers a different rate, and the ROFR pricing policy will tend to lessen price disparities on the system by moving toward a system-wide uniform maximum rate.

b. Consistency with Commission Policy. AGA, APGA, Florida Cites, Process Gas Consumers, Keyspan, NASUCA, and New England argue that the ROFR pricing policy as applied to captive customers is inconsistent with the Certificate Policy Statement and other established Commission policy. They assert that one of the main goals of the Certificate Policy Statement is to assure that the pipeline must be prepared to support the project financially without relying on subsidies from existing customers.[230] They argue that requiring captive customers to pay the highest incremental rate on the pipeline is inconsistent with this goal because the captive customers will subsidize expansion projects at the end of their contract terms.

Further, they assert that the Certificate Policy Statement provides that existing customers should not have to bear the risk of cost overruns of pipeline expansion projects, but that these risks should be apportioned by contract between the pipeline and expansion shippers.[231] They assert that the ROFR pricing policy is inconsistent with this goal because existing captive customers will be required in the future to bear the risks associated with new pipeline projects. In addition, they assert, the Certificate Policy Statement provides that existing customers should not have to pay for a project that does not serve them,[232] and that the ROFR pricing policy conflicts with this goal because captive customers would underwrite expansion projects that were not built to serve them. In addition, they argue requiring subsidization by captive customers conflicts with the goal of sending accurate pricing signals to new shippers.

Contrary to the suggestion of these petitioners, the ROFR pricing policy is not inconsistent with the Certificate Policy Statement, but is an integral part of the policy and works to accomplish its goals. As the Commission explained in the Certificate Policy Statement, a requirement that the new project must be financially viable without subsidies does not eliminate the possibility that in some instances, the project costs should be rolled into the rates of the existing customers.[233] Existing shippers should not subsidize any new construction projects during the term of their contracts.[234] However, where the pipeline charges different rates for the same service under incremental pricing and the pipeline is fully booked,[235] requiring the customer to match the highest competing bid up to the maximum rate sends efficient price signals to existing customers whose contracts are expiring as well as to expansion customers.[236]

The ROFR pricing policy leaves the pipeline at risk for any underutilized expansion capacity because the higher rate can only be charged to historical shippers if the facility is fully booked and there is a bid above the old vintage rate. Further, as the Commission stated in the Certificate Policy Statement, in pipeline contracts for newly constructed facilities, the pipeline should not rely on standard Memphis Clauses to deal with the risk of cost overruns, but should reach a contractual agreement with the new shippers concerning who will bear the risks of cost overruns. Therefore, responsibility for cost overruns should be resolved among the pipeline and the expansion shippers before construction, and cost overruns should not be included in general rate increases that could affect the rates of the existing shippers.

AGA, APGA, Process Gas Consumers, and Keyspan are concerned that ''gaming'' by the pipelines can defeat the goals of the Certificate Policy Statement. They argue that pipelines

[229] *UMDG* v. *FERC*, 732 F.2d 202, 212 (D.C. CIR. 1984); Norwood v. FERC, 587 F.2d 1306, 1310 (Cir. 19).

[230] APGA cites the Policy Statement, 88 FERC at 61, 746–47.

[231] APGA cites 88 FERC at 61,746.

[232] APGA cites 88 FERC at 61,746.

[233] 88 FERC at 61,746.

[234] Order Clarifying Statement of Policy, 90 FERC ¶ 61,128 (slip op. at 12) (2000).

[235] In addition, as explained above, the pipeline must have an approved mechanism to implement the ROFR pricing policy.

[236] *Id.*

will be able to manipulate the timing of system expansions and contract expirations so as to subvert the Commission's goals with respect to approval and pricing for new pipeline facilities, and take advantage of the forced subsidies by captive customers. Further, Process Gas Consumers state that the pipeline can manipulate the process by considering only expansions that would raise rates and ignore those that should cause rates to decrease.

The concerns that pipeline's will ''game'' the system by scheduling expansions to coincide with contract expirations are without foundation. In order to implement a higher rate than the old maximum rate, the pipelines must implement a mechanism that reallocates costs between existing and expansion shippers without changing the pipeline's overall revenue requirement. The pipeline therefore obtains no additional revenue from implementing the higher maximum rate, and there is no incentive to game the system. Further, under the new construction policies, the pipeline must be prepared initially to finance the expansion project without subsidization from existing shippers. The circumstances where a higher maximum rate could be implemented are very limited and it would be quite risky for a pipeline to base a decision to expand its facilities on a prediction that these circumstances might be met. Moreover, the method chosen by the Commission for implementing this new pricing policy gives the Commission the ability to review any rate change mechanisms before they can take effect and gives existing shippers the ability to raise any concerns about gaming.

Process Gas Consumers' concern that the pipeline could manipulate the process by considering only expansions that would raise rates and ignore those that should cause rates to decrease is also without foundation. In the Certificate Policy Statement, the Commission recognized that while incremental pricing will usually avoid subsidies for the new project, the situation may be different in the case of inexpensive expansability that is made possible by earlier costly construction. In that instance, because the existing customers bear the cost of the earlier more costly construction in their rates, incremental pricing could result in a subsidy to the new customers. This issue of rate treatment for cheap expansability must be resolved in each individual proceeding before construction. This will protect the existing shippers where the new shippers benefit from the prior construction.

APGA also argues that the ROFR pricing policy is inconsistent with Order No. 637's stated goal of reducing revenue responsibility of captive customers because this policy could result in huge rate increases to captive customers at the end of their contracts. It is also inconsistent, APGA argues, with the rationale of the ROFR to protect captive customers at the end of the term of their contract. Process Gas Consumers also argue that the new policy violates the spirit of the ROFR derived from the NGA because the ROFR requires that a shipper match the highest rate being offered for that shipper's capacity under that shipper's existing rate schedule, not some number contrived from the rates paid by other shippers resulting from other expansions or other shippers' decisions.

Contrary to AGPA's assertion, the ROFR pricing policy will not result in huge increases to captive customers at the end of their contracts. Rates will increase only in very limited situations, *i.e.,* where the pipeline has vintages of capacity and charges different prices for the same service under incremental pricing; the pipeline is full; a competing shipper bids a rate for the capacity that is above the existing shipper's current maximum rate; and the pipeline has in place an approved mechanism for reallocating costs between the historic and incremental rates. Rates will increase only to the level that another new shipper is willing to pay for the service.

The policy is not inconsistent with the purpose of the ROFR. The purpose of the ROFR is met because the existing customer is still protected against the exercise of market power by the pipeline since the pipeline cannot insist on the shipper paying a higher rate unless its expansion is fully subscribed and there is another bid for capacity at a rate above the vintage maximum rate charged the existing shipper. Any bid that the existing customer must meet to retain its service will be a just and reasonable rate. These conditions ensure that the pipeline is unable to use its market power over captive customers to withhold capacity from the market to raise price. Price will exceed the current maximum rate charged the existing shipper only when a higher price is needed to allocate scarce capacity. While existing pipelines have been filing certificate applications to expand their facilities, the expansion proposals concentrate in certain regions. There is no reason to expect that they would all result in expansions that would justify increasing the maximum rate for historic customers.

In addition, APGA asserts that the ROFR pricing policy is anticompetitive because a customer whose contract expires soon will not be able to compete with another customer whose contract does not expire for a number of years. APGA asserts that the Commission's rationale for the ROFR pricing policy, *i.e.,* that it will promote efficiency and fairness of capacity allocation, is erroneous because captive customers have no alternatives and therefore will be forced to pay the higher rate. Similarly, Keyspan asserts that, contrary to the Commission's suggestion, this policy will not create allocative efficiency, but will require captive customers to pay higher rates when their contracts expire so that incremental customers may pay less.

APGA's concern that shippers with longer term contracts will have a competitive advantage over shippers with shorter term contracts is speculative. Further, awarding capacity to the shipper who values it the most does in fact promote allocative efficiency, and, as explained above, the only time that a shipper will have to bid a higher rate at the contract expiration is when the pipeline is fully booked and there is another bid for the capacity.

In addition, APGA argues that the new ROFR pricing policy is directly inconsistent with the ROFR policy adopted for the electric industry in Order No. 888. APGA states that in Order No. 888–B, the Commission specifically held that the maximum rate that an electric transmission customer had to meet under the ROFR should not reflect any costs for incremental expansions that occurred during the term of the customer's contract that was expiring because ''the right of first refusal is predicated on an existing customer continuing to use its transmission rights in the *existing* transmission system.'' [237] APGA asserts that this same rationale applies to the right of first refusal for captive gas transportation customers since these customers have no choice but to continue to use the existing capacity and thus should pay the rate applicable to that capacity. APGA states that the Commission has failed to justify the implementation of conflicting ROFR policies under its two enabling statutes which embody the same public interest standard.

The Commission's policy is consistent with Order No. 888 and with the portion of Order No. 888–B quoted by AGPA. Order No. 888–B provides that the maximum rate that an existing customer

[237] APGA cites Order No. 888–B, 81 FERC ¶ 61,248 at 62,085 (1997).

must pay to exercise its right of first refusal is ''the just and reasonable transmission rate on file at the time the customer exercises its right of first refusal'' [238] and, further, that depending on the rate design on file for the existing capacity, ''a customer exercising its right of first refusal could face an average embedded cost-based rate, an incremental cost-based rate, a flow-based rate, a zonal rate, or any other rate design that the Commission may have approved under section 205 of the FPA.'' [239] Thus, the electric customer exercising its ROFR is not guaranteed that it can continue service at its old maximum rate, but may be required to meet a bid up to the maximum system rate on file, just as the gas customer is required to do.

New England argues that the policy is unfair because it ignores the fact that the existing shipper has supported the pipeline for many years through a series of long-term contracts for service. Now that these facilities are heavily depreciated, New England asserts that these customers should be permitted to receive service on these facilities that they funded. New England states that the new policy will negate settlements that are in place on certain pipelines. For example, New England states, on both the Tennessee and Algonquin systems, New England LDCs contracted for incremental services and paid incremental rates; by settlement, New England agreed to pay the incremental rate for a given period and gradually roll-in the costs of the facilities over time. Now that the rates are largely rolled-in, New England asserts, it will be denied the benefits of lower rates. New England states that having paid the higher rates for many years, it would be unfair to require these shippers to match a new incremental rate when the contract covering these facilities expires.

As explained below, in order to implement a higher maximum rate, the pipeline must have in place a mechanism that allocates costs between historic and incremental rates. Procedures for approving such a mechanism will allow interested petitioners to participate, and settlements can be taken into account in determining whether a particular method is just and reasonable on a particular pipeline.

4. Implementation Mechanism

In Order No. 637, the Commission gave pipelines the option of proposing an implementation mechanism either in a full section 4 rate case or through the filing of *pro forma* tariff sheets which would provide the Commission and the parties with an opportunity to review the proposal prior to implementation. Several petitioners argue that permitting the mechanism to be implemented in a limited section 4 proceeding does not afford sufficient protections to assure that the rates will be just and reasonable. Process Gas Consumers state that the Commission generally restricts use of a limited section 4 proceeding to instances where pipelines are filing for trackers, true-ups and other minor changes, and that a pipeline seeking to raise its transportation rates is required to file a general section 4 rate case. In contrast, Process Gas Consumers state that this proposal would allow a pipeline to increase the existing shipper's base rate without a balanced opportunity to submit the rate increase to the full scrutiny of section 4 to determine whether the rate is just and reasonable. Process Gas Consumers state that this procedure will not consider the cost savings from intervening pipeline depreciation, cost-cutting, or other efficiencies or additional revenues the pipeline may be receiving from new services or other load-enhancing initiatives. Process Gas Consumers argue that the Commission must require that if a pipeline believes that its expansion benefits other shippers to the extent that they should pay for them, such a case and decision should be made in a full section 4 case to review the merits of roll-in, not through some backdoor easing in of higher maximum rates that will selectively penalize some shippers.

A full section 4 rate proceeding is one of the options a pipeline may use to implement a mechanism, but the Commission will not require it. As the Commission explained in the Order Clarifying Statement of Policy, a full section 4 proceeding can be a cumbersome way to implement this mechanism because it examines cost and revenue items and other issues unrelated to the more limited cost allocation and rate design changes needed to readjust rates at contract expiration. Pipelines, therefore, can also establish the reallocation mechanism by filing *pro forma* tariff sheets which will provide the Commission and the parties sufficient opportunity to review the proposals. Once the review is completed, the pipeline can implement the mechanism through a limited section 4 filing.

5. Grandfathering of Existing Contracts

Several of the petitioners [240] argue that if the Commission does not reverse its ROFR pricing policy, it should allow each historical shipper on an incrementally priced pipeline the opportunity, upon expiration of its contract, to elect an extension term without exposure to roll-up. They argue it is unfair to apply the policy to existing contracts without a grandfather provision because the existing contracts were entered in reliance on a ROFR that required shippers to match the maximum rate for the existing service. They argue that had the new policy been in effect at the time the current contracts were executed, they would have signed a longer-term contract.

As the Commission explained in its Order Clarifying Statement of Policy,[241] it is not appropriate to give existing customers one opportunity to renew their contracts at their existing maximum rate. Where there is insufficient capacity to satisfy all demands for capacity, an efficient system of capacity allocation would award the capacity to the shipper placing the greatest value on obtaining the capacity. A one-time mandatory renewal would conflict with that policy by permitting the existing shipper to continue service at a rate less than the highest bid.

6. Clarification

AGA and several other petitioners [242] present various fact scenarios and ask the Commission to explain how the ROFR will operate in these situations. One question posed by these examples is if there is a maximum incremental rate in effect on a system, but none of the incremental shippers are paying the maximum rate, does the shipper exercising its ROFR have to match a bid above the highest rate actually being paid, or can the shipper retain its capacity by paying the highest rate being paid by an incremental shipper. Other scenarios pose questions concerning what depreciation rate should be used to calculate the incremental rate that must be matched by the existing shipper, whether the rate is affected if the Commission places the pipeline at risk for underrecovery of costs, how the policy will apply on a zoned system,[243] how the pricing policy

[238] 81 FERC at 62,085.

[239] 81 FERC at 62,085 n.90.

[240] *E.g.,* ConEd, Florida Cities, New England.

[241] 90 FERC ¶ 61,128 (2000).

[242] ConEd, Keyspan, National Fuel, and New England.

[243] AGA gives an example where a shipper has long-haul capacity on zones 1–5 of a zoned system, and an incremental rate is in effect on zone 5 and asks, if, at the conclusion of the contract, another potential shipper bids on zone five capacity, must

will operate if a new shipper bids for a portion of the available capacity,[244] and whether a different result should occur if the expansion shipper is an affiliate of the pipeline. In addition, the petitioners ask what incremental rate will be the maximum rate on pipelines with more than one such rate and how will increased revenues paid by pre-existing shippers be credited back to incremental shippers. Keyspan asks the Commission to clarify if a shipper's contract expires in the year 2001, and is subject to the ROFR, and there is a bid in excess of the pre-expansion rate such that the shipper must match that bid, will a shipper whose contract is for the same basic capacity but expires in 2002 have to match what was paid in 2001 if there are no competing bids, or can the shipper utilizing its ROFR in 2002 simply match the pre-existing rate.

National Fuel Gas Distribution asks the Commission to clarify that if a shipper is expected to pay a higher rate, it must only be in the instances where the other shipper is receiving the same service. Distribution states that a shipper may be paying a higher rate on a lateral built specifically for that shipper, but this should not impact a long-haul shipper's cost.

New England states that the proposal will be difficult to implement. New England states that it will not always be a simple matter to determine whether a pipeline is full—the fact that there is a competing bid does not necessarily means that the system is full—if the competing bidder is a new shipper, it may simply mean that the ''old'' capacity held by the existing shipper is a better deal for the new shipper.

The fact patterns presented by the petitioners are complicated, and the Commission concludes that it will be preferable to address complex factual situations if and when they arise in the individual pipeline proceedings to implement the ROFR pricing policy. Moreover, many of the questions do not have generic application but are specific to the particular factual circumstances on a particular pipeline system. The implementation mechanism chosen by the Commission will permit the Commission and the parties to consider all the relevant facts in the specific context before applying the general pricing policy. Some of the issues raised by the petitioners, however, can be clarified here. Thus, the Commission clarifies that the existing shipper must match the highest bid incremental rate up to the maximum incremental being paid on the system. If there is a factual question as to whether there is sufficient capacity to satisfy demand on a particular pipeline, that issue can be addressed in the individual proceeding.

7. Geographical Segmentation

In Order No. 637, the Commission stated that it would not enhance the right of first refusal by holding that it can be exercised for a geographic portion of the existing contract, as requested by several petitioners. The Commission explained that the purpose of the right of first refusal is to protect the captive customer's historical service, and therefore it should apply only when the existing shipper is seeking to contract for its historical capacity. The Commission further explained that the right of first refusal is a limited right and was never intended to permit shippers to increase or change their service.[245] It is intended to be a means of defense against pipeline market power, not a mechanism to award an existing shipper a preference over a new shipper for a different service.

A shipper that can terminate a geographic portion of its historical service must have alternatives in the market that can substitute for its historical service, and therefore the Commission has concluded as a matter of policy that such a shipper does not require the protection of the ROFR. Further, as the Commission stated in Order No. 637, permitting the exercise of the ROFR for a geographic portion of the historical capacity could leave the capacity unused, and thus burden the pipeline and its other customers with the unused capacity. Therefore, the Commission concluded that maintaining the current policy and not expanding the right of first refusal strikes the appropriate balance between protecting the historic service of the captive customer and not burdening the pipeline and its other customers with unused capacity. AGA, Keyspan, Koch, and New England seek rehearing of the Commission's decision on this issue.

The petitioners argue that while the Commission has characterized its decision as a refusal to enhance the ROFR, current Commission policy permits exercise of the ROFR for a geographic portion of the capacity. They argue that Order No. 636–A provides that the ROFR applies to a ''portion'' of the pipeline's capacity without restricting the definition of ''portion,''[246] and that subsequently, in *Williams Natural Gas Co.*[247] the Commission applied this policy to permit a shipper to exercise its right of first refusal to retain its market area and storage area portion of a service agreement, but not the production area capacity. Keyspan states that Order No. 637 is also inconsistent with the Commission's reasoning in *Tennessee Gas Pipeline Co.,*[248] where the Commission held that because the pipeline's tariff did not require shippers to take transportation in both the production and market area, customers renewing their contracts could choose not to take production area capacity. These petitioners argue that the Commission has failed to provide an adequate basis for its departure from its prior holdings.

The Commission's decision is not a departure from its prior holdings. While, as the parties point out, Order No. 636 provides that the ROFR applies to a ''portion'' of the pipeline's capacity without defining the word ''portion,'' the Commission's subsequent decisions interpreting the scope of the term ''portion'' have defined ''portion'' to include a volumetric portion of the capacity, but have decline to extend the definition to include a geographic potion. Thus, in *Transcontinental Gas Pipeline Co.*[249] the Commission explained that the question of whether the ROFR should apply to a geographic portion of the capacity is a different question from whether it should apply to a volumetric portion of the capacity, and raises different policy concerns. Upon further consideration of these policy issues, the Commission determined in Order No. 637 that extending the ROFR to allow it to be exercised for a geographic portion of the capacity would not be consistent with its original purpose. As the Commission explained in Order No. 637, the ROFR is intended to protect captive customers and their historic capacity against the pipeline's exercise of market power, and is not intended to give existing shippers an advantage over other customers

the existing shipper match the bid for zone 5 short-haul, plus the maximum system-wide maximum rate for the haul across zones 1–4.

[244] AGA posits a situation where a new potential shipper seeks 10,000 Dth per day of capacity on incremental facilities bearing an incremental rate, and at the same time, 50,000 Dth per day is expiring under contracts containing the regulatory right of first refusal, and asks whether the holders of all 50,000 Dth per day must match the incremental rate offered by the potential shipper.

[245] As the Commission stated in Williams Natural Gas Company, 65 FERC ¶ 61,221 at 62,013 (1993), ''the character of the service being provided under the expiring contract cannot be changed through use of the right of first refusal.''

[246] AGA cites Order No. 636–A, FERC Stats. & Regs. [Regulations Preambles 1991–1996] ¶ 31,950 at 30,635 (1992).

[247] 81 FERC ¶ 61,350 at 62,627–28 (*Williams I*), *reh'g,* 83 FERC ¶ 61,052 (*Williams II*) (1997).

[248] 76 FERC ¶ 61,022 at 61,128–29 (1999).

[249] 88 FERC ¶ 61,155, *reh'g denied,* 88 FERC ¶ 61,295 (1999). See also Texas Eastern Transmission Corp., 88 FERC ¶ 61,167, *reh'g denied,* 88 FERC ¶ 61,291 (1999).

seeking new or different service from the pipeline. The *Williams* decision is not to the contrary. In *Williams* the Commission addressed a specific factual situation where no-notice service on the pipeline had separate transportation and storage components. In *Williams,* the Commission limited its holding to a situation where service was provided in the production area and the market area under different rates schedules, and the Commission expressly stated that it ''does not reach the issue of the existing shippers' ability to bid for different volumes of capacity in different zones under the same rate schedule.'' [250] Thus, the Commission's decision in that case was not a generic holding, but was based on the specific service characteristics of the pipeline.

Because of the potential impact on pipeline recovery, the Commission will not make a generic finding that shippers may exercise their ROFR for a geographic portion of its capacity. The determination whether this result is justified in a particular case will depend on the specific facts, as was the case in *Williams* and *Tennessee.*

The petitioners challenge the accuracy of the Commission's statement that a shipper that can terminate a geographic portion of its historical service must have alternatives in the marketplace that can substitute for its historical service and therefore is not a captive customer that requires the right of first refusal. They assert that a customer seeking to retain a portion of its service is in all likelihood a captive customer with respect to the portion of the service it seeks to retain, and that if the pipeline can use its monopoly power in the market area to require a shipper to purchase capacity in the production area, the shipper really does not have alternatives. New England states that because the Commission's factual conclusion is inaccurate, the decision to deny ROFR protection to customers seeking to take a geographic portion of their current capacity does not meet the standard set forth by the *UDC* court—it does not adequately protect captive customers from the exercise of pipeline market power.

The petitioners also state that the Commission's concerns about unused capacity do not justify its decision. AGA asserts that these concerns are speculative because projections for increased gas usage over the next decade suggest that capacity turnback by LDCs may not create significant problems for interstate pipelines, and that if unsubscribed capacity does result, there are effective policies for addressing turnback capacity generally and in individual pipeline proceedings. Keyspan states that the Commission does not explain why it is appropriate for captive customers, rather than the pipeline, to bear this burden. In addition, Keyspan states that the court's decision in *Municipal Defense Group* v. *FERC (MDG)* [251] cited by the Commission does not support its decision on geographical segmentation. Keyspan states that in that case the court decided that customers competing for new capacity must do so on an equal basis, while here the customers seeking to use the ROFR are not seeking new capacity; they are seeking capacity to which they have a right under section 7(b) of the NGA. In addition, Keyspan states that the Commission has held that third parties can submit a bid for a portion of a customer's capacity that is subject to the ROFR.[252] Keyspan argues that to the extent that third parties can bid for a geographic portion of a customer's capacity, the existing customer cannot be said to be competing with a third party on a level playing filed as was the case in *MDG.*

These arguments ignore the fact that the ROFR is intended to protect the historic service of captive customers from the pipeline's exercise of market power. It is not intended to give existing shippers an advantage over other shippers in bidding for a different or new service. What the petitioners seek on rehearing is a preference to obtain pipeline service over other shippers where that service is limited and is of high value, and at the same time obtain the ability to change the character of their historic service by eliminating geographic segments that are of less value. The ROFR allows the captive customer to keep its historic capacity, but only when the customer bids for that capacity. If a customer with a ROFR decides that it wants to change its historic service and compete with other shippers, it can always do so, but it cannot retain the ROFR to give it a competitive advantage over other shippers in these circumstances. Moreover, if a third party bids for a portion of their capacity, they may exercise their ROFR to retain the capacity and thus, contrary to Keyspan's argument, the existing customer has an advantage over the third party bidder.

The petitioners also argue that the same rationale that the Commission used in determining that a customer can exercise its ROFR for a volumetric potion of the customer's capacity applies with regard to a geographic portion of the capacity. They assert that the Commission acknowledged that the purpose of allowing the existing capacity holder to exercise its ROFR to retain a volumetric portion of its capacity was to ensure against the inefficient or unnecessary holding of capacity at the expiration of the contract. They assert that the Commission has failed to provide a persuasive rationale for requiring the inefficient retention of capacity on a geographic basis.

However, there are different considerations involved in permitting a shipper to take a geographical portion of its capacity. Allowing shippers to ''cherry pick'' the most desirable segments of their historic capacity is far more likely to leave the pipeline with stranded capacity than permitting a customer to take a volumetric portion for the entire length of the haul. Further, it gives the shipper with the ROFR a competitive advantage over other shippers, while allowing a shipper to take a volumetric portion of the capacity merely allows the customer to adjust its volume of capacity under contract to meet a changing demand.

The petitioners also argue that Order No. 637 is inconsistent with the Commission's policy of fostering competition. They state that allowing shippers to exercise their right of first refusal for a geographic portion of the capacity will promote market centers and liquid gas trading points, and facilitate the development of a competitive market that the Commission hopes to achieve in this order. Koch argues that it is anticompetitive to allow pipelines to require that shippers in the market area must hold capacity in the production area, and this limits customer's choices and the competitors ability to serve customers on these lines.

Koch acknowledges that it would be inappropriate to allow a customer to carve out a small, discrete portion of its capacity and exercise its right of first refusal on only that portion, but that it is different to allow a customer to exercise its right of first refusal for a pipeline's market area facilities so that it could select the production area facilities of another pipeline. Koch and Keyspan argue that this change would allow customers to benefit from wellhead competition and bring all the benefits of competition to parties that historically have been subject to the market power of the longline pipelines. Keyspan argues that the Commission's failure to afford captive customers the same choices as customers with alternatives is unduly discriminatory and cannot be reconciled with the

[250] *Williams,* 81 FERC ¶ 61,350 at 62,627 n.20.

[251] 170 F.3d 197 (D.C. CIR. 1999).

[252] Keyspan cites Order No. 636, FERC Stats and Regs. (1991–1996) ¶ 30,939 at 30,451–52 (1992).

court's decision in *Maryland Peoples Counsel* v. *FERC* [253] and *Maryland Peoples Counsel* v. *FERC.*[254] Keyspan states that in those decisions, the court held that the Commission could not adequately explain its decision to exclude captive customers from the benefits of certain pipeline programs, and that therefore the programs were unduly discriminatory. Similarly, Keyspan argues, in this case, the Commission has failed to explain its decision to refuse to afford captive customers the ability to exercise their ROFR rights to choose to renew only certain geographic portions of their contracts even though such alternatives are available to customers with competitive options.

Koch states that, contrary to the Commission's assertion, this would not change the type of service that the shipper is receiving. Koch states that the only change would be to the primary receipt points, and that all other aspects would remain the same, including the type of service and contract term. Keyspan also states that on a long-line system, transportation typically can be purchased on an individual zone basis and, as a result, permitting customers to exercise their ROFR on a geographic basis does not permit shippers to change their existing service. Koch states that if the service the customer is purchasing is a production area to market area service, then it is an anti-competitive tying arrangement that the Commission should eliminate independent of its right of first refusal policy.

Koch states that, not only does this policy cause an inefficient allocation of capacity, it also sends garbled price signals regarding the construction of new capacity and the corresponding value of that new capacity. Koch states that this distorted information will lead to overbuilding of capacity by the wrong pipeline, which will eventually lead to stranded costs. If the Commission does not grant rehearing on this point, Koch asks that the Commission direct the pipelines to amend their tariffs to provide that a customer can lose its ROFR only if another customer agrees to pay a rate that has a higher net present value for the original long haul than the customer is willing to pay for the short haul.

Shippers with a ROFR have the same rights to bid on geographic portions of a system, and not on other portions of the system, such as the production area, as any other shipper. Thus, this is not similar to *Maryland Peoples' Counsel* where captive customers were denied a benefit that was provided to non-captive customers. However, when bidding for a geographical portion of its capacity, the existing customer must compete with other shippers on an equal basis, and not have an advantage through the ROFR. If another bidder creates a greater net present value by bidding for a long-haul, then that bidder should receive the capacity. If the customer with the ROFR produces the highest net present value with a bid for less than the full length of haul, then it may be able to get the capacity. This benefits the system as a whole and most customers because it brings more revenue to the system, and the Commission has consistently allowed pipelines to allocate their capacity on that basis.[255]

Texas Eastern seeks clarification, or in the alternative, rehearing of the Commission's discussion in Order No. 637 of the shippers' right to exercise its ROFR for a volumetric portion of its capacity. Texas Eastern asks the Commission to clarify that its customers do not have the right to unilaterally terminate portions of their agreements unless Texas Eastern has provided notice of termination because that is the way Texas Eastern's approved tariff operates. National Fuel raises the same issue with regard to Texas Eastern's tariff and asks the Commission to clarify that where a tariff is inconsistent with the shipper's right to reduce its volumetric capacity, the pipeline should be required to file tariff language consistent with the Commission's clarification.

The Commission will not address any tariff-specific issues in this proceeding. However, the Commission has held that the regulatory right of first refusal permits the capacity holder to elect to retain a volumetric portion of its capacity, regardless of the terms of any tariff. If there are any issues regarding a specific tariff provision, they may be addressed in the individual compliance filings.

8. Five-Year Cap

In Order No. 637, the Commission stated that it would not change the length of the term matching cap at this time. In Order No. 636–C, the Commission had determined a five-year matching cap was appropriate given the evidence in that record of the industry trends in contract length, and none of the petitioners in this proceeding presented evidence to show that a five-year contract is atypical in the current market.

On rehearing, INGAA, Great Lakes, and The Williams Companies argue that the Commission should remove the term matching cap. These petitioners argue that there is evidence showing adverse consequences of the five-year cap,[256] and that the five-year cap continues a fundamental imbalance in the risks assumed by a pipeline and shipper.

INGAA argues it is illogical and unsupportable to retain the term matching cap on the basis that it is the median length of long-term contracts entered into since January 1, 1995. INGAA states that this treats half of all renewal contracts entered into since January 1, 1995 as unreasonable, when in fact the market has determined that contracts having terms longer than five years are necessary or appropriate based on commercial considerations. INGAA argues that the Commission should lift the cap and permit market forces to determine what length of contract an existing shipper must match.

TWC and Great Lakes assert that shippers that have competitive alternatives do hold maximum rate firm contracts with rights of first refusal, and TWC argues that the Commission should conclude that the five-year matching cap will not apply unless the shipper makes a positive showing that it is a captive customer and has no available alternatives. In addition, Great Lakes asserts that removal of the five-year cap does not create any unreasonable disadvantages for the existing shipper because if there are no other bidders, the existing shipper can renew its contact for any period, and if there are bidders, it can renew its contract by matching whatever term another shipper is willing to offer. Finally, Great Lakes argues that the Commission's retention of the five-year cap is inconsistent with its decision on ROFR incremental pricing. Great Lakes argues that since it is appropriate to subject a renewing shipper to market forces with regard to price, it is also appropriate to subject renewing shippers to market forces with regard to contract term.

The Commission adopted the five-year matching cap in Order No. 636–C in response to the Court's remand of the 20-year matching cap in *UDC.* In *UDC,* the court approved of the concept of a term-matching limitation ''as a rational

[253] 761 F.2d 768, 770 (D.C. Cir. 1985) (*MPCI*).

[254] 761 F.2d 780, 781 (D.C. Cir. 1985) (*MCPII*).

[255] See Tennessee Gas Pipeline Co., 91 FERC ¶ 61,053 (2000).

[256] INGAA argues that it could result in substantial turnback capacity due to the ROFR's bias toward one-year contracts. Great Lakes argues that the five-year matching cap places an unnecessary stranded capacity risk on the pipeline because it cannot sell, combine with other capacity becoming available, or reduce the need for incremental expansions by utilizing the excising shipper's capacity until the shipper rejects its ROFR.

means of emulating a competitive market for allocating firm transportation capacity,'' [257] but found that the Commission had failed to justify a 20-year matching cap. Thus, eliminating the term-matching cap as requested by the parties is not consistent with the Court's opinion in UDC. As the Commission explained in Order No. 637, there is no evidentiary basis at this time for changing the 5-year matching cap. The pipelines are not disadvantaged by the term-matching cap because it merely substitutes for the section 7(b) requirement that the pipeline obtain permission prior to abandoning service.

B. Negotiated Terms and Conditions

In Order No. 637, the Commission determined not to move forward at this time with pre-approved negotiated terms and conditions of service. The Commission explained that pipelines have been able to create open access tariff-based services with enhanced flexibility for scheduling and handling imbalances without having to negotiate terms and conditions of service with individual shippers, and, therefore, it is not clear that pre-approved negotiated terms and conditions of service are necessary. Further, the Commission explained that the negotiation of terms and conditions of service is directly related to the question of whether the Commission needs to revise its regulatory policy to accommodate a dual market structure in which some shippers with sufficient alternatives want to negotiate terms and conditions of service while other shippers remain captive, still subject to the pipeline's market power. Thus, the Commission concluded that the development of a two-track regulatory model requires further study of the interrelation between various aspects of Commission regulatory policy. TWC, Amoco, NGSA, INGAA, and CNG have asked for rehearing or clarification of this portion of Order No. 637.

TWC asserts that it is concerned that the Commission's existing procedures for implementing new rate schedules and non-conforming contracts are too slow and cumbersome to respond to the needs of the marketplace, and argues that the Commission should grant rehearing and permit negotiated rates and terms and conditions of service. However, as explained above, in Order No. 637, the Commission exercised its discretion to defer further consideration of this issue because it raises other policy questions that are not the subject of this proceeding. There is no basis for granting rehearing of this decision, and TWC's request for rehearing is denied.

Amoco and NGSA ask the Commission to further clarify the distinction between negotiated rates and negotiated terms and conditions, and how it will treat capacity turnback issues. INGAA and CNG urge the Commission to move forward with allowing negotiated terms and conditions as soon and feasible, and, in the interim, to be responsive to innovative service offerings that may be filed within the existing regulatory framework.

In Order No. 637, the Commission explained that it is not possible to formulate generic definitions applicable to all potential situations, but generally the Commission considers negotiated terms and conditions to be related to operational conditions of transportation service while negotiated rates would include the price, the term of service, the receipt and delivery points, and the quantity. A negotiated rate would not include conditions or activities related to the transportation of gas on the pipeline, such as scheduling, imbalances, or operational obligations, such as OFOs. The Commission will not further define the terms in this proceeding, but will consider specific issues, including capacity turnback issues, in response to the service offerings filed in individual pipeline proceedings.

V. Miscellaneous Issues

A. Corrections to Regulations

In Order No. 637, the Commission sought to consolidate its reporting requirements for pipelines providing open access service under subpart B (transportation under section 311 of the NGPA) and subpart G (open access transportation under the NGA) in a single section, § 284.13. But the reports concerning bypass of LDC facilities required under subpart B (§ 284.106) were not included in § 284.13, remaining in § 284.106. Prior to Order No. 637, subpart G pipelines were required to file bypass reports, because § 284.223(b) contained a cross-reference requiring subpart G pipelines to comply with each of the reporting requirements in § 284.106, which included the bypass reports. However, in Order No. 637, § 284.223(b) was removed, with the unintended effect of eliminating the existing requirement that subpart G pipelines file bypass reports. To correct this error, the Commission is revising the regulations to include the bypass reports in § 284.13(f), so that the pre-existing requirement for both subpart B and subpart G pipelines to file bypass reports will be maintained.

B. Filing of Pro Forma Tariff Sheets

The Commission's April 12, 2000 order [258] established a schedule for pipelines to file the *pro forma* tariff sheets necessary to comply with the regulations governing scheduling, segmentation, and penalties. Pipelines making *pro forma* tariff filings in response to this order must make these filings as new RP dockets and should file the *pro forma* tariff sheets on paper as well as electronically as provided in section 154.4 of the Commission's regulations.[259] To reduce the burden required to convert the *pro forma* tariff sheets to final sheets, the *pro forma* sheets should be filed as if they are proposed revisions of sheets in the existing tariff volume (with changes identified as provided in Section 154.201 of the Commission's regulations) with the words Pro Forma before the volume name, e.g., Fourth Revised Sheet No. 150, FERC Gas Tariff, Pro Forma Third Revised Volume No. 1. For the electronically filed tariff sheets, Pro Forma should be inserted at the beginning of the name field (VolumeID) in the Tariff Volume Record, i.e., the TF02 record. When the pipeline files the final tariff sheets, it need only remove the phrase *pro forma* for any unchanged sheets.

Pipelines should file the electronic *pro forma* tariff sheets through Internet E-Mail to 637FASTR@ferc.fed.us in the following format: on the subject line, specify the name of the filing entity; in the body of the E-Mail, specify the name, telephone number, and E-Mail address of a contact person; the *pro forma* tariff sheets should be attached to the E-Mail message. The Commission will send a reply to the E-Mail to acknowledge receipt. Questions about E-Mail filing should be directed to Lorena Finger at 202–208–1222, or by E-Mail to lorena.finger@ferc.fed.us, or to Albert Rogers at 202–208–0078 or by E-Mail to albert.rogers@ferc.fed.us.

Pipelines unable to file using Internet E-Mail must file the *pro forma* tariffs on diskette along with the paper filing and must label the diskette as containing *pro forma* tariff sheets.

VI. Effective Date

The amendments to the Commission's regulations adopted in this order will become effective July 5, 2000.

[257] *UDC,* 88 F.3d at 1140.

[258] Regulation of Short-Term Natural Gas Transportation Services 91 FERC ¶ 61,020 (2000).

[259] 18 CFR 154.4.

List of Subjects in 18 CFR Part 284

Continental shelf; Incorporation by reference; Natural gas; Reporting and recordkeeping requirements.

By the Commission. Commissioner Massey concurred with a separate statement attached.

Linwood A. Watson, Jr.,

Acting Secretary.

In consideration of the foregoing, the Commission amends Part 284, Chapter I, Title 18, Code of Federal Regulations, as follows.

PART 284—CERTAIN SALES AND TRANSPORTATION OF NATURAL GAS UNDER THE NATURAL GAS POLICY ACT OF 1978 AND RELATED AUTHORITIES

1. The authority citation for Part 284 continues to read as follows:

Authority: 15 U.S.C. 717–717w, 3301–3432; 42 U.S.C. 7101–7532; 43 U.S.C. 1331–1356.

2. In § 284.8, paragraph (i) is revised to read as follows:

§ 284.8 Release of firm transportation service.

* * * * *

(i) *Waiver of maximum rate ceiling.* Until September 30, 2002, the maximum rate ceiling does not apply to capacity release transactions of less than one year. The provision of paragraph (h)(1) of this section providing an exemption from the posting and bidding requirements for transactions at the applicable maximum tariff rate for pipeline services will not apply as long as the waiver of the rate ceiling is in effect. With respect to releases of 31 days or less under paragraph (h) of this section, the requirements of paragraph (h)(2) of this section will apply to all such releases regardless of the rate charged.

3. In § 284.12, the first sentence of paragraph (c)(2)(iii) and paragraph (c)(2)(v) are revised to read as follows:

§ 284.12 Standards for pipeline business operations and communications.

* * * * *

(c) * * *

(2) * * *

(iii) *Imbalance management.* A pipeline with imbalance penalty provisions in its tariff must provide, to the extent operationally practicable, parking and lending or other services that facilitate the ability of its shippers to manage transportation imbalances. * * *

* * * * *

(v) *Penalties.* A pipeline may include in its tariff transportation penalties only to the extent necessary to prevent the impairment of reliable service. Pipelines may not retain net penalty revenues, but must credit them to shippers in a manner to be prescribed in the pipeline's tariff. A pipeline with penalty provisions in its tariff must provide to shippers, on a timely basis, as much information as possible about the imbalance and overrun status of each shipper and the imbalance of the pipeline's system.

* * * * *

4. In § 284.13, paragraphs (b)(1) introductory text, (b)(1)(viii), (b)(2) introductory text, b(2)(iv), (b)(2)(vi), and paragraph (d)(1) are revised, and paragraph (f) is added, to read as follows:

§ 284.13 Reporting requirements for interstate pipelines.

* * * * *

(b) * * *

(1) For pipeline firm service and for release transactions under § 284.8, the pipeline must post with respect to each contract, or revision of a contract for service, the following information no later than the first nomination under a transaction:

* * * * *

(viii) Special terms and conditions applicable to a capacity release transaction, including all aspects in which the contract deviates from the pipeline's tariff, and special details pertaining to a pipeline transportation contract, including whether the contract is a negotiated rate contract, conditions applicable to a discounted transportation contract, and all aspects in which the contract deviates from the pipeline's tariff.

* * * * *

(2) For pipeline interruptible service, the pipeline must post on a daily basis no later than the first nomination for service under an interruptible agreement, the following information:

* * * * *

(iv) The receipt and delivery points covered between which the shipper is entitled to transport gas at the rate charged, including the industry common code for each point, zone, or segment;

* * * * *

(vi) Special details pertaining to the agreement, including conditions applicable to a discounted transportation contract and all aspects in which the agreement deviates from the pipeline's tariff.

* * * * *

(d) * * *

(1) An interstate pipeline must provide on its Internet web site and in downloadable file formats, in conformity with § 284.12 of this part, equal and timely access to information relevant to the availability of all transportation services whenever capacity is scheduled, including, but not limited to, the availability of capacity at receipt points, on the mainline, at delivery points, and in storage fields, whether the capacity is available directly from the pipeline or through capacity release, the total design capacity of each point or segment on the system, the amount scheduled at each point or segment whenever capacity is scheduled, and all planned and actual service outages or reductions in service capacity.

* * * * *

(f) Notice of bypass. An interstate pipeline that provides transportation (except storage) to a customer that is located in the service area of a local distribution company and will not be delivering the customer's gas to that local distribution company, must file with the Commission, within thirty days after commencing such transportation, a statement that the interstate pipeline has notified the local distribution company and the local distribution company's appropriate regulatory agency in writing of the proposed transportation prior to commencement.

§ 284.106 [Removed and reserved]

5. Section 284.106 is removed and reserved.

6. In § 284.221, paragraph (d)(2)(ii) is revised to read as follows:

§ 284.221 General rule; transportation by interstate pipelines on behalf of others.

* * * * *

(d) * * *

(2) * * *

(ii) Gives notice that it wants to continue its transportation arrangement and will match the longest term and highest rate for its firm service, up to the applicable maximum rate under § 284.10, offered to the pipeline during the period established in the pipeline's tariff for receiving such offers by any other person desiring firm capacity, and executes a contract matching the terms of any such offer. To be eligible to exercise this right of first refusal, the firm shipper's contract must be for service for twelve consecutive months or more at the applicable maximum rate for that service, except that a contract for more than one year, for a service which is not available for 12 consecutive months, would be subject to the right of first refusal.

* * * * *

Note: The following appendix will not appear in the Code of Federal Regulations.

Appendix

Rehearing Requests Filed in Docket Nos. RM98–10–000 and RM98–12–000

REHEARING REQUEST AND ABBREVIATION

American Gas Association—AGA
American Public Gas Association—APGA
Amoco Energy Trading Corporation and Amoco Production Company—Amoco
Arkansas Gas Consumers—Arkansas Gas Consumers
Atlanta Gas Light Company—Atlanta or AGLC
Cibola Energy Services Corporation—Cibola
CNG Transmission Corporation—CNG
Coastal Companies—Coastal
Columbia Gas Transmission Corporation—Columbia Gas
Columbia Gulf Transmission Co.—Columbia Gulf
Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities Inc.—ConEd or Con Edison
Dynegy Inc.—Dynegy
El Paso Energy Corporation Interstate Pipelines—El Paso
Enron Interstate Pipelines—Enron
Florida Cities—Florida Cities
FPL Energy, Inc.—FPL Energy
Great Lakes Gas Transmission Limited Partnership— Great Lakes
Illinois Municipal Gas Agency—IMGA or Illinois Municipal Gas Agency
Independent Oil and Gas Association of West Virginia—IOGA of WV
Independent Petroleum Association of America—IPAA
Indicated Shippers—Indicated Shippers
Interstate Natural Gas Association of America—INGAA
Keyspan Gas East Corporation and the Brooklyn Union Gas Company—Keyspan
Kinder Morgan Pipelines—Kinder Morgan
Koch Gateway Pipeline Company—Koch
Michigan Gas Storage Company—MGS or Michigan Gas Storage
Minnesota Department of Commerce—MDOC or Minnesota
National Association of State Utility Consumer Advocates, Ohio Office of the Consumers Counsel, Pennsylvania Office of Consumer Advocate—NASUCA
National Energy Marketers Association—NEM
National Association of Gas Consumers—NAGC
National Fuel Gas Distribution Corporation—National Fuel Distribution
Natural Gas Supply Association—NGSA
New England Gas Distributors—New England
Niagara Mohawk Energy, Inc.—NM Energy
Northwest Industrial Gas Users—NWIGU
Ohio Oil & Gas Association—OOGA
Paiute Pipeline Company—Paiute
Process Gas Consumers Group (American Iron and Steel Institute, Georgia Industrial Group, American Forest and Paper Association ALCOA, Inc. and United States Gypsum Company)—Process Gas Consumers or Industrials
Reliant Energy Gas Transmission Company and Mississippi River Transmission Corporation—Reliant
Reliant Energy Minnegasco—Minnegasco
Scana Energy Marketing, Inc.—Scana
Tejas Offshore Pipelines, LLC—Tejas
Texas Eastern Transmission Corporation—Texas Eastern
UGI Utilities, Inc.—UGI
Washington Gas Light Company—Washington Gas
Williams Companies, Inc.—Williams
Williston Basin Interstate Pipeline Company—Williston
Wisconsin Distribution Group—WDG

MASSEY, Commissioner, *concurring:*

One aspect of today's order that I would regard as a retreat from Order No. 637 is the change in the time at which pipelines must file transactional reports. Today's order would alter the timing of the contemporaneous posting of transactional information, from contract execution to first nomination prior to gas flow. Ostensibly, this is being done to achieve comparability between the reporting requirements for pipeline transactions and those for capacity release transactions, which was one of the stated objectives of Order No. 637. With this change, however, one can still regard the pipeline transactional filing requirements as contemporaneous if one is referring to the first nomination prior to gas flow. Nevertheless, I would have preferred not to make this change.

On balance, however, this is a solid, well-reasoned order that retains the character of the original order in most respects.

William L. Massey,

Commissioner.

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