DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Ch. I

[Docket No. RM98–12–000]

Regulation of Interstate Natural Gas Transportation Services

July 29, 1998.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of inquiry.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing this notice of inquiry to seek comments on its regulatory policies for interstate natural gas transportation services in view of the changes that have taken place in the natural gas industry in recent years. Specifically, the Commission is seeking comments on its pricing policies in the existing long-term market and pricing policies for new capacity.

DATES: Comments are due November 9, 1998.

ADDRESSES: Comments should be submitted to the following address: Federal Energy Regulatory Commission, 888 First Street, NE, Washington DC, 20426.

FOR FURTHER INFORMATION CONTACT: Ingrid Olson, Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426. (202) 208–2015

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Notice of Inquiry

In this Notice of Inquiry (NOI), the Commission is seeking comments on its regulatory policies for interstate natural gas transportation services in view of the changes that have taken place in the natural gas industry in recent years. The Commission is concerned that some of its policies, which were developed for a highly regulated market, need to be reexamined in light of the increasingly competitive natural gas industry. This NOI is broad in scope, and complements the Notice of Proposed Rulemaking in *Regulation of Short-Term Gas Transportation Services*, Docket No. RM98–10–000, (Short-Term Transportation NOPR or NOPR), issued today.

In the NOPR, the Commission is making specific proposals for changes in its regulation of short-term transportation services. The NOPR also addresses several long-term transportation issues that have a direct and significant impact on the short-term transportation policy proposals contained in the NOPR.[1] This NOI continues the Commission's review of its regulatory policies, and seeks comment on whether fundamental aspects of its pricing for long-term service and certificate pricing should be modified to be more effective in today's environment.

In the last several years natural gas markets have changed dramatically. As a result of the decontrol of gas prices at the wellhead by Congress[2] and the Commission's restructuring of pipeline services in Order No. 636,[3] gas markets have evolved from highly regulated markets to markets largely driven by competition and market forces.[4] Six years ago, pipelines were gas merchants and sold delivered gas to customers at Commission-regulated prices. Today, shippers can buy gas at the wellhead or from gas marketers, trade gas among themselves, and purchase pipeline capacity from marketers and other shippers in the secondary market, as well as from the pipeline. These changes have benefitted gas consumers by providing a wider range of options in pipeline services. These changes also require that the Commission consider whether the regulatory policies that were appropriate in the past, are well-suited to today's more competitive markets.

There are significant differences between short-term and long-term transportation, and they have been affected differently by the unbundling and restructuring of Order No. 636. The effects of unbundling have been more dramatic in the short-term transportation market, where numerous competitive alternatives for shippers have developed. These alternatives include purchasing capacity from the pipeline on an interruptible or short-term firm basis, purchasing capacity released by firm shippers, or purchasing delivered gas from a marketer or third party. This has led the Commission to propose changes to its regulation of short-term transportation in the companion NOPR. There are fewer alternatives in the long-term transportation market, and pipelines therefore retain a greater degree of

[1] As discussed below, in the NOPR, the Commission is proposing to eliminate the term matching cap of the right of first refusal, and is seeking comments on whether it should encourage term-differentiated rates.

[2] Wellhead Decontrol Act, Pub. L. 101–60, 103 Stat. 157 (1989).

[3] Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 57 FR 13,267 (April 16, 1992), III FERC Stats. & Regs. Preambles ¶ 30,939 (April 8, 1992); *order on reh'g*, Order No. 636–A, 57 FR 36,128 (August 12, 1992), III FERC Stats. & Regs. Preambles ¶ 30,950 (August 3, 1992); *order on reh'g*, Order No. 636–B, 57 FR 57,911 (December 8, 1992), 61 FERC ¶ 61,272 (November 27, 1992); United Distribution Companies v. FERC, 88 F.3d 1108 (DC Cir. 1996); *cert. denied* Associated Gas Distributors v. FERC, 117 S.Ct. 1723 (1997).

[4] *See, e.g.*, Arthur Andersen & Cambridge Energy Research Associates, *North American Natural Gas Trends*, at pp. 3, 8, 10, 51.

market power over some customers in the long-term transportation market.[5]

The trend in the natural gas industry since unbundling has been toward shorter-term contracts.[6] This places greater risks on the pipeline. Specifically, the long-term risk inherent in pipeline investment is the risk that the pipeline owner will not earn enough revenue during the pipeline's useful life to cover the total cost of the pipeline, including the variable cost of operating and maintaining it and an acceptable return on the investment.

In the past, shippers entered into long-term contracts because under those market conditions, the price risk to shippers associated with a long-term contract, *i.e.*, that the rates would increase during the term of the contract, was balanced by the fact that there was little or no supply risk. In the current market, however, the number of reliable alternatives to long-term pipeline transportation and gas supplies has increased, resulting in discounting of short-term transportation, while many shippers' own markets have become uncertain, due to retail unbundling.[7] Thus, an imbalance of risk between pipelines and shippers has developed in the long-term market, resulting in a bias toward short-term markets on existing capacity. This imbalance of risks has led shippers to be less willing to shoulder the price risk associated with long-term contracts.

While the trend in the industry has been toward shorter contracts, long-term contracts provide important benefits to pipelines and customers. Long-term contracts can provide revenue stability and reduce financial risks to the pipeline. This arguably lowers the pipeline's capital costs, to the benefit of its customers. Long-term contracts also act as an important risk-management tool for shippers, and ensure that there will be sufficient capacity available for release in the short-term market to provide competition for pipeline capacity in that market. Further, with removal of the price cap on short-term services as proposed in the companion NOPR published elsewhere in this issue of the **Federal Register**, long-term contracts offer price risk protection for captive customers.

As the Commission explains in the NOPR, it is concerned that some of its regulatory policies result in a bias toward short-term contracts. Specifically, the Commission states in the NOPR that the five-year matching cap in the right of first refusal and the use of the same maximum rate for service under long-term and short-term contracts result in asymmetry of risk and provide little incentive for a shipper to enter into a long-term contract with a pipeline. If a shipper enters into a long-term contract, it runs the risk that its rates will increase during the term of that contract. It can avoid that risk, and still be guaranteed to receive service indefinitely, by entering into a short-term contract with a right of first refusal.

Therefore, the Commission proposes in the NOPR to eliminate the five-year term-matching cap from the right of first refusal, and seeks comments on whether to encourage term-differentiated rates as a means of removing impediments to long-term contracts. Similarly, one Commission objective in the review undertaken in this NOI is to assure that the Commission's policies do not provide an artificial disincentive to long-term contracts, but are neutral with regard to long-term and short-term contracts.

The Commission's review undertaken in this NOI, however, is broader in scope, and is also directed at ensuring that the Commission's regulatory policies in general provide the correct incentives in the context of the realities of today's natural gas transportation market. This task is complicated by the fact that the realities of this market may vary from region to region or market to market, and the Commission's policies must be suited to a variety of circumstances.

For example, when long-term contracts expire and are not renewed, capacity turnback may be a problem on some pipelines or in some markets.[8] On the other hand, it has been projected that demand for capacity will increase in the future.[9] This indicates that market conditions may vary from market to market, and that while, in some markets, demand may be shrinking, and capacity turnback may be a consequence, in other markets, demand may be growing and expansions of capacity may be needed. These changes are likely to occur at the same time and no single development is likely to characterize the whole natural gas market. The Commission wants to ensure that its policies are not biased toward either short-term or long-term service, and provide accurate price signals and the right incentives for pipelines to provide optimal transportation services and construct facilities that meet future demand, but do not result in overbuilding and excess capacity. At the same time, the Commission wants to assure that its policies continue to provide appropriate incentives to producers.

Pricing of Existing Capacity. The Commission's statutory responsibility under the Natural Gas Act is to protect consumers of natural gas from the exercise of monopoly power by pipelines,[10] and to assure that rates for interstate transportation are just and reasonable. The Commission has proposed in the NOPR that removal of the price cap in the short-term transportation market is consistent with these statutory responsibilities. The Commission's proposals for regulatory change in the short-term market are intended to maximize competition in the short-term market, and at the same time protect customers from the exercise of market power.

An important aspect of the regulatory regime proposed in the NOPR is the continued use of cost-based ratemaking in the long-term market as a protection against the pipelines' exercise of market power. If pipelines could charge unregulated rates in the long-term market, then that protection would be eviscerated. Moreover, pipelines continue to be the only source of long-term transportation capacity, and without cost-based regulation for long-term transportation, pipelines would have an incentive to build less than the optimal amount of capacity in order to create scarcity, with the goal of driving up prices and profits. The retention of cost-based regulation for long-term transportation protects customers because it gives pipelines incentives to build new capacity when it is warranted, and thus limits the

[5] *See* Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, 70 FERC ¶ 61,139 (1995), 60 FR 8356 (February 14, 1995).

[6] *See e.g.*, Order No. 636–C, 78 FERC ¶ 61,186, slip op. at 26 (1997), 62 FR 10204 (March 6, 1997). As discussed below, the Commission is seeking comments on whether the trend toward shorter-term contracts is a natural result of competition in gas commodity and pipeline capacity markets, or is a consequence of other factors, such as regulatory policies.

[7] *See* "Future Unsubscribed Capacity," AGA LDC Caucus, December 1995, p.1.

[8] *See e.g.*, El Paso Pipeline Company, 72 FERC ¶ 61,083 (1995); Natural Gas Pipeline Company of America, 71 FERC ¶ 61,391 (1995). *See also* "Future Unsubscribed Capacity," AGA LDC Caucus, December 1995. As discussed below, the Commission is seeking comments on the extent to which capacity turnback is likely to be a problem in the future.

[9] The Energy Information Agency (EIA) of the Department of Energy projects an increase in gas demand from 22.0 Tcf annually in 1996 to between 29.4 Tcf and 34.5 Tcf annually in 2020.

[10] *E.g., FPC* v. *Hope Natural Gas,* 320 U.S. 591, 610 (1944)(the primary purpose of the NGA is "to protect consumers against exploitation at the hands of natural gas companies."); *Associated Gas Distributors* v. *FERC,* 824 F.2d 981, 995 (DC Cir. 1987), *cert. denied,* 485 U.S. 1006 (1988) ("The Natural Gas Act has the fundamental purpose of protecting interstate gas consumers from pipelines' monopoly power.")

pipeline's ability to profit from withholding capacity by not building. The Commission, therefore, is not extending the proposal to remove the price cap to the long-term market. The Commission will retain cost-based regulation in the long-term transportation market to protect shippers against the exercise of market power by pipelines.

Rates must meet statutory requirements and should, at the same time, provide pipelines with the appropriate incentives to provide optimal transportation services. Ideally, these rates should protect customers from the long-term exercise of market power by pipelines, provide the appropriate incentives for new construction, reasonably ensure the financial viability of pipelines, and provide an adequate incentive for pipelines to operate efficiently. Cost-based rates should be determined in an administratively efficient manner and should be current, predictable, fair, and economically rational. The Commission is evaluating whether its existing pricing policies meet these goals. One purpose of this NOI is to obtain public comment on these objectives and the adequacy of Commission policy in achieving these objectives.

The need to re-examine the Commission's policies affecting long-term markets is even greater now as the Commission proposes in the NOPR to eliminate the price cap on pipeline short-term firm and interruptible transportation, and released capacity. The continued availability of viable regulated long-term recourse services will be one of the primary tools for mitigating the market power of capacity sellers in the short-term markets. The extent to which long-term services mitigate the market power of capacity sellers will depend on how well these services meet the existing and future needs of transportation customers, and thus are worth being purchased as an alternative to the short-term market.

Specifically, the Commission's current long-term pricing policies may be deficient by failing sufficiently to take into consideration long-term factors, focusing instead on short-term data such as test period results and the need to recover each pipeline's revenue requirement from its existing customers each year. This policy focuses on each pipeline's individual situation rather than emphasizing the most efficient pricing for the market as a whole. Further, by failing to consider the relationship of cost-of-service pricing to the market value of pipeline services, current regulatory policies often result in pipelines with dramatically different cost-of-service rates serving the same markets. In addition, this pricing policy assumes that as long as customers eventually receive refunds, prices can remain in effect for several years, subject to refund, without adversely affecting the customers or the market as a whole. All these aspects of the Commission's cost-of-service regulatory model may not reflect the realities and needs of the industry today.

The Commission is interested in exploring whether the current pricing policy may have played a role in price distortions in the California and Chicago markets and, if it did, whether it could lead to similar distortions in other Midwestern and Eastern markets in the near future. In the California market, Transwestern Pipeline Company [11] and El Paso Natural Gas Company (El Paso) [12] faced significant turnback of long-term firm capacity at the same time that Mojave Pipeline Company, Kern River Gas Transmission Co., and Pacific Gas Transmission Company (PGT) were constructing additional pipeline capacity to serve the California market. Because of the capacity turnback, El Paso filed to increase its rates to fully recover its annual revenue requirement from its remaining customers. In addition, El Paso argued for a higher return on equity because its business risks had increased. The Commission accepted this increase, subject to refund.

While El Paso, Transwestern, and the parties eventually worked out settlements, the high subject-to-refund rates remained in effect for a significant period. Thus, while the parties avoided the direct ramifications of the Commission's current pricing method, *i.e.*, the shifting of all unrecovered costs to the captive customers, El Paso charged high unreviewed rates pending final resolution before the Commission.

PGT, on the other hand, was fully contracted under long-term contracts. Thus, under the Commission's current pricing method, PGT was able to have relatively low rates while still recovering its Commission-authorized annual revenue requirement. Having relatively low rates placed PGT in the position of receiving requests for additional service which it had to refuse. PGT's solution to this was to expand its system to meet the additional demand for service and roll-in the cost of the expansion into its existing rates to minimize the rate impact on its expansion customers.

A similar sequence of events occurred in the Chicago market with Natural Gas Pipeline Company's turn-back rate filing [13] and the Northern Border expansion. In both instances, the Commission's policies permitted pipelines unable to retain sufficient capacity reservations to increase rates to captive customers, while permitting fully-booked and low-priced pipelines to build expensive expansion facilities that had a higher unit average cost than the average cost of the existing facilities serving the market. The Commission is seeking comments on whether its policies contributed to these price distortions, and, if so, whether and how its policies should be modified to avoid these types of price distortions in the future.

As discussed more fully below, the Commission is seeking comments on whether a type of cost-based ratemaking other than its traditional cost-of-service method may be more appropriate in today's market. Specifically, the Commission seeks comments on whether index rates or incentive rates may now be appropriate as the primary rate-setting methodology. In addition, the Commission seeks comments on whether, if traditional cost-of-service ratemaking is retained, modifications to the traditional method would result in improvements. For example, should there be changes in the straight fixed variable (SFV) rate design preference, the discount adjustment policy, or rate of return policies.

Pricing New Capacity. The Commission is also reviewing its policies for pricing of new capacity to assure that they provide the proper incentives for pipelines to build or not build new capacity to meet increased demand. The Commission seeks comments on these issues as discussed below. If price signals are correct, the problem of overbuilding to attract customers from other merchants may be obviated.

I. Pricing Policies in the Existing Long-Term Market

As explained above, the Commission intends to retain cost-based rate regulation for long-term transportation. The traditional cost-of-service rate regulation currently used by the

[11] Transwestern Pipeline Company, 72 FERC ¶ 61,085 (1995). Transwestern faced a turn-back of 457,281 MMBtu. Transwestern did not unilaterally file to increase its rates to reflect the turn-back in this proceeding. Rather, the right to do so was reserved by Transwestern as the explicit option in the event another accommodation could not be achieved.

[12] El Paso Natural Gas Company, 72 FERC ¶ 61,083 (1995). El Paso faced a total turnback of approximately 1,300,000 MMcf from PG&E, SoCal and others.

[13] Natural Gas Pipeline Company of America, 71 FERC ¶ 61,391 (1995). Although Natural noted that 3.6 Bcf of contracts were due to terminate, its rates reflected only 600,000 MMBTU of turn-back. *See* 73 FERC ¶ 61,050 (1995).

Commission is one type of cost-based ratemaking methodology, but there are other types of cost-based ratemaking, such as index rates or incentive rates. The Commission is reviewing its current cost-of-service ratemaking methodology to determine whether changes to that methodology could result in better price signals and contracts which would strengthen the long-term market.

First, the Commission is considering whether cost-based ratemaking options, other than the traditional cost-of-service model, would be more appropriate in today's market. As discussed below, the Commission is considering several types of index rates, that are based on factors other than only the pipeline's costs and volumes, such as the supply and demand characteristics of the market being served. Second, the Commission is considering whether, if traditional cost-of-service regulation is retained, modifications to the current methodology would result in improved rate regulation. Specifically, the Commission is considering whether it should reevaluate its preference for SFV, whether it should change its current discount adjustment policy, whether it should adopt a policy that shippers with long-term firm contracts should be guaranteed fixed rates, and whether the Commission should allow pipelines to recover any of the costs associated with unsubscribed capacity.

The Commission seeks comment on the specific pricing options discussed below, as well as other aspects of its current rate policies not specifically discussed here that commenters believe may aid in the Commission's deliberations. In addition, the Commission seeks comment on whether the trend toward shorter-term contracts is a natural consequence of competition in natural gas markets, including state retail unbundling programs, or whether it is contributed to in part by the Commission's pricing policies. In addition, the Commission seeks comment on whether there is a substantial basis for its concern that movement away from long-term contracting will have negative consequences.

A. Other Cost-Based Options

1. Index Rates

Index rates may be more responsive to changes in economic conditions, and may provide incentives for pipelines to cut costs and be efficient because they will not have to share those benefits as a result of a rate case.[14] Index or benchmark adjustments to effective rates can avoid much of the regulatory costs and delay involved in resolving cost-of-service, throughput, and capacity issues in a general rate case, although they require data collection and analysis to establish the index or benchmark adjustment. Also, to the extent that current conditions in the gas industry result in a pipeline's inability to recover its cost-of-service, establishing rates based upon an index or benchmark may be of value. There are a number of ratemaking methodologies based upon an index.

In Order No. 561,[15] the Commission adopted an index method of ratemaking for oil pipelines that uses the producer price index for finished goods and an industry cost-based efficiency adjustment to modify existing just and reasonable rates. The oil rule retains a traditional cost-of-service option for special circumstances. The Commission requests comments on whether a similar method for establishing index rates could be used for gas transportation rates, and whether any of the other types of indexes discussed in Order No. 561 should be considered. Specifically, the Commission seeks comments on whether there are differences in the gas industry that make use of such an index to set gas pipeline rates inappropriate, and whether it is significant that the makeup of the entities holding capacity on gas pipelines may be changing to more closely resemble oil pipelines, *i.e.*, more capacity held by pipeline affiliates. Also, the Commission seeks comments as to what rates should be utilized from which index or benchmark adjustments would be made.

Another possible index methodology would be one based upon the existing percent of the end-use price that transportation represents in selected competitive markets. Under this type of methodology, once the transportation percentage was determined, the allowable transportation rate would fluctuate with the end-use price in competitive markets, but the percentage itself rarely would be altered. Because there are differing transportation costs for pipelines in the same markets, implementation of this method might be difficult, and the Commission seeks comments on the feasibility and benefits of such a methodology.

Another index methodology would be to establish a rate per 100 miles based upon current construction costs. The index would adjust rates to reflect changes in the costs of construction. One issue here is whether the index should reflect the greatly varying costs of old, largely depreciated pipelines and new pipelines. Several separate rates could be established for different broadly-defined vintage categories. Such an approach could be administratively difficult, and could lead to widely differing rates for pipelines in the same geographic area, and again the Commission seeks comments on the feasibility and benefits of such an approach. The Commission is also interested in receiving other indexing proposals.

2. Incentive and Performance Rates

The Commission has long had an interest in performance-based and incentive regulation. The Commission invites comment on the adoption of performance-based or incentive regulation in light of the gas market developments since implementation of Order No. 636. Incentive rate proposals are intended to result in better service options at lower rates for consumers while providing regulated companies with the opportunity to a fair return. Incentive regulation is not intended for competitive markets. It is intended for markets where the continued existence of market power prevents the Commission from implementing light-handed regulation without harm to consumers. The Commission continues to believe that incentive rate mechanisms have potential to benefit both natural gas companies and consumers by fostering an environment where regulated companies that retain market power can achieve greater pricing efficiency and cost-effectiveness.

In the January 31, 1996 policy statement,[16] the Commission adopted new criteria for evaluating incentive rate proposals. Under this policy, incentive proposals must explicitly state the incentive performance standards, the mechanism for sharing benefits with customers, and a method for evaluating performance under the proposal, as well as state the specific term during which the incentive program would operate.

Although no pipeline has proposed incentive regulation since the Commission modified the requirements in the policy statement on alternatives to cost-of-service regulation, the

[14] On the other hand, because pipelines are not currently required to file rate cases on a regular basis, they may already have adequate incentives to cut costs. However, as discussed below, the Commission is seeking comments on whether it should require pipelines to undergo periodic rate review under section 5 of the NGA. Also, in the NOPR, the Commission is proposing to implement periodic reviews of the rates, terms, and conditions of recourse service rates to ensure that they remain a viable alternative to negotiated terms and conditions.

[15] FERC Stats. and Regs., Regulations Preambles, January 1991-June 1996, ¶ 30,985 (1993).

[16] Statement of Policy and Request for Comments, 74 FERC ¶ 61,076 (1996), 61 FR 4633 (Feb. 7, 1996).

Commission would like to reopen discussion on whether these alternatives might provide a more equitable sharing of cost savings, enhanced incentives for productive efficiency, or greater pricing flexibility to respond to new competitive realities.

At the outset, the Commission seeks comment on whether a performance-based incentive program is appropriate given the conditions of today's natural gas market, and why pipelines have not proposed an incentive rates program? Does the incentive rate program outlined in the Policy Statement provide an adequate frame work for pipelines to propose incentive rates? Should the Commission simply impose incentive rates of its own design? Is the current ability of pipelines to retain cost savings by simply avoiding a Section 4 rate case an adequate incentive to cut costs and innovate services? Does the cost structure of interstate pipelines lend itself to incentive/performance regulation? Is state experience with incentive/performance rates instructive given the fundamental differences in the cost structure of State regulated utilities compared to interstate pipelines, specifically the lack of purchased gas costs for interstate pipelines?

Assuming incentive and performance rates are appropriate, the Commission seeks comment on whether maximum rates should be based on individual pipeline costs exclusively or whether, in an era of growing competition, aggregate industry-wide measures should also be included. The Commission also seeks comment on what performance-based measures might be used to modify pipeline rates of return and how the rates of return should reflect performance. Commenters should also note whether any proposed performance-based or incentive regulation would require changes to currently reported data or additional market-monitoring requirements.

3. Financial Implications of Other Cost-Based Options

In considering the alternative ratemaking methodologies discussed above, the Commission is interested in obtaining comments on the financial impact these alternative methodologies may have on the pipelines. One such implication is the effect on regulatory assets. A regulatory asset is established when companies are provided with assurances that it is probable that they will be able to recover the deferred costs through future rates. Normally, absent a regulatory decision to allow out-of-period recovery of costs, the amounts would have to be expensed in the period incurred.

If some or all of the industry moves away from setting rates on the basis of jurisdictional pipelines specific costs, accounting standards require companies to eliminate from their financial statements all assets recognized solely due to the actions of regulators. Another impact of departing from cost-of-service ratemaking is that no more regulatory assets and liabilities can be created. Instead companies will have to include in net income any expenses/losses incurred and revenues/gains realized in the periods in which they occur.

In light of the above, the Commission seeks information on the following: What difficulties will companies encounter as a result of writing off regulatory assets (*i.e.,* difficulty in paying out its dividends, obtaining new financing, meeting bond coverage requirements)? Can a rate transition plan be devised that would avoid the write-off? What impacts do companies foresee of no longer being able to use special regulatory accounting principles (*i.e.,* the anticipated write-offs of regulatory assets and impairments losses for fixed assets)? How will the Commission's proposals for the short-term market affect pipelines' return or financial condition?

B. Market-Based Rates for Turnback Capacity

Another approach to ratemaking would be for the Commission to retain cost-based ratemaking as the general rule in long-term markets, but authorize market-based rates in certain circumstances, specifically, in the case of turnback capacity. A concern raised by the existence of turnback capacity is how the costs of such capacity can be recovered. One way of pricing turnback capacity would be to establish a two-step process where the capacity would be first offered for sale by the pipeline. If the pipeline could not market the capacity, the capacity could be deemed excess to the market's need and allowed to be priced in the future using market-based pricing principles.

The rationale would be that all existing and potential customers would first have an opportunity to acquire the capacity at a Commission-established cost-based rate, and further, that a pipeline could not be deemed to have market power over capacity that it cannot sell. As part of this approach, the pipeline would be denied the right to raise the price of its remaining contracted capacity to compensate it for any potential cost underrecovery associated with the capacity being priced on a market basis. While initially the capacity would be sold at a discount rate, if at all, this approach would provide pipelines with the opportunity to recover some, or possibly all, of the losses associated with the turnback capacity because, when market conditions changed and there was a demand for the capacity, the pipeline could continue to charge market-based rates for the capacity.

The Commission seeks comments on this proposal and suggestions for its implementation. Specifically, the Commission seeks comments on how long a pipeline should be permitted to charge market-based rates after a change in market conditions. Should the Commission reexamine the market power issue after one contract term, or after one or two years, or some other period? The Commission also seeks comments on the financial implications of this ratemaking option, and whether the financial implications are the same as those discussed in the preceding section.

C. Cost-of-Service Options

In the companion NOPR, the Commission is proposing to remove the price cap in the short-term market and, therefore, there is the need to provide mitigation of potential or actual market power of capacity sellers. As explained above, the Commission believes that the best method of mitigation is to provide Commission-regulated recourse rates to all shippers who desire such rate protection. The Commission is reevaluating the adequacy of the traditional cost-of-service ratemaking as a means of providing such recourse rates. Under the Commission's traditional cost-of-service ratemaking, the pipeline's rates are based on that pipeline's costs and the shippers' usage patterns. Thus, the level of each pipeline's rates is determined in part by the pipeline's costs, the timing of its recovery, and the level of usage of the pipeline. The Commission seeks comments on whether its traditional cost-of-service method continues to be appropriate for natural gas transportation services, and if so, whether the modifications discussed below, either individually or in combination, could result in more efficient and effective regulation.

One possible modification of the current system would be to use the highest available cost-based incremental rate as the system Part 284 open access rate for new customers. In *PG&E,* [17] the Commission determined that when turnback capacity, permanent capacity release, and new expansion capacity become available on a system with

[17] 82 FERC ¶ 61,289 (1998). See also the discussion in section II, *infra*.

incremental rates for similar services, the pipeline and the releasor may price the capacity at the incremental rate. In the *PG&E* case, the rate for the incremental facilities would ''roll down'' over time as more shippers were subject to the incremental rate. The basis for this decision is that a price found just and reasonable for one set of customers is just and reasonable for all subsequent customers receiving the same service.

The Commission seeks comment on whether the highest available cost-based incremental rate should be used as the system Part 284 open access rate for new customers, consistent with the rationale of *PG&E*. This policy would encourage customers to negotiate long-term contracts to ensure that their rates become ''locked in'' over the long term. Comments should also consider the revenue implications of such a policy. In particular, should the higher revenue from the new contracts at the incremental rate be used to offset the costs of unsubscribed capacity on other parts of the system? Or, should the pipeline be allowed to keep the high revenues garnered from the new contracts during the period between rate case filings?

Another ratemaking option would be to establish a maximum rate equal to the pipeline's cost-of-service divided by its capacity, or some fraction thereof, for example, 80 percent. This methodology would have the advantages of protecting captive customers from paying for extensive discounts to other customers, retaining an incentive for pipelines to add customers, and eliminating rate case gaming over throughput and billing determinants. On the other hand, the difficulties in establishing the cost-of-service and the capacity of the pipeline would still remain, and it may be very difficult for some pipelines to recover their costs under this methodology if the capacity fraction is too high. The Commission seeks comment on this approach.

The Commission also seeks comment on the role of periodic rate review in the ratemaking process. The recourse rates are a mitigation measure for the removal of the price cap in the short-term market, and the Commission is concerned that the recourse rate could become ''stale'' and not an adequate alternative to short-term rates. Under current Commission policy, the filing of a rate case is at the discretion of the pipeline. This policy allows the pipelines to time the filing of a rate case to coincide with a test period that maximizes the benefits to the pipeline of a rate increase filing. It can be argued that the period between rate cases represents an opportunity for pipelines to collect what are, in effect, incentive rates. The pipeline has the incentive to cut costs and operate more efficiently as well as to increase throughput over the level on which the rates are based. If it does so, it can reap the benefits of the additional revenue without sharing it with its customers. With pipelines no longer required to come to the Commission for a periodic rate review, the period where a pipeline can operate this way is at the option of the pipeline.

The Commission seeks comments on whether it should require that pipelines undergo periodic rate review under section 5 of the NGA, and if so, how such a requirement should be implemented.[18] Parties may comment on whether Section 5 proceedings can realistically be expected to operate as a substitute for Section 4 proceedings, and whether the collection of Form No. 2 or other data in such a way that the Commission could quickly and routinely identify large cost-of-service and billing determinant discrepancies would facilitate review.

The Commission also seeks comments on whether it should reevaluate its preference for a straight fixed variable (SFV) rate design. Under SFV rates, all the fixed costs of the pipeline service are recovered in the reservation charge. The usage charge recovers only the variable costs. While SFV rates have furthered the Commission's goal of achieving a national transportation grid, SFV has had other effects that may have contributed to the trend toward short-term contracts and capacity turnback. Shippers may be unwilling to sign long-term contracts when such contracts require a commitment to pay large reservation charges for a long period of time. This reluctance may be greater in this time of transition when LDCs are unsure how retail unbundling will affect their future capacity needs. Shippers may be unsure whether they can recover the majority of their costs in the release market. Thus, SFV rates may encourage some shippers to opt for short-term contracts to cover only peak periods, weakening long-term markets and thus the mitigation power such long-term markets are expected to provide to recourse shippers. The Commission seeks comments on how well SFV suits the needs of the market and whether it is unduly hampering the marketability of long-term firm contracts.

On June 26, 1998, the Public Service Commission of the State of New York (New York) filed a petition[19] asking the Commission to institute a rulemaking proceeding to determine whether changes in natural gas markets require the Commission to revisit its preference for the SFV rate design, and, if so, what changes in Commission policy are appropriate. New York advocates a shift away from SFV, and asserts that such a shift would promote development of a competitive transportation market. New York does not propose any particular alternative to SFV, but recommends that the Commission require pipelines to employ a rate design that recovers some or all of their fixed costs in the usage component of the two-part rate. The concerns raised by New York[20] are similar to the issues raised by the Commission's discussion above. These issues should be discussed by commenters in this docket.

The Commission is also seeking comments on whether it should change its current discount adjustment policy. The discount adjustment permits pipelines to shift revenue recovery from discounted transportation to customers who do not receive discounts. The Commission seeks comments on whether discount adjustments unfairly affect captive customers, and generally create unnecessary rate uncertainty for non-discounted customers. Parties may address whether permitting discount adjustments will be consistent with negotiated rates and terms and conditions; what would be a reasonable limit on a pipeline's ability to recover discounts; whether an absolute prohibition on recovering discounts would be fair, workable, and efficient; and what other types of rate

[18] In the NOPR, the Commission is proposing to implement periodic reviews of the rates, terms, and conditions of recourse service rates to ensure that they remain a viable alternative to negotiated terms and conditions. The review discussed here in this NOI would be broader in nature, and the Commission envisions that this review could involve review of all the pipeline data relevant in a section 4 rate case.

[19] Petition of the Public Service Commission of the State of New York for Rulemaking Proceeding Regarding Rate Design for Interstate Natural Gas Pipelines, Docket No. RM98–11–000.

[20] Specifically, New York states that the SFV rate design shields high cost pipelines from competition from low-cost pipelines because it provides for the collection of fixed costs through the demand charge regardless of throughput. In addition, New York states, as long-term contracts expire, the high reservation charge under the SFV rate design may reduce the marketability unsubscribed turnback capacity. New York argues that permitting parties to negotiate rates that deviate from SFV, while requiring recourse rates to be based on SFV, creates an unjustified rate disparity between customer groups, and allows pipelines to exercise market power over captive customers. Further, New York asserts that a move away from SFV may reduce the need for discounting, and would also discourage inflated equity ratios. New York states that Commission rate design policies should be harmonized with state retail access initiatives, and that it is concerned that SFV reservation charges may discourage the entrance of new suppliers to the retail markets.

mechanisms could be substituted for the current discount adjustment to improve the current practice.

The Commission seeks comments on other specific possible modifications to its cost-of-service ratemaking, as well as any other areas that could be reexamined, including the affect of the various options on a pipeline's ability to achieve a reasonable rate of return.

D. Other Pricing Issues

Several other aspects of the Commission's rate regulation in the long-term market are under review regardless of whether the Commission adopts any of the options discussed above. The Commission also seeks comments on whether it should consider changes in the policies discussed below.

1. Fixed Rates for Firm Contracts

Currently, long-term firm contracts usually do not equate to fixed rates, and this tends to discourage long-term contracting, weakening the long-term market. Absent a fixed-rate contract, firm shippers are offered long-term commitments with price uncertainty. Rates can increase during the term of the contract due to increased costs, including increases in the pipeline's operating costs, rate of return, or diminished demand for capacity. Rates can also increase if expensive new capacity is rolled into the existing rate base without sufficient increases in throughput to offset the cost of the facilities. Currently, with few exceptions, shippers cannot reduce their firm capacity holdings until their contracts expire, even if the price charged for that capacity increases substantially.

The possibility that rates can increase unpredictably during the contract term creates risk. This undermines the value of long-term contracts as a way to mitigate future price risk and discourages long-term contracts. While pipelines are permitted to negotiate customer-specific rates under the Commission's negotiated rate program, it is unclear whether this program provides workable rate certainty or whether this opportunity is available on all pipelines.

In the companion NOPR, the Commission is proposing to allow pipelines and shippers to negotiate terms and conditions of service within certain limits. The Commission requests comments on whether this service flexibility, coupled with existing authority to negotiate rates addresses this concern. Also, the Commission seeks comments on whether the Commission should adopt a policy that with firm contracts shippers should have fixed rates. Specifically, the Commission is seeking comments on what changes to the cost-of-service should be reflected in rates for existing firm contracts, i.e., whether changes in physical plant, taxes, operations and maintenance expenses, and related items should be allowed to affect firm contract rates. The Commission is also seeking comments on whether, in the alternative, this should be left as a contracting matter between the pipeline and its customers. The Commission is also considering whether it should allow existing pipelines that negotiate fixed-rate, long-term contracts to shift future cost increases to other customers, and seeks comments on this issue as well.

Another option would be to permit shippers to reduce their firm capacity if the pipeline increased the reservation charge or, if the Commission moves away from the SFV rate design, any part of the rate. Comments should address pipeline cost recovery issues as well as the rate impact of these proposals.

2. Costs Associated with Unsubscribed Capacity

Even if the Commission changes its regulatory policies for short-term and long-term transportation, there may be cases where the rates will not recover the embedded costs of the pipelines' facilities. The Commission seeks comments on whether it should allow pipelines to recover some or all of these costs, and if so, what approach to adopt.

As discussed above, one approach would be to authorize market-based rates for unsubscribed capacity. Another method could be to follow the lead of the electric industry and impose a non-bypassable access charge on transportation customers.[21] This charge would be independent of the volumes the shipper placed on the system or grid. This could be applied on a system-by-system basis, or on a grid basis. Another method would be to institute a volumetric usage charge designed to recover the fixed costs of the system. This would be similar to ''uplift charges'' as discussed in the electric ISO filings.[22] A third possible method would be to allow pipelines to bank costs, such as depreciation expenses, for future recovery. A fourth possible method would be to permit pipelines to design rates based on less than the total pipeline capacity.

The comments should address these options, and any others, as well as how, as a practical matter, these methods could be implemented. In addition, the Commission is seeking comments on whether capacity turnback is a significant problem in long-term transportation markets, and whether it is likely to be a problem in the future, particularly in light of some projections for the growth of the gas market.[23]

II. Pricing Policies for New Capacity

Some of the discussion above would apply to new capacity as well as to existing capacity. There are, however, issues unique to the pricing of new capacity, and new capacity presents an opportunity for pipelines and customers to balance appropriately the risks associated with the cost of new facilities. Problems resulting from asymmetry of risk between shippers and pipelines in the long-term transportation market[24] that can lead to a bias favoring short-term contracts can be avoided with regard to new pipeline capacity if the issue of allocation of risk is resolved properly before the pipeline is built. The best time to settle the allocation of risk for the costs of new capacity is before construction, and it is crucial to allocate risk and potential rewards at that time. Those who bear the risks should stand to receive the rewards for the risks taken.

A well-balanced policy could help avoid creation of new capacity with unbalanced risks and returns. A well-coordinated certification and pricing policy should also provide proper incentives for pipelines to invest in new facilities that are needed to meet increased demand, and avoid problems of excess capacity that may be caused by construction of facilities to compete for existing market share. In addition, pricing and certification policies should provide incentives to producers so that sufficient quantities of gas will be produced, and to consumers of gas, so that the choice of gas is an economically viable option. The proper incentives to all the parties in the gas market will benefit the market as a whole. For these reasons, the Commission seeks comments on certain issues specifically related to the pricing of new capacity.

A. Risk Allocation

The Commission is seeking comments on whether and how to encourage pipelines and customers to negotiate pre-construction risk and return-sharing

[21] *See e.g.*, Pacific Gas & Electric Co., 77 FERC ¶ 61,204 at 61,794&n.5 (1996); Order No. 888, slip op. at 271.

[22] *See e.g.*, New England Power Pool, 83 FERC ¶ 61,045, slip op. at 22–25 (1998).

[23] The Energy Information Agency (EIA) of the Department of Energy projects an increase in gas demand from 22.0 Tcf annually in 1996 to between 29.4 Tcf and 34.5 Tcf annually in 2020.

[24] See the discussion in the companion NOPR.

agreements. Customers could commit to life-of-the-facilities contracts, fairly short-term contracts, or anything in between. Short-term contracts involve greater risks for the pipeline as to total cost recovery of the new facilities, and this should be reflected in the parties' contract. Pre-construction negotiations and resulting contracts should appropriately and specifically balance risks and return regarding such matters as what price should be paid for early contract termination and cost collection if the term of the contract is less than the life of the facilities.

However, if pipelines and customers do not agree on the allocation of risk and return, the Commission seeks comments on whether it should decide the issue before construction, and not change the risk allocation in later rate cases unless extraordinary circumstances exist, or not approve the construction. Specifically, the Commission seeks comments on what action, if any, the Commission should take to ensure rate and contract certainty for customers and pipelines. Should this include guarantees against future rolling-in of costly expansions, future changes in O&M expenses, or any other future changes? The Commission is also seeking comments on the advantages (or disadvantages) of allowing pipelines and customers to negotiate pre-construction risk and return-sharing agreements.

B. Rate Treatment for New Capacity

The Commission's pricing policy, *Pricing Policy For New and Existing Facilities Constructed by Interstate Natural Gas Pipelines* (Pricing Policy Statement), [25] is intended to minimize pre-construction risk by providing pipelines and their customers with as much up-front assurance as possible about how new capacity will be priced so they can make informed decisions about the amount of capacity to build and to buy. In the Pricing Policy Statement, the Commission adopted a presumption in favor of rolled-in rates when the rate increase to existing customers from rolling-in the new facilities is 5 percent or less and the pipeline makes a showing of system benefits. [26]

In *PG&E Transmission, Northwest Corporation* (*PG&E*), [27] the Commission announced a new policy for rate treatment of permanently released capacity, and new expansion capacity. Prior to the *PG&E* order, each of these types of capacity was subject to different pricing policies. Turnback capacity was usually priced at the system Part 284 rate. Release capacity was priced at the maximum stated rate for the released service. New expansion capacity was priced pursuant to the Pricing Policy Statement, either rolled-in or incremental depending on a variety of factors, including the 5 percent impact test. However, in *PG&E*, the Commission determined that when permanently released capacity, and new expansion capacity become available on a system with incremental rates for similar services, the pipeline and releasor may price the capacity at the incremental rate. The rationale of that decision can also apply to turned back capacity.

This policy has significant implications for long-term pricing. First, *PG&E* has created a uniform pricing approach for unsubscribed and unwanted capacity. Second, the pricing level chosen by the Commission is a form of replacement cost, or incremental cost pricing. This approach effectively limits the pricing differences between generations of customers to the term of their contracts. The rates for new capacity and services establish the higher rate; over a period of time, the system rate effectively rolls into and decreases the higher rate. Older services' rates are stabilized to reflect the deals that were struck at the time. As the contracts gradually expire and the lower cost pre-expansion capacity is included in the new system (formerly incremental) rate, that rate will decline, eventually becoming the rolled-in rate if no other expansions occur.

The Commission also seeks comments on the interrelationship of its at-risk policy and the *PG&E* policy. Although the *PG&E* policy provides clear market benefits, it may raise other issues with respect to incrementally-priced, at-risk pipelines. By permitting pipelines to charge new or renewing shippers on existing pipeline facilities the higher incremental rate, it could be argued that the pipelines are being permitted to place some of the economic risks of the new facilities onto those new or renewing shippers. In other words, if the new incrementally-priced facilities are underutilized, the pipeline would be permitted to mitigate its unrecovered costs through the rates charged to the new or renewing shippers on the existing pipeline.

On the other hand, there are benefits to the *PG&E* policy. One benefit is that it creates a strong incentive for customers to sign long-term contracts. Only through long-term contracts could customers be assured of locking-in the pricing associated with a given vintage of pipeline capacity. Once their contracts expire, customers would need to reacquire capacity at a potentially newer and higher priced vintage. The Commission seeks comments on whether the Commission's *PG&E* policy should be applied to at-risk pipelines.

C. The Effects of Depreciation on Long-Term Pricing

An appropriate depreciation rate for new facilities is established as part of the initial rate in a certificate case, and is, therefore, generally an issue related to new capacity, although a depreciation rate may be reviewed and changed in a later rate case.

In the past, within the context of a highly regulated environment, the Commission based the utility assets' economic depreciable life on the physical life of the asset, and recommended the straight line method of depreciation for allocating the assets' costs to periods benefitted. As changes in the industry occurred, it was evident that other factors, such as obsolescence due to new processes and techniques, environmental constraints, and competing markets were driving the determination of the economic depreciable life of pipeline facilities, and the Commission based the depreciable life on the useful life of the asset.[28] More recently, in initial rate cases for newly constructed facilities, the Commission has tended to equate economic life to the terms of the pipelines' long-term transportation contracts in setting depreciation rates for initial rates in the certificate process.[29] In this scenario, the life of the new facility is established by the contract term so that the new plant would be fully depreciated by the end of the contract.[30] This method, however, is not used in section 4 rate cases.

The physical lives of pipeline facilities can be over 40 years, and the economic lives as approved by the Commission in individual cases have generally been at least 20–25 years. However, current contracted terms may be as short as 10 years. Where the depreciation rate is based on contract term, initial customers ultimately pay the entire asset's costs in higher rates over a shorter period of time, even

[25] 71 FERC ¶ 61,241 (May 31, 1995).

[26] In the discussion of New Capacity Certification Issues above, the Commission has raised the question of whether this policy should apply where the facility is constructed to serve an affiliate.

[27] PG&E Transmission, 82 FERC ¶ 61,289 (1998).

[28] *See e.g.,* Memphis Light, Gas and Water Division v. FPC, 504 F.2d 225 (D.C. Cir. 1974).

[29] Tennessee Gas Pipeline Company, *et al.,* 55 FERC ¶ 61,484 (1991), approving depreciation rate based on the length of the contract with the shippers for whom the facilities were constructed.

[30] Of course, as noted above, the depreciation rate may be reviewed and changed in subsequent rate cases.

though the asset will physically provide benefits for longer than the initial contract term and to other customers.

This policy gives prospective shippers an opportunity to influence a significant part of their rates (*i.e.*, the depreciation component) by their choice of contract length. Continuation of this policy, or a broader application of it, could also help resolve the ''need'' issue discussed below by encouraging a greater shipper commitment before capacity is built. The Commission could both encourage longer term contracting for new capacity and shelter existing ratepayers from capacity turnback by declaring that new pipeline costs are fully recoverable over the contract term that supports its construction. However, on the other hand, such a policy could make the rates too high to make the project economically viable, and also results in a situation where later ratepayers would not pay any depreciation component for use of the facilities.

The Commission seeks comments on what criteria it should use to determine a depreciation period and rate for ratemaking purposes. Parties may address some or all of the following questions.

Given that the industry will stay in a partially cost-based rate regulated environment (*i.e.*, for determining recourse rates), on what criteria should the Commission base a depreciation rate? Would customers be willing to sign up for life-of-the-facilities contracts, thus promoting long-term service? Is it fair to require initial customers who sign up for less than the life-of-the-facilities contracts to pay for all costs of the asset over that shorter term since future customers may use and benefit from the facilities? If the initial customers are unwilling to pay the full costs, should the pipeline be built?

If use of the economic life is more suitable to foster fairness between new and existing customers, how should the economic life or benefit period be determined? Should the economic life be viewed as the expected period of time customers will use the asset or should it be viewed as the known period of time that customers contracted for using the asset? What amount of depreciation, if any, should be allocated to short-term services? What criteria should be used to make this determination? Will the criteria be sufficiently objective to avoid claims of cross-subsidization? How should depreciation be treated when some of the rates are market-based? To what extent does depreciation flexibility aid pipelines having cost recovery problems? Lastly, how should capacity be priced after it has been fully depreciated by its first generation of customers?

For cost-of-service purposes, these questions are not easily answered. For general purpose financial accounting and reporting, the Commission has required pipelines to depreciate facilities over their economic useful life and record regulatory assets and liabilities for the differences between ratemaking depreciation and accounting depreciation.[31] What are the implications of different depreciation rates for cost-of-service rate purposes versus accounting purposes if some portion of pipeline rates is not based on traditional cost-of-service ratemaking? Will pipelines be able to continue to record the difference as a regulatory asset or liability? What about income tax related issues?

V. Comment Procedures

The Commission invites interested persons to submit written comments on the matters and issues discussed in this notice of inquiry, and any related matters or alternatives that commenters may wish to discuss. An original and 14 copies of comments must be filed with the Commission no later than November 9, 1998. Comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426, and should refer to Docket No. RM98–12–000. All written comments will be placed in the Commission's public files and will be available for inspection in the Commission's Public Reference Room at 888 First Street, NE, Washington, DC 20426, during regular business hours.

Additionally, comments should be submitted electronically. Commenters are encouraged to file comments using Internet E-Mail. Comments should be submitted through the Internet by E-Mail to comment.rm@ferc.fed.us in the following format: on the subject line, specify Docket No. RM98–12–000; in the body of the E-Mail message, specify the name of the filing entity and the name, telephone number and E-Mail address of a contact person; and attach the comment in WordPerfect® 6.1 or lower format or in ASCII format as an attachment to the E-Mail message. The Commission will send a reply to the E-Mail to acknowledge receipt. Questions or comments on electronic filing using Internet E-Mail should be directed to Marvin Rosenberg at 202–208–1283, E-Mail address marvin.rosenberg@ferc.fed.us.

Commenters also can submit comments on computer diskette in WordPerfect® 6.1 or lower format or in ASCII format, with the name of the filer and Docket No. RM98–10–000 on the outside of the diskette.

By direction of the Commission.

David P. Boergers,

Acting Secretary.

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[31] See Kern River Gas Transmission Company, 58 FERC 61,073; Mojave Pipeline Company, 58 FERC 61,074 (1992); Florida Gas Transmission Company, 62 FERC 61,024 (1993), Order Granting and Denying Rehearing and Granting Clarification FERC 61,093 (1993); TransColorado Gas Transmission Company, 67 FERC 61,301 (1994), Order Granting in Part and Denying in Part Rehearing and Granting Clarification, 69 FERC 61,066 (1994); Sunshine Interstate Transmission Company, 67 FERC 61,229 (1994); and Mojave Pipeline Company, 69 FERC 61,244 (1994), Order Granting Rehearing in Part, Denying Rehearing in Part and Modifying Prior Order, 70 FERC 61,296 (1995).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 161, 250, and 284

[Docket No. RM98–10–000]

Regulation of Short-Term Natural Gas Transportation Services

July 29, 1998.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing an integrated package of revisions to its regulations governing interstate natural gas pipelines to reflect the changes in the market for short-term transportation services on pipelines. Under the proposed approach, cost-based regulation would be eliminated for short-term transportation and replaced by regulatory policies intended to maximize competition in the short-term transportation market, mitigate the ability of firms to exercise residual monopoly power, and provide opportunities for greater flexibility in the provision of pipeline services. The proposed changes include initiatives to revise pipeline scheduling procedures, receipt and delivery point policies, and penalty policies, to require pipelines to auction short-term capacity, to improve the Commission's reporting requirements, to permit pipelines to negotiate rates and terms of services, and to revise certain rate and certificate policies that affect competition.

DATES: Comments are due November 9, 1998.