

REPORT OF THE NATURAL GAS REGULATION & COMPLIANCE COMMITTEE

This report summarizes decisions and policy developments that have occurred in the area of natural gas regulation from July 1, 2008 to June 30, 2009.*

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I. RULEMAKING ACTIONS

A. *Standards of Conduct*

On October 16, 2008, the Federal Energy Regulatory Commission (FERC) issued Order No. 717¹ promulgating regulations on the Standards of Conduct governing the relationship between a transmission provider and its marketing function employees and the marketing function employees of its affiliates. The Order was intended to clarify and refocus the Standards of Conduct to areas with the greatest potential for abuse.² The Order was additionally designed to conform the FERC's original Standards of Conduct to the U.S. Court of Appeals for the D.C. Circuit's ruling in the *National Fuel* decision.³ As proposed in the Notice of Proposed Rulemaking in this proceeding (NOPR),⁴ the FERC abandoned the concept of energy affiliates and, in its stead, adopted the

1. Standards of Conduct for Transmission Providers, 73 Fed. Reg. 63,796 (2008) (to be codified at 18 C.F.R. pt. 358.) [hereinafter, *Order No. 717*].

2. *Order No. 717*, *supra* note 2, at 1.

3. *Nat. Fuel Gas Supply Corp. v. FERC*, 909 F.2d 1519 (D.C. Cir. 1990).

4. Standards of Conduct for Transmission Providers, 73 Fed. Reg. 16,228 (2008) (to be codified at 18 C.F.R. pt. 358) [hereinafter, *NOPR*].

“employee functional approach”⁵ for determining applicability of the Standards of Conduct, the approach previously relied upon in Order Nos. 497⁶ and 889⁷.

The FERC claimed that, under Order No. 717, it was not establishing a new standard of review or imposing different evidentiary burdens specific to the Standards of Conduct.⁸ The FERC clarified that the revised Standards of Conduct are not intended to contain an exhaustive list of ways in which undue preference may arise and that an entity’s compliance with the Standards of Conduct in other respects will not serve as a defense to a violation of the Natural Gas Act’s prohibition on undue discrimination.⁹

1. Applicability

The FERC excluded Part 157 pipelines from the scope of the Standards of Conduct, relying on the determination that pipelines operating only under Part 157 cannot discriminate because such pipelines can only transport for specific shippers under the authorized terms of their certificates.¹⁰

Indicating that the core abuse to which the Standards of Conduct is directed is that of undue preference in favor of a transmission provider’s affiliate, the FERC also excluded from applicability an electric utility that does not engage in transmission transactions with a marketing affiliate, thus unifying the regulatory expectations for pipelines and public utilities.¹¹ The effective date for a transmission provider not currently engaging in transmission transactions with its affiliate to be in compliance is the date that the transmission provider commences transmission transactions with an affiliate that engages in marketing functions.¹²

Waivers from the Standards of Conduct, which had been granted under the previously existing regulation, were deemed to continue in full force and effect unless rendered moot by revisions contained in Order No. 717.¹³

2. Definitions

Many previously existing definitions were revised in an effort to provide additional clarity. The FERC clarified that transmission function activities can

5. *Order No. 717*, *supra* note 2, at 3.

6. *Inquiry into Alleged Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines*, 53 Fed. Reg. 22,139 (1988); Order No. 497-A, *order on reh’g*, F.E.R.C. Stats. & Regs. [Regs. Preambles 1986-90] ¶ 30,868 (1989); Order No. 497-B, *order extending sunset date*, F.E.R.C. Stats. & Regs. [Regs. Preambles 1986-90] ¶ 30,908 (1990); Order No. 497-C, *order extending sunset date*, F.E.R.C. Stats. & Regs. [Regs. Preambles 1991-96] ¶ 30,934 (1991); *reh’g denied*, 58 F.E.R.C. ¶ 61,139 (1992); *aff’d in part and remanded in part sub nom.*, *Tenneco Gas v. FERC*, 969 F.2d 1187 (D.C. Cir. 1992) [hereinafter, *Order No. 497*].

7. *Open Access Same-Time Information System (Formerly Real-Time Information Network) and Standards of Conduct*, F.E.R.C. Stats. & Regs. [Regs. Preambles 1991-96] ¶ 31, 035 (1996); Order No. 889-A, *order on reh’g*, F.E.R.C. Stats. & Regs. [Regs. Preambles 1996-2000] ¶ 31,049 (1997); Order No. 889-B, *reh’g denied*, 81 F.E.R.C. ¶ 61,253 (1997) [hereinafter, *Order No. 889*].

8. *Order No. 717*, *supra* note 2, at 293.

9. *Id.* at 295.

10. *Id.* at 15.

11. *Id.* at 23.

12. *Id.* at 26.

13. *Id.* at 31-32.

be identified by and are characterized by “day-to-day” responsibilities focused on short-term, real-time results. Individuals who are not typically involved in day-to-day transmission function activities fall outside the scope of the definitions of a “transmission function employee”. Activities focused on long-range planning are not considered activities subject to the Standards of Conduct, although decisions made in advance of real-time, but directed at real-time operations are still considered to be subject to the Standards of Conduct.¹⁴ The FERC included in Order No. 717 unique definitions for electric and gas marketing functions¹⁵ and clarified specific terms used within the context of those definitions as a response to issues raised during the comment period of the NOPR.

The FERC enhanced the definition of a marketing function employee by including the phrase “on a day-to-day basis” to the definition.¹⁶ For further clarification, the FERC introduced the phrase “actively and personally engaged” within both the marketing function employee and transmission function employee definitions as a threshold for determining the level of activity required for an employee to be categorized within either group.¹⁷

The FERC revised the definition of transmission provider to exclude all natural gas storage providers authorized to charge market-based rates.¹⁸

B. Independent Functioning Rule

The FERC narrowed the expectation for independent functioning to the two newly created categories of employees, marketing function employees and transmission function employees,¹⁹ but cautioned repeatedly that outside consultants and agents are subject to the same categorical definitions based on employee job function, regardless of their employment status.²⁰ Following on the logic of the enhanced definitions for marketing function employees and transmission function employees, which stipulate active and personal engagement on a day-to-day basis, the FERC eliminated from the regulatory text the previous references to a shared employee, deeming such a category as unnecessary under the revised definitions.²¹

With elimination of the corporate separation approach and adoption of the employee-functional approach, the FERC reduced the occasions where transmission function employees legitimately need to interact with marketing function employees. The FERC acknowledged, however, that in some circumstances the possibility still remains for this interaction, particularly within small utilities. To eliminate any hesitation on parties to interact when necessary, the FERC eliminated the exclusion pertaining specifically to generation dispatch and included it through a broadened exclusion for reliability concerns. Additionally, the FERC broadened the exclusion for reliability to include general

14. *Id.* at 40.

15. *Id.* at 75.

16. *Id.* at 102.

17. *Id.* at 117.

18. *Id.* at 283.

19. *Id.* at 122.

20. *Id.* at 132.

21. *Id.* at 128.

compliance with reliability standards. Where interaction may be required, the transmission provider is not prohibited from allowing the interaction, but must keep sufficient records to document whether the communications fell within the scope of the exclusion.²² The exclusion was refined to specify that only exchanges of non-public information are subject to recordation.

C. No Conduit Rule

The FERC revised the regulatory text to create a single prohibition on any employee, contractor, consultant, or agent of the transmission provider from disclosing non-public transmission function information to a transmission provider's marketing function employees. The FERC also eliminated the proposed prohibition on marketing function employees receiving non-public transmission information. The FERC made further revisions to the text of this rule to prohibit a transmission provider from using anyone as a conduit to disclose non-public transmission information.²³

D. Transparency rule

The FERC provided clarification with respect to recordation and posting of waivers of tariff language, offering that a waiver is considered to be a determination to do or not do something that is specifically required to be done or not done by the transmission provider's tariff. The FERC continued to require that transmission providers record and log such waivers if granted in favor of an affiliate and to require that the waiver log be posted on the transmission provider's Internet website.²⁴ Retention requirements for the waiver log remain unchanged at five years.²⁵

The FERC concluded that an act of discretion is an action that is within the scope of the tariff provision in question and which typically involves an exercise of judgment on the part of the transmission provider. Recognizing that a transmission provider makes many judgment calls under its tariff on a daily basis, the FERC determined that a direct requirement to record acts of discretion would place a substantial administrative burden on transmission providers. Having made this determination, the FERC required such postings of discretionary actions only when required by other FERC regulations.²⁶

The FERC deleted the posting requirement for offers of discounts made by the transmission provider, maintaining that this information is duplicative with other requirements within the FERC's regulation. The FERC retained the requirement to contemporaneously disclose non-public transmission function information that had been disclosed to a marketing function employee in order to keep the affiliated marketer and any competitor on an even playing field. This requirement was extended to include Critical Energy Infrastructure Information (CEII) and other information that the FERC, by law, had determined to be

22. *Id.* at 173-80.

23. *Id.* at 198-200.

24. *Id.* at 213.

25. *Id.* at 217.

26. *Id.* at 215.

subject to limited dissemination.²⁷ The FERC revised the regulatory text to comport with its clarifications that a transmission function employee may discuss with a marketing function employee the latter's specific request for transmission service, but must refrain from discussing non-public matters beyond the specific request²⁸ and, additionally, that the voluntary consent provision refers to non-public customer information.²⁹

Finally, the FERC revised text related to the posting of job titles and job descriptions for transmission function employees to coincide with the overall revision to the regulation of adopting the employee functional approach.³⁰

The FERC cautioned that the contemporaneous disclosure as a result of violation of the prohibition on disclosing non-public transmission function information would not change the fact that a violation occurred but would be a vital consideration in deciding whether any remedy or other action would be appropriate.³¹

E. Implementation Requirements

The FERC relayed its intent that Standards of Conduct training be focused on those employees with the greatest need to recognize and appropriately handle transmission function information. The FERC described this group to include those most likely to be exposed to transmission function information, *i.e.*, transmission function employees and those to whom the disclosure of transmission function information is prohibited, such as marketing function employees. Additionally, the FERC stated that officers, directors, and supervisors have a clear need for understanding the Standards of Conduct as do others such as regulatory personnel, lawyers, accountants, and risk management personnel.³²

The FERC determined that either a transmission provider or its affiliate should provide training to marketing function personnel employed by the affiliate and that training for other workers should be contingent upon their risk of exposure to transmission function information. The FERC allowed that agents and consultants hired on a short-term basis who provide proof that they have received the appropriate training from another transmission provider may be considered as trained. The FERC reiterated, however, that any contractor, agent, or consultant, acting within one of the categories for which training is required, must receive appropriate training. Initial training must be conducted within thirty days and refreshed annually.³³

The effective date for Order No. 717 was set at thirty days after publication in the Federal Register. The FERC determined that transmission providers were to be in full compliance by that date with the exception of the posting and training requirements, for which the full compliance deadline was no later than sixty days after publication.

27. *Id.* at 235-36.

28. *Id.* at 237.

29. *Id.* at 239.

30. *Id.* at 246.

31. *Id.* at 295.

32. *Id.* at 306-07.

33. *Id.* at 308-10.

Subsequently, industry participants³⁴ filed a joint motion for extension of certain deadlines imposed by Order No. 717. Upon consideration of the concerns raised, the FERC granted requests for extensions of the deadlines for completion of revisions to procedures and training materials, posting of procedures to the transmission provider's website, distribution of procedures to affected employees, and for recordation of information exchanges.³⁵

Multiple parties requested rehearing or clarification on a variety of issues arising from the FERC's issuance of Order No. 717. Recurring items included the FERC's perspective on exclusion from the definition of marketing sales of natural gas sourced solely from a seller's own production, various aspects of Order No. 717 as it related to local distribution companies (LDCs) involved in off-system sales, and application of the term "marketing function employee" to employees of affiliated entities who do not engage in transmission transactions with the regulated transmission provider.

The FERC issued a tolling order³⁶ in the docket and the issues raised currently await a decision.

F. Capacity Release Rules

On November 21, 2008, the FERC issued Order No. 712-A, addressing petitions for rehearing and clarification of the revised capacity release regulations issued in Order No. 712,³⁷ and reported in the Committee's report last year.³⁸ Order No. 712-A largely denied rehearing but granted some clarifications and made some adjustments to the regulations. The FERC reaffirmed its position that the maximum rate ceilings for pipeline short-term transactions are necessary to protect against the potential for the exercise of market power.³⁹ The FERC also held that posting at the same time as consecutive short-term releases whose total term exceeds one year would be contrary to the decision to retain the price ceiling on long-term releases, and the record did not support removal of the price ceiling on long-term releases.⁴⁰ The FERC thus revised the regulations to clarify that the price cap does not apply to a short-term release only if the release takes effect within one year of the date the pipeline is notified of the release.⁴¹

With regard to the definition of an Asset Management Agreement (AMA), the FERC declined to change the delivery/purchase obligation in the definition, explaining that in order to assure that releases of less than one year are part of a bona fide AMA in which the capacity will be used to meet the releasing

34. *Joint Motion of Edison Elec. Institute and the Interstate Natural Gas Ass'n of America*, 125 F.E.R.C. ¶ 61,064, No. RM07-1-000 (Nov. 17, 2008).

35. *Order Granting an Extension of Time and Providing Notice of Change in Personnel*, 125 F.E.R.C. ¶ 61,291 (2008).

36. *Order Granting Rehearing for Further Consideration*, No. RM07-1-001 (Dec. 15, 2008).

37. *Promotion of a More Efficient Capacity Release Market*, 73 Fed. Reg. 37,058 (June 30, 2008); *order on reh'g*, 73 Fed. Reg. 72,692 (Dec. 1, 2008) [hereinafter, *Order No. 712-A*]; *order on reh'g and clarification*, 74 Fed. Reg. 18,127 (Apr. 21, 2009), 127 F.E.R.C. ¶ 61,051 (2009) [hereinafter, *Order No. 712-B*]; *appeal pending sub nom., Interstate Natural Gas Ass'n. of Am. v. FERC*, No. 09-1016 (Jan. 15, 2009).

38. *Report of the Natural Gas Regulation Committee*, 29 ENERGY L.J. 715, 721-723 (2008).

39. *Order No. 712-A*, *supra* note 38, at 16.

40. *Id.* at 60.

41. *Id.* at 62.

shipper's needs, the delivery/purchase obligation should be increasingly stringent the shorter the term of the release.⁴² For releases of more than one year, however, the FERC revised the definition to provide that the delivery/purchase obligation will be five months of each twelve month period and five-twelfths of the days of any additional period not equal to twelve months.⁴³ The FERC clarified that the delivery/purchase obligation under a storage AMA was intended to reflect storage ratchets and is satisfied if the releasing shipper has the right to call upon the asset manager to deliver or purchase gas consistent with the withdrawal or injection rights under the tariff at the time the releasing shipper requires performance.⁴⁴ The FERC denied a requested clarification that the delivery obligation only applied to the capacity released on the downstream pipeline that directly connected to the releasing shipper's delivery point, explaining that if the delivery obligation did not apply to the upstream capacity, the releasing shipper could include capacity in an AMA that it does not need for its own legitimate business purposes during the term of the release.⁴⁵ The FERC stated that the prohibition in Section 284.8(h)(2) on rolling over a thirty-one-day or less release to the same replacement shipper without bidding does not apply to AMAs or to releases pursuant to a state-approved retail access program.⁴⁶ Further, the FERC clarified that because Order No. 712 removed the maximum rate ceiling for all releases of one year or less, all such releases are subject to bidding, unless they qualify for the exemptions from bidding for releases of thirty-one days or less, releases to asset managers, or releases to marketers in a state-regulated retail access program.⁴⁷ The FERC clarified that an asset manager may release capacity it obtained as part of an AMA to another asset manager provided each release is made to implement an AMA and satisfies the delivery/purchase obligation and other criteria in the definition of an AMA.⁴⁸

Other clarifications concerned storage releases and releases related to Liquefied Natural Gas (LNG) terminal capacity. With regard to a storage release that includes a condition regarding the sale/purchase of gas inventory outside the AMA context, the FERC clarified that the parties may negotiate further terms and conditions related to the commodity portion of the transaction, and such agreements are not subject to the tying prohibition.⁴⁹ With respect to LNG terminals providing open access service, the FERC clarified that, where both the LNG terminal and the directly connected interstate pipeline are subject to Part 284 open access regulations, a holder of capacity in the LNG terminal has the right to release both its terminal capacity and its capacity on the downstream pipeline under the FERC's capacity release program and, consistent with existing policy, the releasing shippers can tie releases of upstream and downstream capacity to require a replacement shipper to take a release of

42. *Id.* at 78.

43. *Id.* at 79.

44. *Id.* at 85.

45. *Id.* at 87.

46. *Id.* at 93.

47. *Id.* at 98.

48. *Id.* at 113.

49. *Id.* at 130.

capacity on both.⁵⁰ The FERC denied rehearing with respect to non-open access LNG terminals because there would be no FERC process to ensure that a release of terminal capacity would be nondiscriminatory and transparent.⁵¹

In Order No. 712-B, issued April 16, 2009, the FERC further clarified the delivery/purchase obligation associated with several types of asset management arrangements. In a transaction chain involving capacity on several pipelines, the FERC clarified that the delivery obligation need not be cumulative to the extent gas delivered from upstream pipelines can be delivered using capacity on the downstream pipeline; however, the asset manager's delivery obligation at a releasing shipper's citygate only needs to be up to the contract demand of the released capacity on the downstream pipeline that interconnects directly with the releasing shipper's citygate. Thus, the fact that a releasing shipper may have also released capacity on an upstream pipeline, with total contract demand exceeding the released capacity on the downstream pipeline, does not increase the asset manager's delivery obligation at the releasing shipper's citygate on the downstream pipeline.⁵²

With regard to releases to marketers under state-approved retail access programs, the FERC clarified that the exemptions for releases by LDCs to retail choice marketers apply to any release where the marketer replacement shipper is obligated to use the capacity to provide the gas supply requirement of retail customers in the state program. The marketer need not make the retail sales directly; the condition can be satisfied so long as the marketer has a contractual obligation to use the full amount of the released capacity to supply gas to the retail access marketer and the retail access marketer is, in turn, obligated to supply that gas to the retail customers under the state program.⁵³

As individual pipelines implemented the requirements of Order No. 712, an issue arose as to whether a releasing shipper could pass through discounted usage or fuel charges to an asset manager replacement shipper. In a series of orders, the FERC stated that its policy has been that the releasing shipper cannot bind the pipeline to accept any particular usage charge from the replacement shipper, but the FERC recognized that the revisions of the capacity release regulations to implement AMAs raised the following issues: (1) whether it would be unduly discriminatory for a pipeline to deny an asset manager replacement shipper the same discount of the usage charge provided to the releasing shipper, at least during periods when the asset manager is using the released capacity to satisfy the delivery or purchase obligation of the release; (2) if so, whether the pipeline should be required to include in its tariff a provision concerning the circumstances under which it would provide similar usage charge discounts to an asset manager replacement shipper; and (3) whether the circumstances of individual releases to asset managers are sufficiently case-specific that pipelines should be allowed to decide whether to give a usage charge discount to the asset manager/replacement shipper on a case-by-case basis, subject to a general requirement of no undue discrimination.⁵⁴ Before

50. *Id.* at 145.

51. *Id.* at 146.

52. *Order No. 712-B*, *supra* note 38, at 12-13.

53. *Id.* at 29.

54. *See, e.g., Texas Eastern Transmission, L.P.*, 125 F.E.R.C. ¶ 61,396 at 21 (2008).

deciding the issue, the FERC sought additional information regarding the pipeline's or storage provider's contracting practices. In later orders on the same issue, the FERC explained that the issue only arises if the pipeline has provided discounts or negotiated rates to a releasing shipper, and that pipelines using straight fixed-variable rate design cannot discount the usage charge or fuel retention rates, because those charges only contain variable costs which cannot be discounted.⁵⁵

Although several pipelines have submitted information regarding their contracting practices, to which parties have responded, the FERC has not yet decided the substantive issue of whether a releasing shipper could pass through discounted usage or fuel charges to an asset manager replacement shipper.

G. Market Transparency Rules

The Energy Policy Act of 2005 (EPAc 2005) added Section 23 to the Natural Gas Act (NGA), directing the FERC to "facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce . . ." ⁵⁶ EPAc 2005 authorized the FERC to prescribe rules that "provide for the dissemination, on a timely basis, of information about the availability and prices of natural gas sold at wholesale and in interstate commerce," ⁵⁷ and to obtain such information "from any market participant." ⁵⁸ The FERC has issued two final rules implementing its new authority under NGA Section 23 – Order No. 704, ⁵⁹ requiring market participants to report annual information regarding wholesale physical natural gas purchases and sales, and Order No. 720, ⁶⁰ requiring major non-interstate pipelines to post daily information regarding scheduled volumes and available capacity at high volume receipt and delivery points and requiring interstate pipelines to post information regarding no-notice services volumes.

1. Annual Transactions Reporting

Order No. 704 required market participants to report annual information regarding their wholesale physical natural gas purchase and sales transactions on a new Form No. 552. Each market participant must report whether it operated under a blanket certificate under Part 284 of the FERC's regulations, and indicate whether it reports transactions to any price index publisher. On September 18, 2008, the FERC issued Order No. 704-A, clarifying the reporting requirements and making changes to Form No. 552.

The FERC reiterated that the volumes reportable on Form 552 should include volumes that utilize next-day or next-month price indices, volumes that are reported to any price index publisher, and any volumes that could be reported

55. See, e.g., *Gulf South Pipeline Co., L.P.*, 126 F.E.R.C. ¶ 61,179 at 12 (2009).

56. Natural Gas Act § 23(a)(1), 15 U.S.C. § 717 (2009).

57. Natural Gas Act § 23(a)(2), 15 U.S.C. § 717 (2009).

58. Natural Gas Act § 23(a)(3)(A), 15 U.S.C. § 717 (2009).

59. *Transparency Provisions of Section 23 of the Natural Gas Act*, 73 Fed. Reg. 1,014-01 (Jan. 4, 2008); *order on reh'g and clarification*, 73 Fed. Reg. 55,726 (Sep. 26, 2008) [hereinafter, *Order No. 704-A*]; *order dismissing reh'g*, 125 F.E.R.C. ¶ 61,302 (2008) [hereinafter, *Order No. 704-B*].

60. *Pipeline Posting Requirements under Section 23 of the Natural Gas Act*, 73 Fed. Reg. 73,494 (Dec. 2, 2008) (*reh'g pending*) [hereinafter, *Order No. 720*].

to an index publisher even if the market participant has chosen not to report to a publisher.⁶¹ The FERC explained that Form 552 does not seek the broader range of transaction data necessary to evaluate the size of the national physical natural gas market, but is limited to transactions that utilize, contribute to, or could contribute to index price formation.⁶²

The FERC retained the de minimis threshold of 2.2 million MMBtu per year, but clarified that an entity that has either reportable purchases equal to or greater than 2.2 million MMBtus or reportable sales equal to or greater than 2.2 million MMBtus must report all reportable sales and purchases.⁶³

The FERC clarified that there will be no categorical exclusion of end-use transactions; however, traditional, bundled retail transactions made by an LDC at a state-approved tariff rate (i.e., the majority of transactions to retail customers) would not contribute to the FERC's transparency mission and are not subject to reporting.⁶⁴ The FERC explained that where a transaction could contribute to the formation of price indices and/or relies on a price index, the transaction should be reportable even if the reporting entity is a natural gas end-user.⁶⁵

The FERC adopted a one-year safe harbor covering transactions in calendar year 2008 and reported on Form 552 on May 1, 2009.⁶⁶ The FERC stated that market participants submitting Form 552 in 2009 will benefit from a rebuttable presumption that the data provided is accurate and submitted in good faith. Respondents will not be penalized for errors in reporting on Form 552 provided that respondents use reasonable efforts to comply with the regulations regarding instructions for Form 552 and submit Form 552 in good faith and on a timely basis.⁶⁷

The FERC clarified that transactions involving exploration activities, production area operations, and gathering functions that rely on or could contribute to the creation of price indices are to be reported in the same manner as other types of transactions.⁶⁸ However, the FERC held that transactions regarding unprocessed gas should not be reported on Form 552 and should not be counted when determining whether an entity falls below the de minimis threshold.⁶⁹

The FERC clarified that asset managers may not aggregate customer volumes and that individual customers of asset managers are responsible for the submission of Form 552 and for the reporting of volumes managed by asset managers as well as any other reportable purchases or sales.⁷⁰ The FERC also clarified that joint action agencies will be allowed to report members' data on an aggregated basis in the same manner as corporate affiliates.⁷¹ The FERC stated

61. *Order No. 704-A*, *supra* note 60, at 13.

62. *Id.* at 15.

63. *Id.* at 24.

64. *Id.* at 34.

65. *Id.* at 36.

66. *Id.* at 68.

67. *Id.* at 71.

68. *Id.* at 76.

69. *Id.* at 78.

70. *Id.* at 79.

71. *Id.* at 82.

that for all contracts where deliveries occur or may occur over multiple calendar years and such volumes are reportable, only volumes attributable for delivery that use or may contribute to the formation of price indices during the subject calendar year should be reported on Form 552.⁷²

Finally, the FERC stated that market participants may direct informal questions through appropriate means, including the new compliance help desk.⁷³

On December 18, 2008, the FERC issued Order No. 704-B, dismissing rehearing and further clarifying the annual transactions reporting requirements. The FERC dismissed two rehearing petitions on procedural grounds, one on the ground that the petition was filed after the thirty-day statutory deadline, and the other on the ground that the pleading did not contain a section entitled “Statement of Issues” in accordance with FERC Rule 713(c)(2).

On the substantive issues, the FERC clarified that transactions made by marketers under state-approved retail access programs may or may not be reportable, depending on the terms of the transactions at issue, i.e., if the retail marketer transaction does not utilize an index price, is not reported to an index publisher, and could not contribute to a price index even if reported to a publisher, then the transaction would not be reportable on Form 552. The FERC declined to broadly exclude all retail marketer transactions to end-users.⁷⁴ The FERC also clarified that cash-out, balancing, and in-kind transactions are reportable on Form No. 552, if they rely on, contribute to, or could contribute to a price index.⁷⁵

Further, the FERC clarified that the volumetric information on page three of the form (Schedule of Reporting Companies and Price Index Reporting) should be provided not just for affiliates but also for the respondent itself.⁷⁶ Finally, the FERC stated that it modified the format of Form No. 552 to accommodate the technical requirements necessary for electronic submission of the form, and that an electronic version of the form will be made available.⁷⁷

On April 9, 2009, the FERC granted an extension of time until July 1 for all filers to submit their initial Form 552 containing data for calendar year 2008.

2. Pipeline Posting Requirements

On November 20, 2008, the FERC issued Order No. 720, in order to remove a stumbling block for transparency created when major flows between producing basins and interstate markets occur on non-interstate pipelines that are invisible to the market.⁷⁸

The FERC concluded that market prices of physical natural gas in interstate commerce result from the aggregate of interstate and non-interstate pipeline flows, and that information about the flows on non-interstate pipelines would promote price transparency by providing market participants with highly

72. *Id.* at 87.

73. *Id.* at 95.

74. *Order No. 704-B, supra* note 60, at 13.

75. *Id.* at 15.

76. *Id.* at 16.

77. *Id.* at 16-17.

78. *Order No. 720, supra* note 61, at 40.

relevant information as they make day-to-day economic choices.⁷⁹ The FERC also concluded that pipeline capacity and volume postings would provide market participants a clearer view of the effects on infrastructure, the industry, and the economy as a whole during periods when the gas delivery system is disturbed⁸⁰ and that the final rule will allow the FERC and market participants to identify and remedy potentially manipulative activity.⁸¹

With respect to the specific requirements of the rule, the FERC increased the minimum delivery threshold defining a major non-interstate pipeline from 10 million to 50 million MMBtu annually, and determined that neither major non-interstate pipelines nor interstate pipelines would be required to post actual flow information. The FERC further stated that the final rule requires such pipelines to post scheduled flow information at each receipt and delivery point with a design capacity greater than 15,000 MMBtu per day, and requires interstate pipelines to post certain information regarding no-notice service.⁸²

The FERC clarified that all postings are required to be made public and stated that it will not provide for posting information to be kept confidential.⁸³ The scheduled volume information to be posted for each point is as follows: (1) Transportation Service Provider Name; (2) Posting Date; (3) Posting Time; (4) Nomination Cycle; (5) Location Name; (6) Additional Locational Information if needed to distinguish between points; (7) Location Purpose Description (Receipt, Delivery, or Bilateral); (8) Design Capacity; (9) Scheduled Volume; (10) Available Capacity; and (11) Measurement Unit (Dth, MMBtu, or Mcf).⁸⁴ The FERC required major non-interstate pipelines to post this information no later than 10:00 p.m. central time the day prior to gas flow.⁸⁵

The FERC stated that the final rule excludes from the posting requirements non-interstate pipelines that fall entirely upstream of a processing, treatment, or dehydration plant, pipelines that deliver more than ninety-five percent of natural gas volumes directly to retail end-users, and storage providers.⁸⁶ The FERC did not provide separate exemptions for pipelines in concentrated and transparent markets⁸⁷ or for send-out pipelines from LNG import terminals covered under NGA Section 3.⁸⁸ The FERC also did not categorically exclude Hinshaw pipelines or LDCs operating under an NGA Section 7(f) service area determination from the posting requirements, finding that such pipelines may have a substantial effect on the natural gas market, especially regionally.⁸⁹ The FERC also did not adopt a safe harbor for postings.⁹⁰

79. *Id.* at 46.

80. *Id.* at 47.

81. *Id.* at 49.

82. *Id.* at 57.

83. *Id.* at 89.

84. *Id.* at 94.

85. *Id.* at 97.

86. *Id.* at 107.

87. *Id.* at 147.

88. *Id.* at 148.

89. *Id.* at 149.

90. *Id.* at 151.

The FERC required interstate pipelines to post the volumes of no-notice service flows at each receipt and delivery point before 11:30 a.m. central time three days after the day of gas flow.⁹¹ The FERC explained that the absence of no-notice service reporting means that the market cannot see large and unexpected increases in gas demand and therefore cannot understand price formation during such occasions.

Order No. 720 became effective January 2, 2009, and the compliance deadline for interstate pipelines was January 31. On January 15, the FERC granted an extension of time for major non-interstate pipelines to comply with the requirements of Order No. 720 until 150 days following the issuance of an order addressing the pending requests for rehearing.⁹² The FERC was persuaded that major non-interstate pipelines will need additional time to determine which receipt and delivery points are subject to the posting requirements, obtain corporate approval for expenditures, and develop internet posting systems. The FERC concluded that some compliance activities may be premature prior to the issuance of the rehearing order.

On March 18, FERC Staff held a technical conference to address three discrete issues on which Staff believed they needed additional record information. The issues included: (1) how to define major non-interstate pipelines, including how to assess contiguous and non-contiguous systems, stub lines, and gathering lines; (2) how to address high capacity receipt and delivery points where scheduling does not occur, i.e., virtual, pooling, or aggregating point; and (3) how to estimate compliance costs.

H. Standardization of Business Practices

On February 24, 2009, the FERC issued Order No. 587-T, amending section 284.12 of its regulations which govern standards for natural gas pipeline business practices and electronic communications to incorporate by reference the consensus standards (Version 1.8) most recently promulgated by the North American Energy Standards Board's (NAESB) Wholesale Gas Quadrant (WGQ), formerly the Gas Industry Standards Board, as well as other technical changes.⁹³

The NAESB Version 1.8 standards are designed to upgrade current business practices and improve electronic communication standards, primarily through the new Internet Electronic Transport Related Standards, changes to the Electronic Delivery Mechanism Related Standards, a new standard for gas quality reporting, as well as revisions to both the Nomination Related Standards and the Flowing Gas Related Standards.⁹⁴

In particular, Order No. 587-T incorporated Standard 4.3.93, a new gas quality reporting standard requiring that the pipelines post on their websites specific information on how the pipelines determine gas quality, including the industry standard (or other methodology, as applicable) that the pipeline uses for

91. *Id.* at 160.

92. *Pipeline Posting Requirements under Section 23 of the Natural Gas Act*, 126 F.E.R.C. ¶ 61,047 (2009).

93. *Standards for Business Practices for Interstate Natural Gas Pipelines*, 74 Fed. Reg. 9,162 (Mar. 3, 2009).

94. *Id.* at 5.

the following: procedures used for obtaining natural gas samples, analytical test method(s), and calculation method(s), in conjunction with any physical constant(s) and underlying assumption(s).⁹⁵

Order No. 587-T also incorporated by reference Standard 4.3.23, which provides guidelines for how pipelines are to post certain Standards of Conduct-related information. The FERC incorporated the standard, notwithstanding that some of the data templates found in the standard are “unnecessary” in the wake of FERC’s issuance of Order No. 717, concluding that pipelines will not be required to post affiliate information that is “no longer required to be maintained” under FERC’s regulations as amended by its Order No. 717.⁹⁶

II. ENFORCEMENT ACTIONS

A. *The Cheyenne Plains Settlements*

On January 15, 2009, the FERC approved four settlements, with two Commissioners dissenting, concerning allegations of market manipulation arising from bidding in a Cheyenne Plains Natural Gas Company (Cheyenne Plains) open season.⁹⁷ On the same day, the FERC issued two show cause orders arising out of the same event, also with two Commissioners dissenting.⁹⁸ The open season was held by Cheyenne Plains in March 2007 to sell additional firm capacity. Demand for the capacity was high and there were forty-seven winning bidders, with each winning bidder awarded a pro rata share under the terms of the open season posting. Shortly after the close of the open season the FERC Enforcement Hotline received calls complaining that some bidders had submitted multiple bids through affiliated companies in order to obtain a greater share of the pro rata allocation at the expense of bidders who submitted only a single bid, which they claimed to constitute fraud.⁹⁹ Enforcement Staff initiated an investigation, at the conclusion of which it alleged that certain bidders had engaged in market manipulation, or attempted manipulation, in violation of 18 C.F.R. Section 1c.1 (2008) of the FERC regulations, by submitting multiple affiliate bids for the purpose of acquiring a larger allocation of capacity for one affiliate. Enforcement did not allege any violations of the pipeline’s tariff nor did it allege an impact on market prices.

Two of the settlements involved similar fact patterns. The Tenaska and ONEOK settlements both involved bidding by multiple affiliates where each

95. *Id.*

96. *Id.* at 7.

97. *In re Tenaska Mktg. Ventures*, 126 F.E.R.C. ¶ 61,040 (2009). The order approved four separate settlements: (1) *In re Tenaska Marketing Ventures, Tenaska Energy Services, L.L.C., Tenaska Gas Co., Tenaska Gas Storage, Tenaska Grimes, Inc., Tenaska Marketing, Inc., Tenaska Operations, Inc., and Tenaska Storage Co.* in Docket No. IN09-7-000; (2) *In re ONEOK, Inc., ONEOK Partners, L.P., ONEOK Energy Services Co., L.P., ONEOK Energy Marketing Co., ONEOK Energy Services Canada, Ltd., ONEOK Field Services Co., L.L.C., ONEOK Midstream Gas Supply, L.L.C., Bear Paw Energy, L.L.C., and Kansas Gas Service, a division of ONEOK, Inc.*, in Docket No. IN09-8-000; (3) *In re Klabzuba Oil & Gas, F.L.P.* in Docket No. IN09-11-000; and (4) *In re Jefferson Energy Trading, L.L.C., Wizco, Inc., and Golden Stone Resources, L.L.C.* in Docket No. IN09-12-000.

98. *Seminole Energy Services, L.L.C.*, 126 F.E.R.C. ¶ 61,041 (2009); *National Fuel Mktg. Co.*, 126 F.E.R.C. ¶ 61,042 (2009).

99. *In re Tenaska Mktg. Ventures*, 126 F.E.R.C. ¶ 61,040 at 7.

placed a bid for all the available capacity, for the entire term, at the maximum tariff rate. After the capacity was awarded the affiliates released their capacity to the marketing company affiliate. The Tenaska settlement, in addition to the Cheyenne Plains open season, also covered the use of the same bidding behavior in two other interstate pipeline open seasons. Without admitting or denying a violation, the Tenaska companies entered into a settlement with Enforcement staff, agreeing to pay a \$3 million civil penalty and disgorgement of \$1,972,842. The ONEOK settlement, in addition to settling Enforcement's claims about the Cheyenne Plains open season bidding, also covered self-reported violations of the shipper-must-have-title requirement and buy/sell prohibition. The ONEOK settlement provided for the payment of a \$4.5 million civil penalty and disgorgement of \$787,331 related to the open season bidding and \$1,127,164 for the self-reported violations.

The other two settlements had slightly different facts and dealt with alleged attempted manipulation by Klabzuba Oil & Gas, F.L.P., Jefferson Energy Trading, L.L.C. (Jetco), Wizco, Inc., and Golden Stone Resources, L.L.C. The facts underlying these settlements concerned a proposal from a representative of Tenaska Marketing Ventures, made prior to the Cheyenne Plains open season, to enter into an asset management agreement with Golden Stone Resources, and any other open season bidders, to manage the capacity obtained in the open season. The companies initially planned to join in the proposed asset management agreement but ultimately did not. Instead, Jetco submitted a bid for itself and bids as agent for each of the others. After each entity received an award of capacity, Jetco paid Tenaska \$150,000 for deal information and bidding assistance. In the settlement, Klabzuba Oil & Gas, F.L.P. agreed to pay a civil penalty of \$300,000. Jetco, Wizco, Inc., and Golden Stone Resources, L.L.C. entered into a separate settlement agreeing to pay a \$585,000 civil penalty.

The dissenting Commissioners took the position that prior FERC policy appeared to permit multiple affiliate bidding so that the companies should not be penalized for that conduct. Instead, both dissenting Commissioners would have used these proceedings to announce Commission policy to be applied prospectively.¹⁰⁰

B. *Oasis Pipeline, L.P.*¹⁰¹

Oasis provided intrastate transportation of natural gas regulated by the Texas Railroad Commission. Oasis also provided transportation of interstate gas pursuant to Section 311(a)(2) of the Natural Gas Policy of 1979. Enforcement Staff received a Hotline call alleging discrimination on interstate shipments of gas by Oasis.¹⁰² On July 26, 2007 the Commission directed Oasis to respond to allegations that Oasis: "(1) unduly discriminated against non-affiliated shippers and unduly preferred one or more affiliated shippers; (2) charged rates in excess of the maximum lawful rate for [transportation of interstate gas]; and (3) failed

100. *In re Tenaska Mktg. Ventures*, 126 F.E.R.C. ¶ 61,040. (Dissent of Commissioner Moler referencing dissent in *Nat'l. Fuel Mktg. Co.*, 126 F.E.R.C. ¶ 61,042 (2009), and dissent of Commissioner Marc Spitzer.)

101. *Oasis Pipeline, L.P.*, 126 F.E.R.C. ¶ 61,188 (2009) [hereinafter, *Oasis Settlement*].

102. Brief of Enforcement Staff Recommending Next Steps and Opposition to Respondent's Request for Summary Disposition (Feb. 14, 2008).

to file an amended operating statement.”¹⁰³ After responses and briefing by Oasis and Enforcement Staff, on May 15, 2008 the Commission issued an order setting these matters for hearing.¹⁰⁴ After prepared testimony and deposition of witnesses, on November 18, 2008 the presiding judge issued a Partial Initial Decision granting Oasis’ motion for summary disposition with respect to the principal allegation, the undue discrimination claim.¹⁰⁵

On December 22, 2008, Enforcement Staff and Oasis submitted a joint offer of settlement. Oasis agreed (1) to post capacity available for interstate transportation by 4:00 pm prior to flow day; (2) to post the quantity of interstate transportation scheduled, rates, and whether the shipper is an affiliate of Oasis; (3) to provide interruptible transportation for interstate gas on a first-come, first-serve basis including nominations under the Oasis dual contract program; and (4) to notify the Commission of any capacity lease arrangements involving fifty percent or more of Oasis capacity.¹⁰⁶ Oasis may rely on shipper warranties that gas received from the Enterprise system is intrastate gas, provided that Oasis will take “reasonable steps under the circumstances” to investigate the validity of the shipper warranty if Oasis has information that “calls into question” the validity of the warranty.¹⁰⁷

C. Amaranth

The enforcement proceeding concerning natural gas futures trading activities by Amaranth Advisors L.L.C., its affiliated entities, and two individual traders began in 2007 with the Order to Show Cause and Notice of Proposed Penalties (Show Cause Order) to determine whether the activities violated Section 1c.1 of the Commission’s regulations (Anti-Manipulation Rule).¹⁰⁸ Since the last report, the FERC addressed several issues raised on rehearing¹⁰⁹ and rejected a proposed settlement of the proceeding. The 2008 Rehearing Order largely reaffirmed a number of prior rulings but it did include several important clarifications of the scope of the Anti-Manipulation Rule. Among the rulings reaffirmed were that the FERC has enforcement authority regarding manipulative trading in the natural gas futures contract market that has a direct effect on the price of physical natural gas prices subject to the FERC’s jurisdiction.¹¹⁰ The FERC also reaffirmed its position that review of the assessment of civil penalties is in the Court of Appeals and not a de novo review in the federal district court under NGA Section 22, noting that the federal district courts in New York and the District of Columbia unambiguously agreed that

103. *Oasis Settlement*, *supra* note 102, at 2. (The Order to Show Cause also alleged that affiliates of Oasis manipulated natural gas prices at the Houston Ship Channel); *See also Energy Transfer Partners, L.P.*, 120 F.E.R.C. ¶ 61,086 (2007).

104. *Oasis Settlement*, *supra* note 102.

105. *Oasis Pipeline, L.P.*, 125 F.E.R.C. ¶ 63,019 (2008).

106. *Oasis Settlement*, *supra* note 102.

107. *Id.*

108. *Amaranth Advisors L.L.C.*, 120 F.E.R.C. ¶ 61,085 (2007). In an order issued November 30, 2007, the Commission addressed certain requests for rehearing of the Show Cause Order. *Amaranth Advisors, L.L.C.*, 121 F.E.R.C. ¶ 61,224 (2007) [hereinafter *2007 Rehearing Order*].

109. *Amaranth Advisor,s L.L.C.*, 124 F.E.R.C. ¶ 61,050 (2008) [hereinafter, *2008 Rehearing Order*].

110. *Id.*

review of Commission orders must be by United States Courts of Appeals rather than district courts.¹¹¹

In the 2008 Rehearing Order, the FERC reiterated that Order No. 670 interpreted the term “any entity” in NGA Section 4A to include natural persons:

‘Any entity’ is a deliberately inclusive term. Congress could have used the existing defined terms in the NGA and FPA of “person,” “natural gas company,” or “electric utility,” but instead chose to use a broader term without providing a specific definition. Thus, the Commission interprets “any entity” to include any person or form of organization, regardless of its legal status, function or activities.¹¹²

As a result, it rejected the argument that the Anti-Manipulation Rule cannot be applied to natural persons.

The FERC further ruled, in the 2008 Rehearing Order, “that specific false statements need not be made in order to trigger potential liability under NGA [S]ection 4A.”¹¹³ The Commission concluded that “[o]pen market transactions send false signals to market participants if such transactions are undertaken with the intention of creating a false price.”¹¹⁴

A central issue in this proceeding is whether the Respondents’ activity in the [natural gas] futures contract market on the days in question was intended to create a price that was not reflective of supply and demand and, if so, whether the activity in fact resulted in artificial prices in that market. If these questions are answered in the affirmative, then it would be appropriate to find that the Respondents engaged in manipulation within the meaning of NGA Section 4A.¹¹⁵

The FERC also ruled that “trading undertaken for the purpose of keeping prices at an artificial level serves to inject inaccurate information into the marketplace,” which is cognizable under the Anti-Manipulation Rule.¹¹⁶ The FERC therefore rejected the contention that “actionable manipulation requires some form of deceptive or manipulative conduct that has the effect of injecting inaccurate information into the marketplace” (*i.e.*, false statements) in order to violate NGA Section 4A.¹¹⁷

In the 2008 Rehearing Order, the FERC explained “that the Anti-Manipulation Rule prohibits (1) fraudulent or deceptive behavior, (2) with the requisite *scienter*, (3) in connection with the purchase or sale of jurisdictional natural gas or electric energy.”¹¹⁸ The FERC ruled that the allegations that “Respondents acted intentionally with regard to attempts to manipulate settlement prices in the [natural gas] futures contract market” pled facts sufficient to trigger potential liability under the Anti-Manipulation Rule.¹¹⁹

Subsequently, Enforcement Staff and the Amaranth Respondents reached a settlement which, on December 3, 2008, the Presiding Judge certified to the

111. *Id.* at 77 (citing *CFTC v. Amaranth Advisors, L.L.C.*, 523 F. Supp. 2d 328, 338 (S.D.N.Y. 2007); *Hunter v. FERC*, 527 F. Supp. 2d 9, 20 (D.C. Cir. 2007).

112. *2008 Rehearing Order*, *supra* note 110, at 49.

113. *Id.* at 64.

114. *Id.*

115. *Id.*

116. *Id.* at 65 (citing *Markowski v. SEC*, 274 F.3d 528, 528-29 (D.C. Cir. 2001).

117. *Id.*

118. *Id.* at 72.

119. *Id.*

FERC.¹²⁰ The terms of the settlement were not publicly disclosed. As described by the parties, the Joint Offer of Settlement, if approved, would have resolved all claims asserted against all Respondents and related appellate proceedings in exchange for specified payments and other commitments by certain Respondents. In the Show Cause Order, the Commission had estimated that Amaranth profited far in excess of the proposed settlement amounts as a direct result of alleged manipulation of New York Mercantile Exchange (NYMEX) natural gas futures contract prices that recklessly affected the price of physical natural gas subject to Commission jurisdiction. In entering into this agreement, Enforcement Staff reportedly considered “the financial health of the Amaranth business entities and its effect on ultimately collecting any potential penalty or disgorgement that might be ordered.”¹²¹ Given those and all other facts and circumstances, Enforcement Staff believed that the Settlement Agreement was fair and reasonable and in the public interest.

By order dated February 12, 2009, the FERC rejected the proposed settlement. After considering the gravity of the alleged violations, the potential remedies for those violations if proven to have occurred, and the remedies offered in the Settlement, the FERC concluded, without elaboration, that the settlement was not in the public interest and rejected it.¹²²

III. RATES, TERMS, AND CONDITIONS OF SERVICE

A. Rates

1. El Paso Natural Gas Company

On June 30, 2008, El Paso Natural Gas Company (El Paso) initiated a general rate case pursuant to Section 4(e) of the NGA.¹²³ As part of its application, El Paso proposed a change to rates for existing services, the implementation of new services, and changes to El Paso’s general terms and conditions of service. The filing of this rate case was prompted by the terms of the contested settlement approved in El Paso’s last Section 4 rate proceeding in 2006 (2006 Rate Case Settlement),¹²⁴ which established rates expiring on December 31, 2008. On August 5, 2009, the FERC issued an order accepting and suspending the tariff sheets filed by El Paso subject to refund and conditions.¹²⁵

As part of its filing, El Paso proposed an increase in its rate base of \$200 million and an addition of \$650 million to its cost of service, including rolled-in costs from several new lateral projects.¹²⁶ El Paso’s application seeks a thirteen percent return on equity. Based upon these cost determinants, El Paso proposed

120. *Amaranth Advisors, L.L.C.*, 125 F.E.R.C. ¶ 63,024 (2008).

121. Joint Motion to Certify and Submit for Commission Approval a Joint Settlement Offer and To Waive the Comment Period, *Amaranth Advisors, L.L.C.*, No. IN07-26, (Nov. 24, 2008).

122. *Amaranth Advisors, L.L.C.*, 126 F.E.R.C. ¶ 61,112 (2009).

123. 15 U.S.C. § 717(e) (2006).

124. *El Paso Natural Gas Co.*, 120 F.E.R.C. ¶ 61,208 (2007) (order approving contested settlement). The rate case initiated in 2006 was El Paso’s first rate case in ten years.

125. *El Paso Natural Gas Co.*, 124 F.E.R.C. ¶ 61,124 (2008) [hereinafter, *Aug. 5 Order*].

126. *Id.* at 5-6.

to implement an average total rate increase of twenty-five percent above its currently-effective rates for existing services.¹²⁷ In the August 5 Order, the FERC suspended the tariff sheets implementing the new rates until January 1, 2009 and set the cost-of-service, cost allocation, and rate design issues raised in El Paso's application for hearing.¹²⁸ Discovery and the submission of testimony are currently underway and an initial decision is set for March 22, 2010.¹²⁹ The FERC set all other issues that were not to be addressed in the hearing process for further examination at a technical conference, which was subsequently held on September 11, 2008. On December 18, 2008, the FERC issued an order ruling on the issues raised and commented upon by the parties at the September 11 technical conference.¹³⁰

a. Implementation of New Services and Changes to Existing Services

In its application, El Paso proposed to initiate a new limited firm hourly virtual area transportation service under new Rate Schedule FTH-V for delivery points within the Permian Basin virtual area for shippers with contracts for 10,000 Dth per day or less. Service under new Rate Schedule FTH-V will provide shippers with varying levels of hourly flow rate flexibility for different periods throughout the gas day.¹³¹ In approving El Paso's new service under Rate Schedule FTH-V, the FERC rejected requests from some intervenors to require El Paso to offer the new service to all customers in the Permian Basin area, rather than offering it only to those shippers with contracts for 10,000 Dth per day or less. The FERC accepted El Paso's operational justification for limiting Rate Schedule FTH-V service to small shippers, and noted that "there is nothing in El Paso's proposed tariff language that makes a large shipper ineligible to receive service under Rate Schedule FTH-V, if it requests service for a contract less than or equal to 10,000 Dth per day."¹³²

In addition to the new service proposed under Rate Schedule FTH-V, the FERC approved revisions to El Paso's existing firm and hourly no-notice transportation services. Specifically, the FERC approved El Paso's proposals to allow no-notice shippers to net imbalances among all delivery points in their contracts on a daily basis,¹³³ and to permit shippers with premium and no-notice service to transfer delivery to upstream, operationally equivalent delivery points in the same geographic region.¹³⁴ In approving these revisions, the FERC refused to require El Paso to allow delivery transfers for shippers beyond those with premium and no-notice service. The December 18 Order stated that, unlike

127. *Id.* at 7.

128. *Id.* at 28-29.

129. Order Establishing Procedural Schedule, *El Paso Natural Gas Co.*, No. RP08-426 (Jan. 29, 2009).

130. *El Paso Natural Gas Co.*, 125 F.E.R.C. ¶ 61,309, at 1 (2008) [hereinafter *Dec. 18 Order*]. The FERC has granted rehearing of the December 18 Order for the purpose of further consideration, but has not yet made a substantive ruling on the issues raised in parties' requests for rehearing. Order Granting Rehearing for Further Consideration, *El Paso Natural Gas Co.*, No. RP08-426-005 (Feb. 17, 2009).

131. *Dec 18 Order*, *supra* note 131, at 8 ("FTH-V service provides for 150 percent hourly flexibility for up to five hours of the gas day, 130 percent hourly flexibility for up to nine hours of the gas day . . . and 120 percent hourly flexibility for up to twelve hours of the gas day.").

132. *Id.* at 17.

133. *Id.* at 19.

134. *Id.* at 25.

the netting of imbalances, which FERC regulations mandate transporters to permit,¹³⁵ the right of shippers to make delivery transfers, operationally distinguishable from the netting of imbalances, is not guaranteed under the regulations.¹³⁶

b. Penalties

In the December 18 Order, the FERC rejected El Paso's proposal to set charges for hourly scheduling penalties, daily unauthorized overruns, and Rate Schedule OPAS penalties, assessed under non-critical conditions, at a rate 2.5 times the applicable firm or interruptible rate equivalent. Citing the FERC precedent,¹³⁷ the December 18 Order reaffirmed the FERC policy that penalties assessed under non-critical conditions must be based upon interruptible transportation (IT) rates and cannot exceed 250 percent of the IT rate.¹³⁸ El Paso's proposal to base such penalties on IT and firm rates was thus contrary to FERC policy. In addition, pursuant to the December 18 Order, El Paso will be permitted to eliminate Maximum Delivery Obligation and Maximum Hourly Obligation (MDO/MHO) penalties under non-critical conditions on a trial basis. The FERC found that the pipeline has demonstrated that its mainline system may exhibit sufficient flexibility to forego such penalties during non-critical conditions.¹³⁹

The 2006 Rate Case Settlement established the method whereby El Paso calculates daily authorized and unauthorized overrun charges for shippers with multiple transportation service agreements (TSA) by aggregating quantities from all services provided under all of a shipper's contracts. Such overrun charges were billed based upon a weighted average rate for all delivery points included in all of a shippers TSAs. El Paso complained that this method of billing for unauthorized overrun caused it to under-collect for the service.¹⁴⁰ The December 18 Order accepted El Paso's proposal to bill overrun charges based upon the highest rate for service in the zones where the overruns occurred.¹⁴¹

Under El Paso's Rate Schedules FT-1, FTH, NNTD, and NNTH, shippers may obtain an enhanced scheduling right known as Hourly Entitlement Enhancement Nominations (HEEN), which allows shippers to designate a portion of their daily entitlement to be flowed at non-uniform rates throughout the gas day.¹⁴² Under El Paso's tariff at the time it filed its 2008 rate case, if a shipper's HEEN nominations combined with its flowing gas nominations exceeded the peak hourly entitlements specified under the shipper's Maximum Daily Quantities (MDQ), an overrun penalty was incurred. While El Paso

135. 18 C.F.R. § 284.12(b)(2)(ii) (2008).

136. *Dec. 18 Order*, *supra* note 131, at 29.

137. *Colorado Interstate Gas Co.*, 122 F.E.R.C. ¶ 61,256, at 86 (2008); *Questar Pipeline Co.*, 98 F.E.R.C. ¶ 61,159, 61,584 (2002); *El Paso Natural Gas Co.*, 115 F.E.R.C. ¶ 61,280, at 26-27 (2006).

138. *Dec. 18 Order*, *supra* note 131, at 6.

139. *Id.* at 62.

140. *Id.* at 51.

141. *Id.* at 57 ("Thus, if a shipper's overrun occurs in a lower rate zone, the overrun penalty will be determined by the highest rate in that lower rate zone, and not by the highest rate in the higher rate zone where the overrun did not occur.").

142. *Id.* at 66.

agreed, as part of the 2006 Rate Case Settlement, to use only fifty percent of a shipper's HEEN nominations when calculating daily unauthorized overruns, the pipeline proposed in its 2008 rate case application to gradually increase this percentage.¹⁴³

After considering the issue, the FERC rejected altogether El Paso's use of HEEN nominations in determining daily overrun charges. The December 18 Order determined that under El Paso's overrun calculations, penalties may be incurred "when a shipper's flowing gas is in excess of scheduled quantities, but still within contractual limits."¹⁴⁴ The FERC clarified that where HEEN nominations cause a shipper's flowing gas to exceed the shipper's contract entitlement for certain hours of the day, but the shipper remains within its daily contract demand, such variances should be treated as scheduling variances which may be subject to scheduling penalties. It is not, however, appropriate to treat such variances as overruns since the shipper does not exceed its daily contract entitlement in such a situation.¹⁴⁵ The December 18 Order permitted El Paso to modify its definition of "Hourly Scheduling Penalty" so "that the hourly scheduling penalty is composed of a scheduling penalty component and an overrun component."¹⁴⁶ However, the FERC admonished the pipeline "that the hourly scheduling penalty may not contain an overrun component if the delivered quantities are within contract levels, but in excess of scheduled amounts."¹⁴⁷

The December 18 Order also permitted El Paso to bill charges for unauthorized overrun at meters on its system that do not possess telemetry capability at the rates established for authorized overrun. One party to the proceeding objected that El Paso's authorized overrun charge amounted to an improper penalty for overrun at points that cannot be monitored on a daily and hourly basis so that shippers may adjust their activity to avoid penalties.¹⁴⁸ In approving El Paso's proposal and rejecting the intervenor's objection, the FERC pointed out that, unlike unauthorized overrun, the charge for authorized overrun does not contain a penalty component but is simply a charge for service actually rendered, and, therefore, El Paso's proposal did not impose an improper penalty.¹⁴⁹

c. Contracting Provisions

El Paso's tariff provides that, in general, under the seasonal service option of Rate Schedules FDBS, FT-H, NNTD, and NNTH, a shippers total contract demand (TCD) may not vary from month to month within a season. However, under the 2006 Rate Case Settlement, El Paso agreed to allow shippers to increase or decrease their TCD during the "shoulder months" of April and October to an amount equal to between 50 and 150 percent of the shippers TCD

143. *Id.* at 67-68.

144. *Id.* at 93.

145. *Id.* ("[O]verruns are quantities of gas taken in excess of a shipper's contract demand."); *El Paso Natural Gas Co.*, 114 F.E.R.C. ¶ 61,305, at 91 (2006).

146. *Dec. 18 Order*, *supra* note 131, at 117.

147. *Id.*

148. *Id.* at 101.

149. *Id.* at 105.

for the summer season.¹⁵⁰ El Paso sought to remove the provision of its tariff allowing shoulder month adjustments, arguing that this provision was meant as a temporary negotiated item of the 2006 Rate Case Settlement established to assist shippers in transitioning to El Paso's new service structure. The pipeline contended that if it were required to continue providing annual shoulder month adjustments to its shippers its ability to market annual and seasonal service to new shippers would be limited.¹⁵¹ The December 18 Order agreed with El Paso's rationale and approved the removal of the shoulder month option.¹⁵²

The 2006 Rate Case Settlement also provided certain shippers under El Paso's Rate Schedule FT-1 with MDQs of varying quantity from month to month (sculpted MDQs) the opportunity to convert to El Paso's new firm service option while retaining its sculpted MDQ rights. El Paso sought in its 2008 rate case application to eliminate its obligation to permit sculpted MDQs grandfathered pursuant to the 2006 Rate Case Settlement. The pipeline argued that its sculpted MDQ obligations "exacerbate the stranded capacity situation on El Paso's system because they permit shippers to contract for higher monthly MDQs during peak periods, while shifting the risk of off-peak capacity onto El Paso and its remaining shippers."¹⁵³ The FERC permitted El Paso to abolish shippers grandfathered sculpted MDQ rights under its tariff, but clarified that in so doing, El Paso could not reduce a shipper's MDQ for the remainder of its FT-1 contract "below the highest monthly MDQ for that contract without mutual agreement with the shipper."¹⁵⁴

d. Reservation Charge Credits

Under Section 39 of the General Terms and Conditions (GT&C) of El Paso's tariff,¹⁵⁵ El Paso must provide shippers with reservation charge credits when it cannot, on a firm daily basis, schedule shippers' nominated and confirmed quantities.¹⁵⁶ EL Paso proposed to reduce reservation credits to shippers whose gas quantities are scheduled in a subsequent nomination cycle. The FERC rejected this proposal, observing that "[i]f El Paso fails to schedule shippers' gas quantities in the cycle that they are nominated and confirmed, then El Paso has not provided shippers with the firm service they contracted for, regardless of whether the gas is scheduled in a subsequent cycle."¹⁵⁷ The December 18 Order noted that reservation charge credits provide pipelines an incentive to minimize firm service disruptions and that El Paso's proposal would undermine this purpose.

150. *Id.* at 152.

151. *Id.* at 153.

152. *Id.* at 157.

153. *Id.* at 160.

154. *Id.* at 162.

155. Transportation General Terms and Conditions § 39, FERC Gas Tariff, Second Revised Volume No. 1A, Second Revised Sheet No. 381, *El Paso Natural Gas Co.*, No. RP05-422-000 (Apr. 1, 2006)

156. *Dec. 18 Order*, *supra* note 131, at 185.

157. *Id.* at 189.

e. Waiver of Gas Quality Specifications

El Paso proposed a provision at GT&C Section 5.5 of its tariff that would allow it to agree with a delivery point operator to waive tariff gas quality specifications for non-conforming gas deliveries, provided that “El Paso determine[s] that its operations and commitments to its customers will not be adversely affected by the delivery of such gas.”¹⁵⁸ The December 18 Order accepted El Paso’s proposal subject to several conditions. El Paso was required to amend its proposed tariff section to provide that the pipeline “will use its ‘reasonable’ operational judgment and act in a not unduly discriminatory manner” in granting gas quality waivers for deliveries.¹⁵⁹ In addition, all waiver agreements must be in writing and “only consenting parties will be subject to the non-conforming gas.”¹⁶⁰

f. Fuel Savings Sharing Mechanism

The parties to the 2006 Rate Case Settlement negotiated a fuel savings sharing mechanism under which El Paso may “elect to incur the full cost of a capital project designated to reduce the amount of fuel and lost and unaccounted for fuel (L&U) consumed on its system in exchange for a share of the projected savings attributable to that project.”¹⁶¹ Under the mechanism, El Paso would retain eighty percent of the fuel and L&U savings owing to the designated project, returning the other twenty percent to its shippers, for a period of five years of operation of the facilities. At the end of five years of operation, 100 percent of the fuel and L&U savings generated from the capital investment would pass to El Paso’s shippers. El Paso sought to reincorporate this mechanism in its 2008 rate case filing and to extend the period of time over which it will be permitted to share a portion of the cost savings from five years to seven. In the December 18 Order, the FERC stated that it would investigate El Paso’s proposal further and address the issue in a subsequent order.

On March 19, 2009, the FERC issued an order approving the extension of El Paso’s fuel savings sharing mechanism.¹⁶² Although some parties objected that the sharing mechanism was unnecessary because El Paso already utilized a fuel tracker and a true-up mechanism on its system, the March 19 Order noted that El Paso’s proposed cost savings sharing mechanism would provide additional efficiency benefits to the pipeline and its customers. The fuel tracker and true-up mechanisms utilized on El Paso’s system permitted the pipeline to collect its exact annual fuel costs but nothing beyond this amount. The FERC found that, generally, the collection of only actual fuel costs through fuel trackers and true-up mechanisms “reduces any incentive for a pipeline to make capital improvements to reduce fuel usage and [lost and unaccounted for fuel] LAUF.”¹⁶³ The FERC determined that El Paso’s proposed savings sharing mechanism, addressed this problem by providing “an incentive mechanism

158. *Id.* at 198.

159. *Id.* at 200.

160. *Id.*; *Cheyenne Plains Gas Pipeline Co., L.L.C.*, 124 F.E.R.C. ¶ 61,109, at 9 (2008).

161. *Dec. 18 Order*, *supra* note 131, at 190.

162. *El Paso Natural Gas Co.*, 126 F.E.R.C. ¶ 61,247 (2009) [hereinafter, *Mar. 19 Order*].

163. *Id.* at 12.

under which El Paso and its customers share the cost savings from various specified types of capital improvements intended to reduce fuel usage and LAUF.”¹⁶⁴

Under the approved fuel savings sharing proposal, El Paso will make an annual fuel tracker mechanism filing, which will designate those projects included under the fuel savings sharing mechanism and provide a projection of the fuel cost savings from each designated project. Once the FERC determines that the cost savings projections in El Paso’s annual fuel tracker filing are just and reasonable, the pipeline may then “retain 80 percent of these savings for a seven-year period from the in-service date of the project, and El Paso may not include any of the capital costs of the project in its rates in any future rate proceeding.”¹⁶⁵ The March 19 Order recognized that under the new sharing mechanism it is possible that El Paso may recover more than the capital it invested in a cost saving project during the seven-year payback period, but pointed out that it is also possible for the pipeline to under-recover its investment if cost savings do not sufficiently materialize within the prescribed timeframe.¹⁶⁶ The March 19 Order required El Paso to clarify the specific procedure the pipeline will implement to calculate and distribute to shippers the annual cost savings from projects under the new mechanism. El Paso was also required to state whether its cost savings projections for a particular project reflected in its annual fuel tracker filing will be static over the seven-year recovery period or updated each year.¹⁶⁷

2. Kern River Rate Case

The Kern River Gas Transmission Company (Kern River) 2004 Rate Case is one of the most significant natural gas proceedings of recent years. As of the date of publication, the case is not yet finally resolved, though it has been the subject of four major FERC orders.¹⁶⁸ Kern River proposed its rates to become effective eighteen months after completion of the 2003 system expansion.¹⁶⁹ Kern River generally proposed continuation of its historic cost of service and rate design policies, but Kern River’s debt cost affected all rates, including the 2003 expansion shippers. Therefore, incremental rates under Kern River’s proposal would be based on a system-wide composite, or average, cost of debt for all shippers. The pipeline’s filing reflected individual levelization calculations for each of the various ten-year and fifteen-year shipper groups.

As the filing was scrutinized through the litigation process, shippers and FERC Staff challenged almost every aspect of the filing with the most attention directed to the following issues: rate of return on equity (the proxy group composition controversy described below receiving considerable attention), cost

164. *Id.*

165. *Id.* at 13.

166. *Id.* at 14.

167. *Id.* at 15.

168. *Kern River Gas Transmission Co.*, 114 F.E.R.C. ¶ 63,031 (2006); *modified by, Opinion No. 486*, 117 F.E.R.C. ¶ 61,077(2006), *order on reh’g, Opinion No. 486-A*, 123 F.E.R.C. ¶ 61,056 (2008); *order on reh’g, Opinion No. 486-B*, 126 F.E.R.C. ¶ 61,034 (2009).

169. *See Kern River Gas Transmission Co.*, 100 F.E.R.C. ¶ 61,056 (2000); *reh’g denied*, 101 F.E.R.C. ¶ 61,042 (2002).

of debt, levelized vs. traditional rates,¹⁷⁰ rates applicable to the rate step-down period, the ninety-five percent load factor design for historic customer billing determinants, the three percent operating cost inflation factor, whether an income tax allowance should be authorized for partnership income,¹⁷¹ and the capital structure to be employed within the various levelization calculations.

a. Rate of Return on Equity

The debate in the 2004 Rate Case centered on the composition of the proxy group to be used for rate of return on equity calculations. Shippers and FERC Staff proposed proxies that included gas pipeline holding companies as well as other holding companies that include significant gas and electric distribution segments. Kern River employed a proxy group that included the remaining available traditionally included pipeline holding companies and master limited partnerships (MLPs) that own gas pipelines.

In the Initial Decision the Administrative Law Judge (ALJ) recommended a rate of return on equity of 9.34% consistent with the proposal of one of the shippers. The Commission subsequently adopted a four-company proxy group consisting of Kinder Morgan Inc., Equitable Resources, Inc., National Fuel Gas Co., and Questar Corporation.¹⁷² At the time it issued its Opinion No. 486 regarding the 2004 Rate Case, the Commission required each company included in the proxy group to satisfy three standards: (1) the company's stock must be publicly traded; (2) the company must be recognized as a natural gas company and its stock must be recognized and tracked by an investment information service such as Value Line; and (3), pipeline operations must constitute a high proportion of the company's business (at least fifty percent of assets or operating income over the most recent three-year period).

In Opinion No. 486, the Commission did not authorize inclusion in the proxy group of the MLPs proposed by Kern River due to concerns that MLP distributions (similar to dividends) include a return of capital component. The Commission concluded that the four corporation proxy group it approved included firms of lower risk than Kern River. The Commission, therefore, added fifty basis points to the median return of the selected proxy group and authorized an equity return of 11.2%. Several parties, including Kern River, sought rehearing of Opinion No. 486.

While rehearing of Opinion No. 486 was pending, and in all likelihood in response to the Kern River 2004 Rate Case as well as a remand order in *Petal Gas Storage, L.L.C. v. FERC*,¹⁷³ the Commission issued a proposed and then

170. Traditional rates as described here are rates that result from applying a straight-line depreciation rate to the pipeline investment base, resulting in a declining rate base assuming no plant additions; levelized rates as employed by Kern River result in increasing depreciation charges over time much like the increasing principal payments under a home mortgage – depreciation is the cost of service element that is varied to achieve a level cost of service for each cost of service calculation period.

171. Kern River is technically owned by a partnership, but the partnership is owned entirely by corporations.

172. See generally *Williston Basin Interstate Pipeline Co.*, 104 F.E.R.C. ¶ 61,036 (2003); *High Island Offshore Sys.*, 110 F.E.R.C. ¶ 61,043 (2005).

173. 496 F.3d. 695 (D.C. 2007).

final policy statement¹⁷⁴ permitting the inclusion of MLPs in rate of return on equity determination proxy groups. The FERC applied its Policy Statement in the concurrently issued Opinion No. 486-A, which permitted the parties to the 2004 Rate Case to submit data supporting new proxy group candidates.¹⁷⁵

In September 2008, Kern River, with the support of part of its shippers, filed a settlement proposal that, among other things, was intended to comply with the FERC's determinations in Opinion No. 486 and that included cost calculations based on a 12.5% rate of return on equity. In Opinion No. 486-B the Commission rejected the proposed settlement, finding instead that the rate of return on equity should be 11.55% based on the Commission's new MLP proxy group standard. The FERC included five firms in a new proxy group, including two corporations, Kinder Morgan, Inc. and National Fuel Gas Supply, and three MLPs, Northern Border, TC Pipelines and Kinder Morgan Energy Partners.

The authorized return for Kern River was based on long-term Gross Domestic Product growth projections for MLPs that were limited to fifty percent of analysts' estimates, given the Commission's concerns about potentially overstated MLP distributions.¹⁷⁶ Interestingly, Opinion No. 486-B did not include the fifty basis point increment addition granted Kern River in Opinion No. 486 because the Commission held in Opinion No. 486-B that the pipeline was average risk in relation to the revised proxy group. The contested rate settlement submitted by Kern River was rejected for several reasons, including the finding the settlement did not provide sufficient benefits to offset the overall higher settlement rates.

b. Levelized Rates

Despite intense opposition from a major shipper and FERC Staff, the Commission did not require Kern River to adopt a traditional rate design. All major aspects of Kern River's levelization process and resulting shipper-group specific cost of service and rate calculations, including separate capital structures, were continued. The FERC declined to disturb the underlying levelization premise that underpinned both the initial construction of the pipeline and the subsequent expansions. In a new development, the FERC required the pipeline to state its future rate "step-down period" rates in its tariff, though there is a continuing controversy in the pending compliance process as to whether the step-down rates should be levelized or based on the traditional rate design approach.

c. Billing Determinants and Inflation Factor

Kern River was not permitted to continue to design rates for its original system shippers based on an imputed ninety-five percent load factor for firm billing determinants; rather, use of actual contract MDQs was specified. Though a long-standing feature of cost of service calculations, the Commission rejected continuance of the three percent inflation factor for operating cost calculations.

174. *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 120 F.E.R.C. ¶ 61,068 (2007); *modified by*, 123 F.E.R.C. ¶ 61,048 (2008); *reh'g denied*, 123 F.E.R.C. ¶ 61,097 (2008).

175. 123 F.E.R.C. ¶ 61,056.

176. 126 F.E.R.C. ¶ 61,034.

d. Cost of Debt

The Commission, in contrast to the ALJ's decision and the 2003 Expansion certificate preliminary determination order, permitted the cost of debt for all shippers to be based on a system-wide average calculation. This finding was based on the Commission's conclusion that the 2003 Expansion debt rate reflects the overall credit rating of all shippers.

e. Income Tax Policy

Though Commission Staff and other parties urged disallowance of an income tax allowance in cost of service due to the nature of the Kern River partnership, and though the ALJ agreed, the Commission approved a full income tax allowance for Kern River consistent with an intervening income tax Policy Statement order (*Inquiry Regarding Income Tax Allowances*, 111 F.E.R.C. ¶ 61,139 (2005)). The Commission found that Kern River was entitled to an income tax allowance "under the traditional standards applicable to Subchapter C corporations."¹⁷⁷

f. Future Prospects

The Commission has not resolved the long-pending compliance filings and some of the rehearing petitions submitted in the proceeding. Look for significant future actions on the remaining disputed items, including the rate design roll-in process used for the ten-year shippers, the methodology to be used for the step-down rates and whether cost of service calculations are in line with Commission directives. Also, Kern River paid preliminary refunds to the parties that supported its rate settlement proposal, but those refunds will now need to be refined as the case is completed.

B. Gas Quality and Interchangeability

1. Algonquin Gas Transmission, L.L.C.

On February 19, 2009, the FERC approved a contested settlement in an NGA Section 4¹⁷⁸ tariff proceeding establishing gas quality and interchangeability tariff specifications for Algonquin Gas Transmission, L.L.C. (Algonquin).¹⁷⁹ The FERC had set Algonquin's initial tariff filing under Section 4 of the NGA for hearing to resolve ten stipulated issues following a technical conference.¹⁸⁰ However, a settlement was filed on February 20, 2008, before the hearing was held. The FERC approved the settlement almost exactly one year later.

The FERC approved settlement provisions establishing a combined nitrogen and oxygen limitation of 2.75% and a non-methane (C2+) limit of twelve percent. The FERC found both specifications supported by historical data as necessary to ensure the safety and efficiency of liquefied natural gas

177. *Kern River Gas Transmission Co.*, 117 F.E.R.C. ¶ 61,077, at 220.

178. 15 U.S.C. § 717(c) (2006).

179. *Algonquin Gas Transmission, L.L.C.*, 126 F.E.R.C. ¶ 61,130 (2009).

180. *Algonquin Gas Transmission, L.L.C.*, 121 F.E.R.C. ¶ 61,152 (2007). The technical conference was held on August 21, 2007.

(LNG) peak shaving plants operated by LDCs.¹⁸¹ At the same time, the FERC held that these standards would allow imports of LNG from approximately eighty percent of the potential sources of foreign LNG.¹⁸² With regard to the LNG importers that opposed the settlement's specification, the FERC stated that they had raised "broad policy issues," but had not provided "any specific evidence of direct damage" or "any realistic chance" that the excluded sources of LNG "would actually be available for importation into the United States in the near future."¹⁸³

The FERC also approved the settlement's interchangeability standards over the objections of a power generator. The settlement established a Wobbe Index range of 1,314 to 1,400, finding the specification consistent with Interim Guidelines set forth in the FERC's 2006 Policy Statement on Interchangeability and Gas Quality.¹⁸⁴ The power generator opposed the proposed Wobbe Index range, arguing that it would increase nitrogen oxide emissions from Dry Low NOx (DLN) generation facilities. The FERC dismissed this argument, in part because the generator failed to provide an affidavit alleging a dispute as to a genuine issue of material fact under Rule 602(f)(4).¹⁸⁵ The FERC added, however, that its decision would have been the same in any event. The power generator was the lone opponent to the Wobbe Index range, and owned no generating facilities in Algonquin's service area. Moreover, another generator with facilities in Algonquin's service area did not oppose the settlement. Finally, the FERC found that Algonquin's supporting historical evidence, analyzed in accordance with the Interim Guidelines, supported the settlement's Wobbe Index range and cap.¹⁸⁶

The FERC also rejected the generator's proposal to modify the settlement by imposing a Wobbe Index rate of change limit of two percent per minute, finding that the evidence in the record showed that Algonquin could not implement or enforce such a requirement, and that the record contained no evidence to the contrary.¹⁸⁷ Similarly, the FERC approved the settlement's provisions requiring Algonquin to post hourly average chromatographic data on its website, rejecting arguments that (1) it should post "real-time" data and (2) modify its tariff to expressly provide for such postings. The FERC found that the settlement's posting requirement would produce more reliable data, and that the support of the majority of Algonquin's customers for the settlement indicated that they neither needed nor wanted real-time postings.¹⁸⁸

The FERC approved the remaining gas quality standards provided for in the settlement, all of which were already provided for in Algonquin's tariff. These standards had not been challenged. The FERC stated that if factors changed due to the establishment of new standards by Texas Eastern Transmission, L.L.C., an

181. 126 F.E.R.C. ¶ 61,130 at 51.

182. *Id.* at 52.

183. *Id.*

184. *Natural Gas Interchangeability*, 115 F.E.R.C. ¶ 61,325 (2006); *reh'g. dismissed*, 126 F.E.R.C. ¶ 61,210 (2009).

185. 18 C.F.R. § 385.602(f)(4) (2009).

186. *Natural Gas Interchangeability*, 115 F.E.R.C. ¶ 61,325, at 68-69.

187. *Id.* at 70-71.

188. 115 F.E.R.C. ¶ 61,325 at 75.

interstate pipeline that delivers substantial quantities of gas to Algonquin, it would be reasonable for the parties to revisit Algonquin's standards. However, the FERC added that any proposed change by a customer would need to be filed in the form of a complaint under NGA Section 5.¹⁸⁹

2. Maritimes & Northeast Pipeline, L.L.C.

The gas quality and interchangeability proceeding involving Algonquin's affiliate Maritimes & Northeast Pipeline, L.L.C. (Maritimes) followed a procedural route similar to Algonquin's, described above. Initially, the FERC set Maritimes' gas quality and interchangeability tariff filing for a technical conference.¹⁹⁰ That technical conference resolved most but not all of the issues. Following the filing of comments, the FERC issued an order approving several of Maritimes' proposed specifications, but also setting several stipulated issues for hearing.¹⁹¹ Subsequently, however, before the hearing was held, the parties filed an uncontested settlement resolving all of the remaining issues. The FERC approved that settlement without modification.¹⁹²

At the time of its initial interchangeability and gas quality tariff filing, Maritimes was in the process of constructing expansion facilities to enable it to receive re-vaporized LNG from the Canaport LNG Terminal in Saint John, New Brunswick.¹⁹³ Upon completion of the expansion, the overwhelming majority of Maritimes' firm capacity would be under contract to an LNG importer. Consequently, the principal issues were the Wobbe Index specification, a proposed Wobbe rate-of-change specification, information posting requirements and Maritimes' authority and discretion in waiving the tariff specification.

Based on the technical conference record, the FERC found that the comments of Calpine Energy Services, L.P. (Calpine) raised issues of fact best resolved at an evidentiary hearing. Maritimes had proposed a Wobbe Index maximum of 1400, with a range of 3.17 percent.¹⁹⁴ Calpine contended that Maritimes' proposed specification was not based on historical considerations and technical requirements, as provided for in the Policy Statement.¹⁹⁵

The FERC also set for hearing disputes regarding Maritimes' proposal to post chromatograph information on an hourly basis. Specifically, Calpine raised issues as to the number of points on Maritimes' system at which this information should be provided, the location of the points, and the detail to be provided. The hearing order did not respond directly to Calpine's contention that the FERC should require Maritimes to identify the points and information requirements in its tariff.

However, the FERC refused to set for hearing Calpine's related proposal to impose a rate of change limit of four percent per minute. Indeed, the FERC found, based on the record, that Calpine's proposal would have "unreasonable

189. 15 U.S.C. § 717(d) (2006); 121 F.E.R.C. ¶ 61,152, at 77.

190. *Maritimes & Northeast Pipeline, L.L.C.*, 123 F.E.R.C. ¶ 61,256 (2008).

191. *Maritimes & Northeast Pipeline, L.L.C.*, 125 F.E.R.C. ¶ 61,159 (2008); *on reh'g.*, 126 F.E.R.C. ¶ 61,119 (2009).

192. *Maritimes & Northeast Pipeline, L.L.C.*, 127 F.E.R.C. ¶ 61,065 (2009).

193. 125 F.E.R.C. ¶ 61,159, at 2.

194. *Id.* at 16.

195. *Id.* at 14.

results.”¹⁹⁶ Reviewing Maritimes’ operations, the FERC found that Maritimes’ sources of supply were limited; it had no control over the quality of the gas delivered to it; and it had no storage or processing facilities, or any other means by which to blend different gas streams.¹⁹⁷ Consequently, if it exceeded the proposed rate of change, it would have no choice but to shut in its entire system, and even that extreme action was infeasible.¹⁹⁸

The FERC clarified that it had not established a “policy” of requiring a rate of change limitation in *AES Ocean Express L.L.C. v. Florida Gas Transmission Co.*¹⁹⁹ The FERC distinguished *AES* on several grounds. First, in *AES*, the pipeline, Florida Gas Transmission Company (FGT), proposed the rate of change limitation. In contrast, Maritimes did not propose such a limitation, and in fact opposed a rate of change limitation.²⁰⁰ Second, in *AES*, FGT proposed to impose the rate of change limitation at receipt points, while Calpine proposed a rate of change limitation at delivery points.²⁰¹ As mentioned above, the FERC found that Maritimes’ only option to comply with Calpine’s proposal would be to shut-in its entire system, potentially harming Calpine and Maritimes’ other customers. The FERC found that Maritimes constituted a major supply source to the New England market area.²⁰²

In its order on rehearing,²⁰³ in response to Calpine, the FERC also addressed the role of the 1996 Policy Statement in framing the issues set for hearing.

The FERC’s statement that the hearing should be conducted in the context of the Policy Statement means just that, *i.e.*, that the ALJ may consider the FERC’s policy as outlined in the Policy Statement and the Interim Guidelines as guidelines for addressing the technical issues that may arise during the hearing. It does not mean that the Policy Statement governs on such issues. Parties are free to introduce evidence showing certain aspects of the policy should not apply and the ALJ is free to consider such evidence in ruling on technical issues.²⁰⁴

Maritimes and the parties ultimately settled the issues the FERC set for hearing. The FERC approved the settlement on April 21, 2009.²⁰⁵

3. Natural Gas Pipeline Company of America

In *Natural Gas Pipeline Co. of America*,²⁰⁶ (*NGPL*) the FERC approved a proposal to establish different receipt point interchangeability specifications to

196. *Id.* at 22.

197. 125 F.E.R.C. ¶ 61,159, at 22.

198. *Id.* at 23-24.

199. 119 F.E.R.C. ¶ 61,075 (2007) [hereinafter, *Opinion No. 495*]; *reh’g. denied*, 121 F.E.R.C. ¶ 61,267 (2007) [hereinafter, *AES*].

200. 125 F.E.R.C. ¶ 61,159, at 25.

201. *Id.*

202. *Id.* at 26-27.

203. *Maritimes & Northeast Pipeline, L.L.C.*, 126 F.E.R.C. ¶ 61,119 (2009). The FERC had earlier denied rehearing by operation of law on January 9, 2009. It issued this subsequent order “to explain our reasons for denying hearing.” *Id.* at 1, note 1.

204. 126 F.E.R.C. ¶ 61,119, at 28.

205. *Maritimes & Northeast Pipeline, L.L.C.*, 127 F.E.R.C. ¶ 61,065.

206. 124 F.E.R.C. ¶ 61,034 (2008).

apply to different parts of Natural Gas Pipeline Company of America's (Natural) system. The specifications were more flexible in Natural's Gulf Coast supply area to allow a greater variety of supplies to enter its system, but more restrictive in the northern market area to allow Natural to maximize its operational blending capabilities to limit the impact of the variations in gas quality to end users.²⁰⁷ The FERC resolved all of the issues raised by Natural's proposal based on a technical conference record, finding no need to hold an evidentiary hearing.

The FERC deferred to Natural's application of the Policy Statement and Interim Guidelines methodology in determining appropriate Wobbe Index limits.²⁰⁸ Natural had used data from two points on its two mainlines. The FERC found that these points were "located downstream of any major system inputs," and "accurately represent the gas quality further downstream in the market area."²⁰⁹ The FERC rejected contentions that more restrictive tolerance bands and rate of change limits should be adopted for Natural.

The FERC also rejected arguments that its decision in *AES* required adoption of more restrictive specifications, finding that the procedural posture and the facts in *NGPL* differed substantially from *AES*. In *AES*, Florida Gas Transmission, the pipeline, had proposed the restrictions in *AES*, whereas Natural had not proposed tighter tolerances or rate of change limits.²¹⁰ The FERC further found *AES* differed from *NGPL* factually on some key points. First, electric generation constituted the majority of the gas market on FGT's system. Consequently, "FGT had to propose standards to adapt to that market" and to "accommodate the introduction of LNG directly into its market area without the opportunity for blending."²¹¹ Neither circumstance was present in *NGPL*. The majority of Natural's gas is delivered to end-users, not generators, and the point of entry for LNG allows Natural to blend the LNG with domestic gas supplies.²¹² Second, Natural's system is configured such that much re-vaporized LNG received into its system would be likely to flow to other interstate pipelines in the production area, never entering the Natural's mainlines transporting gas to downstream markets.²¹³ In contrast, *AES*'s pipeline would have delivered re-vaporized LNG directly into FGT's market area.

Finally, as in *AES*, the FERC rejected contentions that it should establish a cost-sharing mechanism to relieve power generators on Natural's system of a

207. Natural proposed a minimum Wobbe Index of 1,274, a maximum Wobbe Index of 1,380, and a maximum Btu value of 1,065 Btu /scf for its downstream and market area zones, a maximum Wobbe Index of 1,400, and a maximum Btu value of 1,110 Btu/scf for the South Texas and Louisiana production area zones. *Id.* at 13. The FERC rejected proposals by several parties that the proposed limits be employed as a safe harbor instead of absolute limits, which would have allowed higher- or lower-Wobbe Index gas receipts. *Id.* at 59. The FERC also rejected arguments that Natural could invoke its Operational Flow Order (OFO) authority due to interchangeability concerns, finding that Natural's OFO authority was limited to "the operating performance of Natural's 'physical system,' not the systems of downstream entities." *Id.* at 92.

208. *Id.* at 37. The FERC approved a similar proposal to use varying btu limits in different parts of Natural's system, based on the same process it used to determine the differing Wobbe Index limits. *See also Id.* at 82-86.

209. *Id.* at 38.

210. *Id.* at 46-47.

211. *Id.* at 47. The FERC made similar findings in accepting Natural's proposed btu limits. *Id.* at 86.

212. *Id.* at 47.

213. *Id.* at 46.

portion of the costs of retrofitting their generation equipment to accommodate the new and revised specifications. First, the FERC found nothing in the record to indicate that Natural's generator customers would incur such costs due to the standards because much of the high-Wobbe Index revaporized LNG entering or expected to enter Natural's system was unlikely to flow into the part of Natural's system supplying the generator's plants.²¹⁴ Second, the FERC reaffirmed its holding in *AES* that it lacked jurisdiction under the NGA to require pipelines to establish a cost-sharing mechanism to mitigate costs incurred by non-jurisdictional downstream customers, relying on the reasoning in *AES*.²¹⁵

4. Columbia Gas Transmission Corporation

The FERC issued an order on December 15, 2008, clarifying an earlier order in the Columbia Gas Transmission Corporation (Columbia) gas quality and interchangeability proceeding.²¹⁶ Specifically, the FERC clarified that Columbia's merchantability obligation does not extend beyond the delivery point to customers' downstream facilities, reaffirming earlier holdings in other proceedings.²¹⁷

5. Certificate and Abandonment Orders

In *Distrigas of Massachusetts, L.L.C.*,²¹⁸ the FERC rejected a request that it condition the abandonment by Distrigas of Massachusetts, L.L.C. (DOMAC) of its LNG Terminal's authorization under NGA Section 7 to be converted to a Section 3 authorization on Distrigas' adoption of specific Wobbe Index and btu limits for liquid LNG service (typically provided by truck from the terminal). The FERC held that it would be "unreasonable to require DOMAC to meet still stricter quality standards to compensate for weathering that may take place after DOMAC relinquishes title and custody of liquid that meets all applicable standards at the time of the delivery."²¹⁹ The objecting shipper had expressed concern that following delivery to the customer, LNG stored in tanks typically undergoes weathering in which btu and Wobbe Index levels increase. Employing the same reasoning as in several of the orders discussed above, the FERC stated that the "responsibility for the consequences of weathering rests with the party in possession of the liquid."²²⁰

In *AES Sparrows Point LNG, L.L.C.*,²²¹ the FERC approved the construction and operation of an LNG import terminal near Baltimore, Maryland, and an interconnecting pipeline to be owned and operated by Mid-Atlantic Express, L.L.C. (Mid-Atlantic), that would deliver re-vaporized LNG from the terminal to several interstate pipelines at interconnections in the mid-

214. *Id.* at 56.

215. *Id.*, citing *AES*, *supra* note 199.

216. *Norstar Operating, L.L.C. v. Columbia Gas Transmission Corp.*, 125 F.E.R.C. ¶ 61,289 (2008).

217. *Id.* at 18, *see also Indicated Shippers v. Tennessee Gas Pipeline Co.*, 121 F.E.R.C. ¶ 61,151, at 108 (2007); *ANR Pipeline Co.*, 116 F.E.R.C. ¶ 61,002 at 62 (2006); *on reh'g.*, 117 F.E.R.C. ¶ 61,286 (2007).

218. 124 F.E.R.C. ¶ 61,039 (2008).

219. *Id.* at 39.

220. *Id.* at 39.

221. 126 F.E.R.C. ¶ 61,019 (2009).

Atlantic states.²²² Several customers of these downstream pipelines raised gas quality concerns due to the locations of the interconnections between Mid-Atlantic and those pipelines near significant market areas. The FERC found, however, that Mid-Atlantic's deliveries of re-vaporized LNG to these pipelines would not "result in a 'subsidy' by those existing pipelines or their captive customers by compelling them to incur expenses to safely accommodate the transportation and consumption" of this new supply of re-vaporized LNG.²²³ The FERC found that the gas delivered by Mid-Atlantic would meet the receiving pipelines' tariff specifications. The FERC added that if customers believed that the existing pipelines' quality specifications were inadequate, "such concerns are appropriately addressed to those pipelines."²²⁴

The FERC also addressed revaporized LNG issues in a proceeding concerning an application by Dominion Cove Point LNG to expand its existing import terminal and companion applications by several interstate pipelines, including Columbia, to expand and extend their existing interstate pipelines to accommodate the increased import quantity. In *Washington Gas Light v. FERC*,²²⁵ the D.C. Circuit had affirmed the FERC's finding that existing leaks on Washington Gas Light's (WGL) system are due primarily to the condition of its pipeline couplings, not the introduction of regasified Cove Point LNG into its system. However, the court nonetheless vacated and remanded the authorizations, finding that the FERC had not found, based on substantial evidence, that WGL could repair its system prior to the proposed in-service date of the expansion.

On remand, the FERC imposed a maximum quantity limit on Columbia's delivery of re-vaporized LNG received at the Cove Point LNG import terminal to WGL.²²⁶ Quality specifications were not directly at issue, because the re-vaporized LNG met Cove Point LNG's tariff specifications.²²⁷ The FERC acknowledged that the Policy Statement and precedent recognized that proceedings for applications for authorization to construct facilities to store LNG and transport regasified LNG should address potential adverse impacts and mitigation. The FERC found that it met this requirement by ensuring that WGL would receive no re-vaporized LNG from Cove Point LNG "that it would not have received under the pre-expansion authorizations."²²⁸

C. Interconnection Policy/Meter Access

In an order issued on July 30, 2008, the FERC rejected as unsupported and inconsistent with the FERC's interconnection and open-access policies a "meter access services" proposal by Columbia Gulf Transmission Company

222. Columbia Gas Transmission Corporation, Transcontinental Gas Pipe Line Corporation, and Texas Eastern Transmission, L.P.

223. 126 F.E.R.C. ¶ 61,019, at 21.

224. *Id.*

225. 532 F.3d 928 (D.C. Cir. 2008).

226. *Dominion Cove Point LNG, L.P.*, 125 F.E.R.C. ¶ 61,018 (2008); *reh'g denied*, 126 F.E.R.C. ¶ 61,036 (2009).

227. 125 F.E.R.C. ¶ 61,018 (2008) (Finding that while the expansion would increase the quantity of revaporized LNG received by WGL, the gas would continue to meet the gas quality standards in Cove Point LNG's tariff provisions, which had been implemented pursuant to an October 2002 settlement agreement).

228. 126 F.E.R.C. ¶ 61,036, at 89.

(Columbia Gulf).²²⁹ Columbia Gulf proposed new firm and interruptible service at delivery points using incremental point capacity created through an expansion. Columbia Gulf proposed to charge its general firm and interruptible forward-haul rates for the proposed service, even though the service did not include mainline transportation, only delivery point capacity.

The FERC found the proposal at odds with its interconnection policy as established in *Panhandle Eastern Pipe Line Corp.*²³⁰ and *Transcontinental Gas Pipeline Corp.*²³¹ *Panhandle* and *Transco* established five conditions which must be met by a party seeking an interconnection with an interstate pipeline, to ensure that interconnection requests would not be denied solely based on economic considerations.²³² The FERC held that “[Columbia Gulf]’s proposal to reserve the sole right to determine when and where to construct new points or upgrade existing points would violate our *Panhandle* policy.”²³³ The FERC further held that access to delivery points did not constitute a discrete “service,”²³⁴ and that Columbia Gulf’s proposed rates for the “service” were improperly designed on firm and interruptible services that had “no similarity” to the point access service Columbia Gulf proposed.²³⁵

IV. INFRASTRUCTURE

A. Gas Storage Projects

During the period from January 2008 through June 2009, the FERC granted certificates for a record number of new, expanded, and amended gas storage projects across the country. The proponents of such projects ranged from gas storage only companies seeking to provide storage, storage-related, and wheeling services at market-based rates, to traditional gas transmission pipeline companies providing storage services under their existing cost-base rate structures. Additionally, 2008 and early 2009 was the period for a number of applications at the FERC regarding storage field integrity and gas migration. What follows is a short, chronological summary of each of the cases grouped by the subtopics discussed above, namely market-based rates, transmission pipeline storage services, and field integrity orders.²³⁶

229. *Columbia Gulf Transmission Co.*, 124 F.E.R.C. ¶ 61,113 (2008).

230. 91 F.E.R.C. ¶ 61,037 (2000) [hereinafter, *Panhandle*].

231. 95 F.E.R.C. ¶ 61,245 (2001) [hereinafter, *Transco*].

232. *Panhandle*, *supra* note 231, at ¶ 61,141; *Columbia Gulf*, 124 F.E.R.C. ¶ 61,113, at 24: “(1) the party seeking the interconnection must bear the cost of construction [or] construct the facilities [itself] in compliance with the pipeline’s technical requirements; (2) the proposed interconnection must not adversely affect the pipeline’s operations; (3) the proposed interconnection and resulting transportation must not result in diminished service to the pipeline’s existing customers; (4) the proposed interconnection must not cause the pipeline to be in violation of any applicable environmental or safety laws or regulations with respect to the facilities required to establish an interconnection with the pipeline’s facilities; and (5) the proposed interconnection must not cause the pipeline to be in violation of its right-of-way agreements or any contractual obligations with respect to the interconnection facilities.”

233. 124 F.E.R.C. ¶61,113, at 25.

234. *Id.* at 26.

235. *Id.* at 28.

236. Other applications considered by the Commission include the following: *Egan Hub Storage, L.L.C.*, 122 F.E.R.C. ¶ 61,209 (2008), (clarifying, among other things, that Egan Hub is to construct and place the authorized facilities into service by December 31, 2012 because this date more accurately reflects the

1. Market-Based Rates

Many applications for certificates to construct and operate interstate natural gas storage facilities and for approval of Natural Gas Policy Act (NGPA) Section 311 rates for intrastate storage facilities include requests for authority to charge market-based rates for the storage and storage-related services as well as for wheeling services.²³⁷ In the following orders issued during the period from January 2008 through June 2009, the FERC granted such market-based rate authority.

a. PetroLogistics Natural Gas Storage, L.L.C.

The Commission granted PetroLogistics Natural Gas Storage, L.L.C. (PetroLogistics) a certificate of public convenience and necessity authorizing the construction and operation of a salt dome natural gas storage facility and associated pipeline facilities in Iberville Parish, Louisiana.²³⁸ The project will have 6 Bcf of storage with approximately 300,000 Mcf per day of deliverability, interconnected with Florida Gas Transmission Company, Texas Eastern Transmission, Bridgeline Pipeline Company, CrossTex LIG Pipeline, and Southern Natural Gas. The Commission granted PetroLogistics' request to charge market-based rates for its storage, storage-related and wheeling services. PetroLogistics identified the relevant product market as interruptible and firm natural gas storage, hub, and balancing services and the relevant geographic market as the highly competitive Gulf Coast production area, comprising Louisiana, Texas, Alabama, and Mississippi (the Gulf Coast Supply Region).

b. Enstor Houston Hub Storage & Transportation, L.P.

The Commission granted Enstor Houston Hub Storage and Transportation, L.P. (Houston Hub) a certificate of public convenience and necessity authorizing the construction and operation of a high-deliverability salt dome natural gas storage facility²³⁹ and associated pipeline header consisting of two 2.34-mile, 24-inch-diameter, bi-directional pipelines, connecting the storage facility to two interstate natural gas pipelines, Natural Gas Pipeline Company of America

anticipated construction timeline); *Wyckoff Gas Storage Co., L.L.C.*, 124 F.E.R.C. ¶ 62,192 (2008), (granting request to reclassify certain previously approved facilities due to valid technical reasons to better observe and understand the performance of the two zones); *Wyckoff Gas Storage Co., L.L.C.*, 127 F.E.R.C. ¶ 61,107 (2009), (granting certificate amendment that would authorize Wyckoff to transfer a passive ownership interest in certain facilities at its authorized storage field and lease back the facilities to qualify for sales, use, and property tax exemptions. The Commission granted Wyckoff's request that the certificate amendment be made effective retroactive to March 1, 2009, despite its general policy not to grant retroactive certificate authority, because Wyckoff demonstrated that absent such retroactive authority, Wyckoff would lose the entire property, sales, and use tax exemptions for the 2009 tax year, amounting to a loss of \$750,000).

237. Wheeling service is the transportation by the facility of gas between interstate pipelines interconnected with the storage facilities.

238. *PetroLogistics Natural Gas Storage, L.L.C.*, 122 F.E.R.C. ¶ 61,193 (2008).

239. *Enstor Houston Hub Storage & Transp., L.P.*, 123 F.E.R.C. ¶ 61,019 (2008). "Initially, Houston Hub state[d] that each cavern will have a capacity of 6.175 Bcf (4 Bcf working gas and 2.175 Bcf cushion gas) for a total capacity of 24.7 Bcf (16 Bcf working gas and 8.7 Bcf cushion gas). The caverns under this phase of the project will be operational in 2009 . . . Houston Hub asserts that when fully developed, the storage facility will have a total capacity of 46.32 Bcf comprising 30 Bcf of working gas and 16.32 Bcf of cushion gas. It projects withdrawal capability of approximately 1.0 Bcf per day and injection capability of approximately 0.6 Bcf per day. Houston Hub anticipates the caverns will reach full capacity by 2012." *Id.* at 8.

(NGPL) and Transcontinental Gas Pipe Line Corporation (Transco). The Commission granted Houston Hub authority to charge market-based rates for the proposed storage and hub services, finding that Houston Hub's aggregate share of the relevant storage market will be relatively small. The "bingo card" market power analysis typically applied to evaluate wheeling services demonstrated to the FERC's satisfaction that the pipelines that either connect, or are accessible, to the Houston Hub Project have forty-one direct paths to markets centers in the Texas and Gulf Coast regions.

c. Steckman Ridge, L.P.

The Commission granted Steckman Ridge, L.P. (Steckman Ridge) a certificate of public convenience and necessity authorizing the construction and operation of a multi-cycle natural gas storage facility that will be converted from an existing natural gas production field in Bedford County, Pennsylvania,²⁴⁰ with an associated piping network "consist[ing] of a 2.83-mile 16-inch pipeline, a 4.12-mile 16-inch pipeline, and 23 well laterals totaling 3.48 miles of 6-inch and 8-inch pipeline."²⁴¹ Additionally, the Commission granted Steckman Ridge's request to charge market-based rates for the proposed storage services, but denied market-based rate authority for interruptible wheeling services.

Steckman Ridge's market power study showed Herfindahl-Hirschman Index (HHI) calculations for working gas capacity well below the FERC's threshold level of 1,800. However, the 2,053 HHI calculation for daily deliverability created the need for further scrutiny. Nevertheless, the Commission approved Steckman Ridge's request to charge market-based rates for its proposed firm storage service and for its enhanced and interruptible park and loan services because of market competition in the geographic area. However, Steckman Ridge also proposed wheeling service at market-based rates. The Commission found that, because wheeling is a transportation service, a "bingo card" market power study was necessary. Steckman Ridge did not provide the required additional information and therefore did not demonstrate that it lacks market power for its proposed interruptible wheeling service. The FERC subsequently denied several rehearing requests of this order.²⁴²

240. *Steckman Ridge, L.P.*, 123 F.E.R.C. ¶ 61,248 (2008); *reh'g denied*, 125 F.E.R.C. ¶ 61,217 (2008). The project consists of the conversion of five existing production wells into storage wells, the drilling of eighteen new storage wells, the construction of a storage field piping network, a 9,470 horsepower (hp) compressor station consisting of two 4,735 hp reciprocating compressor units, as well as gas processing and dehydration facilities, a meter and regulator station, and certain non-jurisdictional facilities, and the removal of existing production field piping. Steckman Ridge states that the project will have a total capacity of 17.7 Bcf (12 Bcf working gas and 5.7 Bcf cushion gas), a maximum withdrawal rate of 300 MMcf per day, and a maximum injection rate of 227 MMcf per day. Steckman Ridge will locate its new storage facility on approximately ninety-six acres.

241. *Steckman Ridge, L.P.*, 123 F.E.R.C. ¶ 61,248, at 8 (2008).

242. *Steckman Ridge, L.P.*, 125 F.E.R.C. ¶ 61,217, at 3 (2008), regarding: "(i) landowners' difficulties in understanding Commission processes and procedures; (ii) water pollution; (iii) impacts of the proposal on the development of natural gas production from the Marcellus Shale and other formations; (iv) metering of individual injection wells; (v) alleged misconduct of Steckman representatives; (vi) eminent domain; (vii) disputes over construction activities, routing, and rights-of-way; and (viii) mining subsidence."

d. Black Bayou Storage, L.L.C.

The Commission granted Black Bayou Storage, L.L.C. (Black Bayou) a certificate of public convenience and necessity to construct and operate a salt dome natural gas storage facility in Cameron Parish, Louisiana at market-based rates for its proposed services.²⁴³ “Black Bayou’s market power study for storage service defines the relevant product and geographic market [(Gulf Coast production region)], measures market share and concentration and evaluates other factors.”²⁴⁴ The FERC found that Black Bayou’s modified “bingo-card” analysis was a reasonable indication that good alternatives exist for shippers to obtain interruptible wheeling service. Black Bayou’s prospective market shares for storage and hub services are low and that market area HHIs are mitigated by Black Bayou’s small market share and the availability of competing services.

e. Tarpon Whitetail Gas Storage, L.L.C.

The FERC granted Tarpon Whitetail Gas Storage, L.L.C. (Whitetail) a certificate of public convenience and necessity authorizing the construction and operation of a natural gas storage facility and associated facilities in Monroe County, Mississippi (Whitetail Gas Storage Project).²⁴⁵ The FERC granted Whitetail’s requests to charge market-based rates for the proposed storage services. Whitetail proposed to offer its firm and interruptible storage, hub, and wheeling services at market-based rates. The FERC found that Whitetail’s market power study demonstrates that Whitetail’s relatively small market share, along with numerous alternatives to the proposed services, “given the number and size of existing storage facilities and interruptible wheeling services in the relevant market, will not enable Whitetail to exert market power in the relevant market area.”²⁴⁶ In addition, the Commission found that Whitetail did “not possess market power because the relevant market is easy to enter.”²⁴⁷

As for Whitetail’s wheeling service, the Commission denied Whitetail’s request to charge market-based rates. Whitetail did not submit a “bingo-card” analysis to the FERC because Whitetail only proposed a single physical interconnection to an interstate pipeline. The Commission found that if Whitetail does obtain additional interconnections to an interstate pipeline, Whitetail must submit a properly supported proposal for a proposed wheeling

243. *Black Bayou Storage, L.L.C.*, 123 F.E.R.C. ¶ 61,277 (2008). Black Bayou proposes to construct and operate a high-deliverability salt dome natural gas storage facility on the Black Bayou salt dome, approximately fifteen miles west of Hackberry in Cameron Parish, Louisiana. The Black Bayou Storage Project will consist of two natural gas storage caverns providing an ultimate total working gas capacity of fifteen billion cubic feet (Bcf). *Id.* at 24. Black Bayou proposes to construct a 30-inch diameter, 2.45-mile pipeline to connect the Black Bayou compressor station with Transco and a 24-inch diameter, 4.7-mile pipeline to connect with Kinder Morgan Louisiana Pipeline, L.L.C. (Kinder Morgan), both of which will deliver gas to and from Black Bayou’s storage facility.

244. *Id.* at 24.

245. *Tarpon Whitetail Gas Storage, L.L.C.*, 123 F.E.R.C. ¶ 61,274 (2008); *order granting reh’g and tariff revision*, 125 F.E.R.C. ¶ 61,050 (2008). Whitetail proposed to construct and operate a multi-cycle natural gas storage facility that will be converted from an existing natural gas production field know as the Aberdeen Gas Storage Field. The Whitetail Gas Storage Project will have a total capacity of 20.8 Bcf, a maximum withdrawal rate of 300 MMcf per day, and a maximum injection rate of 300 MMcf per day.

246. 123 F.E.R.C. ¶ 61,274, at 27.

247. *Id.* at 28.

service. As submitted, the Commission rejected Whitetail's Rate Schedule IW and the proposed market based rate because Whitetail did not provide the appropriate information.²⁴⁸

f. Petal Gas Storage, L.L.C.

The Commission granted Petal Gas Storage, L.L.C. (Petal Gas) a certificate to expand its storage operation near Hattiesburg, Mississippi to add two new salt dome natural gas storage caverns and three additional compression units.²⁴⁹ In addition, Petal Gas sought authority to interconnect the proposed new caverns with Petal Gas' existing storage facilities through the construction and operation of new natural gas pipeline facilities and to construct and operate freshwater and brine pipelines. Petal Gas' market power analysis, which included the proposed expansion capacity, showed HHI calculations for working gas capacity and peak day deliverability well below the Commission's threshold level of 1,800. The Commission therefore concluded that Petal Gas does not have market power in the relevant market area. The FERC therefore found "that Petal Gas may continue to charge market-based rates for its storage services."²⁵⁰

g. Caledonia Energy Partners, L.L.C.

The FERC granted Caledonia Energy Partners, L.L.C. (Caledonia) a certificate of public convenience and necessity to expand its existing storage facility, known as the Caledonia Field, in northwest Mississippi.²⁵¹ Caledonia proposed to develop the County Line Field, "a depleted production reservoir approximately two miles northeast of the Caledonia Field, as an additional field capable of storing approximately 1.6 Bcf of working gas."²⁵² The FERC concluded that Caledonia could continue charging market-based rates for its firm and interruptible storage services. In preparing to file the application, Caledonia conducted tests pursuant to its blanket certificate under Section 157.215 of FERC regulations, "to determine the Caledonia Field's response to increased pressures and the time required for stabilization of the reservoir."²⁵³ Since Section 157.215(a)(4) does not permit the blanket certificate holder to provide service in connection with the testing activities without first obtaining Commission approval, Caledonia's actions violated Section 157.215(a)(4) of the regulations. The FERC elected not to impose penalties on Caledonia, but did direct it to "disgorge all unjust profits and report the disgorgement to the Office of Enforcement."²⁵⁴

248. *Tarpon Whitetail Gas Storage, L.L.C.*, 125 F.E.R.C. ¶ 61,050, at 6 (2008), (the Commission granted rehearing, and the Commission held that Whitetail may retain its proposed language regarding governmental action in the definition of force majeure, "as long as [Whitetail] deletes the definition's references to testing and maintenance."). *Id.* at 6.

249. *Petal Gas Storage, L.L.C.*, 124 F.E.R.C. ¶ 61,066 (2008).

250. *Id.* at 24.

251. *Caledonia Energy Partners, L.L.C.*, 124 F.E.R.C. ¶ 61,041 (2008).

252. *Id.* at 6.

253. *Id.* at 31.

254. *Id.* at 33.

h. Floridian Natural Gas Storage Co., L.L.C.

The Floridian Natural Gas Storage Company, L.L.C. (Floridian) Project is located in the Florida market area. The Floridian Project convinced the FERC that the project would not have market power to set rates for its firm and interruptible storage services.²⁵⁵ The project established that, although it was the first storage project in the Florida market area, it was competing with other storage projects in the Gulf Coast gas production area connected to the two pipelines, Florida Gas Transmission Company (FGT) and Gulfstream Natural Gas System (Gulfstream), serving the Florida market. The Floridian Project demonstrated that, under the traditional methodology used by the FERC under NGA Section 7 of measuring market power using the HHI, the Floridian Project possessed a low market share for use of its working gas and peak day deliverability capacity.

The FERC expressed concern that there was not sufficient pipeline capacity into the Florida market for storage facilities in the Gulf Coast production area to compete with the Floridian Project. However, its concerns were allayed because of the firm transportation agreements held by the major Florida gas users with FGT and Gulfstream and by the capacity expansion projects proposed by FGT and Gulfstream and the Cypress expansion project of Southern Natural Gas into Florida. The Commission also noted that the Floridian Project will mainly serve the dual-fueled electric generation market in Florida and will also have to compete against No. 2 and No. 6 fuel oil. Based on these facts, the Commission found that the Floridian Project “will not be able to exert market power”²⁵⁶ and approved its request for market-based rates for its proposed storage services.

i. Leaf River Energy Center, L.L.C.

The Commission granted Leaf River Energy Center, L.L.C. (Leaf River) a certificate of public convenience and necessity authorizing the construction and operation of a high deliverability salt dome natural gas storage facility in Smith, Jasper, and Clarke Counties, Mississippi, with four solution-mined storage caverns and associated header pipelines to connect the gas handling facility with Destin Pipeline Company (Destin), Gulf South, Southern Natural Gas Company, Tennessee Gas Pipeline, and Transco.²⁵⁷ Leaf River proposed that the header system would provide storage and wheeling services, but no stand-alone transportation service. The Commission approved Leaf River’s proposal. The Commission concluded that Leaf River will lack significant market power, and approved Leaf River’s request to “charge market-based rates for its firm and interruptible storage and its hub and wheeling services.”²⁵⁸

j. Orbit Gas Storage, Inc.

The FERC granted Orbit Gas Storage, Inc. (OGS) a certificate of public convenience and necessity to build a gas storage project in Hopkins County, Kentucky, with a projected 5 Bcf of working gas and 100,000 Mcf per day of

255. *Floridian Natural Gas Storage Co., L.L.C.*, 124 F.E.R.C. ¶ 61,214 (2008).

256. *Id.* at 28.

257. *Leaf River Energy Center, L.L.C.*, 125 F.E.R.C. ¶ 61,131 (2008).

258. *Id.* at 47.

deliverability.²⁵⁹ The project will be connected to ANR Pipeline. The Commission also approved OGS' request to charge market-based rates for the proposed storage services because OGS' analysis showed an HHI of market concentration for working gas capacity and for peak day deliverability below 1,800. In addition, the FERC found that OGS' relatively small market shares of both total working gas capacity and peak day deliverability in its defined market will not enable OGS to exert market power acting alone in the relevant market.

k. SG Resources Mississippi, L.L.C.

The FERC approved SG Resources Mississippi, L.L.C.'s (SG Resources) request to expand further the capacity of its Southern Pines Energy Center.²⁶⁰ In 2007, the Commission authorized SG Resources to expand its storage project to a third salt dome cavern and to increase its interconnections with interstate pipelines to include FGT and Transco through construction of a lateral.²⁶¹ In the latest order involving the Southern Pines project, the FERC approved a further expansion into a fourth cavern, an increase in the working gas capacity of the first three caverns, and a loop of one of the project laterals to Destin Pipeline. The latest expansion will give the project a "total working gas capacity of 690.76 Bcf and total peak day deliverability of 19,125 MMcf."²⁶² The Commission's approval included a continued authorization of the project to charge market-based rates for its storage, storage-related, and wheeling services. Despite the project's size, the Commission found that the project's share of the East Texas, Louisiana, Mississippi, and Alabama storage market was sufficiently small both percentage-wise and under the HHI to conclude that the project will not hold market power.

l. Port Barre Investments, L.L.C.

The Commission approved the application of Port Barre Investments Bobcat Gas Storage (Bobcat) for a certificate of public convenience and necessity to construct and operate an expansion of its existing Bobcat Gas Storage Project in St. Landry Parish, Louisiana for three new salt dome natural gas storage caverns, additional compression, and new pipeline facilities.²⁶³ The project would increase Bobcat's authorized gas storage capacity to approximately 52 Bcf and the maximum deliverability to approximately 3 Bcf per day. Bobcat also proposed to construct two pipeline loops. One of the proposed pipelines is a 9.96-mile, 20-inch diameter pipeline extending north from the gas storage site to a Transco interconnect. The second proposed pipeline is a 2.68-mile, 16-inch diameter pipeline extending west from Bobcat's South Pipeline Corridor to the Gulf South.²⁶⁴ Bobcat is also connected to ANR Pipeline and Texas Eastern Transmission. The Commission also approved Bobcat's continuing authority to charge market-based rates for its storage, storage-related, and wheeling services.

259. *Orbit Gas Storage, Inc.*, 126 F.E.R.C. ¶ 61,095 (2009).

260. *SG Resources Mississippi, L.L.C.*, 125 F.E.R.C. ¶ 61,197 (2008).

261. *SG Resources Mississippi, L.L.C.*, 118 F.E.R.C. ¶ 61,048 (2007).

262. 125 F.E.R.C. ¶ 61,197, at 21.

263. *Port Barre Investments, L.L.C.*, 126 F.E.R.C. ¶ 61,240 (2009).

264. *Id.* at 21.

m. MoBay Storage Hub, L.L.C.

The Commission granted the request of MoBay Storage Hub L.L.C. (MoBay) to amend its certificate to add two priority interruptible services and to charge market based rates for the proposed services over objections from Florida Power that such services would degrade its firm service flexibility under its existing contract with MoBay.²⁶⁵ Specifically, MoBay proposed “to add an enhanced interruptible storage service under Rate Schedule EISS and an enhanced interruptible loan service under Rate Schedule EILS to the services already authorized.”²⁶⁶ MoBay’s pro forma tariff already provided for firm storage service, interruptible storage service, interruptible parking, interruptible loaning, interruptible wheeling service, interruptible imbalance trading, interruptible balancing, a sales service, and a firm hourly balancing service.²⁶⁷

The Commission found that the priority interruptible services would benefit shippers “by increasing service options, enhancing shipper flexibility, and meeting the needs of shippers seeking a greater level of certainty regarding the availability and scheduling of interruptible services.”²⁶⁸ MoBay’s existing certificate authority was granted in December 2006²⁶⁹

to construct and operate a new, high-deliverability natural gas storage facility consisting of three underground depleted natural gas storage reservoirs located offshore in Alabama state waters; thirty new injection and withdrawal wells supported by ten offshore caissons and approximately seven miles of offshore distribution (storage field) pipeline; an onshore compressor station with 37,880 horsepower (hp) of compression; two 8,500 hp compressor units located offshore on an existing platform; three metering stations and approximately 3.5 miles of 24-inch diameter pipeline laterals; and a 15-mile long, 36-inch diameter pipeline connecting the storage reservoirs to the onshore compressor station.”²⁷⁰

The FERC also granted market-based rate authority for MoBay’s storage and hub services.

n. Arlington Storage Company, L.L.C.

The Commission authorized Arlington Storage Company, L.L.C.’s (Arlington) proposal to construct and operate a natural gas storage facility with approximately 7.0 Bcf of working gas storage capacity and associated facilities in Steuben County, New York (Thomas Corners Project).²⁷¹ The Commission granted Arlington’s request to charge market-based rates for the proposed storage and hub services. Arlington conducted studies analyzing market power, market share, and market concentration for: (1) firm interruptible market area natural gas storage and storage-related hub services; and (2) interruptible wheeling service. The Commission found that Arlington will lack significant market power, and therefore, the Commission approved Arlington’s request to

265. *MoBay Storage Hub, L.L.C.*, 126 F.E.R.C. ¶ 61,241 (2009).

266. *Id.* at 4.

267. *Id.* at 3.

268. *Id.* at 18.

269. *MoBay Storage Hub, Inc.*, 117 F.E.R.C. ¶ 61,298 (2006).

270. *Id.* at 3.

271. *Arlington Storage Co., L.L.C.*, 125 F.E.R.C. ¶ 61,306 (2008).

charge market-based rates for all firm and interruptible storage, hub, and wheeling services.

o. Southeast Gas Storage Company, L.L.C.

The Commission accepted Southeast Gas Storage Company, L.L.C.'s (Southeast) application for a certificate of public convenience and necessity authorizing the construction and operation of a natural gas storage facility and associated facilities in Monroe and Lowndes Counties, Mississippi (Black Warrior Storage Project).²⁷² The Commission granted Southeast's request to charge market-based rates finding that Southeast's market power analysis demonstrated that Southeast will lack significant market power because the proposed storage facilities will be in a highly competitive area, Southeast's proposal increases the storage alternatives in the Gulf Coast Supply Area, Southeast's prospective market shares are low, and the barriers to entry are likely to be low. Thus, the FERC approved Southeast's request to charge market-based rates for all firm and interruptible storage and hub services. The Commission denied the request for rehearing because the request for rehearing presented no authority, fact, or argument sufficient to alter the determinations made in the underlying Order.²⁷³

p. Liberty Gas Storage, L.L.C.

The Commission granted Liberty Gas Storage, LLC (Liberty Gas) a certificate of public convenience and necessity to expand its existing storage project in Cameron Parish, Louisiana.²⁷⁴ The expansion will provide a total of approximately 19 Bcf of storage with deliverability of 1.2 Bcf per day connected to Cameron Interstate, FGT, Tennessee, Texas Eastern Transmission, and Transco. The FERC also granted Liberty Gas' request to continue to charge market-based rates for storage, storage-related, and wheeling services.

q. Columbia Gas Transmission Corporation

The Commission granted Columbia Gas Transmission Corp. (Columbia) authority to abandon, construct, and operate natural gas storage, compression, and pipeline facilities in Ohio, West Virginia, and Virginia as well as authority to accelerate certain replacement and reliability work at certain compressor stations.²⁷⁵ The FERC further approved Columbia's request to "restate the certificated volume of base gas contained in the Coco A storage field from

272. *Southeast Gas Storage Co., L.L.C.*, 125 F.E.R.C. ¶ 61,307 (2008).

273. *Southeast Gas Storage Co., L.L.C.*, 126 F.E.R.C. ¶ 61,131 (2009).

274. *Liberty Gas Storage, L.L.C.*, 127 F.E.R.C. ¶ 61,221 (2008).

275. *Columbia Gas Transmission Corp.*, 122 F.E.R.C. ¶ 61,021 (2008). "Specifically, Columbia propose[d] to: [c]onstruct approximately 7.24 miles of 26-inch diameter [pipe], . . . 5.17 [total] miles of 36-inch diameter pipeline; . . . increase working gas capacity and maximum capacity by 2,900 MMcf, increase deliverability by 29 MMcf/d. . . recondition four existing injection/withdrawal wells, increase deliverability by "and 20 MMcf/d, construct three new injection/withdrawal wells, and recondition three existing injection/withdrawal wells[at two separate gas storage fields] in West Virginia; increase working gas capacity by 2,763 MMcf, increase cushion gas by 1,140 MMcf (increase total inventory by 3,903 MMcf), increase deliverability by 45 MMcf/d, construct seven new injection/withdrawal wells, reclassify eight existing "special" wells, and recondition seven existing injection/withdrawal wells in . . . Ohio." *Id.* at 7 (2008).

22,805 MMcf to 16,545 MMcf, and the overall certificated capacity of the storage field from 44,500 MMcf to 36,240 MMcf²⁷⁶ due to a paper error rather than physical loss of gas. The FERC further granted Columbia's request for a predetermination that the costs of the reliability and replacement work of \$26,929,452 may be rolled into Columbia's system-wide rates in the next general rate case absent a significant change of circumstances.

r. Colorado Interstate Gas Company

The FERC granted Colorado Interstate Gas Co. (CIG) a certificate of public convenience and necessity for the construction and operation of the Totem Gas Storage Field, in Adams County, Colorado which will have a working gas capacity of 7.0 Bcf, an injection rate of 100 MMcf per day, and a withdrawal rate of 200 MMcf per day.²⁷⁷

Upon completion of all phases of development the storage project will consist of the following: (i) 13 injection/withdrawal wells (eight new horizontal wells and five vertical re-entered wells); (ii) 1 water disposal well; (iii) up to twelve observation wells depending on the circumstances described above; (iv) a 9,470 horsepower (ISO) compressor station for injection operations; (v) gas conditioning and dehydration facilities, (vi) piping to connect the injection/withdrawal wells; and (vii) piping to connect dehydration facilities with the water disposal well.²⁷⁸

In order to reduce gas costs associated with the Totem Project, CIG decided to defer the bulk of base gas injections to allow CIG to utilize the proposed permanent compression instead of temporary compression to inject the base gas. Thus, CIG no longer needed the temporary compression originally proposed to effectuate base gas injections, nor does it need observation Well No. 25 for the safe and efficient operation of the Totem Project.²⁷⁹

s. Tennessee Gas Pipeline Company

The FERC approved Tennessee Gas Pipeline Company's (Tennessee) proposal to construct and operate the Concord Lateral Expansion Project

276. *Id.* at 15. In a subsequent amendment to this certificate, the Commission modified the distribution capacity for the Coco A storage field to 22,600 MMcf due to an additional inadvertent calculation error. *Columbia Gas Transmission Corp.*, 124 F.E.R.C. ¶ 62,204 (2008).

277. *Colorado Interstate Gas Co.*, 123 F.E.R.C. ¶ 61,099 (2008).

278. *Id.* at 8. CIG stated that the total capital cost for Totem Gas Storage Field is approximately \$125 million, including the base gas to be injected into the Field. CIG proposed to provide new incremental firm and interruptible storage services from the Totem Storage Field pursuant to new Rate Schedules FS-T and IS-T, respectively. In addition, CIG proposed a new one-hour notice transportation and storage balancing service under Rate Schedule TSB-T. CIG proposed to provide firm storage service from the Totem Storage Field pursuant to new Rate Schedule FS-T. The rights under this rate schedule include firm injection, withdrawal, and storage capacity. CIG will also provide interruptible service from the Totem Storage Field pursuant to new Rate Schedule IS-T. This interruptible storage rate will consist of a capacity charge and injection and withdrawal charges. CIG also proposed a new firm service under Rate Schedule TSB-T that combines the transportation and storage features offered under the recently-approved High Plains Rate Schedule TF-HP and Totem Rate Schedule FS-T with an additional one-hour notice feature. *Id.* at 12-16.

279. *Colorado Interstate Gas Co.*, 125 F.E.R.C. ¶ 61,136 (2008).

(Concord Project) and to charge an incremental rate for service on the Concord Project under Tennessee's existing Rate Schedule FT-A.²⁸⁰ The Concord Project will allow Tennessee to provide 30,000 Dth per day of firm transportation service for EnergyNorth Natural Gas, Inc. The FERC found that the proposal will provide needed natural gas transportation capacity to support the local distribution demand of EnergyNorth. The Commission also found that Tennessee's proposal will not adversely affect Tennessee's existing customers, or other pipelines and their customers, and the proposal will have minimal detrimental effect on other landowners or the environment. In addition, the Commission found that Tennessee's proposed rates were consistent with Commission policy. Finally, the Commission found that Tennessee's submitted precedent agreement for the Concord Project contained material deviations from Tennessee's pro forma FT-A agreement, but the Commission found that almost all of the material deviations were permissible.

t. Natural Gas Pipeline Company

Natural Gas Pipeline Co. (Natural) sought authorization for various activities that will "enable it to provide an additional 10 Bcf of incremental firm storage service for its customers by better utilizing the Herscher Galesville (HG) storage field."²⁸¹ Natural proposed to charge incremental rates for services using the proposed expansion capacity, thus meeting the threshold requirement of no subsidization by existing customers. The Commission found that Natural demonstrated a need for the additional storage capacity to provide service, that the rate treatment will not result in "subsidization of the project by existing shippers"²⁸² (despite "concern regarding recovery of contributions in aid of construction related to pipeline facilities that would not be operated under the Commission's open-access policies and regulations"),²⁸³ and no other pipelines, their captive customers or landowners will be adversely affected.

u. Williston Basin Interstate Pipeline Company

The Commission granted Williston Basin Interstate Pipeline Co.'s (Williston) application for the authority to lease, on a temporary basis, approximately 5 bcf of natural gas to be used as cushion gas for its Elk Basin Storage Reservoir (a natural gas underground storage facility in Park County, Wyoming and Carbon County, Montana).²⁸⁴ The Commission found that the proposed lease "involve[d] no new service, no new customers, no degradation of service to its existing customers, and no adverse physical impact on the storage

280. *Tennessee Gas Pipeline Co.*, 124 F.E.R.C. ¶ 61,198 (2008).

281. *Natural Gas Pipeline Co.*, 124 F.E.R.C. ¶ 61,154, at 1 (2008).

282. *Id.* at 20.

283. *Id.* at 23. *See also id.* at 20. Natural is making a payment to ComEd, the local electric distribution company, for upgrades to ComEd's electric distribution infrastructure necessary to support Natural's proposed storage expansion project. All of the contribution in aid of construction is assigned to the expansion services and the incremental rate design for the project ensures that only expansion shippers will pay for these costs. The Commission approved Natural's contribution in aid of construction to ComEd in the initial incremental rates for this project.

284. *Williston Basin Interstate Pipeline Co.*, 125 F.E.R.C. ¶ 61,117 (2008).

assets.²⁸⁵ The Commission also found that the project would benefit Williston's existing customers, while the proposal would not adversely impact other pipelines, their customers, landowners, or surrounding communities. Therefore, the Commission found that the public convenience and necessity required the approval of the lease proposal.

v. Transco

The Commission granted Transco's application for permission and approval to abandon its Hester Storage Field located in St. James Parish, Louisiana.²⁸⁶ The FERC also granted Transco's application to install temporary compression facilities to facilitate the withdrawal of injected base gas from the field. The Commission granted Transco's application because of the ongoing inventory loss at the Hester Storage Field (losses that have occurred since the 1980s). Despite numerous studies, Transco has been unable to determine the cause of these losses, and therefore Transco has been unable to develop a course of intervention or repair to halt the losses. The Commission determined that the abandonment will not impact service to Transco's customers. In fact, a portion of the proceeds from the sale of the recovered gas will be shared with Transco's customer. Thus, the FERC found that the requested authorizations are required by public convenience and necessity.

The Commission also issued an authorization for Transco to install an additional compression unit and related facilities at its existing Eminence Salt Dome Storage Field in Covington County, Mississippi (Eminence facility).²⁸⁷ The sole purpose of the Eminence facilities and related service is to increase injection capacity. The Commission found that Transco's proposal will provide subscribing customers with enhanced storage injection rights, allowing more injection and withdrawal cycles per year. Thus, the proposal will provide customers with greater operating flexibility and more effective use of their storage service. The Commission rejected Transco's proposed cost allocation method and recourse rates for the proposal, and instead, the Commission required Transco to allocate all costs of the project to a single injection reservation charge and to submit revised recourse rates. The Commission reasoned that such an allocation would better serve the stated purpose of the Transco facilities.

w. Columbia Gas Transmission

In addition to granting certificate authority,²⁸⁸ the Commission approved Columbia's request pursuant to NGA Section 4(f) to provide storage service through expanded facilities at market-based rates.

285. *Id.* at 13.

286. *Transcontinental Gas Pipe Line Corp.*, 125 F.E.R.C. ¶ 62,003 (2008).

287. *Transcontinental Gas Pipe Line Corp.*, 126 F.E.R.C. ¶ 61,189 (2009).

289. *Columbia Gas Transmission Corp.*, 126 F.E.R.C. ¶ 61,237 (2009). Columbia requested authority "to construct new storage wells, as well as upgrade and convert existing wells, within the existing Crawford Storage Field boundary", and "to construct facilities at its Weaver Storage Field enabling it to initiate a continually operating withdrawal-only, or counter storage system", and "to abandon and construct certain facilities in order to expand storage capabilities at its Crawford and Weaver Storage Fields in Ohio (the Ohio Storage Project)." *Id.* at 1, 5, 8.

“[I]n order to gain authority to provide service at market-based rates: (1) the capacity providing the storage service must relate to a ‘specific facility’ requiring certification placed in service after the date of the [EPAct2005], be it a new storage cavern or a facility which expands capacity at an existing cavern or reservoir; (2) market-based rates must be in the public interest and necessary to encourage the construction of storage capacity in an area needing storage services; and (3) customers must be adequately protected.”²⁸⁹

V. ORDERS REGARDING STORAGE CAVERN INTEGRITY AND OTHER TECHNICAL CONSIDERATIONS

Although 2008 and early 2009 have seen a substantial increase in the number of certificates granted for construction of new and expanded storage projects, other Commission activity has centered around applications to protect storage field boundaries, limit gas migration, and otherwise protect the integrity of a company’s storage resources. The following orders demonstrate the Commission’s recent consideration of such concerns.

A. *Southern Star Central Gas Pipeline, Inc.*, 124 FERC ¶ 61,042 (2008), *Order Issuing Certificate*, Docket No. CP07-89-000

Southern Star Central Gas Pipeline, Inc. (Southern Star) requested changes to its existing North Welda storage facility to protect the integrity of the field by expanding the field boundary both geographically and geologically and to collect gas that has migrated beyond the existing certificated field boundary. The Commission was

convinced that the success of Southern Star’s gas recovery plan require[d]: (1) reclassification of the cap rock. . . and (2) granting Southern Star certificate authority to (a) acquire [property rights] into which its storage gas is upwardly migrating so that it becomes part of Southern Star’s certificated storage facility; (b) acquire all existing oil wells in accordance with its Gas Recovery Plan. . . above the existing certificated boundary of the North Welda storage field; (c) acquire all mineral and leasehold interests within the proposed lease acquisition areas. . . above the existing certificate boundary of the North Welda storage field; and (d) install compression facilities and convert certain specific oil wells to gas recovery wells.²⁹⁰

The Commission was not persuaded, however, that expanding the certificated boundary of the North Welda storage field laterally to encompass an approximately 1,240 additional acres was necessary to maintain the integrity of the North Welda storage field.²⁹¹ The Commission authorized Southern Star to increase the maximum certificated shut-in wellhead pressure to 433 psig from 430 psig, and to decrease the storage field’s maximum certificated capacity from 15.5 Bcf to 13.3 Bcf to “simplify operations at the Welda compressor station.”²⁹²

B. *Southern Star Central Gas Pipeline, Inc.*, 124 FERC ¶ 61,141 (2008), *Order Granting Rehearing and Amending Certificate Authorization*, Docket No.

289. *Id.*

290. *S. Star Cent. Gas Pipeline, Inc.*, 124 F.E.R.C. ¶ 61,042, at 30.

291. *Reh’g denied, S. Star Cent. Gas Pipeline, Inc.*, 125 F.E.R.C. ¶ 61,325 (2008).

292. 124 F.E.R.C. ¶ 61,042, at 64.

CP08-4-001

The FERC granted Southern Star's rehearing request for additional certificate authority to acquire certain real property rights. Southern Star requested rehearing of a May 9, 2008 Commission order (May 9 Order)²⁹³ "granting in part an application by [Southern Star] for certificate authorization. . . to construct facilities and acquire additional property rights to expand the certificated boundaries of its South Welda Storage Field."²⁹⁴ The FERC found that the rehearing was "in the public interest to ensure that Southern Star [could] acquire all the property interests necessary to prevent the South Welda storage field's integrity from being further compromised."²⁹⁵ The FERC found that migration of storage gas from the South Welda Storage would be exacerbated by any production of oil, and therefore determined that Southern Star's acquisition of the property rights was necessary to prevent further oil production activities. Finally, the Commission "affirm[ed] that Southern Star is entitled, absent a material change in circumstances, to a presumption of rolled-in rate treatment for this project's costs when it initiates a future [S]ection 4 rate proceeding to recover the costs."²⁹⁶

C. Northern Natural Gas Company, 125 FERC ¶ 61,127 (2008), Order Issuing Certificate, Docket No. CP07-107-000

Northern Natural Gas Co. (Northern Natural) requested a certificate of public convenience and necessity to expand the certificated boundary of its Cunningham Storage Field, originally certificated in 1978.²⁹⁷ Northern Natural argued that, in order to re-establish the integrity of its storage facility after underlying litigation in Federal District Court ruled that no storage gas had migrated, expansion of the north certificated storage boundary of the Cunningham Storage Field to encompass approximately 4,800 additional acres was necessary.²⁹⁸ The Commission agreed in part, satisfied that Northern demonstrated that storage gas has migrated into at least the southernmost part of the proposed 4,800-acre extension area in one well. However, Northern presented no geologic and engineering data that demonstrates that storage gas is present in any other wells in the proposed extension area. Therefore, the Commission granted Northern certificate authority to expand the certificated boundaries to encompass only 1,760 of the 4,800 acres requested. Northern sought and was denied rehearing of this finding,²⁹⁹ arguing that the certificated 1,760 acres is insufficient for Northern to protect the integrity of the storage field.

293. *S. Star Cent. Gas Pipeline, Inc.*, 123 F.E.R.C. ¶ 61,138 (2008).

294. *S. Star Cent. Gas Pipeline, Inc.*, 124 F.E.R.C. ¶ 61,141, at 1 (2008).

295. *Id.* at 17.

296. *Id.*

297. The storage facility has eighty-one wells, including fifty-two injection/withdrawal wells, twenty-eight observation wells, and a water disposal well; pipelines interconnecting the wells; and compression facilities. *Northern Natural Gas Co.*, 125 F.E.R.C. ¶ 61,127 (2008); *reh'g denied*, 127 F.E.R.C. ¶ 61,038 (2009).

298. *Id.* at 5.

299. *Id.*

D. Williston Basin Interstate Pipeline Company, 127 F.E.R.C. ¶ 61,045 (2009), Order issuing certificate, Docket No. CP08-158-000

Williston sought to amend its existing certificate authorization to enlarge the vertical and lateral boundaries of its Elk Basin storage reservoir and establish a buffer zone to add approximately 3,340 acres to its existing 1,556.47-acre storage facility. Williston claimed that its operation of the storage facility and the capability of the underground reservoir to contain storage volumes were being compromised by nearby production activities. Williston claimed that since several oil production wells went into service, it “has seen the loss of approximately 10 Bcf of its cushion gas from the Elk Basin Storage Reservoir, in contrast to no appreciable gas losses from the reservoir in the over 50 years of storage operations prior to that time.”³⁰⁰ Williston insisted that studies demonstrated that “while the physical capacity of its underground reservoir is the same as when it was certificated, the geological and stratigraphic extent of the reservoir is larger.”³⁰¹

The FERC found “an inherent uncertainty regarding the performance of an underground reservoir; its actual boundaries depend on characteristics that can generally be confirmed only after the facility has commenced operation.”³⁰² Thus, the Commission noted that it is not unusual for initially designated boundaries of a reservoir to shift over time permitting gas to escape confinement. The FERC found that updated geological interpretation shows that the certificated boundaries of the storage facility did not encompass the physical dimensions of the underground storage reservoir and that storage volumes therefore are moving beyond the current certificate boundaries. “[T]o protect the integrity of the Elk Basin Storage Reservoir and to establish a buffer zone”, the Commission authorized boundaries of the storage facility to be increased, but ordered “[t]he certificated maximum inventory, maximum pressure, and deliverability [to] remain the same.”³⁰³

The Commission acknowledged that the cost of expanding the storage facility could result in an increase in storage customers’ rates, but found that because expanding the Elk Basin facility is to ensure Williston can continue to meet its existing service obligations to its customers – and not to add new services or increase the facility’s capacity or deliverability – costs of the expansion may be allocated to Williston’s existing customers in a future Section 4 rate proceeding.

E. Monroe Gas Storage Company, L.L.C., 127 F.E.R.C. ¶ 62,046 (2009), Order Amending Certificate, Docket No. CP07-406-003

Monroe Gas Storage Co., L.L.C. (Monroe) sought authorization to implement its Revised Well Plan Project at its certificated gas storage field currently under construction in Monroe County, Mississippi³⁰⁴ in order to reduce

300. *Williston Basin Interstate Pipeline Co.*, 127 F.E.R.C. ¶ 61,045, at 2 (2009).

301. *Id.* at 4.

302. *Id.* at 11.

303. *Id.* at 38.

304. Monroe was originally granted certificate authority to, among other things: “construct nine new natural gas injection/withdrawal wells; convert five existing natural gas production wells to observation wells; construct approximately two miles of 12- and 18-inch diameter pipeline to interconnect injection/withdrawal

the reliance on horizontally drilled wells in favor of vertically drilled wells and to overcome subsurface conditions that make it impracticable to achieve the injection, withdrawal, and storage capabilities. Monroe proposed to relocate two wells, to add eight new wells, and to change the ancillary facilities including new access roads to serve the wells. The FERC approved the requested modifications and Monroe's request to continue relying on its previous market demand analysis and the Commission's granted market-based rate authority.³⁰⁵

VI. PENDING STORAGE APPLICATIONS

As of publication, the following applications for Section 7 certificates for storage projects are pending before the Commission:

Equitrans, L.P. (Logansport Reservoir Storage Pool in Marion County, West Virginia), FERC Docket Nos. CP08-416 & 417 (request to abandon four wells and replace them with two other wells; approximately 2.2 Bcf of storage with deliverability of 115,000 Mcf per day);

CenterPoint Energy-Mississippi River Transmission Corporation (MRT) (East Unionville Storage Field in Lincoln Parish, Louisiana), FERC Docket No. CP08-457 (expansion to provide over 26 Bcf of storage with deliverability of up to 390,000 Mcf per day connected to MRT);

Atmos Pipeline and Storage, L.L.C. (Fort Necessity Project in Franklin Parish, Louisiana), FERC Docket No. CP09-22 (approximately 15 Bcf of storage with deliverability of up to 1.5 Bcf per day to be connected to ANR Pipeline, Columbia Gulf Transmission, Regency Energy Partners and Tennessee Gas Pipeline, with a request to charge market-based rates for storage, storage-related and wheeling services);

Mississippi Hub, L.L.C. (existing storage project in Simpson and Jefferson Davis Counties, Mississippi), FERC Docket No. CP09-110 (expansion to provide 15 Bcf of storage with deliverability of up to 2.8 Bcf per day to be connected to CrossTex Energy, Gulf South Pipeline, Southeast Supply Header System, Southern Natural Gas and Transcontinental Gas Pipe Line, with a request to charge market-based rates for storage, storage-related and wheeling services); and

Perryville Gas Storage, L.L.C. (Crowville Project in Franklin and Richland Parishes, Louisiana), FERC Docket No. CP09-418 (approximately 15 Bcf of storage with deliverability of up to 600,000 Mcf per day to be connected to CenterPoint Energy Gas Transmission and Columbia Gulf Transmission, with a request to charge market-based rates for storage, storage-related and wheeling services).

wells . . . construct an approximately 5.7-mile long, 24-inch diameter lateral pipeline to interconnect the proposed compressor station with Texas Eastern Transmission Corporation; and construct an approximately 17.2-mile long, 24-inch diameter lateral pipeline to interconnect the proposed compressor station with Tennessee Gas Pipeline Company." *Monroe Gas Storage Co., L.L.C.*, 121 F.E.R.C. ¶ 61,285 (2007).

305. *Id.* at 14. The market power study asserts that interruptible wheeling services are a separate relevant product market "since wheeling service is a transportation service which facilitates the transfer of gas from one interconnected pipeline to another and does not provide a storage function." Therefore, the Commission found that Monroe cannot exercise market power acting together with the Gulf Coast production area hub operators. *Id.* at 23.

VII. GAS WAIVERS TO ALLOW FOR THE ORDERLY TRANSFER OF ASSETS

Several recent decisions mark an evolution of the Commission's analysis for evaluating requests for waivers of the capacity release regulations and related policies.³⁰⁶ In *Sempra Energy Trading Corp.*,³⁰⁷ *Bear Energy L.P.*,³⁰⁸ *Barclays Bank P.L.C. and UBS AG*,³⁰⁹ and *Macquarie Cook Energy, L.L.C.*,³¹⁰ the FERC granted broader waivers of its capacity release regulations and policies to allow for the orderly transfer of natural gas assets, including capacity rights on interstate pipelines and at jurisdictional storage facilities. In these orders, the FERC permitted pipeline capacity to be transferred to prearranged replacement shippers along with other contracts without any bidding process hosted by a pipeline. This spurred a petition for rulemaking, filed by Dominion Resources, Inc. (Dominion),³¹¹ requesting the FERC to clarify its policy regarding waivers of the capacity release regulations and related requirements for gas marketers transferring firm transportation rights on interstate pipelines as part of larger, integrated transactions. Dominion asserted the waivers granted in the recent orders were larger in scope and waived the capacity release posting and bidding requirements while earlier waivers were more narrowly tailored and required the entities seeking the waiver to follow the pipeline's posting and bidding procedures.

In *Macquarie Cook Energy, L.L.C.*, and an order dismissing the Dominion petition for rulemaking,³¹² the Commission explained that its earlier waiver orders (such as *Duke*) had granted waivers when marketers wanted to exit certain natural gas marketing activities but in those circumstances the marketers simply wanted to release firm transportation capacity in conjunction with gas supply contracts. No other assets or transfers of business units and employees from one corporation to another were involved, and certainly the financial trauma of 2008 was not present. The Commission reasoned, therefore, it was more practicable in the earlier cases for the marketers to use the pipeline's bidding process for release of interstate pipeline capacity, and accordingly the Commission did not waive all posting and bidding requirements. The later cases such as *Bear Energy*, the Commission explained, involve more complex transactions and the transfer of other assets and employees, as a result of various types of corporate

306. *Vitol Inc. & Natural Gas Pipeline Co. of America*, 121 F.E.R.C. ¶ 61,099 (2007) (waiver granted); *Northern Natural Gas Co.*, 119 F.E.R.C. ¶ 61,204 (2007) (waiver denied); *Gas Transmission Nw. Corp.*, 119 F.E.R.C. ¶ 61,031 (2007) (waiver denied); *Wasatch Energy, L.L.C. & Northwest Pipeline Corporation*, 118 F.E.R.C. ¶ 61,173 (2007) (waiver granted); *Duke Energy Marketing America L.L.C.*, 114 F.E.R.C. ¶ 61,309 (2006) (waiver granted); *Louis Dreyfus Energy Servs., L.P.*, 114 F.E.R.C. ¶ 61,246 (2006) (waiver denied); *Duke Energy Marketing America L.L.C.*, 114 F.E.R.C. ¶ 61,198 (2006) (waiver granted); *Tennessee Gas Pipeline Co. & Dartmouth Power Assoc., L.P.*, 111 F.E.R.C. ¶ 61,509 (2005) (waiver granted); *Wyoming Interstate Co.*, 110 F.E.R.C. ¶ 61,325 (2005) (waiver denied); *Cheyenne Plains Gas Pipeline Co.*, 110 F.E.R.C. ¶ 61,326 (2005) (waiver denied); and *Northwest Pipeline Corp. & Duke Energy Trading & Marketing*, 109 F.E.R.C. ¶ 61,044 (2004) (clarification denied), 112 F.E.R.C. ¶ 61,187 (2005) (waiver granted).

307. *Sempra Energy Trading Corp.*, 121 F.E.R.C. ¶ 61,005 (2007).

308. *Bear Energy, L.P.*, 123 F.E.R.C. ¶ 61,219 (2008).

309. *Barclays Bank PLS & UBS AG*, 125 F.E.R.C. ¶ 61,383 (2008).

310. *Macquarie Cook Energy, L.L.C.*, 126 F.E.R.C. ¶ 61,160 (2009).

311. *Request for Clarification of Policy Regarding Waivers of Applicable Requirements to Facilitate Integrated Transfers of Marketing Businesses*, 127 F.E.R.C. ¶ 61,106 (2009).

312. *Id.*

restructurings, including corporate mergers and sales of entire business units. In these cases, the FERC granted broader waivers (including the posting and bidding requirements) so the parties could consummate the transfer of an entire business unit. The FERC found that the capacity release mechanism in the regulations³¹³ is not suited to these types of complex, integrated deals that do not permit the disaggregation of assets.

In so ruling, the FERC advised that waivers of its regulations and policies by their very nature need to be evaluated on a case-by-case basis, because they turn on the specific circumstances of individual cases, and that applicants for such waivers should:

- (1) identify with as much specificity as possible the regulations and policies for which they seek waiver, (2) identify the pipeline capacity at issue, (3) provide a sufficient description of the overall transaction and its claimed benefits to permit the Commission and other interested parties to analyze whether granting the requested waivers are in the public interest based upon the factors discussed above, and (4) file the request as much in advance of the requested action date as possible.³¹⁴

VIII. LNG PROJECTS

A. Onshore LNG Projects

1. Projects Receiving FERC Authorization

a. AES Sparrows Point

On January 15, 2009, the FERC issued an authorization under Section 3 of the NGA for AES Sparrows Point LNG, L.L.C. (AES) to construct, own, and operate an LNG terminal on the Chesapeake Bay in Baltimore County, Maryland.³¹⁵ In the same order, the FERC issued a certificate of public convenience and necessity pursuant to Section 7(c) of the NGA and a blanket certificate to transport natural gas under Part 157 of the FERC's regulations³¹⁶ to AES's affiliate, Mid-Atlantic Express, L.L.C., for the construction and operation of a 30-inch natural gas pipeline, which will transport vaporized LNG eighty-eight miles from the tailgate of AES's terminal to a point near Eagle, Pennsylvania.³¹⁷ The approved terminal and pipeline will have the capacity to vaporize and transport up to 1.5 billion cubic feet (Bcf) of natural gas per day.³¹⁸ The facilities will provide a new source of LNG to markets in the eastern United States through interconnections with downstream interstate pipelines owned by Transco, CGT, and Texas Eastern Transmission, L.P.³¹⁹

Several commenters, including members of Congress, state legislators, other government officials, objected to the proposed terminal and pipeline facilities. Objectors raised concerns about the impacts the project might pose to

313. 18 C.F.R. § 284.8 (2009).

314. 127 F.E.R.C. ¶ 61,106, at 10.

315. *AES Sparrows Point LNG, L.L.C.*, 126 F.E.R.C. ¶ 61,019, at 1 (2009).

316. 18 C.F.R. pt. 157 (2009).

317. 126 F.E.R.C. ¶ 61,019, at 2.

318. *Id.* at 1-2.

319. *Id.* at 20, note 2.

safety, security, and the environment.³²⁰ Some parties to the proceeding also challenged the market need for the project.³²¹ The FERC determined that most of the objections raised by the commenting parties had been adequately addressed by the Final Environmental Impact Statement (FEIS) issued by the FERC staff in the proceedings on December 5, 2008.³²² The FERC ultimately determined that the proposed AES terminal will not be inconsistent with the public interest, satisfying the standard in NGA Section 3, provided that it is constructed and operated consistent with the conditions specified in the January 15 FERC order.³²³

As part of its approval of AES's terminal and the associated pipeline, the FERC attached 169 individual conditions with which AES will be required to comply before it may commence construction and operation of its facilities. These measures range from environmental mitigation procedures to coordination with the Coast Guard and local agencies to develop an Emergency Response Plan to respond to safety and security issues. The FERC authorizations are also contingent upon the project's receipt of "all other necessary permits and approvals."³²⁴

The order approving the AES terminal included a dissent by Commissioner Jon Wellinghoff.³²⁵ Commissioner Wellinghoff stated that, despite AES's willingness to bear the financial risks associated with the project, approval of the terminal was not consistent with the public interest as, AES had not demonstrated that the additional LNG that the terminal would provide was needed to serve the Mid-Atlantic and South-Atlantic markets.³²⁶ The dissent argued that the energy needs of the region could be more adequately met through domestic natural gas production, development of renewable energy sources, and advances in distributed generation.³²⁷ Finally, Commissioner Wellinghoff expressed concerns about the environmental impact that dredging and associated activities would have on the local environment. The FERC's January 15 Order is currently under review pursuant to a petition for reconsideration.

In addition to the FERC authorization under Section 3 of the NGA, in order to construct the Sparrows Point terminal, AES must obtain authorizations from the Maryland Department of the Environment (MDE) under Section 307(c)(3)(B) of the Coastal Zone Management Act of 1972 (CZMA)³²⁸ and Section 401 of the Federal Water Pollution Control Act of 1972 (Clean Water Act).³²⁹ Under the CZMA, an applicant for a federal license or permit for an activity that may affect a state's identified coastal zone must obtain a concurrence from the designated state coastal zone management agency that the proposed activity is consistent with the state's coastal zone policies. The MDE

320. *Id.* at 16.

321. *Id.* at 25.

322. *Id.* at 3.

323. *Id.* at 26.

324. *Id.* at 62.

325. Commissioner Wellinghoff has since been appointed Chairman of the FERC.

326. 126 F.E.R.C. ¶ 61,019, at ¶ 61,096 (Comm'r Wellinghoff dissenting).

327. *Id.* at 61,097.

328. 16 U.S.C. § 1456(c)(3)(B) (2006).

329. 33 U.S.C. § 1341 (2006).

issued an objection to the consistency certification submitted to the agency by AES. However, on June 26, 2008, acting pursuant to Section 307 of the CZMA, the Secretary of Commerce found that the AES project may proceed despite MDE's objection.³³⁰ MDE has filed a petition for review in the Federal District Court for the District of Maryland challenging the Secretary of Commerce's decision to override MDE's objection.³³¹

In addition to the authorizations received from the FERC under Sections 3 and 7 of the NGA, on March 18, 2009, AES received a Letter of Recommendation (LOR) from the United States Coast Guard.³³² The Coast Guard, in exercising its authority pursuant to the Ports and Waterways Safety Act of 1972 (PAWSA)³³³ and Section 127.009 of the Coast Guard's regulations,³³⁴ determined that "the Chesapeake Bay is not currently suitable, but can be made suitable, for the type and frequency of LNG marine traffic associated with the proposed LNG facility, provided additional safety measures necessary to responsibly manage the maritime safety and security risks are in place."³³⁵ The Waterway Suitability Assessment (WSR) prepared by AES and the Waterway Suitability Report prepared by the Coast Guard contain several risk mitigation measures that may be implemented to make the waterway suitable for the vessel transits proposed by AES under the PAWSA. The Coast Guard is responsible for ensuring the safety of the nation's ports and under its implementing regulations at 33 C.F.R. Part 127 requires persons seeking to transport LNG by vessel to obtain an LOR from the relevant Coast Guard Captain of the Port concluding that the waterway proposed for such transit is suitable.

b. Bradwood Landing

On September 18, 2008, the FERC issued an order (September 18 Order) granting authorization under Section 3 of the NGA to Bradwood Landing, L.L.C. (Bradwood Landing) to construct, own, and operate an LNG terminal to be located along the Columbia River in Bradwood, Oregon.³³⁶ The FERC also issued a certificate of public convenience and necessity under Section 7(c) of the NGA to Bradwood Landing's affiliate, NorthernStar Energy, L.L.C., to construct, own, and operate interstate natural gas pipeline facilities extending from the tailgate of Bradwood's proposed LNG terminal to an interconnection with Northwest Pipeline Company's interstate pipeline facilities north of Kelso, Washington.³³⁷ The LNG terminal and pipeline facilities have been designed

330. U.S. Secretary of Commerce, Decision and Findings in the Consistency Appeal of AES Sparrows Point LNG, L.L.C. and Mid-Atlantic Express, L.L.C., from an Objection by the State of Maryland (June 26, 2006); *AES Sparrows Point LNG, L.L.C.*, 126 F.E.R.C. ¶ 61,019, at 130.

331. Maryland Dep't of the Env't v. U.S. Dep't of Commerce, No. 09-CV-1208 (D. Md. May 11, 2009).

332. Letter of Recommendation from B.D. Kelley, Captain of the Port, Baltimore, & P.B. Trapp, Captain of the Port, Hampton Roads to Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission (Mar. 18, 2009) [hereinafter, *Kelley Recommendation*].

333. 33 U.S.C. § 1221-1236 (2009).

334. 33 C.F.R. § 127.009 (2009).

335. *Kelley Recommendation*, *supra* note 333, at 3.

336. *Bradwood Landing, L.L.C.*, 124 F.E.R.C. ¶ 61,257, at 1-2 (2008); *reh'g denied*, 126 F.E.R.C. ¶ 61,035 (2009).

337. *Id.*

with a peak send-out capacity of 1.3 Bcf per day, serving customers primarily in the states of Oregon and Washington, and to a lesser extent, Idaho, California, and Nevada.³³⁸

Among those opposing the issuance of the NGA Section 3 authorization for the Bradwood Landing terminal were Oregon governor, Ted Kulongoski,³³⁹ and the state's U.S. Senator, Ron Wyden.³⁴⁰ Several other elected officials, state agencies, interest groups, and citizens expressed opposition to the FERC's action. Commenters objected, among other things, on the grounds that the FEIS issued by the FERC was insufficient, and that the impacts of the project on the local environment and threatened and endangered species around the Columbia River, in particular, were not justified by the need for the project.³⁴¹ Additionally, many commenters suggested that the energy needs of the Pacific Northwest could more adequately be served by other alternatives, such as renewable generation and domestic natural gas supplies from the Rocky Mountains. The FERC determined, however, that the examined alternatives to the LNG terminal would not "be able to provide an amount of energy equivalent to the Bradwood Project to the same market area and in a similar timeframe."³⁴²

In its final analysis, the FERC found that "if constructed and operated in accord with the numerous conditions imposed in the order . . . the Bradwood Landing Project will provide numerous public benefits, outweighing any residual adverse effects it might have."³⁴³ Consistent with this determination, the FERC imposed 106 individual conditions, which must be met before the proposed terminal may begin operation. Several engineering conditions were included in the order to address concerns about the potential for damage to the proposed facilities from seismic activity in the area.³⁴⁴ The FERC also conditioned its authorization on the compliance of the Bradwood Landing project with numerous state and federal regulatory requirements, including a determination from the Oregon Department of Land Conservation and Development that the project is consistent with the state's coastal zone management policies pursuant to the CZMA.

Commissioner Wellinghoff dissented from the September 18 Order.³⁴⁵ The dissent described the Bradwood Landing project as providing natural gas supplies far in excess of the projected demand of the Pacific Northwest, and questioned the conclusion in the September 18 Order that such supplies were intended primarily for the states of Oregon and Washington.³⁴⁶ Commissioner Wellinghoff stated that "there are reasonable alternatives for serving the projected energy needs of the Pacific Northwest," including "domestic natural gas infrastructure and deployment of renewable and distributed energy

338. 124 F.E.R.C. ¶ 61,257, at 25.

339. *Id.* at 40.

340. *Id.* at 139, note 59.

341. *Id.*

342. *Id.* at 71.

343. *Id.* at 20.

344. *Id.*

345. *Id.* at ¶ 62,335 (Comm'r Wellinghoff dissenting).

346. *Id.* at ¶¶ 62,335-36.

resources.”³⁴⁷ The dissent also expressed concern that the measures proposed to mitigate impacts upon fish species in the Columbia River had not been adequately developed in the FERC’s FEIS analysis.³⁴⁸

On January 15, 2009, the FERC issued an order denying rehearing of its September 18 Order approving the Bradwood Landing project.³⁴⁹ The parties requesting rehearing challenged the authority of the FERC to issue a conditional determination authorizing the Bradwood Landing facilities before the proponents of that project have obtained a Water Quality Certification under the Clean Water Act,³⁵⁰ a consistency concurrence under the CZMA,³⁵¹ and an air quality permit under the Clean Air Act.³⁵² The parties argued that the FERC may not issue conditional approvals pursuant to its authority under the NGA, until the required state authorizations have been issued.³⁵³ In dismissing the parties legal conclusions, the FERC stated that its conditional approval of the Bradwood Landing project “does not impact any substantive determinations that need to be made by the states under [the Clean Water Act, the CZMA, and the Clean Air Act.]”³⁵⁴ The FERC noted that its September 18 Order approving the LNG terminal would not permit the project to go forward without all of the necessary authorizations including authorizations under the statutes cited by the parties seeking rehearing. The rehearing order also rejected challenges to the completeness of the FERC’s environmental and market analysis, finding that there was “sufficient information in the record to use in balancing public benefits and adverse impacts in determining that the project is in the public interest.”³⁵⁵ Commissioner Wellinghoff dissented to the order denying rehearing as he had in the order issuing authorization.

The states of Oregon and Washington, along with several environmental groups, filed appeals of the FERC’s order denying rehearing in the Ninth Circuit Court of Appeals.³⁵⁶ The appellants in these cases are seeking to challenge, among other things, the FERC’s authority to issue a conditional order authorizing the construction of facilities under the NGA before the necessary authorizations have been granted under the Clean Water Act, the CZMA, and the

347. *Id.*

348. *Id.*

349. *Bradwood Landing, L.L.C.*, 126 F.E.R.C. ¶ 61,035 (2009).

350. The Clean Water Act states that no federal “license or permit shall be granted until the certification required by this section [a Water Quality Certification] has been obtained or has been waived . . .” 33 U.S.C. § 1341(a)(1) (2009).

351. The CZMA provides that no federal license or permit for an activity affecting the resources in a covered state’s coastal zone may be issued until the requirements of the CZMA, including the concurrence of designated state agencies, have been fulfilled. 16 U.S.C. § 1456(c)(3)(A) (2008).

352. 42 U.S.C. §§ 7401-7661 (2009). Section 176(c) of the Clean Air Act states that “[n]o department, agency or instrumentality of the Federal Government shall engage in, support in any way or provide financial assistance for, license or permit, or approve, any activity which does not conform to an implementation plan after it has been approved or promulgated under Section 7410 of this title.”

353. *Bradwood Landing, L.L.C.*, 126 F.E.R.C. ¶ 61,035, at 27; *see also* Natural Gas Act § 3(d), 15 U.S.C. 717b(d) (2009) (“Except as specifically provided in this chapter, nothing in this chapter affects the rights of States under [the CZMA, the Clean Air Act, and the Clean Water Act].”).

354. *Bradwood Landing, L.L.C.*, 126 F.E.R.C. ¶ 61,035, at 29.

355. *Id.* at 181.

356. *Oregon v. FERC*, No. 09-70269 (9th Cir. 2009); *Pet. for Review, Wa. Dep’t of Ecology v. FERC*, No. 09-70442 (9th Cir. 2009); *Pet. for Review, Columbia Riverkeeper v. FERC*, No. 09-70477 (9th Cir. 2009).

Clean Air Act. This issue has been recently addressed by the D.C. Circuit Court of Appeals in *Delaware Department of Natural Resources and Environmental Control v. FERC*,³⁵⁷ in which a D.C. Circuit panel upheld the FERC's authority to issue conditional orders notwithstanding pending action under the CZMA. No ruling has yet been made in the case before the Ninth Circuit challenging the Bradwood Landing Project. The Department of Justice, on behalf of the National Marine Fisheries Service, has also filed a petition for review in the Ninth Circuit.³⁵⁸

c. Dominion Cove Point

On June 16, 2006, the FERC issued an order (June 16 Order) approving an application by Dominion Cove Point LNG (Cove Point) for authorization under Section 3 of the NGA to expand its LNG terminal facilities located in Cove Point, Maryland.³⁵⁹ The terminal expansion project would increase the send-out capability of the Cove Point facilities by 800 million cubic feet (MMcf) and will increase storage capacity at the terminal by approximately 6.8 Bcf.³⁶⁰ Cove Point also sought certificate authority under Section 7(c) of the NGA to add several looping facilities to carry up to 800 MMcf of regasified LNG per day imported as a result of the expansion of Cove Point's LNG terminal.³⁶¹ Finally, Dominion Transmission, Inc. (Dominion), an affiliate of Cove Point that operates interstate pipeline facilities downstream of the Cove Point LNG terminal, proposed to expand its existing transmission and storage facilities to provide an additional 700,000 MMcf per day of firm transportation service and 6.0 Bcf of firm storage service.³⁶²

One of the intervenors in the certificate proceeding, WGL, a downstream local distribution company, asserted that the introduction of regasified LNG from the Cove Point terminal, due to the gas's low heavy hydrocarbon concentration, was causing an above-average failure rate for mechanical couplings installed on WGL's system, leading to an increased number of leaks since the terminal was reactivated in 2003.³⁶³ WGL claimed that, while the problem had previously been confined to a discrete portion of its facilities in Maryland, the expansion of the Cove Point terminal would spread the effects on WGL's entire system.³⁶⁴ WGL argued that the FERC should not approve Cove Point's expansion until the company took steps to ensure that the increased deliveries of regasified LNG from its expanded terminal will not damage WGL's system.³⁶⁵ While the FERC stated that it did not rule out the introduction of regasified LNG as a contributing factor to the failure of the mechanical couplings, it found that the increased instance of leaks experienced by WGL

357. Del. Dep't of Natural Resources & Env'tl. Control v. F.E.R.C., 558 F.3d 575 (D.C. Cir. 2009).

358. National Marine Fisheries Serv. v. F.E.R.C., No. 09-70770 (9th Cir. 2009).

359. *Dominion Cove Point LNG, L.P.*, 115 F.E.R.C. ¶ 61,337 (2006); *order on reh'g*, 118 F.E.R.C. ¶ 61,007 (2007); *order dismissing request for reh'g*, 119 F.E.R.C. 61,276 (2007).

360. 115 F.E.R.C. ¶ 61,337, at 10.

361. *Id.* at 21.

362. *Id.* at 27.

363. *Id.* at 46-47.

364. *Id.* at 48.

365. *Id.* at 40.

“was not caused primarily by a change in [the concentration of heavy hydrocarbons in regasified LNG,] but instead, other factors such as the application of hot tar to the couplings, increased operating pressure, and colder temperatures had a greater impact on leak rates.”³⁶⁶ The FERC further determined that WGL’s conclusions regarding the effect of regasified LNG from the Cove Point terminal on its system was based on a flawed analysis.³⁶⁷ The FERC concluded that “it is clear that any shrinkage due to [exposure to regasified LNG] was small, particularly when compared to other contributing factors. . . and would not have caused any increase in leak rates on WGL’s system in the absence of those other more significant contributing factors.”³⁶⁸

On January 4, 2007, in an order on rehearing (January 4 Order), the FERC granted and denied several parties’ requests for rehearing and clarification of its June 16 Order.³⁶⁹ Specifically, the January 4 Order denied WGL’s request for rehearing of the FERC’s determination regarding the primary cause of the leaks on its system, reasoning that regasified LNG from the Cove Point terminal “would not have adversely affected WGL’s system if a subset of the compression couplings had not been compromised during the installation process” due to exposure to excessive amounts of hot tar.³⁷⁰ The January 4 Order determined that the terminal expansion project could go forward on schedule as proposed by Cove Point, despite the safety concerns raised by WGL, finding that “there is time for WGL to complete any remaining corrective measures that are needed on its system so that it can safely accommodate regasified LNG.”³⁷¹

On July 18, 2008, the D.C. Circuit Court of Appeals vacated and remanded the FERC’s previous orders approving the Cove Point Expansion project.³⁷² Extending an “extreme degree of deference” to the FERC, the court found that “substantial evidence supports FERC’s conclusion that the unblended LNG would not have caused the leaks if the couplings had not been damaged by the hot tar.”³⁷³ While affirming the FERC’s substantive determination regarding the primary cause of the leaks on WGL’s system, the D.C. Circuit determined that the administrative record did not contain substantial evidence supporting the FERC’s finding that the project should proceed on schedule despite the safety issues raised by WGL. The court observed that while the January 4 Order found that WGL would be able to repair the portion of its system that had previously been affected by the leaks it attributed to regasified LNG introduced by Cove Point’s terminal (approximately fourteen percent of WGL’s facilities) before the November 2008 in-service date proposed for the expansion project, the January 4 Order “does not even begin to suggest WGL will be able to fix the other 86% of its system before the Expansion begins operations in a couple of months.”³⁷⁴

366. *Id.* at 56.

367. *Id.* at 58.

368. *Id.* at 73.

369. *Dominion Cove Point LNG, L.P.*, 118 F.E.R.C. ¶ 61,007 (2007).

370. *Id.* at 54.

371. *Id.* at 29.

372. *Washington Gas Light Co. v. F.E.R.C.*, 532 F.3d 928 (D.C. Cir. 2008).

373. *Id.* at 932.

374. *Id.*

“Having found WGL’s system is defective, FERC had to explain why the Expansion could nevertheless proceed consistent with the public interest requirements of sections 3 and 7 of the NGA.”³⁷⁵ On this basis, the D.C. Circuit vacated the FERC’s orders approving the project and remanded the case to the FERC so that it could make a determination whether the Expansion project could “go forward without causing unsafe leakage.”³⁷⁶

On October 7, 2008, the FERC issued an order (October 7 Order) on the D.C. Circuit’s remand of the previous orders authorizing the Cove Point Expansion project.³⁷⁷ The October 7 Order reincorporated all of the analysis of the FERC’s previous vacated orders justifying the approval of the Cove Point terminal and associated Dominion pipeline, and reissued the Section 3 authorization and Section 7 certificate.³⁷⁸ In order to address the safety issue remanded by the D.C. Circuit’s order in *WGL v. FERC*, the October 7 Order’s reissuance of the approvals for the Expansion project were subject to the condition that no additional volumes of regasified LNG resulting from the expansion would be allowed to enter WGL’s system. The FERC determined that this restriction would address the concerns raised by WGL about leakage caused by additional volumes of regasified LNG from the expansion.³⁷⁹ The FERC found that Dominion was capable of operating its system so that “WGL will be isolated from any volumes of LNG in excess of those that it could already receive under agreements entered into pursuant to the existing authorization” ensuring “that no additional LNG can be delivered into WGL’s system as a result of the expansion project.”³⁸⁰ The October 7 Order noted that the FERC may remove this restriction at some point in the future if it is demonstrated that additional volumes of regasified LNG may be accommodated on WGL’s system without a significant risk of leakage.³⁸¹

On January 15, 2009, the FERC issued an order (January 15 Order) granting in part and denying in part requests for rehearing and clarification of the October 7 Order.³⁸² The January 15 Order affirmed the FERC’s reissuance of authorizations for the expansion project and rejected the arguments of WGL and other parties that the October 7 Order did not adequately address the D.C. Circuit’s mandate that the FERC assess whether it was in the public interest for the terminal expansion to go forward in light of the risk of leakage posed to WGL’s system from additional volumes of regasified LNG. In order to ensure compliance with the October 7 Order’s directive that Cove Point maintain deliveries of regasified LNG onto WGL’s system at pre-expansion levels, the January 15 Order imposed an additional requirement that Cove Point report to the FERC “any delivery of regasified LNG at Columbia-Loudoun that exceeds

375. 523 F.3d at 932.

376. *Id.*

377. *Dominion Cove Point LNG, L.P.*, 125 F.E.R.C. ¶ 61,018 (2008); *order on reh’g and clarification*, 126 F.E.R.C. ¶ 61,036 (2009).

378. *Id.* at 51.

379. *Id.* at 52.

380. *Id.* at 69. In order to accomplish this condition, deliveries of regasified LNG onto Columbia Gas Transmission’s system at Loudon, Virginia were restricted to 530,000 Dth/d, the existing level of firm primary delivery rights at the point prior to the terminal expansion. *Id.*

381. *Id.* at 52.

382. 126 F.E.R.C. ¶ 61,036.

530,000 Dth/d within three days of such occurrence.”³⁸³ The FERC subsequently denied a request by WGL to stay the effectiveness of the October 7 and January 15 Orders until judicial review of the FERC’s previous orders had been completed.³⁸⁴

On July 29, 2009, Cove Point received an LOR from the United States Coast Guard.³⁸⁵ The Coast Guard, in exercising its authority under the PAWSA³⁸⁶ and Section 127.009 of the agency’s regulations,³⁸⁷ determined that “the waterway leading up to the Cove Point LNG terminal is suitable for the increased LNG marine traffic associated with” the terminal expansion.³⁸⁸

d. Freeport

On May 6, 2009, the FERC approved the application of Freeport LNG Development, L.P. (Freeport) to amend its authorization under NGA Section 3 to permit the terminal operator to export foreign-source LNG to international destinations.³⁸⁹ Freeport’s application cited “increasing worldwide demand for LNG and relatively low market prices for natural gas in the United States” leading to a lower-than-expected number of LNG deliveries to its facilities, and stated that the requested authorization “would enable it to sell to non-U.S. markets those volumes not required for cryogenic facility maintenance.”³⁹⁰ The FERC found Freeport’s request to export foreign-sourced LNG to be in the public interest as it would permit the terminal to maintain and operate its cryogenic facilities “during those periods when LNG deliveries for ultimate domestic use may not otherwise be adequate to maintain the terminal in a state of readiness to serve U.S. markets.”³⁹¹

Freeport also sought authorization to construct a boil-off gas liquefaction system that would capture and re-liquefy LNG that has been vaporized due to ambient heat, and facilities that would allow the terminal to receive shipments of LNG by truck.³⁹² In the absence of new shipments of LNG, Freeport contended that these additional facilities were necessary to ensure a reserve of LNG sufficient to keep its in-tank pumps submerged and its storage tanks in a cryogenic state.³⁹³ In approving these additional facilities, the FERC indicated that they would enable Freeport “to maintain safe and continuous cryogenic terminal operations without altering the basic purpose or character of the existing LNG terminal facility.”³⁹⁴

383. *Id.* at 46.

384. *Dominion Cove Point LNG, L.P.*, 126 F.E.R.C. ¶ 61,238 (2009).

385. Letter of Recommendation from Austin J. Goul, Alternate Captain of the Port, Baltimore, & Patrick B. Trapp, Captain of the Port, Hampton Roads to Mike Frederick, Director LNG Operations, Dominion Cove Point LNG, L.P. (July 29, 2008). [hereinafter, *LOR*]

386. 33 U.S.C. §§ 1221-1236 (2009).

387. 33 C.F.R. § 127.009 (2009).

388. *LOR*, *supra* note 386, at 1.

389. *Freeport LNG Dev., L.P.*, 127 F.E.R.C. ¶ 61,105, at 1 (2009).

390. *Id.* at 4.

391. *Id.* at 15.

392. *Id.*

393. *Id.* at 7.

394. *Id.* at 15.

e. Sabine Pass

On May 29, 2009, the FERC issued an order approving an application submitted by Sabine Pass LNG, L.P. (Sabine Pass) to amend its authorization under Section 3 of the NGA to export LNG that had previously been imported and stored in Sabine Pass's LNG terminal.³⁹⁵ Sabine Pass stated that the modified authorization requested in its application would allow its customers "the opportunity to purchase cargoes of LNG at current LNG world market prices with the intention of exporting the LNG for redelivery to a foreign market at a later date, in the event that U.S. market prices are lower than world market prices."³⁹⁶ Sabine Pass also maintained that the authorization would help it to maintain continuous operation of its terminal facilities even when U.S. natural gas markets are depressed.³⁹⁷ The FERC adopted Sabine Pass's rationale and approved its request as being not inconsistent with the public interest.³⁹⁸

2. Projects Requesting FERC Authorization

a. Downeast LNG

On December 22, 2006, Downeast LNG, Inc. (Downeast) filed an application with the FERC for authorization to construct an LNG terminal under Section 3 of the NGA. The proposed terminal, to be located in Passamaquoddy Bay near the town of Robbinston, Maine, has been designed to import, store, and vaporize up to 625 MMcf of natural gas per day.³⁹⁹ Simultaneously, Downeast's subsidiary, Downeast Pipeline L.L.C., filed an application for a Certificate of Public Convenience and Necessity and a blanket certificate application under the FERC's regulations to permit it to construct, own, and operate a 29.8-mile-long, 30-inch-diameter natural gas pipeline capable of transporting up to 625 MMcf of natural gas per day. The pipeline facilities would extend from the proposed terminal to an interconnection with the existing facilities of Maritimes and Northeast Pipeline L.L.C. near Baileyville, Maine.⁴⁰⁰

On January 9, 2009, pursuant to the PAWSA⁴⁰¹ and section 127.009 of the Coast Guard's regulations,⁴⁰² the Captain of the Port, Sector Northern New England, issued a WSR and an LOR which determined the suitability of LNG vessel transits as proposed by Downeast in Passamaquoddy Bay.⁴⁰³ After analyzing the nature of the proposed waterway and the safety and security risks posed by the LNG vessel transits associated with Downeast's proposed project, the WSR proposed several mitigation measures designed to improve conditions

395. *Sabine Pass LNG, L.P.*, 127 F.E.R.C. ¶ 61,200 (2009).

396. *Id.* at 6.

397. *Id.*

398. *Id.* at 11.

399. Notice of Applications for Certificates of Public Convenience and Necessity and Section 3 Authorization, Docket Nos. CP07-52-000, *et al.*, at 2 (Dec. 29, 2006).

400. *Id.*

401. 33 U.S.C. §§ 1221-1236 (2009).

402. 33 C.F.R. § 127.009 (2009).

403. Letter of Recommendation from J.B. McPherson, Captain of the Port, Sector Northern New England to J.M. Robinson, Director of Gas, Environment, and Engineering, Federal Energy Regulatory Commission (Jan. 6, 2009).

in Passamaquoddy Bay for such transits. The LOR concluded that if the measures proposed in the WSR were implemented, the Passamaquoddy Bay Waterway would be “suitable for the type and frequency of marine traffic associated with [the] proposed project.”⁴⁰⁴

On May 15, 2009, the FERC staff issued a Draft Environmental Impact Statement (DEIS) assessing the proposed LNG terminal and natural gas pipeline.⁴⁰⁵ The DEIS recommended ninety-six separate mitigation measures. The FERC staff concluded that if the proposed LNG terminal and pipeline were constructed and operated according to the recommended measures, the project “would be an environmentally acceptable action.”⁴⁰⁶ The final date for the submission of comments on the Downeast DEIS was July 6, 2009, at which point the FERC staff will begin drafting a FEIS for the project.

b. Jordan Cove LNG

On September 4, 2007, Jordan Cove Energy Project, L.P. (Jordan Cove) filed an application with the FERC for authorization to construct an LNG terminal under Section 3 of the NGA.⁴⁰⁷ The proposed LNG facility will be located in Coos Bay, Coos County, Oregon and has been designed with a peak capacity of up to 1.0 Bcf of natural gas per day.⁴⁰⁸ Also, on September 4, 2007, Pacific Connector Gas Pipeline, L.P. (Pacific Connector) filed an application for Certificate of Public Convenience and Necessity and a blanket certificate under the FERC’s regulations to permit it to construct, own, and operate a 230-mile-long, 36-inch-diameter natural gas pipeline. The pipeline facilities are designed with a peak throughput of 1.0 Bcf per day and will extend from the proposed terminal to an interconnection with Northwest Pipeline Company, Avista Corporation, Pacific Gas and Electric Company, Gas Transmission Northwest Corporation, and Tuscarora Gas Transmission Company.⁴⁰⁹ The proposed facilities will serve markets in the Pacific Northwest, northern Nevada, and northern California.

On April 24, 2009, pursuant to the PAWSA⁴¹⁰ and Section 127.009 of the Coast Guard’s regulations,⁴¹¹ the Captain of the Port, Sector Portland, issued an LOR which determined the suitability of LNG vessel transits as proposed by Jordan Cove in Coos Bay.⁴¹² The LOR discussed the Captain of the Port’s review of the safety and security risks posed by the project and the mitigation measures proposed in the Waterways Suitability Assessment submitted by the applicant in February 2007 and the Waterways Suitability Report prepared by

404. *Id.* at 1.

405. Draft Environmental Impact Statement, Docket No. CP07-52-000. (May 15, 2009) [hereinafter, *Downeast DEIS*].

406. *Id.* at 5-1.

407. Notice of Applications for Certificates of Public Convenience and Necessity and Section 3 Authorization, Docket Nos. CP07-441-000, *et al.*, at 1 (Sept. 13, 2007) [hereinafter, *Jordan Cove Application*].

408. *Id.*

409. *Id.*

410. 33 U.S.C. § 1221-1236 (2009).

411. 33 C.F.R. § 127.009 (2009).

412. Letter of Recommendation from F.G. Myer, Captain of the Port, Sector Portland to Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission (Apr. 24, 2009).

the Coast Guard on July 1, 2007. The LOR concluded that if the measures proposed in the assessment and the report were implemented, Coos Bay leading up to Jordan Cove could be suitable for the type and frequency of LNG marine traffic associated with the project.⁴¹³

On May 1, 2009, the FERC staff issued a FEIS evaluating the proposed Jordan Cove LNG terminal and Pacific Connector pipeline.⁴¹⁴ The DEIS recommended 130 separate mitigation measures. The FEIS recognized several adverse environmental impacts that may arise from the project; however, the FERC staff concluded that most of these impacts would be reduced to less-than significant levels if the FEIS's proposed mitigation measures were adopted, in which case the project "would be an environmentally acceptable action."⁴¹⁵

c. Oregon LNG

On October 10, 2008, LNG Development Company, L.L.C., d/b/a Oregon LNG (Oregon LNG), filed an application with the FERC for authorization to construct and operate an LNG terminal under Section 3 of the NGA.⁴¹⁶ The proposed terminal has been designed with a peak capacity of up to 1.5 Bcf per day and would be located in the town of Warrenton, Oregon. Oregon LNG's affiliate, Oregon Pipeline Company, L.L.C. (Oregon Pipeline Company) filed an application for a Certificate of Public Convenience and Necessity to construct own and operate a 121-mile long, 36-inch diameter natural gas pipeline. The pipeline facilities described in Oregon Pipeline Company's application will extend from Oregon LNG's proposed terminal near Molalla, Oregon to interconnections with the natural gas facilities of Northwest Natural Gas Company and Williams Northwest Pipeline Company. The pipeline has been designed with a peak deliverability of up to 1.5 Bcf per day.⁴¹⁷

On April 24, 2007, pursuant to the PAWSA⁴¹⁸ and Section 127.009 of the Coast Guard's regulations,⁴¹⁹ the Captain of the Port, Sector Portland, issued a LOR which determined the suitability of LNG vessel transits as proposed by Oregon LNG along the Columbia River.⁴²⁰ The LOR discussed the Captain of the Port's review of the safety and security risks posed by the project and the mitigation measures proposed in the Waterway Suitability Assessment submitted by Oregon LNG in March 2008. The LOR concluded that the "applicable portions of the Columbia River and its approaches are not currently suitable, but could be made suitable for the type and frequency of LNG marine traffic associated with this project," provided that the mitigation measures proposed in

413. *Id.* at 2.

414. Final Environmental Impact Statement, Docket Nos. CP07-441-000, *et al.* (May 1, 2009) [hereinafter, *Jordan Cove FEIS*].

415. *Id.* at 5-1.

416. Notice of Application, Docket No. CP09-6-000, at 1 (Oct. 27, 2008).

417. *Id.*

418. 33 U.S.C. §§ 1221-1236 (2009).

419. 33 C.F.R. § 127.009 (2009).

420. Letter of Recommendation from F.G. Myer, Captain of the Port, Sector Portland to Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission (Apr. 24, 2009).

the WSA and other measures proposed by the analysis accompanying the LOR are implemented.⁴²¹

d. Weaver's Cove LNG

On July 15, 2005, the FERC authorized Weaver's Cove Energy, L.L.C. (Weaver's Cove) to construct and operate an LNG terminal in Fall River, Massachusetts with a peak send-out capacity of 800 MMcf of natural gas per day.⁴²² The terminal as currently authorized would incorporate marine berthing facilities to unload LNG cargos from ocean-going vessels at the site of the proposed terminal along the Taunton River.⁴²³ On January 30, 2009, Weaver's Cove filed an application under Section 3 of the NGA to amend its authorization to permit the construction of an offshore berth for receiving and unloading LNG in Mount Hope Bay in Massachusetts.⁴²⁴ This proposal is an alternative to the shore-side berthing facilities proposed along the Taunton River in Weaver's Cove's previous application. An LNG transfer system containing four-mile, cryogenic LNG transfer lines, would transfer LNG from the offshore berth in Mount Hope Bay to the Fall River terminal. The transfer system would be buried beneath the seabed of Mount Hope Bay and the Taunton River. The LNG transfer lines will utilize an insulated "pipe-in-pipe" technology to transfer LNG from the offshore berth to the LNG terminal.⁴²⁵

3. Projects at Pre-Filing Stage

a. Calais LNG

On November 20, 2008, the FERC issued a Notice of Intent to Prepare an Environmental Impact Statement for the Calais LNG Project proposed by the Calais LNG Project Company (Calais).⁴²⁶ The project as described in the Notice would consist of an onshore LNG import terminal along the St. Croix River in Washington County, Maine. The project would also include an associated 36-inch natural gas pipeline extending approximately 20.5 miles from the proposed terminal to the existing facilities of Maritimes & Northeast Pipeline, L.L.C. (M&NE) in Princeton, Maine.⁴²⁷ The proposed terminal and associated pipeline facilities would be capable of achieving a peak send-out capacity of 1.0 Bcf per day. It is estimated that M&NE will have to add an additional 233.4 miles of 36-inch pipeline looping and additional compression facilities in order to accommodate the vaporized LNG expected from the Calais terminal.⁴²⁸ "Although M&NE is not proposing to construct these facilities and does not

421. *Id.* at 1-2.

422. *Weaver's Cove Energy, L.L.C.*, 112 F.E.R.C. ¶ 61,070, at 9 (2005).

423. *Id.*

424. Notice of Filing, Docket No. CP04-36-005, at 1 (Feb. 11, 2009).

425. *Id.*

426. Notice of Intent to Prepare an Env'tl. Impact Statement for the Calais LNG Project, Request for Comments on Env'tl. Issues, and Notice of Public Scoping Meeting, Docket No. PF08-24-000 (Jun 6, 2009).

427. *Id.*

428. *Id.*

have an application before the FERC, these expanded M&NE facilities are likely a necessary part of the [Calais] project.⁴²⁹

4. Offshore LNG Projects

a. Bienville Offshore Energy Terminal

On January 12, 2006, TORP Terminal, L.P., filed an application with the U.S. Coast Guard and the Maritime Administration (MARAD) for authorization to construct an offshore LNG receiving terminal under the Deepwater Port Act of 1974 (DPA).⁴³⁰ The proposed facility, the Bienville Offshore Energy Terminal (Bienville Project), was proposed to be located in the federal waters of the Outer Continental Shelf, approximately sixty-three miles south of Mobile Point, Alabama.⁴³¹ The terminal was designed to send out an average of 1.2 Bcf of vaporized LNG per day to interconnections on the existing facilities of Dauphin Island Gathering System, Transco, Destin Pipeline Company, L.L.C., and Viosca Knoll Gathering System.⁴³²

On October 9, 2008, TORP Terminal, L.P. informed the U.S. Coast Guard and MARAD that it was withdrawing its application for authorization to construct the Bienville Project pursuant to 33 C.F.R. § 148.213.⁴³³ TORP Terminal, L.P. cited several environmental concerns raised by the National Oceanic and Atmospheric Administration (NOAA) and the lack of sufficient time to address such concerns before the expiration of the statutory time period for the Governor of Alabama to approve or disapprove the Bienville Project.⁴³⁴ Under Section 9(b) of the DPA, the MARAD may not issue an authorization for the construction of a deepwater port if the project is disapproved by the governor of an "Adjacent Coastal State."⁴³⁵ TORP Terminal, L.P. noted that withdrawal of its application would give it additional time to consider possible modifications to the Bienville Project.⁴³⁶

b. Calypso LNG

On March 1, 2006, Calypso LNG, L.L.C. (Calypso) filed an application under the DPA with the U.S. Coast Guard and the MARAD for authorization to

429. *Id.*

430. 33 U.S.C. §§ 1501-1524 (2009).

431. *TORP Terminal, L.P., Bienville Offshore Energy Terminal Liquefied Natural Gas Deepwater Port License Application*, 71 Fed. Reg. 26,605-6 (May 5, 2006).

432. *Id.*

433. Letter from Joseph P. Berno, Chief Executive Officer, TORP Terminal, L.P., to Sean T. Connaughton, Administrator, Maritime Administration, MARAD Docket No. USCG-2006-24644 (Oct. 9, 2008) [hereinafter, *Bienville Withdrawal*].

434. *Id.* at 1. Under Section 9 of the DPA, if a governor of an Adjacent Coastal State has not transmitted his decision whether to approve or disapprove of a project within 45 days following the final public hearing on the project application, the state's approval is legally presumed. 33 U.S.C. § 1508(b) (2009).

435. 33 U.S.C. § 1508(b) (2009). An "Adjacent Coastal State" is defined as "any coastal State which (A) would be directly connected by pipeline to a deepwater port as proposed in an application, or (B) would be located within 15 miles of any such proposed deepwater port." *Id.* § 1508(a). The state of Alabama was designated as an Adjacent Coastal State in the notice of the project published by MARAD in the Federal Register. 71 Fed. Reg. at 26,606 (May 5, 2006).

436. *Bienville Withdrawal*, *supra* note 434, at 1.

construct and operate an offshore LNG terminal. The proposed terminal would be located in federal waters in the Outer Continental Shelf ten miles off the coast of Florida, near Port Everglades.⁴³⁷ The offshore LNG terminal would be connected to the facilities of Calypso U.S. Pipeline, L.L.C., a proposed interstate natural gas pipeline under the jurisdiction of the FERC. The Calypso terminal was designed with a peak delivery capacity of 1.9 Bcf of vaporized LNG per day.⁴³⁸

On February 25, 2009, Calypso sent a letter to the U.S. Coast Guard and MARAD informing the agencies of its intention to suspend its application for authorization to construct the offshore LNG terminal.⁴³⁹ The letter cited “recent comments made by the Governor of Florida,” as the basis for the withdrawal of the application.⁴⁴⁰ Reports indicate that the Governor of Florida was prepared to disapprove of the project pursuant to his authority as the governor of an “Adjacent Coastal State” under Section 9(b) of the DPA.⁴⁴¹ Calypso’s letter concluded with the statement that it “hope[s] with the passage of time and further dialogue with interested parties that [Calypso’s parent company] will again submit a License application to the Maritime Administration so that we might be able to bring this worthy Project to the people of Florida.”⁴⁴²

c. Safe Harbor

On May 8, 2007, Atlantic Sea Island Group, L.L.C. (ASIG) filed an application with the U.S. Coast Guard and the MARAD for authorization to construct, own, and operate an offshore LNG terminal, known as the “Safe Harbor Energy” project, located approximately 13.5 miles south of Long Beach, New York, nineteen miles east of Highlands, New Jersey, and twenty-three miles southeast of the Ports of New York and New Jersey.⁴⁴³ The terminal would be connected to the interstate natural gas facilities of Transco by a 36-inch subsea pipeline extending 12.6 miles. The Safe Harbor Energy project was designed with an average send-out capacity of 1.15 Bcf per day.⁴⁴⁴

Under the DPA, a state may have “Adjacent Coastal State” status, thus granting the state an effective veto over the project in several ways. A state is entitled to status as an Adjacent Coastal State if it “would be directly connected by pipeline to a deepwater port as proposed in an application,” or if it “would be located within 15 miles of any such proposed deepwater port.”⁴⁴⁵ The DPA also

437. *Calypso LNG, L.L.C., Calypso Liquefied Natural Gas Deepwater Port License Application*, 71 Fed. Reg. 65,031 (Nov. 6, 2006)

438. *Id.* at 65,032.

439. Letter from Claibourne L. Harris, President & Chief Executive Officer, Calypso LNG, L.L.C., to Yvette M. Fields, Director, Office of Deepwater Ports and Offshore Activities, Maritime Administration, MARAD Docket No. USCG-2006-26009 (Feb. 25, 2009) [hereinafter, *Calypso Withdrawal*].

440. *Id.*

441. See, e.g., Amy Sherman & Beth Reinhard, *Gov. Charlie Crist Opposes Pipeline off Fort Lauderdale*, MIAMI HERALD, Feb. 19, 2009, at B1; *Governor Rejects Natural Gas Project*, SO. FLA. SUN-SENTINEL, Feb. 26, 2009, at 17.

442. *Calypso Withdrawal*, *supra* note 440, at 2.

443. *Atlantic Sea Island Group, L.L.C., Safe Harbor Energy Liquefied Natural Gas Deepwater Port License Application*, 72 Fed. Reg. 49,041 (Aug. 27, 2007).

444. *Id.* at 49,042.

445. 33 U.S.C. § 1508(a)(1) (2009).

provides the Secretary of Transportation the authority, exercised through the MARAD Administrator, to grant Adjacent Coastal State status if, after reviewing recommendations made by the NOAA, “he determines that there is a risk of damage to the coastal environment of such State equal to or greater than the risk posed to a State directly connected by pipeline to the proposed deepwater port.”⁴⁴⁶ Section 9(a)(2) of the DPA directs the Secretary of Transportation through the MARAD Administrator to render a determination whether to designate a requesting state as an Adjacent Coastal State “not later than the 45th day after the date he receives such a request from a State.”⁴⁴⁷

In the Federal Register notice announcing the receipt of ASIG’s application to the U.S. Coast Guard and the MARAD, the state of New York was designated as an Adjacent Coastal State. On September 6, 2007, the state of New Jersey filed a request with the MARAD Administrator seeking to be designated as an additional Adjacent Coastal State under the discretionary authority granted to the Secretary of Transportation under Section 9(a)(2) of the DPA. After consulting the NOAA, the MARAD Administrator issued a letter to the Governor of New Jersey on November 2, 2007, informing him that New Jersey would be granted Adjacent Coastal State status for the purposes of reviewing ASIG’s application. ASIG petitioned the MARAD Administrator for reconsideration of his November 2 decision. In a letter dated February 8, 2008, the MARAD Administrator denied ASIG’s request for reconsideration of the decision.

Thereafter, ASIG brought suit in the Federal District Court for the District of Columbia challenging the MARAD Administrator’s decision to designate New Jersey as an Adjacent Coastal State, on the grounds that, among other things, “the agency record did not contain factual evidence that supported the conclusion” to designate New Jersey as an Adjacent Coastal State and that the Administrator’s decision was “arbitrary and capricious” under the Administrative Procedure Act.⁴⁴⁸ ASIG also argued that since the MARAD Administrator had not issued a decision until after the expiration of the 45-day time limit for making such a decision as set forth in the statute, the Administrator was therefore precluded from exercising any authority to issue such a determination.⁴⁴⁹ The District Court for the District of Columbia upheld the agency’s decision to permit New Jersey to become an Adjacent Coastal State for the purposes of evaluating ASIG’s application. The court found that, although the initial November 2, 2007 decision did not itself constitute a reasoned basis upon which the Administrator’s actions could be sustained, the analysis provided in the February 8, 2008 letter denying ASIG’s request for consideration “reflect[ed] a full consideration of the merits of the designation.”⁴⁵⁰ Regarding the MARAD Administrator’s failure to issue a decision within the statutorily directed forty-five day time limit, the court noted that since the statute did not provide any specific consequences for the agency’s failure to meet the deadline, the proper remedy was an order directing the agency to complete the task contemplated by the statute rather than stripping the agency of its authority to act.

446. *Id.* at § 1508(a)(2) (2009).

447. *Id.*

448. *Atlantic Sea Island Group, L.L.C. v. Connaughton*, 592 F. Supp. 2d 1, 12 (D.D.C. 2008).

449. *Id.* at 11-12.

450. *Id.* at 14.

Since the Administrator had already issued a decision, the court held that ASIG was without a legal remedy.⁴⁵¹

5. Major Regulatory Changes

On March 18, 2009, the U.S. Coast Guard published Navigation and Vessel Inspection Circular (NVIC) 05-08 amending the internal procedures that the agency will follow when fulfilling its obligation to issue LORs for onshore LNG terminals under the PAWSA and Part 127 of the Coast Guard's regulations.⁴⁵² NVICs are non-binding, legal documents that provide guidance for Coast Guard personnel in carrying out the agency's responsibilities under federal law and the agency's regulations. NVIC 05-08 supersedes NVIC 05-05, which had previously served as the primary guidance for the conduct of the LOR process required by the PAWSA for LNG terminals.

Relative to the previous guidance set forth in NVIC 05-05, NVIC 05-08 provides a more clear and complete description of the process that will be followed by the Coast Guard and the FERC when reviewing applications for the construction of LNG terminals. The document establishes a more precise timeframe for the Coast Guard's review, requiring that the agency's LOR be submitted prior to the FERC's issuance of its draft documentation under the National Environmental Policy Act (NEPA).⁴⁵³ The new policy established under NVIC 05-08 requires certain additional information to be submitted by the applicant to the agency during its review process. NVIC 05-08 also provides more detailed guidance on the necessary contents of the documents required to be issued by the agency in response to a request for an LOR. Finally, NVIC 05-08 requires Captains of the Port, in processing an application, to retain a file composed of all relevant documents issued and received by the agency in connection with an LNG project.

On April 28, 2009, the Coast Guard issued a notice of proposed rulemaking (NPRM) proposing to amend the agency regulations governing the processing and review of LORs by applicants proposing to construct onshore LNG terminals.⁴⁵⁴ The NPRM would amend 33 C.F.R. Part 127, the Coast Guard's regulations implementing the provisions of the PAWSA. The Coast Guard's stated purpose in issuing the NPRM was to "harmonize the Coast Guard's regulations for LNG with those established by the [FERC]."⁴⁵⁵ Specifically, the NPRM amends 18 C.F.R. § 127.007 to require the submission of certain information by an applicant seeking authorization from the FERC to construct an LNG facility. The proposed regulations also provide a specific timeframe for the submission of required information to correspond to the requirements currently in force under the FERC's regulations at 18 C.F.R. Parts 153 and 157.

451. *Id.* at 12.

452. U.S. Coast Guard, Navigation and Vessel Inspection Circular 05-08, Guidance Related to Waterfront Liquefied Natural Gas (LNG) Facilities (Mar. 18, 2009).

453. *Id.* at 1-4.

454. *Revision of LNG & LHG Waterfront Facility Gen. Requirements*, 74 Fed. Reg. 19,158 (Apr. 28, 2009).

455. *Id.*

6. Other Developments

On March 20, 2008, the FERC issued an order authorizing Broadwater Energy L.L.C. (Broadwater) under Section 3 of the NGA to construct, own, and operate an LNG terminal in Long Island Sound.⁴⁵⁶ The Broadwater LNG terminal was designed to provide up to 1.25 Bcf of vaporized LNG per day through a subsea interconnection with the facilities of Iroquois Gas Transmission System.⁴⁵⁷ In addition to the authorization it received from the FERC under the NGA, before it may begin construction of its proposed LNG terminal, Broadwater is required to obtain all other necessary federal authorizations. Specifically, Broadwater must obtain a concurrence from the New York State Department of State (NYSDOS) that the proposed activity in Long Island Sound is consistent with the policies of the state's federally-approved Coastal Zone Management Program pursuant to the CZMA.⁴⁵⁸

Under the CZMA, an applicant for a federal license or permit that "affect[s] any land or water use or natural resource of the coastal zone" of a state covered by the statute must submit a certification that the issuance of the proposed federal license or permit is consistent with the Coastal Zone Management Program approved by the NOAA and enforced by the state.⁴⁵⁹ If the state agency responsible for administering the state's Coastal Zone Management Program objects to an applicant's consistency certification, the subject federal permit or license may not be issued for the project. However, the statute provides that the Secretary of Commerce may override the state's objection if the Secretary determines that the proposed "activity is consistent with the objectives of [the CZMA] or is otherwise necessary in the interest of national security."⁴⁶⁰

Broadwater submitted its consistency certification to the NYSDOS, and the agency began its review of the certification on November 17, 2006. On April 10, 2008, the NYSDOS issued a letter informing Broadwater that the agency objected to the company's certification that its proposed activity was consistent with the policies of New York's Coastal Zone Management Program.⁴⁶¹ In issuing its objection, the NYSDOS cited, among other things, the safety and security risks posed by the location of the proposed LNG terminal near a populated area and the impacts on the views, character, and natural habitat in and around Long Island Sound.⁴⁶² On June 6, 2008, Broadwater petitioned the Secretary of Commerce to override the state's objection under 16 U.S.C. § 1456(c)(3)(A).

On April 13, 2009, the Secretary of Commerce issued a decision denying Broadwater's request to override the NYSDOS's objection to the project.⁴⁶³ In issuing his decision, the Secretary found that Broadwater had not established that

456. *Broadwater Energy, L.L.C.*, 122 F.E.R.C. ¶ 61,255; *reh'g denied*, 124 F.E.R.C. ¶ 61,225 (2008).

457. 122 F.E.R.C. ¶ 61,255, at 1.

458. 16 U.S.C. § 1456(c)(3)(A) (2009).

459. *Id.*

460. *Id.*

461. Letter from Lorraine Cortez-Vasquez, New York Secretary of State to Jimmy Culp, Commercial Manager, Broadwater Energy, L.L.C. (April 8, 2008).

462. *Id.* at 2.

463. U.S. Secretary of Commerce, Decision and Findings in the Consistency Appeal of Broadwater Energy, L.L.C. and Broadwater Pipeline, L.L.C. from an Objection by the State of New York (April 13, 2009).

its project was consistent with the objectives of the CZMA by demonstrating that the national interest furthered by the construction and operation of its LNG terminal outweighs the adverse coastal effects posed by the project.⁴⁶⁴ Likewise, the Secretary found that Broadwater had not demonstrated that its LNG terminal was required in the interests of national security. Unless the Secretary of Commerce's decision is reversed by a reviewing federal court, the authorizations issued by the FERC under the NGA may not go into effect, and thus the Broadwater LNG terminal may not be constructed under its current configuration.

IX. STATE REVENUE DECOUPLING AND ENERGY EFFICIENCY DEVELOPMENTS

As discussed in the 2008 Natural Gas Committee Report, there has been a steady increase in the number of state utility commissions recognizing and endorsing ratemaking approaches that “decouple” a utility's sales from its revenues.⁴⁶⁵ Since 2002 the number of state commissions that have approved revenue decoupling mechanisms for LDCs has dramatically risen, and since 2008 more have approved or considered such mechanisms. A key factor leading to this rise has been the increased importance placed upon energy efficiency. Energy efficiency is no longer viewed simply as a means for customers to reduce their monthly utility bills. Instead, energy efficiency is now widely considered as a viable energy resource and is receiving increased attention on both state and national levels. Moreover, energy efficiency is viewed as a key component to reducing carbon emissions.

The increased importance of energy efficiency has posed regulatory challenges for state commissions. In particular, traditional rate regulation may serve as a barrier to energy efficiency reaching its full capabilities as an energy resource. Traditional cost of service rate regulation may deter LDCs from promoting end-use efficiency because utility revenues are directly tied to the throughput of gas sold. To remove this potential barrier and to encourage utility sponsored energy efficiency programs, a growing number of states have investigated and approved alternative approaches to align their utilities' financial interests with the delivery of cost effective energy efficiency programs. Decoupling has become one of the primary tools being used by state commissions to make utilities indifferent to sales variations and thereby allowing utilities to promote energy efficiency programs without concern of adversely affecting their revenues.

Decoupling typically refers to the regulatory mechanisms by which a natural gas utility has an opportunity to recover the fixed costs (including income) found “just and reasonable” in a rate proceeding on a basis other than its customers' consumption of therms of gas. That is, under decoupling, utilities collect revenues based upon the regulatory determined revenue requirement and then the revenue requirement is divided by expected sales. Then, on a pre-determined basis, the utility's prices are re-set to collect a target revenue based on actual sales volumes. These regulated adjustments can be designed to occur on a monthly or quarterly basis, or at some other regular interval. By separating

464. *Id.* at 2.

465. Report of the Natural Gas Regulation Committee, 29 ENERGY L.J. 711, 715 (2008).

a utility's revenues from changes in sales, the utilities' incentive to maximize their sales is eliminated because their rate of return does not change within the set revenue requirement.

As more national and state programs promote the use of energy efficiency measures as an energy resource, more states and utilities have employed decoupling mechanisms. As of May 2009, seventeen states have approved LDC revenue decoupling mechanisms as part of an individual utility proceeding, through legislation or via statewide initiatives. In addition, four other states have pending revenue decoupling proposals. A list of approved and pending decoupling mechanisms as of May 29, 2009 is provided below.⁴⁶⁶

466. American Gas Association, *available at* <http://www.aga.org/Legislative/RatesRegulatoryIssues/ratesregpolicy/Issues/Decoupling> (last visited Sept. 20, 2009).

APPROVED – 29 Companies, 17 States, 20 Million Res. Customers			
	Utility	State	Case Number
1.	Arkansas Oklahoma	AR	Docket No. 06-026-U
2.	Arkansas Western	AR	Docket No. 06-124-U
3.	CenterPoint Energy	AR	Docket No. 06-161-U
4.	Pacific Gas and Electric	CA	Application No. 02-02-012
5.	San Diego Gas and Elec.	CA	Application No. 02-02-012
6.	Southern California Gas	CA	Application No. 02-02-012
7.	Southwest Gas	CA	Application No. 02-02-012
8.	Public Service Co. of Colorado	CO	Docket No. 06-656-G
9.	Integrys – Peoples Gas	IL	Docket No. 07-0242
10.	Integrys – North Shore Gas	IL	Docket No. 07-0241
11.	Citizens Energy Group	IN	IURC Cause No. 42767
12.	Vectren Indiana Gas	IN	IURC Cause No. 42943
13.	Vectren Southern Indiana Gas	IN	IURC Cause No. 42943
14.	Baltimore Gas and Elec.	MD	Case No. 8780
15.	Washington Gas	MD	Case No. 8990
16.	New Jersey Natural Gas	NJ	Docket No. GR05121020
17.	South Jersey Gas	NJ	Docket No. GR05121020
18.	Consolidated Edison	NY	Case No. 06-G-1332
19.	National Fuel Gas Dist.	NY	Case No. 07-G-0141
20.	Piedmont Natural Gas	NC	Docket G-9, Sub. 499, G-9, Sub. 461, G-44, Sub. 15
21.	Public Service Co. of North Carolina	NC	Docket G-5, Sub. 495
22.	Vectren Ohio	OH	Case No. 05-1444-GA-UNC
23.	Cascade Natural Gas	OR	Docket UG-167
24.	NW Natural Gas	OR	Docket UG-143
25.	Questar Gas	UT	Docket No. 05-057-T01
26.	Virginia Natural Gas	VA	PUE-2008-00060
27.	Avista	WA	Docket No. UG-060518
28.	Cascade Natural Gas	WA	Docket No. UG-060256
29.	Questar Gas	WY	Docket No. 30010-94-6R-08

PENDING – 13 Companies, 4 Additional States, 6 Million Res. Customers			
	Utility	State	Case Number
1.	Connecticut Natural Gas	CT	Docket No. 08-12-06
2.	Southern Connecticut Gas	CT	Docket No. 08-08-17
3.	Bay State Gas	MA	Docket No. D.P.U 09-30
4.	New England Gas	MA	Docket No. D.P.U. 08-35
5.	Consumers Energy	MI	Case No. U-15506
6.	CenterPoint Minnesota Gas	MN	Docket No. G- 008/GR08-1075
7.	Southwest Gas	NV	Docket No. 09-04003
8.	Pivotal Utility Holdings	NJ	Docket No. GR09030195
9.	Central Hudson Gas & Electric	NY	Case No. 08-G-0888
10.	National Grid Niagara Mohawk	NY	Case No. 08-G-0609
11.	Orange and Rockland Utilities	NY	Case No. 08-G-1398
12.	NW Natural Gas	WA	Docket No. UG- 080546
13.	Integrus – Wisconsin Public Service Co.	WI	Docket No. 6690- UR-119

The focus on expanding the role of energy efficiency is likely to continue for the foreseeable future. Specifically, Section 410(a) of the *American Recovery and Reinvestment Act of 2009*⁴⁶⁷ (ARRA) provides:

The Secretary shall make grants under this section in excess of the base allocation established for a State under regulations issued pursuant to the authorization provided in Section 365(f) of such Act only if the governor of the recipient State notifies the Secretary of Energy in writing that the governor has obtained necessary assurances that each of the following will occur:

(1) The applicable State regulatory authority will seek to implement, in appropriate proceedings for each electric and gas utility, with respect to which the State regulatory authority has ratemaking authority, a general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently and that provide timely cost recovery and a timely earnings opportunity for utilities associated with cost-effective measurable and verifiable efficiency savings, in a way that sustains or enhances utility customers' incentives to use energy more efficiently.⁴⁶⁸

467. *American Recovery and Reinvestment Act of 2009*, Pub. L. No. 111-5 § 410(a), 123 Stat. 115 (2009).

468. *Id.* at § 410(a).

Under this provision, those state utility commissions that have not yet approved revenue decoupling may need to open investigations regarding policies and actions that should be implemented to ensure compliance with the requirements of Section 410(a) of the ARRA. Such measures could include revenue decoupling and other steps that have the potential to encourage utility energy efficiency and conservation while ensuring the financial viability of the utilities.⁴⁶⁹

Other recent federal legislative initiatives are likely to affect state policies as to energy efficiency. For example, on June 26, 2009, the U.S. House of Representatives approved the *American Clean Energy and Security Act* (ACES Act).⁴⁷⁰ The ACES Act, as passed by the House of Representatives, provides in Section 784 that no less than one third of the carbon emission allowances distributed to LDCs be used for cost-effective energy efficiency programs for natural gas consumers.⁴⁷¹ Although passage of the bill, and the final contents of the bill, remain uncertain, it is clear that energy efficiency measures and revenue decoupling will continue to be focal issues for state commissions and LDCs.

469. *E.g., Compliance of Commonwealth of Pennsylvania with Section 410(a) of the American Recovery and Reinvestment Act of 2009*, Docket No. I-2009-2099881 (May 16, 2009).

470. H.R. 2454, 111th Cong. (2009).

471. *Id.*

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John A. Eckstein	John R. Morris
Joseph H. Fagan	Paula K. Motzel
Russell A. Feingold	S. Diane Neal
James G. Flaherty	Karol Lyn Newman
Michael J. Fremuth	Brian D. O'Neill
Jeffrey L. Futter	Adina Owen
Kirstin E. Gibbs	Jeffrey M. Petrash
Susan W. Ginsberg	Robert C. Platt
Marvin T. Griff	William E. Rice
Christopher Gulick	Randall S. Rich
John R. Hays, Jr.	Janice E. Rogers
Thomas E. Hirsch, III	Richard G. Smead
Marcia C. Hooks	Andrew K. Soto
Kenneth W. Irvin	Zackary Starbird
Barbara S. Jost	Justin Stuhldreher
Leslie Idom Kalmbach	Kevin M. Sweeney
James R. Lacey	Thomas P. Thackston
Karin L. Larson	Peter I. Trombley
William S. Lavarco	Andrea C. Wolfman
Jason F. Leif	Joel A. Youngblood
Steven H. Levine	Joel F. Zipp
Leslie E. LoBaugh, Jr.	