

REPORT OF THE COMMITTEE ON NATURAL GAS REGULATION*

I. CERTIFICATE ISSUES

The Federal Energy Regulatory Commission (FERC) acted in a number of major section seven¹ certificate cases in 1997, elaborating further on issues significant to natural gas regulation.

A. *Demonstration of Market*

As a condition to certification, the FERC continued to require that a “substantial amount of . . . capacity” be subscribed to under long-term contracts, while recognizing an exception for low cost supply projects using existing rights-of-way with little or no environmental impact.² The FERC also recognized exceptions for new offshore facilities for which reserve commitments are expected,³ offshore expansions of existing pipelines where rates are set incrementally,⁴ and cases where no protests are filed, no environmental impact results, and the applicant is at risk through market-based rates.⁵

The FERC also addressed the effect of less than one hundred percent subscription of the proposed capacity for long terms (i.e., ten years or more) on certification. In that regard, the FERC held that the pipeline would be at risk to the extent that five-year contracts covering forty percent of the proposed capacity are not extended, resulting in unutilized facilities, placing it at risk for discounts given to shippers on expansion projects. Stating that it may not be able to recover those discounts from other shippers through a discount adjustment, the FERC also denied the request for a predetermination of rolled-in treatment.⁶

A new factor is changing the character of the market. Increasingly, shippers are marketers as marketing affiliates of the pipeline or one or more of the pipeline’s sponsoring parties, rather than local distribution companies or end-users. Although this issue has been flagged as a concern, the FERC regarded contracts with such entities as adequate for

* The FERC wishes to express special thanks to Gregory Camet, Associate at Morgan, Lewis & Bockius, and Danny G. Smith, Director-Federal Regulatory Affairs at Public Service Company of North Carolina, Inc., for their assistance in preparing this report.

1. 15 U.S.C. § 717f (1994).

2. *Transwestern Pipeline Co.*, 81 F.E.R.C. ¶ 61,172, at 61,752-53 (1997).

3. *Nautilus Pipeline Co.*, 78 F.E.R.C. ¶ 61,325 (1997); *Chevron U.S.A. Inc.*, 81 F.E.R.C. ¶ 61,183 (1997).

4. *Transcontinental Gas Pipe Line Corp.*, 78 F.E.R.C. ¶ 61,333 (1997), *amended*, 79 F.E.R.C. ¶ 61,286 (1997).

5. *Egan Hub Partners, L.P.*, 81 F.E.R.C. ¶ 61,017 (1997).

6. *East Tennessee Natural Gas Co.*, 79 F.E.R.C. ¶ 61,071, at 61,344 (1997).

purposes of issuing certificates. The FERC issued a certificate to Maritimes and Northeast Pipeline based on a single precedent agreement with an affiliate, even though the FERC found constraints on the system of the interconnecting upstream pipeline might prevent delivery of the maximum daily contract quantity on a regular basis.⁷ Similarly, the FERC issued a preliminary determination and a certificate for expansion of Transcontinental Gas Pipe Line Corporation's (Transco) Mobile Bay lateral based on a single fifteen year contract with an affiliate.⁸ Nautilus Pipeline Co. (Nautilus) also received a certificate based primarily on commitments from affiliates.⁹ The question of market support is also an issue in the Granite State Wells LNG project.¹⁰

B. The Ashbacker Doctrine

The FERC rejected a number of requests for a comparative hearing under the *Ashbacker* doctrine. The FERC issued a certificate to Nautilus authorizing construction of a pipeline in the Gulf of Mexico, while contemporaneously issuing a preliminary determination to ANR Pipeline Co. (ANR) to construct offshore facilities, subject to satisfactory environmental review. Furthermore, the FERC denied ANR's request to consolidate and hold a comparative hearing, finding that ANR had not shown the projects to be "necessarily mutually exclusive."¹¹ The FERC also stated that for many of the construction proposals targeting offshore Louisiana, it would let market forces decide as long as existing customers are protected and found that Nautilus' affiliation with its primary shipper did not require a different result. The FERC denied ANR's request for a stay, again rejecting the argument that *Ashbacker* was applicable because the projects are "measurably different and . . . there is no certainty that the two proposals are necessarily dependent upon the same reserves."¹² Stating *Ashbacker* did not require holding up action on a completed application so that a dilatory applicant could catch up, even assuming ANR's proposal would have less significant environmental consequences, the FERC would not preclude certifying both projects because: (a) the potential adverse effects of Nautilus could be mitigated; (b) NEPA does not require a comparative hearing, (particularly when ANR's application

7. *Maritimes & Northeast Pipeline, L.L.C.*, 80 F.E.R.C. ¶ 61,136, at 61,474 (1997), *clarified*, 80 F.E.R.C. ¶ 61,388 (1997), *on reh'g*, 81 F.E.R.C. ¶ 61,166 (1997).

8. *Transcontinental Gas Pipe Line Corp.*, 81 F.E.R.C. ¶ 61,104 (1997), *reh'g denied and certificate issued*, 82 F.E.R.C. ¶ 61,084 (1998). Petitions for review pending, *see* Brooklyn Union Gas Co. v. FERC, No. 98-60057 (5th Cir. 1998) and Southern Natural Gas Co. v. FERC, No. 98-60114 (5th Cir. 1998).

9. *Nautilus Pipeline Co.*, 78 F.E.R.C. ¶ 61,325 (1997), *stay denied*, 79 F.E.R.C. ¶ 61,151 (1997) (*reh'g pending*).

10. *Granite State Gas Transmission, Inc.*, 82 F.E.R.C. ¶ 61,232 (1998).

11. *ANR Pipeline Co.*, 78 F.E.R.C. ¶ 61,326, at 62,405 (1997) (*reh'g pending*), *quoting*, *Midwestern Gas Transmission v. FERC*, 589 F.2d 603, 624 (D.C. Cir. 1978).

12. *Nautilus Pipeline Co.*, 79 F.E.R.C. ¶ 61,151, at 61,648. *See also* 78 F.E.R.C. ¶ 61,326, at 62,405.

was incomplete with respect to environmental information); and (c) Order No. 363, in which the FERC established a policy of maximizing facility utilization in offshore Louisiana, did not preclude reliance on the market.¹³

The FERC dismissed Natural Gas Pipeline Company of America's (Natural) application to construct facilities to compete with Northern Border Pipeline Company's (Northern Border) proposed extension, because it depended on an unwilling participant, Northern Border, to provide a lease or a contract.¹⁴ Concluding Natural's proposal involved less environmental disturbance, the FERC decided Northern Border's proposal would provide a competitive alternative to Natural's captive customers in the Harper to Chicago corridor, determining that Natural had not demonstrated market support through executed precedent or service agreements. Finally, the FERC found no need to retest the market to see if customers desired Natural's proposal over Northern Border's, as the relevant market had already made that choice.¹⁵

In a series of orders, the FERC addressed issues related to Southern Natural Gas Company's (Southern) proposal to construct facilities to provide service to new customers and to two existing customers of Alabama-Tennessee Natural Gas Company (Alabama-Tennessee) in light of Alabama-Tennessee's vigorous objections and alternative proposal. The FERC issued a certificate to Southern, stating that it had undertaken the "flexible balancing process" inherent in the term "public convenience and necessity" to weigh all relevant factors, including environmental factors.¹⁶ While Alabama-Tennessee's alternative was preferred from an environmental standpoint, the FERC held that this does not end the inquiry. The FERC also considered the benefit of providing Alabama-Tennessee's captive customers with access to new transportation options, the mitigation of environmental impacts listed in the Environmental Impact Statement, and the strong support of the customers for Southern's proposal.¹⁷ The FERC found that the record did not support Alabama-Tennessee's claim that its existing customers would be hurt by the departure of the two existing customers as it had received bids for the capacity to be released and had developed new customers. In any event, "the Commission has found that when historic customers terminate service . . . it is inappropriate to expect the remaining customers to pay for all of the remaining costs of the pipeline."¹⁸ The FERC reaffirmed its prior finding that roll-in was appropriate in light of the low cost impact and system benefits. It also rejected arguments that Southern engaged in predatory pricing and that twenty year long-term contracts constituted

13. *Id.* at 61,648-49.

14. *Natural Gas Pipeline Co. of America*, 80 F.E.R.C. ¶ 61,151 (1997), *reh'g denied*, 81 F.E.R.C. ¶ 61,216 (1997).

15. *Id.* at 61,623.

16. *Southern Natural Gas Co.*, 79 F.E.R.C. ¶ 61,280 at 62,208 (1997).

17. *Id.*

18. *Id.* at 62,212 citing *El Paso Natural Gas Co.*, 72 F.E.R.C. ¶ 61,083, at 61,441 (1995); *Natural Gas Pipeline Co. of America*, 73 F.E.R.C. ¶ 61,050, at 61,129 (1995).

violations of antitrust laws.¹⁹ The FERC deferred action on Alabama-Tennessee's alternative proposal as it had not held an open session to determine the correct sizing of its proposed project and had not solicited existing customers to release capacity on a permanent basis. In addition, the FERC noted that it generally requires some showing of the market prior to authorizing construction of the facilities. Alabama-Tennessee had not provided any market support in the form of contracts with the three customers it proposed to serve. On the contrary, those three customers had executed agreements with Southern.²⁰

Finally, the FERC addressed problems resulting from the delay in processing Southern's application, due to landowner issues and the right of first refusal mechanism in Alabama-Tennessee's tariff. The FERC first stayed the timing for exercising the right of first refusal for ninety days beyond the date ordinarily required in the tariff. It then stayed the timing for the operation of pre-granted abandonment for one year beyond the expiration date of the contracts of the existing customers. The FERC recognized this might not cure the problem the existing customers would face, giving up capacity before the new capacity is available, but "in a competitive market, it is not unusual for participants to have to make choices whether to contract with one supplier, while there is uncertainty concerning other potential supply options."²¹ On rehearing, the FERC held pre-granted abandonment would occur at the expiration of the contracts unless the customers exercised their right of first refusal.

C. Rolled-In Versus Incremental Pricing

The FERC continued to apply its "Pricing Policy Statement"²² to determine, in advance, whether the costs of new facilities may be "rolled-in" to system-wide rates in subsequent rate cases. It addressed the question of segmenting several times, i.e., whether the project being considered is part of a larger project, whether the cost of the larger project should be used for purposes of determining whether or not the costs of the facilities may be rolled into system-wide rates, and what costs should be considered.

The FERC authorized Great Lakes Gas Transmission Limited Partnership (Great Lakes) to construct and operate approximately 24.5 miles of thirty-six inch diameter mainline loop to complete its planned looping of its entire mainline system on grounds that the facilities were needed to increase reliability and flexibility of the system to benefit all

19. *Id.* at 62,214,15,18-20.

20. *Alabama-Tennessee Natural Gas Co.*, 79 F.E.R.C. ¶ 61,283 (1997).

21. *Decatur Util. v. Alabama-Tennessee Natural Gas Co.*, 79 F.E.R.C. ¶ 61,282 at 62,237 (1997), *on reh'g*, 81 F.E.R.C. ¶ 61,034 (1997), *notice of denial of reh'g*, 81 F.E.R.C. ¶ 61,327 (1997).

22. *Pricing Policy for New and Existing Facilities Constructed By Interstate Natural Gas Pipelines*, 71 F.E.R.C. ¶ 61,241 (1995) [hereinafter *Pricing Policy Statement*]. Generally, if the effect of new construction on existing rates is less than five percent and system benefits are provided, it is presumed that rolled-in pricing is in order.

customers.²³ The FERC found that facilities necessary to increase system reliability and flexibility and to facilitate system maintenance are *not* subject to the Pricing Policy Statement and, assuming no changed circumstances, Great Lakes would be permitted to roll the costs of the project into the rate base in the next rate case. The FERC also found that Great Lakes had not segmented projects to come within the Pricing Policy Statement's five percent threshold for a presumption of rolled-in rates. It had always been contemplated that Great Lakes would complete its looping in phases, and in prior phases, the FERC had approved rolled-in pricing.²⁴ In a second *Great Lakes* case,²⁵ the FERC again addressed the segmenting issue. The FERC determined it was inappropriate to consider the costs of a previously planned system security and reliability project in determining whether a market-driven proposal's cost exceeded the five percent threshold.

In 1997, for the first time, the FERC held the cost of fuel should be considered in determining the impact of a construction project on existing rates. The FERC issued a certificate to Northern Border expanding the capacity of its existing main line and extending the terminus of its facilities by 243 miles to just south of Chicago, Illinois. In discussing whether Northern Border should be permitted to roll-in the cost of its facilities, the FERC stated (a) the appropriate comparison year for determining the rate effect of rolling-in the facility costs was the year in which the order was issued, and (b) fuel should be included in the comparison.²⁶ Even though the impact on existing rates of a roll-in was more than five percent, the FERC found substantial system-wide operational benefits through increased deliverability, flexibility, and reliability and gave advance approval for a roll-in.

Northern Border proposed to place certain compression station facilities and a loop in service before the entire project became operational. It also proposed to exclude the cost of these facilities from the rate base, continue the accrual of allowance for funds used during construction (AFUDC) and to postpone depreciation until the in-service date of the entire project, stating this phased construction was necessary to avoid an interruption of service while work was conducted on existing facilities. The FERC approved postponing recovery of the cost of the facilities and directed Northern Border in two ways. First, it was to record a regulatory asset for the difference between the cost-of-service impact due to including the cost of the new facilities in rates on the actual in-service date of the individual facilities and the in-service date of the entire expansions directed on project. Second, Northern Border was directed to cease accruing a carrying charge and begin amortizing the regulatory asset

23. *Great Lakes Gas Transmission Ltd. Partnership*, 80 F.E.R.C. ¶ 61,105 (1997).

24. *Id.* at 61,353.

25. 80 F.E.R.C. ¶ 61,135 (1997).

26. *Northern Border Pipeline Co.*, 80 F.E.R.C. ¶ 61,152, at 61,630-31 (1997), *reh'g denied*, 81 F.E.R.C. ¶ 61,215 (1997).

over a ten-year period when the entire project is placed in service.²⁷

D. Initial Rate Structures

In orders certifying offshore facilities, the FERC accepted negotiated rate schedules which differed in material respects from the recourse rate schedules. For example, in *Nautilus*, the FERC approved a negotiated rate schedule for shippers willing to commit reserves for life to the project. Under this rate schedule, rates are billed on a volumetric basis for firm service so long as the shipper annually uses eighty-five percent of its maximum daily transportation quantity (MDTQ). Furthermore, the shipper may pay a reservation charge or turn back the unused capacity if it fails to meet the eighty-five percent minimum throughout. Also, shippers have flexibility in establishing their MDTQs.²⁸ During the open seasons in these cases, all shippers elected the negotiated rate schedule.

While holding that precedent agreements or service agreements reflecting discounted rates are valid for purposes of determining whether the new capacity is needed, the FERC found National Fuel had not presented any evidence that its discounting was driven by a need to meet competition. The FERC, thus, held National Fuel must charge either the maximum rate to the new shippers or offer all similarly situated Rate Schedule FT shippers the same discount offered to the proposed new shippers.²⁹ The FERC reached a similar result regarding discounts for Iroquois Gas Transmission System, L.P. (Iroquois).³⁰

The FERC issued a preliminary determination for Alliance Pipeline, L.P. (Alliance) to obtain an optional certificate to construct and operate a pipeline extending from the Canadian border to an interconnection with People's Gas Light & Coke Co. in Illinois.³¹ As originally proposed, fifteen of the seventeen limited partners were producers.³² In an open season, all shippers elected negotiated rates, which were available only to certain shippers. Such shippers would agree not to contest certain elements of Alliance's cost of service in return for Alliance's agreement not to change these cost of service elements for the length of the primary contract term and any extensions thereof, over recourse rates.³³

27. *Id.* at 61,635-36.

28. 78 F.E.R.C. ¶ 61,325, at 62,381, *supra* note 3. See also *Garden Banks Gas Pipeline, L.L.C.*, 78 F.E.R.C. ¶ 61,066 (1997); *Discovery Producers Services L.L.C.*, 78 F.E.R.C. ¶ 61,194 (1997). But see *Dauphin Island Gathering System*, 79 F.E.R.C. ¶ 61,391, at 62,669 (1997).

29. *National Fuel Gas Supply Corp.*, 80 F.E.R.C. ¶ 61,040 (1997).

30. *Iroquois Gas Transmission System, L.P.*, 79 F.E.R.C. ¶ 61,394 (1997) (the rate is low because Iroquois will recover the cost associated with the new shippers' use of existing capacity from existing customers).

31. *Alliance Pipeline, L.P.*, 80 F.E.R.C. ¶ 61,149 (1997).

32. *Id.* at 61,590.

33. The negotiated rate structure is based on a formula which:

"(1) uses an imputed capital structure of [seventy] percent debt and 30 percent equity during the term of . . . [the] agreement[,] regardless of project's actual . . . capital structure; (2) locks in the base rate of return on equity at 12 percent[,] but provides an incentive mechanism under which each 10 percent

Two parties contended that Alliance's proposed negotiated/recourse rates did not require Alliance or its investors to assume sufficient risk to qualify under the optional certificate procedure. The FERC, however, found the availability of the recourse rate placed Alliance fully at risk, and the design elements of the rate proposal were available to prospective shippers freely accepting the negotiated rates and any associated risk. The FERC imposed a three year filing requirement to permit it to examine claimed operating costs and make determinations regarding the need for mileage-based, zoned and peak/off-peak rates. The FERC rejected arguments that negotiated rates are not available to applicants under the optional certificate procedure.³⁴ While finding the recourse rate should be based on a higher volume determinant, the FERC permitted Alliance to use a lower volume determinant to derive the negotiated rate.³⁵ The approved rate included a provision which would increase the rate of any shipper which notifies Alliance that it will not extend the primary fifteen year term for a period sufficient to permit Alliance to achieve a four percent depreciation rate over the term of the agreement.³⁶

The FERC denied rehearing regarding the certificate issued to Transco to construct and operate a two-phase expansion of its southeast Louisiana gathering system in the offshore Louisiana area.³⁷ This confirmed Transco's proposal to design firm rates on an incremental basis and to charge rates for interruptible service on the incremental facilities based on the one-hundred percent load factor equivalent at the proposed incremental firm rate.

E. Allocation of Capacity

The FERC continues to require an open season as a prerequisite to major construction. In response to a protest alleging that Williams Natural Gas Company's (Williams) open season for the construction of a pipeline loop for market area firm transportation had been improperly conducted (because Williams had unlawfully bundled services by requiring bidders for market area transportation to take production area transportation as well), the FERC required a new open season.³⁸ The original open season announcement stated that Williams "projects that expressions of interest for additional Production Area Firm Transportation Service ("FTS-P") must accompany requests for Market Area Firm Transportation Service in

deviation from the estimated capital costs . . . would result in a 0.5 percent inverse adjustment to the base rate of return on equity, capped at 2 percent; (3) uses the actual cost of debt and operation and maintenance expenses; (4) calculates income taxes on a normalized basis . . . [; and] (5) employs a schedule of annual depreciation rates [on design capacity]."

It also included authorized overrun service. *Id.* at 61,592.

34. *Id.* at 61,597.

35. *Id.* at 61,598.

36. *Id.* at 61,599-600.

37. *Transcontinental Gas Pipe Line Corp.*, 78 F.E.R.C. ¶ 61,333 (1997), *amended*, 79 F.E.R.C. ¶ 61,286 (1997).

38. *Williams Natural Gas Co.*, 79 F.E.R.C. ¶ 61,055 (1997).

order to justify the economics of the proposed expansion."³⁹ The FERC found the notice inconsistent with Williams' tariff for three reasons. First, under the tariff, a shipper could take either production or market area capacity or both; second, the tariff requires service be made available to a shipper only to the extent Williams had available capacity, without mention of revenue streams as necessary elements; and third, Williams' tariff contains reservation charges separately stated for production and market area services.⁴⁰ The FERC found no operational justification for the bundling and ordered Williams to hold a new two-week open season.

F. Leases

The FERC denied rehearing and clarified its *Texas Eastern* declaratory order in which it held that no *per se* rule precludes pipelines from holding capacity on other pipelines, but required pipelines to make filings to obtain approval in advance of any acquisition.⁴¹ The FERC clarified that any acquisition of capacity is subject to analysis under decisions applying the Pricing Policy Statement. Under that analysis, the applicant must affirmatively respond to the concerns listed in the declaratory order regarding rate impact on existing custom, the acquiring pipeline, the effect on affiliates, and abuse due to market power. A pipeline may be placed at risk for the recovery of the costs of such upstream capacity.

The FERC authorized several lease arrangements in which one pipeline holds capacity on another pipeline. The FERC's concern over the impact of a lease on existing customers is illustrated by its orders issuing a certificate to Destin Pipeline Company (Destin) and Southern.⁴² Destin and Southern proposed to construct and operate a new interstate pipeline to transport gas from the Outer Continental Shelf to onshore interconnects. Several major interstate pipelines in Mississippi were to provide access to Texas Eastern Transmission Corp. (Texas Eastern) through a lease arrangement with Southern. The FERC initially approved the lease proposal, including Southern's request for rolled-in rate treatment of the costs attributed to the incremental lease facilities. It found the revenue credits of the yearly lease payment would generally offset the cost of service for the first year. However, the FERC denied the request to determine that no additional costs would be allocated to the lease during its twenty year term. The FERC noted that the payment had been negotiated between two affiliates and did not appear to provide adequate compensation to Southern for the cost of providing the service. Because it could not determine if Southern's customers would be worse off

39. *Id.* at 61,255.

40. *Id.* at 61,256.

41. *Texas E. Transmission Corp.*, 74 F.E.R.C. ¶ 61,074 (1996), *clarified and reh'g denied*, 78 F.E.R.C. ¶ 61,277 (1997), (*petition for review pending*).

42. *Destin Pipeline Co.*, 79 F.E.R.C. ¶ 61,395 (1997), *order on reh'g and issuing certificates*, 81 F.E.R.C. ¶ 61,211 (1997).

as a result of the lease transaction, the FERC held that Southern would be at risk for the recovery of costs that might be allocated to the lease service in future rate proceedings. Accordingly, it denied the request for pre-granted abandonment and reversion to Southern on termination of the lease. On rehearing, the FERC found that Southern should not be authorized to include any of the costs associated with the lease in its rates, but should be at risk to the extent such costs are not recovered from Destin.

The FERC first authorized CNG Transmission Corp. (CNG) to construct facilities and to lease pipeline capacity from Texas Eastern and then authorized Texas Eastern to construct facilities and lease capacity to CNG.⁴³ The FERC found the proposed facilities would be less expensive, have less environmental impact, and be smaller in scale than any facilities that CNG would construct to duplicate the capacity to be leased from Texas Eastern. The FERC noted that it had approved lease arrangements where the lessee's payments would be less than, or equal to, the lessor's firm transportation rates for comparable service over the term of the lease on a net present value basis. Here, the proposed lease payment is less than Texas Eastern's firm transportation rates and therefore is appropriate. The FERC stated, however, that Texas Eastern is free to negotiate a lease payment with CNG, excluding transition costs and *polychlorinated biphenyl* (PCB) surcharges, but that Texas Eastern can not shift the risk of recovery of those surcharges to its other customers. Finally, the FERC did not approve Texas Eastern's request for pre-granted abandonment.

The FERC also authorized Texas Eastern to construct facilities and lease capacity to Columbia Gas Transmission Corporation (Columbia), permitting Columbia to avoid looping certain of its facilities at a cost greater than the lease cost. It however required Texas Eastern to hold a reverse auction, clarifying that a shipper turning back capacity would be responsible for any difference between its rate and the lease rate, and declined to grant pre-granted abandonment.⁴⁴ On rehearing, the FERC noted that the lease provided substantial benefits for Columbia's customers by way of reduced costs and it was not essential to find Texas Eastern's customers also benefited, so long as they are not harmed. However it also noted that they would be better off because the lease capacity enlarges the pool eligible for sharing of PCB and transition costs. In response to complaints that the lease payment is less than the Part 284 rate, the FERC stated that because Columbia does not have all of the rights of a Part 284 customer, a rate below the Part 284 rate reflects the nature of the service. This lack of rights is due to flexible receipt and delivery points and the ability to release capacity. With respect to the use

43. *CNG Transmission Corp.*, 80 F.E.R.C. ¶ 61,092 (1997), *modified*, 80 F.E.R.C. ¶ 61,269 (1997), *reh'g pending*.

44. *Columbia Gas Transmission Corp.*, 78 F.E.R.C. ¶ 61,030, at 61,123 (1997), *on reh'g*, 79 F.E.R.C. ¶ 61,160 (1997), *amended*, 81 F.E.R.C. ¶ 62,151 (1997), *Petition for review pending sub nom.*, *New York State Elec. & Gas Corp. v. FERC*, No. 97-1430 (D.C. Cir. 1997).

of turn-back capacity, the FERC stated that a pipeline is required to evaluate all offers of turn-back capacity "for which the general location, term, and price is sufficiently similar to the location, term, and price for which the expansion project is being constructed," but is not required to take back capacity unrelated to the capacity needed for the project.⁴⁵

Applying the lease principle to a unique arrangement, the FERC approved a joint application by Tennessee Gas Pipeline Co. (Tennessee) and Columbia Gulf Transmission Co. (Columbia Gulf) to abandon their respective capacity rights on the South Pass system and the Muskrat system by lease to each other and to authorize the acquisition of the leased capacity.⁴⁶ In support of their application, Tennessee stated that its capacity on South Pass was currently fully subscribed, whereas Columbia Gulf did not have the facilities or infrastructure to connect South Pass with the rest of its system. Columbia Gulf's shippers had to enter into separate transportation agreements with Tennessee to access Columbia Gulf's mainline system. The lease on Tennessee's Muskrat line is a displacement arrangement, allowing Columbia Gulf's customers to access directly South Pass's area of production for the first time. The approved lease payment was one dollar, having practically no impact on customers. However, the FERC rejected Tennessee's proposal to retain any capacity that would otherwise be assigned to Columbia Gulf if the South Pass system is expanded, stating that it did not have sufficient facts to make an informed decision. Finally, the FERC denied the request for pre-granted abandonment, as it could not make a determination on an abandonment that would take place at an unspecified future time.

The FERC has not approved all applications by pipelines to hold capacity on other pipelines. The FERC rejected Northern Natural Gas Co.'s (Northern Natural) proposal "to acquire and hold contractual rights on other pipelines for interruptible transportation and storage capacity for the benefit of its shippers," holding that Northern Natural had failed to address how its proposal was consistent with the policy behind permitting pipelines to acquire capacity on other pipelines; i.e., to explore methods and to retain and expand markets where options other than system expansion exist.⁴⁷ The FERC noted that it typically does not authorize system expansions for the benefit of interruptible services. The FERC also noted that Northern Natural did not provide information necessary to make a determination as to undue preference, competition, and rate impact, all of which are criteria for pipelines' holding capacity on other pipelines. Finally, the FERC noted that the proposal appeared to tie acquired interruptible storage capacity to Northern Natural's on-system services, thereby improperly limiting customer choices.

45. *Columbia Gas Transmission Corp.*, 79 F.E.R.C. ¶ 61,160, at 61,759 (1997).

46. *Tennessee Gas Pipeline Co.*, 78 F.E.R.C. ¶ 61,182 (1997).

47. *Northern Natural Gas Co.*, 80 F.E.R.C. ¶ 61,018, at 61,041 (1997).

G. Lateral Line Issues

The FERC has applied its Pricing Policy Statement to lateral lines, requiring pipelines to establish a separate incremental lateral line rate based solely on the cost of the lateral line for service to a point of delivery on a newly-constructed lateral line.⁴⁸

In denying rehearing of its order authorizing Kern River Gas Transmission Co. (Kern River) to construct and operate a meter station to permit deliveries to Southwest Gas Co. (Southwest) of up to 321,000 Mcf per day, supported by a service agreement for 40,000 Mcf per day, the FERC rejected arguments that the metering facilities would result in an expansion of Kern River's system beyond certified system design levels⁴⁹ because metering facilities would merely permit greater deliveries at a particular point and would not affect mainline capacity. The FERC rejected arguments that the Southwest lateral was in fact an expansion of the Kern River system. Although Southwest had received a contribution in aid of construction,⁵⁰ the FERC confirmed that Southwest is a nonjurisdictional pipeline not affiliated with Kern River and the lateral is not an expansion of Kern River's system.⁵¹ Notably, the FERC exercised its authority under section five⁵² to require "Kern River to modify its tariff to provide the terms and conditions under which it [would] make such contributions to similarly situated customers."⁵³

H. Jurisdictional Issues

In 1995, the FERC found that the natural gas pipeline system comprised of Kansas Pipeline Partnership, Riverside Pipeline Co. L.P., and KansOk Partnership, (operated by and affiliated with Kansas Pipeline Operating Co.), constituted one interstate pipeline system subject to the FERC's Natural Gas Act jurisdiction, and therefore ordered the companies to file an application for a section seven certificate.⁵⁴ In 1997, the FERC denied rehearing and issued the requested certificate. In applying traditional interstate pipeline rate principles, the FERC substantially modified the initial rates requested by authorizing a rate base of \$39 million rather than \$100.6 million and a cost of service of \$21.8 million rather than \$36.7 million. Thereafter, the FERC granted a stay, in part, and clarified its prior order, noting allegations that a transition from state to federal regulation under the rate provisions of its orders could lead to the bankruptcy of companies that had previously relied upon state

48. *Algonquin Gas Transmission Co.*, 81 F.E.R.C. ¶ 61,220 (1997).

49. *Kern River Gas Transmission Co.*, 80 F.E.R.C. ¶ 61,399, at 62,320-23 (1997).

50. Kern River also was authorized to make a contribution in aid of construction to Southwest for a pipeline to be built to connect to the meter station which would be owned by Southwest. *Id.*

51. 80 F.E.R.C. ¶ 61,399, at 62,323 (1997).

52. 15 U.S.C. § 717(d) (1997).

53. 80 F.E.R.C. ¶ 61,399, at 62,323 n. 11.

54. *KansOk Partnership*, 73 F.E.R.C. ¶ 61,160 (1995), *on reh'g*, 81 F.E.R.C. ¶ 61,005, *stay granted*, 81 F.E.R.C. ¶ 61,250 (1997).

regulatory policies. The FERC, however, denied a request that the companies be required to post a bond, since this was not authorized in initial rate proceedings.

I. Conversion of LNG Facilities

The FERC issued a certificate to Total Peaking Services, L.L.C., (Total Peaking) to lease a liquid natural gas (LNG) peak shaving facility from a local distribution company (LDC) and to provide open access service.⁵⁵ Total Peaking proposed to offer bundled sales service from the facility and arranged through mutual sales to use capacity the LDC held on various interstate pipelines. The FERC found the proposal inconsistent with Order No. 636, but generally in the public interest, if it were restructured to offer open access storage. Accordingly, it issued a Part 284 blanket certificate conditioned on Total Peaking filing tariff provisions setting forth open access terms and conditions of service.

In a similar case, Hopkinton LNG Corporation, (Hopkinton) filed an application for a certificate of limited jurisdiction to operate an existing LNG facility so that capacity not needed for service to its affiliated local distribution company might be leased to an affiliated interstate marketing company. While recognizing that its previous decision in *United Cities Gas Co.*⁵⁶ supported Hopkinton's position, the FERC found that unlike United Cities' proposal, Hopkinton's proposal was protested. The FERC then found that arrangements like *United Cities* do not serve the public interest but offered Hopkinton the opportunity to restructure the proposal to make it consistent with open access provisions of Order No. 636. It also issued a blanket certificate conditioned on Hopkinton's filing within sixty days of the date of the issuance of the order. Also included were tariff provisions setting forth terms, conditions and rates for open access firm and interruptible storage service and storage-related transportation complying with the requirements of Part 284 and Order No. 636.⁵⁷

J. Preemption

The FERC clarified its views on preemption, holding that "the [Natural Gas Act (NGA)] preempts State and local agencies from regulating the construction and operation of interstate pipeline facilities."⁵⁸ Nevertheless, the FERC required applicants to cooperate with state and local agencies, interact with them before proposing a pipeline route, and observe appropriate procedures that states have for review of proposed projects, in part to implement the National Environmental Policy Act of 1969. The FERC found the principles of preemption will apply if a conflict

55. *Total Peaking Services, L.L.C.*, 81 F.E.R.C. ¶ 61,246 (1997).

56. *United Cities Gas Co.*, 71 F.E.R.C. ¶ 62,220 (1995) [hereinafter *United Cities*].

57. *Hopkinton LNG Corp.*, 81 F.E.R.C. ¶ 61,291, at 62,383 (1997).

58. *Maritimes & Northeast Pipeline, L.L.C.*, 80 F.E.R.C. ¶ 61,136, (1997), *clarified*, 80 F.E.R.C. ¶ 61,388 (1997), *on reh'g*, 81 F.E.R.C. ¶ 61,166, at 61,730 (1997) (paraphrasing *National Fuel Gas Supply Corp. v. Public Serv. Comm'n of the State of N.Y.*, 894 F.2d 571, 575-76).

arises between the requirements of a state or local agency and its certificate conditions, but a state requirement of something more or different than the FERC's requirements does not make it unreasonable to comply with both or necessarily create a preemption conflict. Rather, a rule of reason must govern, and the FERC will not act as a referee on an ongoing basis between applicants and state and local authorities. The FERC found very few of the conditions to which Maritimes and Pacific Natural Gas & Transmission Service (PNGTS) objected are in actual conflict with the certificate or likely to cause unreasonable delay.

K. Three Year Requirement

The FERC imposed triennial rate reviews for certificates issued to several pipelines.⁵⁹ The FERC found no illegality in imposing a certificate condition requiring rates be reviewed in light of the actual costs of constructing the pipeline and which take into account operating history. The FERC stated that this is not a rate change requirement, but rather a requirement to file a cost and revenue study, in the form specified by section 154.313 of its regulations.⁶⁰ The FERC stated that it would determine whether to exercise its section five authority based on that study.

L. Mediation

The FERC initiated mediation procedures between Maritimes and Portland regarding definitive agreements to share expenses and to operate the joint pipeline. The FERC's stated objective was limited to assuring such agreements "are adequate to permit a determination of accountability for financial and other responsibilities" if problems arise that "threaten the maintenance of certificated service obligations relying on the joint facilities," rather than to "draft the agreements or to substitute its judgment for that of either applicant in the process of negotiating its rights, risks, and responsibilities under the agreements."⁶¹

II. GATHERING

The FERC continued its recent practice of allowing interstate pipelines to spin-off or spin-down gathering systems to unregulated third-parties⁶² and affiliates.⁶³ In making such determinations, the FERC relies on the modified primary function test, also known as the *Farmland* test.⁶⁴

59. *Id.* at 61,726-27.

60. Schedules for Minor Rate Changes, 18 C.F.R. § 154.313 (1998).

61. *Maritimes and Northeast Pipeline, L.L.C.*, 80 F.E.R.C. ¶ 61,289, at 62,028 (1997).

62. *See, e.g., Natural Gas Pipeline Co. of America*, 81 F.E.R.C. ¶ 61,390 (1997); *Blazer Energy Corp.*, 81 F.E.R.C. ¶ 62,131 (1997).

63. *See, e.g., Texas E. Transmission Corp.*, 81 F.E.R.C. ¶ 62,162 (1997); *Trunkline Gas Co.*, 81 F.E.R.C. ¶ 61,351 (1997); *Panhandle E. Pipe Line Co.*, 81 F.E.R.C. ¶ 61,212 (1997).

64. *Farmland Indus. Inc.*, 23 F.E.R.C. ¶ 61,063 (1983) [hereinafter *Farmland*]. Under the *Farmland* test, the FERC considers the following factors: (1) the length and diameter of the lines, (2)

The Fifth Circuit reaffirmed the FERC's conclusion that gatherers are outside of its Natural Gas Act jurisdiction, even when they are wholly-owned subsidiaries of jurisdictional interstate pipelines.⁶⁵ In several new cases, the FERC continued determining whether offshore pipeline facilities were non-jurisdictional gathering facilities or jurisdictional interstate pipelines by applying the 1996 outer continental shelf (OCS) gathering policy,⁶⁶ in several new cases.⁶⁷

The Fifth Circuit remanded the FERC's determination that Sea Robin Pipeline Co. (Sea Robin) remain a jurisdictional interstate pipeline.⁶⁸ The FERC based its jurisdictional determination in large part on the non-physical criteria of the primary function test, 1) emphasizing Sea Robin's prior certification as a jurisdictional pipeline and 2) its ownership by an interstate pipeline, as opposed to a producer. The court concluded the FERC did not consistently apply the primary function test and had discounted, without reasoned analysis, the application of any factor pointing to a non-jurisdictional result.⁶⁹ The court indicated, on remand,

the extension of the facility beyond the central point in the field, (3) the lines' geographic configuration, (4) the location of compressors and processing plants, (5) the location of wells along all or part of the facility, and (6) the operating pressure of the lines. In 1989, the FERC modified the application of the primary function test to consider, especially for offshore facilities, the changing technical and geographic nature of exploration and production. The FERC explained that a relatively long pipeline in the OCS may have a primary function of gathering while an onshore line of similar length may not and essentially announced a sliding scale to permit gathering lines of increasing lengths and diameters in relation to the distance from shore and water depth of the production area. *Amerada Hess Corp.*, 52 F.E.R.C. ¶ 61,268, at 61,988 (1990).

65. *Pacific Gas & Electric Co. v. FERC*, 106 F.3d 1190, (5th Cir. 1997). The Fifth Circuit followed the D.C. Circuit's decision in *Conoco Inc. v. FERC*, 90 F.3d 536 (D.C. Cir. 1996), *cert. denied*, 117 S.Ct. 1017 (1997).

66. On Feb. 28, 1996, the FERC issued a Statement of Policy adding an additional factor to the primary function test for facilities constructed to collect gas produced in water depths of 200 meters or greater. Under the policy, it presumes that new facilities at such depths qualify as gathering facilities up to the point or points of potential interconnect with the existing interstate pipeline grid, essentially the point at which the new facility would duplicate or be in proximity to established transmission facilities. From that point on, the FERC will apply the primary function test to determine whether the remainder of the facility is a jurisdictional pipeline or an exempt gathering facility. *Gas Pipeline Facilities and Services on the Outer Continental Shelf--Issues Related to the Commission's Jurisdiction Under the Natural Gas Act and the Outer Continental Shelf Lands Act*, 74 F.E.R.C. ¶ 61,222, at 61,756-57 (1996).

67. See, e.g., *Venice Gathering Co.*, 79 F.E.R.C. ¶ 61,037 (1997) (168 miles, eight to twenty-six inches, shallow water depth, jurisdictional); *Green Canyon Gathering Co.*, 78 F.E.R.C. ¶ 61,287 (1997) (133 miles, twenty-four inches, shallow water depth, jurisdictional); *Discovery Producers Services, L.L.C.*, 78 F.E.R.C. ¶ 61,194 (1997) (160 miles, eighteen to thirty inches, shallow water depth except for 2.5 miles, jurisdictional); *Manta Ray Offshore Gathering Co.*, 78 F.E.R.C. ¶ 61,193 (1997) (169 miles, twelve to twenty-four inches, deep OCS, no duplicate interstate pipeline, gathering); *Shell Gas Pipeline Co.*, 74 F.E.R.C. ¶ 61,219 (1996), *reh'g denied*, 78 F.E.R.C. ¶ 61,192 (1997) (Commissioners Bailey and Santa dissenting on rehearing) (downstream of central platform: forty-five miles, thirty inch, shallow water depth, existing interstate pipelines, jurisdictional; upstream of central platform: forty-five miles of fourteen inch and sixty-eight miles of twelve inch sub-sea, deep OCS, gathering).

68. *Sea Robin Pipeline Co. v. FERC*, 127 F.3d 365 (5th Cir. 1997).

69. *Id.* at 370. In particular, the Court found that the FERC presumptively concluded that Sea Robin is a transportation facility based upon its size. The Court, however, found that, in doing so, the

the FERC may wish to reformulate the primary function test “to discontinue [the use of] criteria not relevant to the physical, geographical, and operational characteristics of pipelines in the OCS.”⁷⁰

III. GAS INDUSTRY STANDARDS BOARD

The FERC continued its efforts to standardize business practices and communications standards through the adoption of additional standards proposed by the Gas Industry Standards Board (GISB) in 1997. The FERC first amended its open-access regulations to incorporate by reference GISB’s standards requiring interstate natural gas pipelines to conduct certain standardized business transactions with their trading partners, using Internet servers and Internet addresses and permitting the exchange of files formatted in ASC X12 using hypertext transfer protocol (HTTP) as the Internet protocol.⁷¹ The FERC selected this model over the Web browser model because it provided: 1) the framework for conducting business transactions efficiently; 2) a time stamp indicating when a transmission was received; and 3) whether any errors occurred in communication, requiring that the transmission be sent again.

Shortly thereafter, in Order No. 587-C, the FERC adopted the GISB’s standards, requiring pipelines to publish certain information on Internet web pages. This was adopted with the exception of the standards requiring such information to be downloadable in a GISB-specified electronic structure. This is because the GISB failed to specify the structure to be used, and all but three standards (for intra-day nominations, netting of imbalances, and operational balancing agreements) for intra-day nominations and flowing gas.⁷² The FERC declined to adopt these three standards because the pipelines obligations under them were unclear and its experience in implementing prior GISB standards had shown that lack of precision caused problems.⁷³ In Order No. 587-D, the FERC denied requests for rehearing seeking to extend the filing deadlines prescribed in Order No. 587-C.⁷⁴

In Order No. 587-E,⁷⁵ the FERC noted that the GISB committed itself to completing the standardization of all functions and information now

[FERC] had “abandoned, without reasoned consideration, its ‘sliding-scale’ of Amerada Hess that would ‘allow the use of pipelines of increasing lengths and diameters in correlation to the distance from shore and the water depth of the production area.’” *Id.* at 370.

70. *Id.* at 371.

71. Order No. 587-B, *Standards for Business Practices of Interstate Natural Gas Pipelines*, 62 Fed. Reg. 5521 (1997) (codified at 18 C.F.R. pt. 284).

72. Order No. 587-C, *Standards for Business Practices of Interstate Natural Gas Pipelines*, 62 Fed. Reg. 10,684, at 10,685-86 (1997) (codified at 18 C.F.R. pt. 284).

73. *Id.* at 10,686-87.

74. Order No. 587-D, *Standards for Business Practices of Interstate Natural Gas Pipelines*, 62 Fed. Reg. 10,684 (1997), 62 Fed. Reg. 19,921 (1997) (codified at 18 C.F.R. pt. 284) (proposed November 18, 1997).

75. Order No. 587-E, *Standards for Business Practices of Interstate Natural Gas Pipelines*, 62 Fed. Reg. 25,842 (1997) (to be codified at 18 C.F.R. pt. 284).

provided on pipeline electronic bulletin boards (EBBs) and requested a report, by September 1, 1997, on the extent of the GISB's progress and its contemplated completion date.

In Order No. 587-F,⁷⁶ the FERC proposed to amend its regulations to incorporate, by reference, the most recent version of the GISB's standards and to adopt regulations not developed by the GISB, governing intra-day nominations, operational balancing agreements, netting and trading of imbalances, standardization of communications over the public Internet, and notices of operational flow orders.⁷⁷ The Order provided policy guidance on other issues related to business practices of interstate natural gas pipelines to eliminate disputes within the GISB and to assist the GISB in developing implementation standards that could be adopted by the FERC in future regulations.⁷⁸

IV. GAS RESEARCH INSTITUTE

Gas Research Institute's (GRI) continued funding problems occupied considerable attention within the FERC in 1997. The FERC extended the current funding mechanism, first approved in a 1993 settlement, through December 31, 1998, clarifying that the prior modification of the settlement's refund mechanism applied only to 1997.⁷⁹

The FERC also initiated a rulemaking proceeding to determine a long-term funding mechanism for GRI.⁸⁰ The proposed funding mechanism would fund "core" research, development and demonstration programs that benefit gas consumers through a non-discountable, non-bypassable volumetric surcharge on all pipeline throughput, while voluntary funding continued for all other GRI programs.

These matters were still pending before the FERC at the end of 1997. The parties filed a settlement proposing a seven-year transition to a

76. Order No. 587-F, *Standards for Business Practices of Interstate Natural Gas Pipelines*, 62 Fed. Reg. 19,921 (1997); 62 Fed. Reg. 61,459 (1997) (codified at 18 C.F.R. pt. 284).

77. These proposed standards address "requiring pipelines to give firm intra-day nominations priority over already nominated and scheduled interruptible transportation; require pipelines to enter into operational balancing agreements at all pipeline to pipeline interconnects; require pipelines to permit shippers to offset imbalances accruing on their different contracts with a pipeline and trade imbalances when such imbalances have similar operational impact on the pipeline's systems; require pipelines to post all information and conduct all business transactions using the public Internet and Internet protocols by June 1, 1999; require pipelines to adhere to specific standards in posting information on pipeline web sites and in maintaining electronic records; and require pipelines to provide shippers with notice of operational flow orders by posting the notices on the pipelines' Internet web sites as well as by notifying shippers through Internet e-mail or through notification to the shipper's Internet (URL) address." 62 Fed. Reg. 61,459, at 61,461 (1997).

78. The FERC also provided policy guidance on "the extent of notice interruptible shippers should be given of rescheduled capacity allocations, as well as the pipelines' responsibilities to support title transfer tracking, to permit gas package ranking across contracts, and to support the use of third-parties to provide reimbursement for compressor fuel." *Id.* at 61,461.

79. *Gas Research Inst.*, 79 F.E.R.C. ¶ 61,110 (1997), *reh'g denied and clarification granted*, 79 F.E.R.C. ¶ 61,396 (1997).

80. *Id.*

voluntary funding mechanism.

V. IMPORTS/EXPORTS

The FERC updated its regulations governing imports and exports to reflect legislative changes and the division of responsibilities between the FERC and the Department of Energy (DOE) under various DOE delegation orders.⁸¹

VI. MARKETING AFFILIATE RULES

A. Procedural Matters

The FERC increased its enforcement activities with respect to marketing affiliate issues. It began considering these issues as part of the standard pipeline audit process by the Division of Audits of the FERC's Office of Chief Accountant,⁸² and initiated an industry-wide audit program to conduct special purpose random audits of pipelines to determine compliance with the marketing affiliate rules.

The FERC also cleared some antiquated cases through consent agreements. El Paso Natural Gas Co. (El Paso) agreed to pay a civil penalty of \$200,000 to resolve all issues arising from a 1992 order,⁸³ which had proposed civil penalties of \$1.2 million for various violations of the FERC's regulations.⁸⁴ Tennessee Gas Pipeline Co. (Tennessee) also agreed to pay civil penalties of \$342,550 for alleged affiliate violations that occurred in 1992 and 1993.⁸⁵

For the first time, the FERC undertook an audit of potential marketing affiliate violations in response to a shipper complaint, directing staff to "conduct an audit of the records, procedures, and practices related to the allocation of capacity on Natural's system, including requests for service and contracting for capacity, for the period from January 1, 1995, to the present."⁸⁶ Staff conducted a three-week, on-site audit, interviewed numerous pipeline and affiliated personnel, and "performed an extensive review of [the pipeline's] contract and discount files."⁸⁷ As a result of the complaint and audit process, the FERC found numerous violations of the

81. Order No. 595, *Applications for Authorization to Construct, Operate, or Modify Facilities Used for the Export or Import of Natural Gas*, 79 F.E.R.C. ¶ 61,245 (1997) (codified at 18 C.F.R. pt. 153).

82. *KN Wattenberg Transmission Ltd. Liab. Co.*, 78 F.E.R.C. ¶ 62,132 (1997) (Chief Accountant directing pipeline to take corrective action based on violations of Marketing Affiliate rules found as part of standard audit process).

83. *El Paso Natural Gas Co.*, 80 F.E.R.C. ¶ 61,219 (1997).

84. *El Paso Natural Gas Co.*, 59 F.E.R.C. ¶ 61,188 (1992).

85. *Tennessee Gas Pipeline Co.*, 80 F.E.R.C. ¶ 61,218 (1997).

86. *Amoco Production Co. v. Natural Gas Pipeline Co. of Am.*, 78 F.E.R.C. ¶ 61,313, at 62,337 (1997).

87. Audit of Natural Gas Pipeline Company (July 8, 1997), Docket No. RP97-232 (filed jointly by the Commission's Offices of Chief Accountant, General Counsel, and Pipeline Regulation).

marketing affiliate rules, including Standard E (improper disclosure of shipper information to an affiliate), Standard F (disclosure of transportation information to an affiliate without contemporaneous disclosure to other shippers), Standard G (failure to operate independently from marketing affiliate to maximum extent practicable), and Standard K (failure to maintain a log of tariff waivers).⁸⁸ The FERC imposed the maximum civil penalty of \$5,000 per diem, for a total penalty of \$8.8 million, half of which is suspended if Natural does not engage in subsequent violations within two years following the order.

B. Substantive Matters

In a series of orders, the FERC clarified and expanded its definition of an "operating employee"⁸⁹ to include senior personnel who "mapped procedures and processes and developed goals for gas-related operations"⁹⁰ or provided "strategic direction."⁹¹ The FERC determined that a senior executive of the pipeline who provides "executive leadership and overall management of company planning and operations" related to both transmission and marketing functions is "more than just a shared policy making person," and must be considered a "shared operating employee."⁹²

The FERC appears to have taken the position that the existence of a shared operating employee will also generally constitute a violation of the "independent functioning" requirements of Standard G.⁹³ Moreover, the FERC found, to the extent a shared operating employee possessed any third-party shipper information, the pipeline, by definition, would be in violation of Standard E, whether or not that information is divulged.⁹⁴ Similarly, based on the "imputed knowledge standard," whenever a shared employee gains information related to the transportation of gas, such information must contemporaneously be disclosed to all nonaffiliated potential shippers to avoid a violation of Standard F.⁹⁵

The FERC also expressly banned "cycling" employees—the practice of allowing an employee to work alternatively for the pipeline, then a marketing affiliate, then returning to the pipeline. The FERC found such employees to be "shared operating employees" even though they are not employed by both the pipeline and the affiliate at any single time.⁹⁶ The

88. *Amoco Production Co. v. Natural Gas Pipeline Co. of Am.*, 82 F.E.R.C. ¶ 61,038 (1998) [hereinafter *Amoco v. NGPL*].

89. An operating employee is one "who has day-to-day duties and responsibilities for planning, directing, organizing, or carrying out gas-related operations." Order No. 497-E, [Reg. Preambles 1991-1996] F.E.R.C. STATS. & REGS., ¶ 30,987, at 30,996 (1994).

90. *K N Interstate Gas Transmission Co.*, 80 F.E.R.C. ¶ 61,212, at 61,838 (1998).

91. *Amoco*, 82 F.E.R.C. at 61,156.

92. *Williston Basin Interstate Pipeline Co.*, 80 F.E.R.C. ¶ 61,089, at 61,310 (1997).

93. *Id.* at 61,311. See also, *Amoco v. NGPL*, 82 F.E.R.C. at 61,155.

94. *Amoco*, 82 F.E.R.C. at 61,158.

95. *Id.* at 61,159.

96. *K N Interstate Gas Transmission Co.*, 80 F.E.R.C. ¶ 61,212, at 61,839 (1998).

FERC further required the pipeline to institute procedures which ensure the employee transferring to a marketing affiliate does not use transportation information gained during the employee's tenure with the pipeline until that information has lost its commercial value.⁹⁷

The FERC clarified that a pipeline acquiring capacity and moving gas on an affiliated pipeline in order to relieve operational constraints on its own system is not acting as a "marketing affiliate" as defined by the FERC's rules.⁹⁸ The FERC reiterated its policy that the Marketing Affiliate Rules do not apply where a pipeline is not aware that an affiliate transportation transaction is taking place.⁹⁹

VII. MARKET POWER

When the FERC denied rehearing of its policies on market-based and incentive rates, and permissive negotiated rates (Policy Statement),¹⁰⁰ it stated that it would "evaluate specific proposals based on the facts and circumstances relevant to the applicant and to address any concerns regarding the application of the criteria on a case-by-case basis."¹⁰¹ In 1997, the FERC reviewed market and negotiated rate applications with an eye to the application's facts, and provided a substantive interpretation of the Policy Statement's criteria. The opposite was true for the Policy Statement itself, as review of its merits came to a halt, with the District of Columbia Circuit's dismissal without prejudice of a petition for review on the grounds that it was "incurably premature."¹⁰²

A. Market Power and Market-Based Rates

The Policy Statement established that an applicant must demonstrate it lacked market power (or could mitigate it) before market rates would be approved.¹⁰³ The success of an application often turned on whether a

97. *Id.* at 61,839-40.

98. *Mojave Pipeline Co.*, 78 F.E.R.C. ¶ 61,104 (1997).

99. *Pacific Interstate Transmission Co.*, 79 F.E.R.C. ¶ 61,287 (1997), *on reh'g*, 81 F.E.R.C. ¶ 61,067 (1997). Based on the specific facts of that case, the FERC declined to require the pipeline to solicit information from its marketing affiliate to determine whether affiliate transactions were occurring on a pipeline on which it held capacity rights. In doing so, the FERC recognized that requiring the pipeline to solicit sufficient information from its marketing affiliate to determine when the affiliate was using the pipeline system (operated by a third party) would potentially cause a violation of Standard G, which requires the operating personnel of a pipeline and its marketing affiliate to function independently of each other to the maximum extent practicable. 81 F.E.R.C. at 61,293.

100. *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines Statement of Policy and Request for Comments*, 74 F.E.R.C. ¶ 61,076 (1996), *clarification granted*, 74 F.E.R.C. ¶ 61,194 (1996), *reh'g denied*, 75 F.E.R.C. ¶ 61,024 (1996), *reh'g denied*, 75 F.E.R.C. ¶ 61,066 (1996), *petition for review dismissed without prejudice sub nom.*, *United Distribution Co. v. FERC*, 1997 WL 150071 (D.C. Cir. 1997).

101. 75 F.E.R.C. ¶ 61,024, at 61,076.

102. *United Distribution Co.*, 1997 WL 150071, at 1 (D.C. Cir. 1997).

103. The FERC used a three-step analysis for evaluating market power: (i) two markets are defined as the "product market" comprising the applicant's service and all "good alternatives," and the "geographic market" which comprised the applicant and all alternative sellers; (ii) the applicant's

sufficient number of "good alternatives" were present. If good alternatives were not present, the product and geographic markets became narrow, often leading to high market shares and Herfindahl-Hirshman Index (HHI) values. In one decision, the FERC noted it has not yet approved an applicant with both a high market share and a high market concentration. The FERC remained faithful to this analysis and generally required applicants to do so. A recent administrative law judge (ALJ) decision, however, may explore the rigidity of this criteria.

The failure to comply with the Policy Statement's requirements led to rejection of an application for market-based rates for transportation services.¹⁰⁴ Claiming it did not have the financial resources to conduct complex market studies, Gulf States Transmission Corp. (Gulf States) offered a more limited range of data. The FERC characterized this as "unsupported" assertions of its market share percentage and HHI index, and noted the lack of information made it impossible to determine the relevant markets or if sufficient "good alternatives" existed to prevent Gulf States from exercising market power.¹⁰⁵

The FERC denied another petition for market-based transportation rates in *CNG Transmission Corp.*¹⁰⁶ CNG's most critical problem was that its HHI index was derived by using the aggregate of all delivery and receipt points within a region. According to the FERC, CNG should have generated a HHI value for each individual receipt and delivery pair, holding that, "[u]nless CNG can demonstrate that there are substitutes for each individual receipt and delivery point, it is unable to prove that there are alternative transporters and storage providers to demonstrate a lack of market power."¹⁰⁷ The FERC also rejected CNG's attempt to establish capacity release as a "good alternative" to its transportation services, finding that capacity release is so uncertain in availability, time, volume, price, bidding, scheduling priority, and receipt and delivery points that it could not protect customers if CNG restricted services or charged prices above competitive levels. CNG additionally failed to count the capacity of its affiliates when evaluating market share. These corrections left CNG with a high market share in a highly concentrated market. The FERC had never authorized market rates where the HHI index indicated a highly concentrated market and the applicant had a large market share. Finally, the FERC observed that CNG requested a firm transportation rate increase of twenty percent and a firm storage rate increase of over twenty-six percent, which were considered "clearly indicative" of an ability to

market share and market concentration (as shown by the HHI index) were measured; and (iii) other factors, such as ease of entry, buyer power and mitigation of market power, were evaluated. For transportation services, the FERC emphasized that the geographic market would consist of sellers offering service between the same origin and destination points and sellers offering transportation out of the origin market or into the destination market. 74 F.E.R.C. at 61,233.

104. *Gulf States Transmission Corp.*, 80 F.E.R.C. ¶ 61,091 (1997).

105. *Id.* at 61,315-16.

106. 80 F.E.R.C. ¶ 61,137 (1997), *reh'g denied*, 81 F.E.R.C. ¶ 61,031 (1997).

107. 80 F.E.R.C. ¶ 61,137, at 61,503 (1997).

exercise market power.

In *Koch Gateway Pipeline Co.*,¹⁰⁸ the ALJ, citing the Policy Statement, approved the pipeline's application for market-based rates for its firm (FT) and interruptible transportation services (IT). The ALJ concluded that FT and IT services could be treated as one product market with IT service as a "good alternative" because Koch Gateway Pipeline Co.'s (Koch) FT service was under-subscribed during peak periods due to significant discounting and low firm volumes, and that this under-subscription demonstrated little possibility for capacity constraints or curtailment. The ALJ allowed Koch to define its geographic market broadly, to include the five state region it served, rather than requiring it to treat every pairing of individual receipt and delivery points as a separate market. It also found Koch was not a "long-line" pipeline with a production area at one end and a market area at the other, but rather a "feeder line" transporting gas from numerous production areas to even more numerous markets.¹⁰⁹ The ALJ permitted Koch to submit estimates of available capacity, competitor connection costs and competitor rates because more accurate information was not available to Koch, and found that released capacity on Koch's pipeline was a "good alternative." The ALJ further held Koch's market share and HHI index were both sufficiently low to obviate concerns of market power, accepting Koch's argument that its market share and HHI index should be calculated for the five-state region as a whole or, alternatively, for the five individual states. Finally, the judge found the remaining factors—ease of entry, significant discounting and demand elasticity also mitigated in favor of finding the absence of market power.

The FERC approved several facility expansions and market-based rates for small storage and hub service providers operating in production areas. In *Egan Hub Partners*, the FERC approved Egan Hub Partners' (Egan Hub) compliance with the analysis in the Policy Statement and its separate application of that analysis to storage services and interruptible hub services, and found Egan Hub fit a familiar pattern; it was a "relatively new, comparatively small entrant, with a low market concentration and with competitors apparently facing few barriers to entry."¹¹⁰ The FERC also noted that entry into the production market was relatively easy, because competition appeared to be increasing, and no one had protested the application. Accordingly, it concluded Egan Hub would be forced to charge competitive rates to attract customers.¹¹¹

The FERC built on the principles of *Egan Hub* by granting market-

108. 80 F.E.R.C. ¶ 63,008 (1997).

109. The ALJ also concluded that the total number of paired delivery and receipt points (366,000) made it impossible to present a market power case for every combination and the majority of shippers on Koch were gas marketers, which did not view the system in terms of a pair of receipt and delivery points. 80 F.E.R.C. ¶ 63,008 at 65,095-96.

110. *Egan Hub Partners, L.P.*, 81 F.E.R.C. ¶ 61,017 (1997)[hereinafter *Egan Hub*].

111. See also, *Central Oklahoma Oil & Gas Corp.*, 80 F.E.R.C. ¶ 61,250 (1997) (approving market-based rates for a small market-share entrant into the production-area storage market); *Pontchartrain Natural Gas Sys.*, 80 F.E.R.C. ¶ 61,279 (1997).

based rates for a Hinshaw Pipeline's storage service despite the presence of high market concentration.¹¹² Unlike that in *Egan Hub*, New York State Electric and Gas Corp.'s (NYSEG) geographic market (New York and Pennsylvania) was highly concentrated with an HHI of 4082 for deliverability and 4678 for capacity. The FERC held that, while it more closely scrutinizes applicants whose markets have an HHI above 1800, NYSEG's application survived heightened scrutiny. It found the high market concentration was due to CNG's and National Fuel Gas Supply's high market shares, rather than NYSEG's small share of the market. As NYSEG was a small entrant with a small market share and in a market with few barriers to entry, the FERC concluded NYSEG would still be under pressure to attract customers by charging competitive prices. In any event, the rates of NYSEG's competitors were regulated, which led the FERC to conclude customers could always resort to those "just and reasonable" rates.

Relying on the application of its affiliate, Egan Hub, Moss Bluff Hub Partners, L.P. (Moss Bluff), a Hinshaw Pipeline, filed for market-based rates for its storage and interruptible hub services.¹¹³ Unlike its affiliate, Moss Bluff did not follow the requirements in the Policy Statement, but nevertheless survived scrutiny. The FERC clarified that hub service providers were to provide a separate market analysis for each hub service such as wheeling, parking and loaning. Even though Moss Bluff had been able to rely on Egan Hub's petition to establish the necessary market data, the FERC warned future applicants it would be difficult to succeed without explicitly following the analysis required in the Policy Statement.¹¹⁴

The FERC cancelled an experimental pilot program designed to remove price ceilings for releases of capacity as well as "sales of interruptible and short-term firm transportation in qualifying markets."¹¹⁵ The FERC hoped to gain valuable information regarding whether it should release the price cap for secondary markets. It decided the San Juan lateral did not qualify because of concerns that Transwestern Pipeline Co. and other parties could exercise market power on the lateral. Pacific Gas & Electric and Southern California Edison withdrew largely because of the limitations resulting from exclusion of the San Juan lateral.

112. *New York State Elec. & Gas Corp.*, 81 F.E.R.C. ¶ 61,020 (1997).

113. *Moss Bluff Hub Partners, L.P.*, 80 F.E.R.C. ¶ 61,181 (1997).

114. Inventory Management and Distribution Co. (IMD) sought clarification regarding the market-based rate Moss Bluff could charge, arguing that as the sole customer for a service, it was the "market," and Moss Bluff was obligated to provide the service at IMD's proposed rate. The FERC disagreed, stating that Moss Bluff did not have an obligation to accept a rate unilaterally proposed by one customer. Moss Bluff could not discriminate by denying a rate to one shipper that it was providing to another; however, the allegation here was the opposite--IMD alleged only that it was the sole customer seeking the service. The FERC also stated that Moss Bluff could deny a request for service simply because it had found another customer willing to pay a higher rate than IMD, and if IMD did not want to pay that rate, it could "shop around" for alternative service. *Id.* at 61,749.

115. *Transwestern Pipeline Co.*, 78 F.E.R.C. ¶ 61,200, at 61,858 (1997).

B. Negotiated and Recourse Rates

The FERC's treatment of negotiated rates continued to focus on the concerns outlined in the Policy Statement. While it closely examined negotiated rate proposals which appeared to shift costs to recourse rate shippers, the FERC for the first time allowed discount adjustments for a negotiated rate program. Additionally, the FERC issued significant decisions addressing how negotiated rates would impact capacity release, whether recourse rates remained available to all shippers that did not choose negotiated rates, and what the FERC would require in a filing for specific negotiated rates.

The FERC allowed discount adjustments under an "innovative" negotiated rate program when shippers entered into a Part 284 service agreement prior to negotiating the rates.¹¹⁶ The Part 284 rate had to be either the recourse rate or a discounted recourse rate, and if Northwest Pipeline Corp. (Northwest) and the shipper subsequently agreed to a negotiated rate, the Part 284 agreement would be converted to a negotiated rate contract.¹¹⁷ The FERC approved the program, focusing most heavily on its belief that recourse rate shippers would be protected from cost shifting.¹¹⁸ The FERC decided that Northwest would have to satisfy the standard applied to affiliate discounts¹¹⁹ when seeking discount adjustments for negotiated rates in its next rate case.¹²⁰

After *Northwest Pipeline Corp.*, the FERC affirmed several of its 1996 decisions, denying discount adjustments for other negotiated rate programs. In rejecting these programs, the FERC distinguished *Northwest*

116. *Northwest Pipeline Corp.*, 79 F.E.R.C. ¶ 61,416 (1997).

117. Discount adjustments would be sought for the converted negotiated rate contracts if the original Part 284 rate was discounted. The discount adjustment would be based on the greater of: "(1) the negotiated rate revenues [actually] received; or (2) the discounted [initial Part 284] recourse rate revenues which otherwise would have been received" had the Part 284 agreement not been converted to a negotiated rate contract. *Id.* at 62,752.

118. The FERC explained that if the Part 284 rate revenues were higher, then Northwest would get a discount adjustment based on those revenues. This would not result in cost shifting because Northwest would have been entitled to this discount anyway in the absence of the negotiated rate program. If the negotiated rate revenues were higher, then Northwest would get a discount adjustment based on these revenues. Because *higher* revenues mean a *lower* discount, the discount adjustment resulting from higher negotiated rate revenues would actually be lower than the discount from the Part 284 rate revenues. Thus, the FERC concluded that higher negotiated rate revenues actually accrued to the benefit of recourse rate shippers because the negotiated rate revenues could result in a discount *lower* than Northwest would have been entitled to under the original Part 284 agreement. *Id.*

119. The FERC closely scrutinizes the affiliated shipper discounts and the pipeline retains the burden to justify the discounts. See, e.g., *Southern Natural Gas Co.*, 65 F.E.R.C. ¶ 61,347 (1993), *modified on other grounds*, 67 F.E.R.C. ¶ 61,155 (1994). This treatment is different from that applied to non-affiliated shipper discounts, where the pipeline must only generally explain the reason for the discount and then the burden shifts to those opposing the adjustment. See, e.g., *Panhandle E. Pipe Line Co.*, 71 F.E.R.C. ¶ 61,228 (1995).

120. Commissioner Santa concurred but disagreed with the application of the affiliate standard. *Northwest Pipeline Co.*, 79 F.E.R.C. ¶ 61,416, at 62,758. Commissioner Massey dissented because he believed the discount adjustment provisions would negatively impact recourse rate shippers. *Id.* at 62,757-58.

on the ground that Northwest's program protected recourse rate shippers from cost-shifting, while the discount adjustments in these cases did not. The FERC reiterated it was not establishing a per se rule against all discount adjustments, but would not allow discount adjustments without adequate protection for recourse rate customers.¹²¹

The FERC rejected a request requiring Northwest to accept negotiated rate contracts between the original capacity holder and a replacement shipper.¹²² The FERC reaffirmed that its negotiated rate program was completely voluntary and the pipeline's consent was needed for negotiated rate contracts for released capacity. Additionally, the FERC upheld Northwest's requirement that the original capacity holder remain responsible for payment obligations, procedures and crediting mechanisms that varied from those in Northwest's tariff. This approval was conditioned on Northwest filing, each negotiated rate agreement that varied from the tariff as a non-conforming service agreement.

The FERC rejected a "Terms and Conditions" provision which stated that only FT-1 shippers on an offshore pipeline could permanently release capacity, finding the provision to be inconsistent with its offshore negotiated rate policy.¹²³ As the other shippers also needed capacity release to mitigate their minimum revenue obligations, Dauphin Island Gathering System (Dauphin Partners) was obligated to provide all other shippers with the same capacity release opportunity it gave FT-1 shippers.¹²⁴

TransColorado Gas Transmission Co. (TransColorado) addressed the validity of a tariff provision that states during the term of a negotiated rate agreement, a negotiated rate shipper cannot use the recourse rate for all other services to the same delivery and receipt points mentioned in the negotiated rate agreement.¹²⁵ The FERC reaffirmed the importance of recourse rates by rejecting this provision. The FERC held that the recourse rate is available for all contracts and volumes other than the volume in the contract that specifies the negotiated rate. TransColorado believed this would allow negotiated rate shippers to resort to other rates when the negotiated rate is not favorable. The FERC stated the recourse rate is needed to check market power whenever a negotiated rate shipper considered additional services on the same system.

121. *NorAm Gas Transmission Co.*, 81 F.E.R.C. ¶ 61,204 (1997); *Koch Gateway Pipeline Co.*, 81 F.E.R.C. ¶ 61,205 (1997); *Columbia Gulf Transmission Co.*, 81 F.E.R.C. ¶ 61,206 (1997); *Tennessee Gas Pipeline Co.*, 81 F.E.R.C. ¶ 61,207 (1997). For the FERC's treatment of other accounting issues in the context of negotiated rates, see the Commission's preliminary determination on non-environmental issues in *Alliance Pipeline L.P.*, *supra* note 31.

122. *Northwest Pipeline Co.*, 79 F.E.R.C. ¶ 61,416 (1997).

123. See *Dauphin Island Gathering Sys.*, 79 F.E.R.C. ¶ 61,391, *reh'g granted on other grounds*, 80 F.E.R.C. ¶ 61,237, (1997). *reh'g pending*

124. Other off-shore negotiated rate programs examined by the FERC in 1997 include: *Sea Robin Pipeline Co.*, 81 F.E.R.C. ¶ 61,169 (1997); *Chevron USA Inc.*, 81 F.E.R.C. ¶ 61,183 (1997); *Garden Banks Gas Pipeline, L.L.C.*, 78 F.E.R.C. ¶ 61,066 (1997).

125. *TransColorado Gas Transmission Co.*, 78 F.E.R.C. ¶ 61,306 (1997).

Similarly, the FERC rejected a tariff provision which stated that recourse rates were not available to negotiated rate shippers between the receipt and delivery points specified in the negotiated rate agreement.¹²⁶ The FERC found the recourse rate was unavailable for the contract demand in the negotiated rate agreement, but that it did not want to give the impression that the remaining contract demand was also precluded from recourse rate treatment.

The FERC also addressed requests to approve specific negotiated rate contracts or tariff sheets. Consistent with the Policy Statement, the FERC continued to require the individual negotiated rates be on record either by filing the contract itself or additional tariff sheets. The FERC held it would require at least the following information: (1) the negotiated rate and its components or the formula used to calculate the rate, (2) the rate schedule, (3) the receipt and delivery points, (4) the type of service, and (5) the quantity to be transported.¹²⁷ The term of the contract would only be required where option fees were concerned. Applicants filing a tariff sheet instead of a contract must include a statement that the negotiated rate contract does not materially vary from the form of service agreement in the tariff. They do not, however, have to provide references to the accounting they plan to use for the negotiated rate revenues in the tariff or the supplemental sheets filed for individual rates.¹²⁸

The FERC also examined the Policy Statement's requirement that the contracts or tariff sheets be filed as soon as the pipeline enters into the transaction, rejecting a request that a negotiated rate be made effective two weeks before the day it was actually filed.¹²⁹ The FERC distinguished its decision from *NorAm Gas Transmission Co.*, where it allowed a negotiated rate filed on the first business day of the month to be retroactive to the first day of the month. The FERC stated it had allowed the *NorAm* rate to be retroactive because it was tied to certain business indices which were not published until the first business day of the month, and *NorAm* had filed the rates as close as possible to the time the transaction was consummated.¹³⁰ *Koch Gateway Pipeline Co.* (*Koch*) failed to show any similar necessity.¹³¹

Koch also addressed another retroactivity issue of whether *Koch* could file a revised tariff sheet revising the contract volumes of a negotiated rate contract and have the revisions become effective before the filing date of the revision. It stated the policy behind requiring timely

126. *El Paso Natural Gas Co.*, 79 F.E.R.C. ¶ 61,017 (1997).

127. *Transwestern Pipeline Co.*, 79 F.E.R.C. ¶ 61,021, at 61,096, *reh'g denied*, 79 F.E.R.C. ¶ 61,310 (1997). See also *Koch Gateway Pipeline Co.*, 80 F.E.R.C. ¶ 61,050 (1997); *Panhandle E. Pipe Line Co.*, 78 F.E.R.C. ¶ 61,011, *reh'g denied*, 81 F.E.R.C. ¶ 61,234 (1997).

128. *Northern Natural Gas Co.*, 79 F.E.R.C. ¶ 61,402 (1997).

129. *Koch Gateway Pipeline Co.*, 79 F.E.R.C. ¶ 61,323 (1997).

130. *NorAm Gas Transmission Co.*, 75 F.E.R.C. ¶ 61,322 (1996), *reh'g denied*, 77 F.E.R.C. ¶ 61,101 (1996).

131. See, e.g., *Trailblazer Pipeline Co.*, 79 F.E.R.C. ¶ 61,274 (1997) (refusing to give retroactive effect to tariff sheets filed ten business days after the negotiated rate contract was consummated).

filed contracts and tariff sheets detailing negotiated rate transactions was to allow similarly situated shippers to determine if they were being discriminated against. The FERC found Koch's proposal violated this policy by rendering the earlier publications of the transaction inaccurate.

VIII. ORDER 636 AND RESTRUCTURING MATTERS

Over five years after Order No. 636 was issued, the Supreme Court confirmed its basic validity by declining to review the District of Columbia Circuit's decision affirming in part and remanding in part the FERC's original orders.¹³²

While the petitions for a writ of certiorari were pending, the FERC issued Order No. 636-C,¹³³ addressing the issues remanded by the District of Columbia Circuit. If a pipeline offers no-notice service prospectively, the FERC requires offering the service on a non-discriminatory basis to all customers who request it under section 284.8(b)(1)¹³⁴ to the extent it has capacity (including storage capacity which may be needed to provide such service); however, it is not required to expand its capacity or acquire additional facilities to provide such service. Second, the FERC reduced the maximum term which must be matched in the right-of-first-refusal process, from twenty years to five years, concluding that "[a] five-year cap will avoid customers' being locked into long-term arrangements with pipelines that they do not really want" It is also "consistent with the current industry trend of short-term contracts, as indicated by the FERC's newly-available data." Further, the FERC, requiring all pipelines whose tariffs require term caps longer than five years to revise them, providing for the new term, and stated it would consider whether any relief is appropriate for contracts renewed since Order No. 636.¹³⁵ Third, the FERC reaffirmed its preference for customer-by-customer mitigation rather than customer-class mitigation, stating that the implementation of SFV rate design under Order No. 636 was not to have a significant cost shift to individual customers.¹³⁶ Fourth, the FERC reaffirmed its decision to determine, on a case-by-case basis, the eligibility of customers of downstream pipelines for the upstream pipeline's small-customer rate,

132. Order No. 636, *Pipeline Service Obligations*, 57 Fed. Reg. 13,267 (1992), *on reh'g*, Order No. 636-A, 57 Fed. Reg. 36,128 (1992), *on reh'g*, 57 Fed. Reg. 57,911 (1992), Order No. 636-B, 61 F.E.R.C. ¶ 61,272 (1992), *reh'g denied*, 62 F.E.R.C. ¶ 61,007 (1993), *aff'd in part and remanded in part sub nom. United Distribution Co. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *cert. Denied sub nom. Associated Gas Distribs. v. FERC*, 117 S. Ct. 1723 (1997).

133. *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, 62 Fed. Reg. 10,204 (1997).

134. Certain Sales and Transportation of Natural Gas under the Natural Gas Policy Act of 1978 and Related Authorities, 18 C.F.R. § 284.8(b)(1) (1998).

135. 62 Fed. Reg. 10,204 at 10,209-10 (1997) (to be codified at 18 C.F.R. pt. 284).

136. Because the issue had acquired significance only on one pipeline, and then only because of unique circumstances that developed after restructuring, the FERC concluded that the issue had no continuing vitality and declined to revisit its prior rulings. *Id.* at 10,210-11.

concluding that a generic determination concern the class of customers eligible for the small customer rate would not permit the FERC to consider the needs of small customers and the impact of expanding the universe of small customers on the pipelines' other customers.¹³⁷ Fifth, the FERC reaffirmed its decision to allow the interstate pipelines to recover all of their prudently incurred gas supply restructuring (GSR) costs on the ground that Order No. 636 caused the incurrence of those costs, noting its decision on remand would not affect settlements in which pipelines had agreed to absorb a portion of their GSR costs to avoid litigation.¹³⁸ Finally, the FERC decided it would not require the allocation any specific percentage of GSR costs to interruptible transportation for those pipelines which do not have approved settlements or final, non-appealable orders specifying the allocation of such costs, and directed those pipelines to file proposals to recover a percentage of their GSR costs from interruptible transportation. Those pipelines with approved settlements or final orders were not required to modify their approved resolutions of this issue.¹³⁹

The FERC approved Tennessee's settlement establishing a mechanism for the recovery of its massive transition costs, nearly \$1.2 billion, under Order No. 636.¹⁴⁰ This settlement disposed of thirty-four dockets at the FERC and thirty-nine separate proceedings at the District of Columbia Circuit. The cost sharing mechanism requires Tennessee to absorb certain percentages of costs depending on the level of costs incurred and specifies the percentages of costs and caps to be paid by firm and interruptible customers. It also requires, with some exceptions, the recoverable costs be incurred by December 31, 2000, or payable by January 2, 2002, under settlements reached by the earlier date. Finally, the settlement permits firm customers to satisfy at least portions of their obligations by applying refunds due to them under the settlement in Tennessee's rate case (Docket No. RP95-112), and extend the moratorium on the base rates established in that proceeding, with defined exceptions, for two additional years through October 31, 2000, and limited increase in the settlement rates for five years through October 31, 2005, for firm service agreements in effect on October 23, 1996. The settlement also permitted customers, with contract rollover rights on October 23, 1996, to extend those contracts for up to five years for any quantity up to the maximum daily quantity.

The FERC dismissed a complaint regarding an LDC's capacity release practices, holding that it was "vague and confusing with [t]he single allegation . . . consist[ing] of a few conclusory statements devoid of any factual support."¹⁴¹ The FERC also expressed concern that the issues might relate to the ongoing unbundling activities in Florida.

137. *Id.* at 10,212.

138. *Id.* at 10,213.

139. *Id.* at 10,218-10,219.

140. *Tennessee Gas Pipeline Co.*, 79 F.E.R.C. ¶ 61,031, at 61,181 (1997).

141. *Energy Management Corp. v. Peoples Gas Sys., Inc.*, 78 F.E.R.C. ¶ 61,044, at 61,181 (1997).

The FERC dismissed Southern California Edison's complaint against Southern California Gas' capacity release practices, holding firm capacity holders are not required to release capacity or accept discounts for released capacity.¹⁴² Rather, firm capacity holders are permitted to prescribe minimum bids which must be accepted to obtain the capacity, and the FERC will not second guess capacity holders' decisions on whether to release capacity as any unused capacity is available as interruptible transportation.

The FERC reaffirmed its policy of determining on a case-by-case basis whether pipelines will be allowed to hold upstream capacity on other pipelines.¹⁴³ The FERC rejected arguments by two pipelines requiring pipelines to obtain such capacity only on a case-by-case basis discriminated against them. The FERC also rejected the argument that its order was inconsistent with Order No. 636, noting *United Distribution Companies v. FERC* had held *Texas Eastern* had mooted claims that Order No. 636 prohibited pipelines from holding capacity on upstream pipelines.

In *Brooklyn Union Gas Co. v. Transcontinental Gas Pipeline Co.*,¹⁴⁴ the FERC refused to allow customers to use secondary delivery points under an open access transportation service to inject gas into a certificated storage service. While a customer is permitted to deliver gas to any secondary delivery point in a zone for which it pays a demand charge, the FERC found that customers are not permitted to inject gas into a Part 157 individually certificated bundled storage service at any point in the zone. The FERC reiterated its holding in Order No. 636¹⁴⁵ that "[t]he flexible receipt and delivery point authority accorded Part 284 service by Order No. 636 does not extend to individually certificated NGA section 7(c) services."¹⁴⁶

At the same time, the FERC ruled a shipper under a section 7(c) certificate must convert to open access transportation if it desires to have flexible receipt and delivery points and incur the associated transition costs.¹⁴⁷

IX. RATES

The major rate decisions during 1997 revolved around the new mechanism for deriving the long-term growth component in the discounted cash flow (DCF) methodology for calculating the return on equity. This mechanism uses the average of a short-term growth factor based on five-year projections from Institutional Brokers Estimate System (IBES) data

142. *Southern Cal. Edison Co. v. Southern Cal. Gas Co.*, 79 F.E.R.C. ¶ 61,157 (1997).

143. *Texas E. Transmission Corp.*, 78 F.E.R.C. ¶ 61,277 (1997).

144. *Brooklyn Union Gas Co. v. Transcon. Gas Pipe Line Corp.*, 79 F.E.R.C. ¶ 61,074 (1997) [hereinafter *Brooklyn*].

145. Order No. 636-A, III F.E.R.C. STATS. & REGS. Preambles ¶ 30,950, at 30,585, and Order No. 636-B, 61 F.E.R.C. ¶ 61,272, at 61,992-94.

146. 79 F.E.R.C. at 61,369.

147. *Tennessee Gas Pipeline Co.*, 78 F.E.R.C. ¶ 61,340 (1997).

for proxy company groups and a long-term growth factor derived from gross domestic product (GDP) projects from DRI/McGraw Hill (DRI), the Energy Information Administration (EIA) and Wharton Economic Forecasting Associations (Wharton).¹⁴⁸ Although no data source or methodology provides a perfect determination of the long-term growth figure for a particular pipeline or the pipeline industry, the FERC concluded the long-term growth of the United States economy, measured by the GDP, provides a reasonable long-term growth factor for the DCF calculation. The long-term factor is to be calculated using DRI, EIA and Wharton data for twenty-five years, or the longest period available if a source does not provide twenty-five year data. This analysis yields a rate of return for each of the companies in the proxy group, and the rate for the subject pipeline will be selected from the lowest, midpoint or highest return for the proxy group depending upon the pipeline's risk or other special circumstances. Pipelines will be permitted returns outside this range only in special circumstances such as a capital structure that differs markedly from those for the proxy group or for startup or new entrants whose business risks differ from those of the established companies in the proxy group.

The affected pipelines and others sought rehearing. The pipelines claimed the FERC denied them due process by adopting a methodology from outside the record, which was unsupported by any evidence and untested by a participant to the proceeding. They also challenged the attempt to dictate a generic methodology for prospective application in all cases through adjudication rather than rulemaking with the opportunity for notice and comment. Other pipelines urged the FERC mission to permit them to challenge the new policy in their own cases in the future.

Thereafter, the FERC required many pipelines to revise their section four rate filings to calculate their proposed returns on equity using the new policy.¹⁴⁹ This generated another series of requests for rehearing, leading the FERC to permit those pipelines and other parties to the affected proceedings to litigate why the FERC's precedent should not be applied to those particular pipelines.

Capital structure also occupied the FERC's attention. It adhered to the position that the pipeline subsidiary's own capital structure should be used when it is responsible for its own financing and issues its debt.¹⁵⁰ While preferring to use the actual capital structure of the pipeline for rate-making purposes, the FERC noted it will not use an equity-rich capital structure which imposes additional costs on consumers. It will use a pipeline's own capital structure as long as its equity ratio falls within the

148. *Williston Basin Interstate Pipeline Co.*, 79 F.E.R.C. ¶ 61,311 (1997); *Northwest Pipeline Corp.*, 79 F.E.R.C. ¶ 61,309 (1997).

149. *Wyoming Interstate Co. Ltd.*, 79 F.E.R.C. ¶ 61,399 (1997), *on reh'g*, 81 F.E.R.C. ¶ 61,029 (1997); *CNG Transmission Corp.*, 80 F.E.R.C. ¶ 61,137 (1997), *on reh'g*, 81 F.E.R.C. ¶ 61,031 (1997); *Equitrans, L.P.*, 80 F.E.R.C. ¶ 61,144 (1997), *on reh'g*, 81 F.E.R.C. ¶ 61,030 (1997).

150. *Williams Natural Gas Co.*, 77 F.E.R.C. ¶ 61,277 (1996), *on reh'g*, 80 F.E.R.C. ¶ 61,158 (1997); *Transcon. Gas Pipe Line Corp.*, 80 F.E.R.C. ¶ 61,157 (1997).

range of the equity ratios of the pipelines within the proxy group. If the pipeline's equity ratio falls outside this range, the FERC will use the parent's capital structure as long as its equity ratio falls within the range of those of the proxy group; if both the pipeline's and the parent's capital structures fall outside the range of those of the proxy group, the FERC will resort to a hypothetical capital structure.

X. STATUTORY PENALTIES

The FERC issued regulations to implement section 223 of the Small Business Regulatory Enforcement Fairness Act of 1996.¹⁵¹ The FERC adopted most of the statutory criteria for reducing or waiving penalties that otherwise would be imposed on small business entities for violating statutory or regulatory requirements, stating that "to be considered for a reduction or waiver of a penalty, a small entity must not have a history of previous violations, and the violations at issue must not have been the product of willful or criminal conduct, or have caused loss of life or injury to persons, damage to property or the environment, or endangered persons, property or the environment."¹⁵² The FERC may also consider a waiver if a small entity "demonstrate[s] that it performed timely remedial efforts, made a good faith effort to comply with the law and did not obtain an economic benefit from the violations," and will "consider the entity's ability to pay before assessing a civil penalty."¹⁵³

XI. TARIFF AND SERVICE ISSUES

A. *Right of First Refusal*

As noted above, in Order No. 636-C, the FERC reduced the contract matching term cap to five years, required all pipelines whose current tariffs contain term caps longer than five years to revise their tariffs accordingly and stated that it would consider on a case-by-case basis whether relief is necessary in connection with contracts renewed under right of first refusal procedures since issuance of Order No. 636. Late in the year, the FERC granted the request of a shipper for relief from a twenty year contract with Transco entered into pursuant to the old twenty year matching term, concluding the shipper had shown that it had agreed to a longer term contract renewal than it otherwise would have because of the twenty year

151. Order No. 636, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations and Regulation of the Natural Gas Pipeline After Partial Wellhead Decontrol*, [Reg. Preambles Jan. 1991-June 1996] F.E.R.C. STATS. & REGS. ¶ 30,939, 57 Fed. Reg. 13,267 (1992) (codified at 18 C.F.R. pt. 284), *order on reh'g*, Order No. 636-A, [Regs. Preambles Jan. 1991-June 1996] F.E.R.C. STATS. & REGS. ¶ 30,950, 57 Fed. Reg. 36,128 (1992) (codified at 18 C.F.R. pt. 284), *order on reh'g*, Order No. 636-B, 62 F.E.R.C. ¶ 61,272 (1992), *reh'g denied*, 62 F.E.R.C. ¶ 61,007 (1993), *aff'd in part, vacated and remanded in part*.

152. *Id.* at 30,591.

153. *Id.*

requirement.¹⁵⁴ The shipper requested a five year term, but was required to match a twenty year term third party bid in order to retain its capacity. The relief granted, however, is expressly subject to FERC action on rehearing of Order No. 636-C.

The FERC also resolved disputes regarding the operation of the right of first refusal (ROFR) provisions contained in the tariff of Williams Natural Gas Company (Williams).¹⁵⁵ Williams presented some unique issues because its no-notice service, around which the controversy centered, consists of three possible components: (1) a firm storage component, (2) a firm transportation service in the market area, and (3) a firm transportation service in the production area.¹⁵⁶ After reviewing the general principles of the ROFR mechanism, the FERC determined the ROFR is defined by the essential elements of the service involved, as stated in the tariff. Thus, any party wishing to retain capacity must submit a bid conformed to the terms of the tariff, as the tariff defines the service. The FERC clarified, however, an existing shipper with a no-notice component only in the market area need not match a third party's bid for a particular volume in the production area, stating capacity outside the scope of the service agreement and the tariff could not be considered in the ROFR process. Finally, the FERC stated it was difficult to respond to the question of options for capacity holders to extend contracts at times other than the ROFR posting as no specific proposed tariff provisions had been provided. The FERC noted two different goals in this regard: (1) to assure the existing holder of capacity a reasonable opportunity to retain it, and (2) to assure that capacity may become available on a nondiscriminatory basis. The FERC stated its initial conclusion the general language in a tariff providing that the ROFR does not apply if Williams and an existing shipper renegotiate an existing contract before the contract expires, would be too general and would afford opportunities for undue discrimination.

B. Interconnection Policy

The FERC approved, with critical modifications, the interconnected construction policy of Panhandle Eastern Pipeline Company (Panhandle).¹⁵⁷ The FERC permitted Panhandle to require, as conditions

154. *Horsehead Resource Dev. Co. v. Transcon. Gas Pipe Line Corp.*, 81 F.E.R.C. ¶ 61,293 (1997).

155. *Missouri Gas Energy v. Williams Natural Gas Co.*, 81 F.E.R.C. ¶ 61,350 (1997), *pending on reh'g*.

156. The questions asked included (1) whether the ROFR rights are applicable to each of the discrete components or only to the aggregate, (2) whether bidders could offer to bring in other capacity to boost the economic value of their bid, (3) whether an existing shipper could bid a different combination of no-notice service as between the components, (4) whether bids submitted pursuant to the ROFR mechanism should be based on economics or upon the specific capacity posted, and (5) whether Williams could provide options that would allow existing capacity holders to extend contracts at times other than as provided in the ROFR posting provisions in the tariff. *Id.* at 62,624.

157. *Panhandle E. Pipe Line Co.*, 79 F.E.R.C. ¶ 61,016 (1997), *reh'g denied*, 81 F.E.R.C. ¶ 61,295 (1997). *Petition for review pending*, *Panhandle E. Pipe Line Co. v. FERC*, No. 98-1048 (D.C. Cir. 1998).

to an interconnect: (1) the construction of the interconnect not create significant operational problems for Panhandle, (2) the interconnect be at a mutually agreed location, provided Panhandle may not reject a site without adequate operational, environmental or legal justification, (3) the interconnect not adversely affect the rendition of existing service or adversely alter system operations, (4) Panhandle be provided with data necessary to properly design and construct the facility, (5) the interconnect not result in any minimum pressure receipt or delivery requirement, without Panhandle's consent (such consent not to be unreasonably withheld) or make Panhandle responsible for downstream facilities and (6) the service supporting the interconnect be in accord with tariff and regulatory requirements. The FERC directed Panhandle to delete a requirement that a shipper demonstrate market demand commensurate with the facility requested, holding if the interconnect does not require any mainline capacity expansion or significantly impact the environment, and the party requesting the interconnect is willing to reimburse all reasonable construction costs and expenses, a market demand showing is not required. Panhandle was also directed to delete language which would have required that the interconnect result in no adverse economic impact to Panhandle, because the Commission found this proposal vague, unduly discriminatory, and anti-competitive. This was due to the fact that it would allow Panhandle to deny an interconnection promoting efficiency in the overall gas market because it would result in Panhandle losing business. Finally, Panhandle was required to revise the interconnect policy to cover requests for interconnection by parties other than shippers.¹⁵⁸

Citing to the cost burden between rate cases, Northwest Pipeline Co. (Northwest) proposed to modify its standard facilities reimbursement clause by deleting the economic benefits test, pursuant to which it did not always charge shippers for reimbursement of facilities.¹⁵⁹ Northwest proposed, and the FERC accepted, a revision requiring customers to pay for the construction of receipt and delivery facilities in *all* instances via a lump sum payment or by reimbursement of the cost of service attributable to the facilities (clarified to mean cost of capital, related taxes and depreciation, but generally not operation and maintenance expense (O&M) and administration and general expenses (A&G) as those items probably do not exist for new facilities) under one of several rate methodologies, including volumetric rates, cost of service charges, leveled rate payments, or a combination of reservation and commodity charges. Details of the selected option would be spelled out in certificate filings.¹⁶⁰ The FERC required, Northwest to reinstate an option, contained in its existing tariff, permitting shippers to acquire an ownership interest in the facilities in proportion to the cost paid and held under the new provision

158. *Id.*

159. *Northwest Pipeline Corp.*, 78 F.E.R.C. ¶ 61,189 at 61,805 (1997), *modified*, 79 F.E.R.C. ¶ 61,101 (1997).

160. *Id.*

Northwest would bear the risk of cost under recovery.¹⁶¹

C. Operating Statement

Intrastate pipelines undertaking section 311 transportation must file Operating Statements setting out the terms and conditions of service.¹⁶² In *Texas Gas Pipeline Co.*,¹⁶³ the FERC rejected an Operating Statement which it found discriminated against interstate shippers by giving section 311 service a lower priority than comparable intrastate service or the pipeline's own use, providing firm service that is not firm since it could be canceled at any time. This would allow the pipeline discretion to grant preferential access to capacity in contracting and curtailment and allow the pipeline to contract for service in ways contrary to its Operating Statement.

D. Miscellaneous

The FERC accepted various proposals to allocate capacity based on value. The FERC accepted tariff sheets filed by Texas Eastern to implement a net present value allocation method to allocate available capacity on its system,¹⁶⁴ following precedent set by Tennessee.¹⁶⁵ Under this method, Texas Eastern has the option to hold an open season for capacity available for less than 90 days; all other capacity is subject to open season procedures. Capacity will be awarded based on net present value. In addition, subject to certain conditions, Texas Eastern is able to reserve unsubscribed capacity for future expansion projects.¹⁶⁶

The FERC accepted tariff sheets filed by Panhandle to revise its pro rata method for scheduling secondary point firm transportation to one based upon proximity to the applicable maximum rate.¹⁶⁷ Consistent with the FERC's approach in cases involving negotiated rates, a shipper paying a negotiated rate higher than the maximum rate would be considered as paying the maximum rate for purposes of scheduling.

In addition, 1997 saw a large number of cases addressing revisions to penalty, imbalance and cash-out provisions of pipeline tariffs as pipelines gained more experience under Order No. 636 tariffs.¹⁶⁸ These changes are

161. *Id.* at 61,808.

162. Natural Gas Policy Act § 311, 15 U.S.C. § 3371 (1978).

163. *Tejas Gas Pipeline Co.*, 81 F.E.R.C. ¶ 61,053 (1997).

164. *Texas E. Transmission Corp.*, 79 F.E.R.C. ¶ 61,258 (1997), *on reh'g*, 80 F.E.R.C. ¶ 61,270 (1997), *appeal pending sub nom.* MDG v. FERC, No. 97-1673 (D.C. Cir.).

165. *Tennessee Gas Pipeline Co.*, 76 F.E.R.C. ¶ 61,101 (1996), *on reh'g*, 79 F.E.R.C. ¶ 61,297 (1997).

166. *Texas E. Transmission Corp.*, 80 F.E.R.C. ¶ 61,270, at 61,981.

167. *Panhandle E. Pipe Line Co.*, 79 F.E.R.C. ¶ 61,019 (1997), *on reh'g*, 80 F.E.R.C. ¶ 61,198 (1997). *Petition for review pending sub nom.* Anadarko Petroleum Corp. v. FERC, No. 97-1623 (D.C. Cir.). Further proceedings are also pending at the FERC.

168. See, e.g., *NorAm Gas Transmission Co.*, 79 F.E.R.C. ¶ 61,126 (1997) (penalty for unauthorized overrun quantities); *Koch Gateway Pipeline Co.*, 79 F.E.R.C. ¶ 61,127 (1997) (cash-in/cash-out revenue crediting); *Southern Natural Gas Co.*, 80 F.E.R.C. ¶ 61,233 (1997) (graduated

responsive to perceived gaming of the penalty system by shippers to make profits on differences in prices and in order to establish better system control.

Pipelines continued in 1997 to propose variations on basic services, such as parking and lending, balancing and pooling services. Not all of the proposed variations were accepted. The FERC rejected Koch's proposal to implement a new Daily No Fuel Interruptible Transportation Service.¹⁶⁹ Under the proposal, Koch would provide customers an opportunity to compete for certain deliveries on its system by posting on a daily basis receipt and delivery points at which such service would be available. Koch claimed it would determine the eligible point based on scheduled volumes and nominations, selecting daily points which should not use fuel or incur any gas losses on that day. The FERC rejected the proposal, finding that it might be unduly discriminatory.¹⁷⁰ Unlike other proposals in which pipelines have been permitted not to charge fuel for transportation on facilities without compression or for backhaul transactions, Koch's proposal did not specify objective criteria, clearly limiting its service to those types of transactions. It appeared Koch had the ability to select certain capacity as eligible while other capacity, along the same facility, would carry a fuel component. Further, it was not clear under the test proposed by Koch that the selected capacity would not require fuel. Finally, the FERC stated it did not believe Koch could ever show there was no lost and unaccounted for gas tied to certain capacity, and not other capacity of the same type.¹⁷¹

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169. *Koch Gateway Pipeline Co.*, 81 F.E.R.C. ¶ 61,313 (1997).

170. *Id.* at 62,444.

171. 81 F.E.R.C. ¶ 61,313.