REPORT OF THE JUDICIAL REVIEW COMMITTEE

This report sumarizes cases reviewing decisions made by the Federal Energy Regulatory Commission. The time frame covered by this report is January 2007 to December 2007.

I. ADMINISTRATIVE LAW

A. Ripeness

The Federal Energy Regulatory Commission (FERC or the Commission), as lead federal agency in authorizing LNG facilities, issued a conditional authorization to Weaver's Cove Energy, LLC (WCE) to site, construct, and operate a liquefied natural gas (LNG) terminal in Fall River, Massachusetts.[1] The FERC conditioned its approval on (1) approval by the U.S. Coast Guard (USCG) of WCE's transportation plan and (2) the Department of Interior finding that the project would not have a substantial adverse effect on the Taunton River's potential designation as a Wild and Scenic River.[2] Opponents of the LNG terminal appealed the FERC's order.[3] The Court declined "to review the merits of FERC's conditional project approval because it [was] not yet ripe for review."[4] Noting that the "ripeness doctrine is designed to prevent courts from entangling themselves in abstract disagreements . . .' and from improperly interfering in the administrative decision-making process,"[5] the Court stated, "WCE's proposed LNG project may well never go forward because FERC's approval of the project is expressly conditioned on approval by the USCG and the DOI."[6]

B. Choice of Law

Southern California Edison Company (SCE) contracted with Corona, California (Corona) to construct interconnection facilities and provide wholesale distribution service and filed the agreements with the FERC.[7] The agreements required Corona to pay SCE for the interconnection facilities and for SCE to determine the actual cost of the facilities and provide Corona with a final invoice within twelve months of the in-service date.[8] Twenty months after the contract deadline, SCE filed revised tariff sheets to collect interconnection facility costs for which it had never provided a final invoice.[9] The FERC concluded that SCE's revised tariff sheets were contrary to the contract and rejected them.[10] The contract included a choice of law provision that provided, "[e]xcept as otherwise provided by federal law, this Agreement shall be governed by and construed in accordance with, the laws of the state of California."[11] SCE requested rehearing, asserting that the FERC should have analyzed the contract under California law, and argued that its failure to provide a timely invoice was not a material breach justifying Corona's failure to pay for the interconnections facilities.[12] The FERC determined that it was appropriate to apply its precedent because SCE's request involved interpreting a jurisdictional agreement on file with the FERC and rejected SCE's arguments regarding the results about the outcome under California law as irrelevant and a red herring.[13] SCE sought

1. *Weaver's Cove Energy, LLC*, 112 F.E.R.C. ¶ 61,070 at P 112 (2005).
2. City of Fall River, Massachusetts v. FERC, 507 F.3d 1, 4-5 (1st Cir. 2007).
3. *Id.* at 3.
4. *Id.* at 6.
5. *Id*. (internal quotation marks and citations omitted).
6. *Id.* at 7.
7. Notice of Filing, *Detroit Edison Co., et al.; Electric Rate and Corporate Filings*, 68 Fed. Reg. 7360, 7361 (2003).
8. Southern Cal. Edison Co. v. FERC, 502 F.3d 176, 177 (D.C. Cir. 2007).
9. *Southern Cal. Edison Co.*, 113 F.E.R.C. ¶ 61,018 at P 1 (2005).
10. *Id*. at P 12.
11. *Southern Cal. Edison Co.*, 502 F.3d at 178.
12. *Southern Cal. Edison Co.*, 115 F.E.R.C. ¶ 61,100 at P 1 (2006).
13. *Id*. at P 11.

judicial review of the FERC's orders.[14] The Court stated, "[t]hus, FERC appears to have selected federal law over California law simply because the Agreement was filed with the Commission, without identifying any difference between federal and California law to justify [the] selection under the [except as otherwise provided by federal law] clause of the choice of law provision."[15] The Court ruled that the FERC must give effect to the unambiguous intent of the parties and that filing of the agreement did not alter the obligation to apply state law[16] and remanded the matter to the FERC to enforce the choice of law provision.[17]

C. *Agency Reasoning*

In *Connecticut Dept. of Public Utility Control v. FERC*,[18] ISO New England, Inc. filed an installed capacity requirement (ICR) at the FERC under section 205 of the Federal Power Act. The Connecticut Department of Public Utility Control (CDPUC) intervened in the section 205 proceeding and asserted that the FERC lacked statutory authority to regulate generation resource adequacy.[19] In both its initial order and its order denying rehearing, the FERC ruled that the ISO tariff and an agreement between participating utilities granted it the jurisdiction to accept the ICR.[20] The CDPUC sought judicial review. The FERC abandoned its reliance on the ISO tariff as a source of statutory authority and argued that section 201 of the Federal Power Act permitted it to regulate generation resource adequacy.[21] The Court rejected the FERC's arguments as "appellate counsel's *post hoc* rationalizations for agency action" and remanded the matter for further proceedings consistent with its opinion.[22]

D. *Filed Rate Doctrine*

1. Failure to File Calculation Method

The New York State Reliability Council (NYSRC) set the reliability reserve margin based on installed capacity (ICAP).[23] The New York Independent System Operator (NYISO) enforced the NYSRC standard by requiring load-serving entities (LSE) to purchase capacity in accordance with filed tariff provisions.[24] In 2001, NYISO changed LSE's capacity purchase requirement from ICAP to unforced capacity (UCAP) by applying forced outage adjustments.[25] NYISO used different forced outage factors to convert LSE's ICAP requirement to a UCAP requirement than it used to convert a generator's

14. *Southern Cal. Edison Co.*, 502 F.3d at 177.
15. *Id.* at 181.
16. *Id*.
17. *Id.* at 182.
18. Connecticut Dep't of Pub. Util. Control v. FERC, 484 F.3d 558, 559 (D.C. Cir. 2007).
19. *Id*. at 560.
20. *Id*.
21. *Id*.
22. *Id*. at 560-561.
23. Keyspan-Ravenswood, LLC v. FERC, 474 F.3d 804, 806 (D.C. Cir. 2007).
24. *Id.* at 807-808.
25. *Id*. at 807.

ICAP to UCAP resulting in a reduction of capacity that LSEs had to purchase.[26] Keyspan-Ravenswood filed a complaint with the FERC asserting that NYISO had violated the filed-rate doctrine by failing to enforce NYSRC's ICAP reliability margin.[27] The FERC rejected Keyspan-Ravenswood's complaint stating "the rates charged by NYISO . . . conformed with the Commission's applicable orders governing NYISO's ICAP and UCAP requirements, and were consistent with NYISO's then-effective tariffs, rate schedules and manuals."[28]

Keyspan-Ravenswood requested rehearing arguing that the FERC's UCAP Orders were irrelevant and that the ICAP manual relied on by the FERC could not cure a violation of the filed rate doctrine because the manual had never been filed with the FERC.[29] The FERC denied rehearing for slightly different reasons, deemphasizing the UCAP Orders, minimizing the reliance on the ICAP Manual, and introducing an alternative ground that Keyspan-Ravenswood had failed to prove its injury sufficiently.[30] The Court described as undisputed that NYISO had a filed obligation to enforce NYSRC's installed capacity requirements, that NYISO effectively reduced the quantity of installed capacity purchased, and that NYISO never filed its translation methodology and concluded that the FERC acted arbitrarily and capriciously in ruling NYISO had not violated the filed rate doctrine.[31] The Court found unpersuasive the FERC's arguments that nothing expressly spelled out the methodology to be used, that the ICAP manual had been incorporated into the tariff by reference, that a requirement to file the translation methodology went beyond the rule of reason, and that NYISO's violation should be excused.[32]

2. Negotiated Rates

The ISO New England tariff contains market rules that provide for the determination of amounts paid to out-of-merit generators required to operate due to transmission constraints.[33] Market Rule 17 provides certain rates that out-of-merit generators would be paid in the absence of a negotiated agreement between the generator and ISO New England.[34] Market Rule 17.3.3(b) allows ISO New England to pay an agreed upon rate to out-of-merit generators.[35] NSTAR sought refund of amounts paid for negotiated rates that exceeded the rates specified in Market Rule 17, contending that (1) the FERC arbitrarily and capriciously waived the sixty day notice rule of section 205 of the Federal Power Act, (2) the FERC's orders violated the filed rate doctrine by allowing negotiated rate agreements to govern rates charged prior to their being filed, (3) the FERC did not determine that the filed rates were just and reasonable, and (4) the FERC's

26. *Id*.

27. *Id*. at 809.

28. *Id.* at 808-809 (quoting Keyspan-Ravenswood, LLC v. N.Y. Indpep. Sys. Operator, 110 F.E.R.C. ¶ 61,116 at P 2 (2005) (internal quotations omitted, ellipsis in original)).

29. *Keyspan-Ravenswood*, 474 F.3d at 809.

30. *Id*.

31. *Id*. at 810.

32. *Id.* at 810-811.

33. NSTAR Elec. & Gas Corp. v. FERC, 481 F.3d 794, 797 (D.C. Cir. 2007).

34. *Id.* at 796-98.

35. *Id*. at 797.

refusal to order refunds was an abuse of discretion.[36] The Court upheld the sixty day notice waiver.[37] The Court stated the filed rate doctrine is satisfied "when parties have notice that a rate is tentative and may be later adjusted with retroactive effect. . . ."[38] The Court found that ISO New England's authority to negotiate rate agreements "was part of a filed and accepted tariff and market participants were on notice of its provisions."[39] The Court ruled that ISO New England did not violate the filed rate doctrine[40] and that the FERC failed to satisfy its statutory obligation to ensure that rates are just and reasonable, and remanded to the FERC for additional consideration of the issue.[41]

E. Standard of Review

Columbia Gas Transmission Corp. and Columbia Gulf Transmission Co. (Columbia) agreed to provide discounted service to several local distribution companies (LDCs) on the condition that the LDCs waived their rights under section 5 of the Natural Gas Act to challenge any rates for any Columbia services.[42] The FERC rejected the agreements on the basis that the section 5 waivers were too broad.[43] The FERC also denied Columbia's petition for rehearing; Columbia petitioned for judicial review.[44] The FERC distinguished the precedents that Columbia claimed the Commission had failed to follow, and argued Columbia did not successfully contradict the distinctions.[45] The FERC offered an economic rationale justifying a restriction on the breadth of the section 5 waivers.[46] Columbia offered contradictory arguments against the rationale in its initial and reply briefs.[47] The Court stated that it was not its "duty to identify, articulate, and substantiate a claim" for Columbia and declined to do so.[48] The Court concluded that the FERC had articulated a rationale that was not transparently defective, that Columbia had not presented a coherent critique, and that it could not find the FERC's conclusion arbitrary or capricious.[49] Finally, Columbia argued that the FERC erroneously decided Columbia's agreements were unduly discriminatory against small shippers.[50] The Court stated "to say that FERC's preservation of the large shippers' right to bring challenges is an imperfect protection for small shippers' interests is a far cry from establishing that the benefits of FERC's policy are outweighed by its drawbacks . . . . We see

36. *Id.* at 796.

37. *Id*. at 799.

38. *Id.* at 801 (quoting Consolidated Edison Co. of New York v. FERC, 347 F.3d 964, 969 (D.C. Cir. 2003)).

39. *NSTAR*, 481 F.3d at 801.

40. *Id.*

41. *Id*. at 804.

42. Columbia Gas Transmission Corp. v. FERC, 477 F.3d 739, 740 (D.C. Cir. 2007).

43. *Id*. at 741.

44. *Id*.

45. *Id*. at 743.

46. *Id*.

47. *Id*. at 744.

48. *Id*.

49. *Id*.

50. *Id*.

no basis for concluding that FERC's rationale is arbitrary or capricious."[51] The court upheld the FERC's orders.[52]

II. FEDERAL POWER ACT

A. Refunds

Port of Seattle, Washington v. FERC[53] had its genesis in the 2000-2001 western power markets crisis and in a complex procedural background. In October 2000, Puget Sound Energy (Puget) filed a complaint with the FERC under section 206 of the Federal Power Act asking the FERC to impose price caps on the sales of energy and capacity into the Pacific Northwest wholesale energy spot markets. In December 2000, the FERC dismissed Puget's complaint, and Puget subsequently sought rehearing. In a separate proceeding (California Complaint Proceeding), the FERC imposed price caps on sales in the California spot markets and established an area-wide investigation into western spot markets. The FERC adopted a market monitoring and market power mitigation plan for the western markets, including the Pacific Northwest. In addition, the FERC directed market participants to engage in settlement talks to resolve past accounts, and clarified that the scope of these talks could also include the Pacific Northwest.

During this time, Puget filed a notice of withdrawal of its complaint, asserting that the FERC's decision to impose price mitigation in the Pacific Northwest satisfied its complaint. The City of Seattle and the Attorney General of Washington objected to Puget's filing. The FERC thereafter directed all parties to Puget's complaint proceeding to participate in a separate evidentiary proceeding to try to settle accounts related to spot market sales in the Pacific Northwest. After the hearing, the presiding Administrative Law Judge (ALJ) found that while prices in California impacted the Pacific Northwest market, there were other factors at work as well. The ALJ further found no evidence of market manipulation in the Pacific Northwest spot market. Consequently, the ALJ concluded that refund relief was not warranted. Several months later, in May 2002, the FERC released documents relating to manipulation of the California energy market. As a result, several parties requested that the FERC reopen the evidentiary record in the Puget complaint proceeding. The FERC did so. When it ruled on the ALJ's decision, however, the FERC did not take into account the new evidence of market manipulation, and concluded that the "balance of factors tipped against ordering refunds."[54]

Petitioners sought judicial review of the FERC's decision not to provide refunds to wholesale electricity purchasers in the Pacific Northwest spot market at unusually high prices. Petitioners asserted that the FERC failed to consider the new evidence of market manipulation and questioned the Commission's decision to exclude from the universe of transactions that were potentially

51. *Id*.

52. *Id.* at 745.

53. Port of Seattle, Washington v. FERC, 499 F.3d 1016 (9th Cir. 2007).

54. *Id.* at 1026.

eligible for a refund those transactions involving energy purchased in the Pacific Northwest for consumption in California.

Before the Court could address these substantive points, it had to resolve several procedural issues. First, the Court evaluated whether the FERC erred in finding that Puget's complaint was not withdrawn as a matter of law. Puget argued the notice of withdrawal became effective fifteen days after it was filed, in accordance with the FERC's procedural rules, and claimed that the withdrawal opponents—the City of Seattle and the Attorney General of Washington—had not timely intervened in the proceeding and thus their opposition was not effective. The Court disagreed with this contention, concluding that the FERC reasonably interpreted its procedural regulations as placing no limit on who may oppose a notice of withdrawal, and that the FERC did not err in finding that Seattle and the Attorney General were interveners for purposes of opposing Puget's notice. Accordingly, the court held that the FERC could use Puget's complaint as a basis for granting refund relief in the Pacific Northwest.

Second, several of the companies opposing refunds (Refund Opponents) asserted that the Pacific Northwest proceeding "was procedurally doomed" because the Puget complaint did not request a "refund effective date," which meant that the FERC did not have any authority to order refunds.[55] The Refund Opponents also argued that because the FERC had dismissed Puget's complaint in December 2000, parties to transactions in the Pacific Northwest did not have the requisite notice that there may be refund exposure. The Court rejected these claims. First, the court pointed to the complaint itself, in which Puget had requested a refund effective date be established sixty days after filing. Second, the Court observed that the FERC's public notice of Puget's complaint specified the requested refund effective date. The Court also pointed out that Puget's request for rehearing kept the parties on notice.

Finally, the Refund Opponents contended that the FERC was required to establish a refund effective date prior to instituting a section 206 refund proceeding. Again, the Court rejected the Refund Opponents' argument. The Court looked to section 206, which provides that whenever the FERC "institutes" a proceeding under that section, it "shall establish a refund effective date."[56] Thus, the Court concluded that while section 206 requires the FERC to establish a refund effective date, it does not mandate when the FERC must establish that date. Although recognizing that the term "institutes" could be ambiguous, the Court deferred to the FERC's reasonable interpretation of that language because it was "consistent with the overall framework of the statute, which indicates the primary concern of Congress was to afford notice to market participants of the period of time during which they may be liable for refunds."[57]

Having addressed the procedural arguments regarding Puget's complaint and the refund effective date, the Court next turned to the petition of several parties challenging the FERC's exclusion of purchases made by the California Energy Resources Scheduling (CERS) in the Pacific Northwest. The FERC argued that the ALJ had found that a witness testified that energy deliveries to CERS occurred in California, and not in the Pacific Northwest. The FERC

55. *Id*. at 1030.

56. 16 U.S.C. § 824e(b) (2000).

57. *Port of Seattle*, 499 F.3d at 1032.

concluded that it was appropriate to exclude the CERS purchases from refund consideration. The Court disagreed. First, the Court explained that the ALJ never expressly found that a CERS witness admitted that deliveries took place in California. Moreover, the Court concluded the record demonstrated that "even if physical delivery of the energy took place in California, the legal change of ownership of energy occurred . . . at interconnections located within the Pacific Northwest" in accordance with the relevant confirmation agreement.[58]

The Court also observed that Puget's complaint was "silent as to any constraint on the identity of the buyers or where the energy ultimately would be consumed."[59] The Court pointed out that the FERC's interpretation of Puget's complaint was inconsistent with the interpretation it adopted in the California Complaint Proceeding because the FERC did not interpret the California Complaint "as limited refunds to entities that purchased energy for ultimate consumption in California . . . . FERC's interpretation of the California complaint is the better one . . . ."[60] The Court also stated that it had excluded the CERS transactions from the California Complaint Proceeding because it had accepted arguments that these transactions could be addressed in the Pacific Northwest proceeding.

Finally, the Court found that the FERC acted arbitrarily and capriciously in refusing to consider new evidence of market manipulation in California and its potential ties to the Pacific Northwest. The Court stated that the FERC should have considered whether the Pacific Northwest spot market was not competitive based on this evidence.

B. Order 2003

In *National Association of Regulatory Utility Commissioners v. FERC*,[61] the court addressed the FERC's Order No. 2003 final rule,[62] which established standardized large generator interconnection procedures and a *pro forma* large generator interconnection agreement. In particular, the court heard concerns raised by two sets of petitioners—the Utility Petitioners and the Governmental Petitioners.

Both sets of petitioners took issue with Order No. 2003's assertion of jurisdiction over the terms of interconnection between generators and transmission providers, even when the transmission facility to which the generator is interconnected also has a local distribution function. According to the Utility Petitioners, this was an unlawful exercise of jurisdiction over "dual-use facilities." In support, the Utility Petitioners pointed to an earlier D.C. Circuit opinion in which the court rejected the FERC's attempt to assert jurisdiction over unbundled retail service. The court, however, disagreed, noting

58. *Id*. at 1033.

59. *Id.* at 1034.

60. *Id.*

61. National Ass'n of Regulatory Util. Comm'ns v. FERC, 475 F.3d 1277 (D.C. Cir. 2007).

62. Order No. 2003, *Standardization of Generator Interconnection Agreements and Procedures*, 104 F.E.R.C. ¶ 61,103 (2003), 68 Fed. Reg. 49,846 (2003), *order on reh'g*, Order No. 2003-A, 106 F.E.R.C. ¶ 61,220 (2004), 69 Fed. Reg. 15,932 (2004), *order on reh'g*, Order No. 2003-B, 109 F.E.R.C. ¶ 61,287 (2004), 70 Fed. Reg. 265 (2004), *order on reh'g*, Order No. 2003-C, 111 F.E.R.C. ¶ 61,401 (2005), 70 Fed. Reg. 37,661 (2005) [hereinafter Order No. 2003].

that Order No. 2003 only applies to FERC-jurisdictional transactions, not facilities, and stated that "interconnections appear to be relationships between parties with respect to electricity flowing over facilities, and the orders here by their terms control the agreements governing those relationships."[63]

Governmental Petitioners argued that the FERC engaged in jurisdictional "boot-strapping" by asserting jurisdiction over interconnection with dual-use facilities, and that Order No. 2003 created uncertainty "by making jurisdiction turn on (among other things) whether the facility is covered by an [open access transmission tariff]" (OATT).[64] In addition, Governmental Petitioners contended that the FERC should have applied its seven-factor test to determine whether a particular facility should be classified as transmission or distribution. The Court found that the situation was "the exact opposite of boot-strapping," because Order No. 2003 only asserts jurisdiction over interconnections to distribution facilities only when the facility is covered by an OATT and the interconnection is for purposes of making wholesale sales.[65] In response to Governmental Petitioners' claims regarding the application of the seven-factor test, the Court stated that Order No. 2003 asserted jurisdiction over transactions, not facilities, and thus had no reason to apply the test.

The Utility Petitioners asserted that Order No. 2003-A's requirement that transmission providers not discriminate against independent generators in the exercise of eminent domain power amounted to commandeering a states' eminent domain authority, contrary to the U.S. Supreme Court's recent Tenth Amendment precedent. The Court found that the FERC's determination was "a far cry from what the Supreme Court found objectionable" in the Tenth Amendment cases.[66] The Court concluded that all Order No. 2003-A did was impose a non-discrimination requirement on jurisdictional public utilities, and noted that Order No. 2003-A expressly provides that any exercise of eminent domain authority pursuant to this non-discrimination requirement must be consistent with state law:

> Thus the states remain completely free to continue licensing public utilities to exercise eminent domain, or to discontinue that practice. . . . Nothing in the federal rule compels either continued state retention of the license, or public utilities' continued employment of eminent domain. . . . [T]he orders here leave state law completely undisturbed and bind only utilities—not state officials.[67]

The Court also rejected the Utility Petitioners' related constitutional claim that Order No. 2003-A's eminent domain provisions amounted to an unlawful taking and, in particular, that the exercise of eminent domain power on behalf of independent generators could harm the "good will" that transmission owners have with landowners. The Court found that anti-discrimination rules often "require the incurrence of costs by the obligated parties; their very imposition presupposes that some such parties would, in the pursuit of their self-interest, violate the anti-discrimination norm."[68] The Court did not believe that the

63. *National Ass'n of Regulatory Util. Commn'rs*, 475 F.3d at 1280.

64. *Id.* at 1282.

65. *Id.*

66. *Id.* at 1283.

67. *Id.*

68. *Id.* at 1284.

potential loss of good will would be more than the costs associated with non-discrimination provisions.

Finally, both sets of petitioners challenged the interconnection pricing policy described in Order No. 2003, under which generators are responsible for the costs of facilities between the generating plant and the point of interconnection, and transmission providers are responsible for facilities constructed at or beyond the point of interconnection "for the purpose of accommodating the new Generating Facility."[69] According to the petitioners, the rule departed from prior precedent, violated cost causation principles, and was inconsistent with the FERC's obligation to ensure the efficient siting of facilities pursuant to section 212 of the Federal Power Act. The court rejected all of these contentions. First, the Court stated that it had never rejected the "at or beyond" test; rather, it had earlier directed the FERC to clarify the test and that the FERC had since consistently applied the "at or beyond" test. In response to the cost causation argument, the court stated that it had previously endorsed the FERC's approach that the costs of system-wide benefits should be assigned to all customers. Finally, regarding the "efficient siting" argument, the court reasoned that because generators are required to pay the entire cost of facilities and equipment located between the plant and the point of interconnection, cost affects siting choices.

The Utility Petitioners also advanced another argument regarding Order No. 2003's interconnection pricing policy. They asserted that there was no empirical evidence that "network upgrades"—the facilities at or beyond the point of interconnection—benefited the entire network. The Court, however, found the Utility Petitioners' evidence in this regard to be conclusory.

Judge Sentelle dissented in part from the opinion, stating that he could not join the majority with respect to Order No. 2003's eminent domain provisions. Judge Sentelle argued that the FERC, as a "creature of statute," does not have authorization "to regulate the use of state-granted eminent domain power. . . ."[70] Judge Sentelle invoked the Supreme Court's "clear statement" rule, under which Congress must make its intent clear if it wishes to change the balance between federal and state jurisdiction, and stated that Congress did not clearly provide the FERC with authority regarding eminent domain, which is traditionally a state power.

C. Tariffs

1. ISOs

In *Wisconsin Public Power, Inc. v. FERC*,[71] the court considered a number of petitioners related to the implementation of the "Day 2" energy markets approved by the FERC for the Midwest Independent Transmission System Operator, Inc. (MISO). Several petitioners attacked the FERC's decision regarding the treatment of certain long-term, "grandfathered" bilateral agreements (GFAs) between transmission owners in the MISO region and other

69. *Id.* (quoting Order 2003, *supra* note 62, at P 676).

70. *National Ass'n of Regulatory Util. Commn'rs*, 475 F.3d at 1286.

71. Wisconsin Public Power, Inc. v. FERC, 493 F.3d 239 (D.C. Cir. 2007).

entities. Other petitioners complained that the FERC erred in accepting MISO's proposed market power monitoring and mitigation framework. These same petitioners argued that the FERC erred in its treatment of calculating refunds associated with MISO's marginal loss pricing scheme.

With respect to the GFA issue, MISO had proposed that GFA parties that did not voluntarily convert transmission service to the MISO's tariff could choose one of three options for scheduling transactions and settling charges. Under Option A, the "GFA Responsible Entity" (i.e., the entity that would be financially responsible for charges under MISO's tariff)[72] would pay congestion and loss charges under MISO's tariff and were eligible for firm transmission rights (FTR) allocations, which could be used to hedge congestion charges. Under Option B, the GFA Responsible Entity would pay congestion and loss charges, but would receive a guaranteed reimbursement of congestion costs and loss charges provided that the designated "Scheduling Entity" for the GFA provided MISO with a day-ahead schedule of GFA transmission. Under Option C, the GFA Responsible Entity would pay congestion and loss charges but would not be eligible for refunds or FTR allocations. Many GFA parties either voluntarily converted to service under the MISO tariff or chose one of the three options. In determining whether remaining GFAs should be "carved out" of the Day 2 market, the FERC looked to each GFA's standard of review. In the case of those GFAs with *Mobile-Sierra* clauses, the FERC concluded that the public interest did not require that these contracts be modified. However, the FERC required parties to GFAs with the just and reasonable standard of review to choose between either Option A or Option C. Finally, the FERC held that the administrative costs—termed Schedule 17 charges, based on the relevant rate schedule of MISO's tariff—associated with the Day 2 markets should be assessed on all load using the MISO, including the "carved out" GFAs.[73]

Two separate groups of petitioners sought review of the FERC's underlying orders as they pertained to the GFA determination. The first group, primarily comprised of cooperatives (Cooperative Petitioners), argued that the imposition of Schedule 17 charges on carved-out GFAs was in error. In the meantime, a group of transmission owners (TO Petitioners) asserted that all of the GFAs should have been required to choose converting to service under the MISO tariff, Option A, or Option C. In other words, the TO Petitioners contended that the FERC erred in carving out some GFAs and providing others with preferential treatment under Option B.

The court held that the Cooperative Petitioners lacked standing because they did not suffer an injury-in-fact. The court noted that MISO's transmission owners submitted, in a different proceeding, a proposal for passing through Schedule 17 charges to certain carved-out GFA customers. According to the court, that was the proceeding where the Cooperative Petitioners should have challenged the imposition of Schedule 17 charges on carved-out GFAs, noting that even if the Cooperative Petitioners were aggrieved under those orders it did not follow that they suffered a cognizable injury in this proceeding.[74]

72. *Id.* at 253.
73. *Id.* at 277.
74. *Id.* at 269.

The court also rebuffed the TO Petitioners, but addressed the merits of their arguments. First, with respect to the carved-out GFAs, the court held that the public interest did not require GFAs with *Mobile-Sierra* clauses to convert to service under MISO's tariff. With respect to the ability of settling GFAs to take advantage of Option B, the court stated that permitting this option "reduced the scope of the 'fundamental problem' that the GFAs presented; increased GFA participation in the markets also increased the markets' reliability . . . ."[75] Moreover, the court reasoned that all market participants "reaped the benefit of having MISO's new markets start up faster than would have been possible had FERC been forced into litigation with all of the settling GFA parties."[76] Finally, the court rejected the TO Petitioners' claim that the FERC erred in finding that the carve-out and Option B settlements together were just and reasonable.

Another area of dispute raised by the underlying orders involved MISO's Day 2 market monitoring and mitigation measures. These measures established Narrow Constrained Areas (NCAs), areas where transmission constraints are expected to be binding for at least 500 hours during a given year and thus posed persistent competitive issues, and Broad Constrained Areas (BCAs), which posed only "intermittent" competitive concerns. MISO's independent market monitor would employ a "conduct and impact" test to determine whether a supplier's bid should be mitigated. Under the "conduct" prong of the test, the monitor would compare a supplier's bid to its "reference price" plus a fixed cost adder that was an amount based on the seller's net annual fixed cost divided by the constrained hours in a particular year. The FERC approved the basic construct, finding that it avoided both over-mitigation and under-mitigation, and approved the use of the fixed-cost adder in the conduct test.

Certain petitioners, led by the Midwest Transmission Dependent Utilities (TDU Petitioners), asserted that the FERC erred in approving this market mitigation construct. First, it argued that the FERC should have required MISO to employ a "market concentration metric" in defining NCAs. Second, the TDU Petitioners claimed that the FERC erred in approving a fixed cost adder, arguing that the adder "was vaguely defined and overly generous to suppliers at the expense of buyers . . ." and in the "few NCAs where recovery of fixed costs poses a genuine problem, MISO should simply have set the adder at the supplier's marginal cost plus a 10-percent booster."[77] The TDU Petitioners next argued that MISO's BCA proposal gave suppliers in those areas too much discretion to charge high prices before they are mitigated. They also objected to the FERC's authorization of mitigation within BCAs one year at a time.

The court rejected these arguments. First, the court concluded the FERC reasonably explained that using a market concentration metric "carried too great a risk of over-mitigation in the context of this market power mitigation scheme" and was not needed to identify areas that warranted NCA designation.[78] Second, the court found that the FERC's approval of a fixed cost adder "was a reasonable

75. *Wisconsin Public Power*, 493 F.3d at 276.

76. *Id.*

77. *Id.* at 260.

78. *Id.* at 259.

predictive judgment that warrants judicial deference."[79] Moreover, the TDU Petitioners' proposal "goes astray" when it substitutes a "pinpoint (marginal cost plus 10 percent, and not a penny more) for a zone of reasonable options the FERC can choose from."[80] The court also rejected the contention that suppliers in BCAs could charge high prices before they are mitigated because, "by definition," suppliers in BCAs will normally face competition.[81] The court also found that the FERC's decisions regarding the BCA "ceilings" were just and reasonable. Finally, the court stated that the FERC acted reasonably in applying a one-year limitation on the BCA mitigation authority given its concerns about over-mitigation "and the contribution of unfettered discretion on the part of the independent market monitor to that over-mitigation."[82]

The third separate topic from the underlying orders that was in dispute involved MISO's proposed use of marginal loss pricing for transmission losses. Prior to this change, MISO had used average loss pricing, which calculated average transmission losses for the entire transmission system and then charged on a *pro rata* basis. Marginal loss pricing, by contrast, would be determined by the applicable locational marginal price. In approving MISO's proposal, the FERC recognized that marginal loss charges would exceed average loss charges. The FERC therefore directed MISO to provide refunds to market participants so that they would end up paying no more than their average losses for a five-year transition period.

The TDU Petitioners viewed the FERC's determination as requiring MISO to provide refunds based on average losses incurred by each individual customer. However, the TDU Petitioners claimed that this could not be squared with the FERC's later approval of MISO's proposed approach to refunds, under which groups of transmission customers by "Balancing Authority" compute average losses on a grouped basis.

The court rejected the TDU Petitioners' claims on this issue, holding that the FERC acted reasonably in interpreting its instructions. According to the court, the TDU Petitioners did not point to any commitment by the FERC to require individual loss calculations. The court also noted that the FERC seemed to recognize that the computation method it endorsed could be refined; however, the court stated, this does not "undercut FERC's conclusion that the overall method affords a just and reasonable rate for the transmission customers."[83]

2. Calculation/Refunds

The root of *Louisiana Public Service Commission v. FERC*[84] was a 1982 "System Agreement" among the Entergy Corporation's (Entergy) subsidiary operating companies. Under the System Agreement, capacity costs were allocated among the operating companies and each of the operating companies was liable to make an "equalization payment" each month, depending on the amount of electricity it took at the time of peak monthly demand on the Entergy

79. *Id.* at 260.
80. *Id.*
81. *Id.* at 264.
82. *Id.*
83. *Id.* at 266.
84. Louisiana Pub. Serv. Comm'n v. FERC, 482 F.3d 510 (D.C. Cir. 2007).

system. If an operating company took more electricity than it generated at peak time, then it had to pay the operating companies that were in the reverse situation. In 1995, the Louisiana Public Service Commission (LA PSC) filed a complaint with the FERC against Entergy, claiming that the System Agreement's formula for peak load was unjust and unreasonable because it included both firm and interruptible load. The FERC rejected the complaint. However, in 1999, the court remanded the case back to the agency, noting that the FERC had previously held that it was unjust and unreasonable for a utility to charge capacity costs to a customer that had only purchased interruptible transmission service.

When the FERC issued a decision in March 2004, it concluded that it was in fact unjust and unreasonable for Entergy to include interruptible load in its calculation of peak load responsibility because the operating companies could control capacity costs by curtailing interruptible service during peak demand. In its rehearing request, Entergy argued that the FERC's order should apply prospectively. The FERC responded, "Entergy must adjust the system peaks and its rates beginning April 1, 2004 . . . ."[85] Entergy took the FERC to mean that it could phase the interruptible load out of its formula over a twelve month period.

The LA PSC petitioned the court for review of the FERC's decision regarding the appropriate interpretation of the phase out of interruptible load from the peak load formula. In addition, the LA PSC asserted that, given the FERC's determination that it was unjust and unreasonable for Entergy to include the interruptible load component in the peak load calculation, the Entergy operating companies that benefited from the inclusion of that component should provide refunds to those operating companies that were harmed. Finally, the LA PSC raised the issue of whether the FERC erred in permitting Entergy to include an amendment to the System Agreement that provided that each of the operating companies would be paid for any sulfur dioxide emission allowances used to generating electricity exchanged among those companies.

The court agreed with the LA PSC that the FERC's order required Entergy to remove the interruptible load component from the peak load calculation immediately and thus concluded that the agency acted arbitrarily and capriciously by allowing Entergy to phase out the interruptible load component. Moreover, the court remanded the issue of refunds back to the FERC "for a more considered determination."[86] The court was not convinced by the FERC's argument that it does not have authority to direct a state agency to allow an operating company owing refunds to collect the necessary revenue from retail customers and that the retroactive nature of the refund would violate the state's filed rate doctrine. The court stated that the FERC did not address why the filed rate doctrine would be violated if refunds were ordered, citing an older FERC order stating that under section 206 of the Federal Power Act, refunds would be "prospective" from the refund date. The court also noted that the FERC did not explain why "a rate increase ordered by the Commission may be recovered through retail rates but a refund ordered by the Commission may not be."[87] Finally, the court rejected the LA PSC's arguments regarding the sulfur dioxide

85. *Louisiana Pub. Serv. Comm'n v. Entergy Servs., Inc.*, 111 F.E.R.C. 61,080 at P 31 (2005).

86. *Louisiana Pub. Serv. Comm'n*, 482 F.3d at 520.

87. *Id.*

issues, finding that the FERC decided to defer consideration of the matter until the next time Entergy makes a filing with regard to the System Agreement or pursuant to a separate complaint raising the issue.

D. Cost allocation

In *California Department of Water Resources v. FERC*,[88] the Court of Appeals for the Ninth Circuit denied as unfounded the California Department of Water Resources' (CDWR) petition for review of the FERC orders that categorized certain facilities owned by Pacific Gas & Electric Company (PG&E) as "transmission" based on the "exclusive use" test and allowed PG&E to use rolled-in pricing to recover the costs of these facilities. The court found that the FERC's decision was consistent with the FERC precedent and was "a reasonable approach to allocate the cost of facilities whose operation benefit all grid users."[89]

The facilities at issue were PG&E facilities that had been transferred to the control of the California Independent System Operator Corporation (CAISO) and that the FERC had determined were transmission facilities to be included in PG&E's rate base. In Opinion No. 466, the FERC held that the proper test to determine whether the facilities were transmission facilities was whether they had been transferred to the control of the CAISO. If they had, then the facilities would be included in the rate base; otherwise they would be excluded.[90] In Opinion No. 466-A, the FERC granted rehearing, finding that CAISO control, although necessary, was not the only consideration in determining whether the facilities were transmission facilities. Nevertheless, the FERC affirmed that the facilities should be included in PG&E's rate base, because all of the facilities at issue performed a transmission function.

The facilities at issue consisted of: (1) loop facilities, including 500 kV and 230 kV lines that connected generation facilities to the PG&E transmission system, as well as connecting network substations; (2) "dual function" facilities, which were primarily step-up transformers; and (3) and "network-only" facilities, consisting of transformer banks and lines connecting network stations. Although these facilities also served generation functions, the FERC applied the "exclusive use" test pursuant to which facilities qualify as generation, only if they are used exclusively to generate power, step up power, or transmit power from the generator to the grid.[91]

The court agreed with the FERC that all of the facilities at issue served a network transmission function, in addition to benefiting PG&E's generation, and that the FERC's application of the "exclusive use" test was consistent with its treatment of dual purpose facilities.[92] The court noted that the loop facilities served a transmission function because they functioned as parallel paths to Path 15 (i.e., a high voltage transmission line that is the principal means of

88. California Department of Water Res. v. FERC, 489 F.3d 1029 (9th Cir. 2007).

89. *Id*. at 1031.

90. *Id.* at 1032-33 (citing Opinion No. 466, *Pac. Gas & Elec. Co.*, 104 F.E.R.C. ¶ 61,226 (2003), *reh'g granted*, Opinion No. 466-A, 106 F.E.R.C. ¶ 61,144, *reh'g denied*, Opinion No. 466-B, 108 F.E.R.C. ¶ 61,297 (2004)).

91. *CDWR*, 489 F.3d at 1036.

92. *Id.*

transmitting power between Northern and Southern California and the Pacific Northwest), carried local area load, and connected substations. The transformer banks within the group of "dual function facilities" both transformed power at the generating station (supporting PG&E generation) and transformed power that passes through the banks between various levels of voltage (a transmission function). Finally, the network-only facilities served only a transmission function, because the generators they previously supported had been decommissioned.[93]

With respect to transmission pricing, the court upheld the FERC's decision to apply rolled-in pricing, whereby all customers share proportionately in the costs of all transmission facilities, rather than PG&E's "sub-functional" pricing method.[94] The court found that the FERC precedent strongly favors rolled-in pricing for facilities that are part of an integrated transmission system because all customers, whether wholesale, retail, or wheeling customers, receive the benefits inherent in an integrated transmission system. The court concluded that, because CDWR benefited from the integrated grid, the "FERC reasonably required it to pay its share of the cost."[95]

Finally, the court rejected CDWR's argument that the FERC had modified its transmission pricing policy generally, based on the alternative pricing methods contained in Order No. 888, Order No. 2000, the Standard Market Design rulemaking proceeding, and Order No. 2003, and for PG&E in particular because the FERC had sanctioned PG&E's sub-functional method. The court found that, while the FERC had adjudicated rate disputes involving PG&E, the FERC had never adjudicated the merits of the sub-functional method and that in the orders cited by CDWR, the FERC had explicitly declined to make any findings regarding the merits of the method.[96]

1. Studies

In *Public Service Electric and Gas Company v. FERC,*[97] the Court of Appeals for the District of Columbia Circuit upheld the FERC's interpretation of certain interconnection provisions of PJM Interconnection, L.L.C.'s open access transmission tariff (PJM Tariff). The petitioners (i.e., PJM, certain transmission-owning members of PJM, state agencies, and an industrial customer) argued that the PJM Tariff permitted unlimited restudy prior to the completion of an interconnection service agreement, whereas the FERC interpreted the PJM Tariff to permit restudy in only a limited set of circumstances.

Under the PJM Tariff, PJM must undertake three types of studies before granting a request for interconnection service: a "feasibility study," a "system

93. *Id.* at 1037.

94. To apply the sub-functional pricing method, PG&E studied its transmission facilities and assigned each facility a subcategory based on the facility's function within the transmission category (namely: (1) backbone; (2) generation tie; (3) system interconnection; (4) exclusive use; and (5) area transmission). Customers were charged "postage stamp" rates for each sub-function utilized, meaning the rate was set without regard to the distance the power traveled. *Id.* at 1035.

95. *Id.* at 1038-39.

96. *Id.* at 1040 (citing Opinion No. 356, *Pac. Gas & Elec. Co.*, 53 F.E.R.C. ¶ 61,146 (1990) and *Pac. Gas & Elec. Co.*, 71 F.E.R.C. ¶ 61,394 (1995)).

97. Public Serv. Elec. & Gas Company v. FERC, 485 F.3d 1164 (D.C. Cir. 2007).

impact study" (SIS), and a "facility study." In the order under review,[98] the FERC granted a complaint filed by Neptune Regional Transmission System, LLC (Neptune), a transmission customer that was seeking interconnection service from PJM. PJM had performed a total of five SISs, in which the estimated costs of necessary upgrades had increased from $3.7 million to $26.3 million. The second SIS was required due to the withdrawal of a higher-queued interconnection project and concluded that upgrade costs would be $4.4 million, and the third, fourth, and fifth SISs were due to generator retirements. Neptune argued, and the FERC agreed, that Neptune should not be required to pay for the third, fourth, and fifth SISs. The FERC found that, while the PJM Tariff was ambiguous, it would be unreasonable to permit unlimited restudy and that the PJM Tariff permitted restudy in only the limited set of circumstances specified in FERC Order No. 2003.[99] According to the FERC, the PJM Tariff generally precludes restudies based on events post-dating an interconnection service request being placed in the queue. The FERC stated that the queue position should provide a potential customer a reasonable degree of certainty regarding its costs and that to hold the customer responsible for subsequent events would render it impossible for the customer to make reasoned decisions.[100] The FERC concluded that PJM should have provided Neptune a facilities study immediately upon completion of the second System Impact Study and that restudies could only be performed for the three circumstances discussed in Order No. 2003: (1) the withdrawal of a higher-queued project, (2) the modification of higher-queued project, and (3) when the point of interconnections is re-designated.[101]

The court began its analysis[102] by noting that it reviews the FERC's interpretation of tariffs in the same way it applies deference under *Chevron U.S.A., Inc. v. NRDC*[103] to agency interpretations of statutes.[104] The court agreed that the two PJM Tariff provisions at issue were ambiguous: one set forth the process for a restudy but was silent as to the circumstances permitting restudy,[105] while the other provided that interconnection customers were responsible for costs for upgrades that would not have been incurred but for the interconnection service request, but was silent as to "the time as of which 'but for' causation should be assessed."[106] Petitioners argued that the relevant time was when the interconnection service agreement was signed, while the FERC concluded that these costs should be assessed when the interconnection customer had received its place in the queue. The court agreed with the FERC because the

98. *Neptune Regional Tran. Sys., LLC v. PJM Interconnection, L.L.C.,* 110 F.E.R.C. ¶ 61,098 (2005) (*Neptune*).

99. Order No. 2003, *supra* note 62.

100. *PSEG*, 485 F.3d at 1167 (citing *Neptune*, 110 F.E.R.C. ¶ 61,098 at P 23).

101. *PSEG*, 485 F.3d at 1167 (citing *Neptune*, 110 F.E.R.C. ¶ 61,098 at P 22).

102. The court first rejected the FERC's argument that the petitioners lacked standing and that their claims were not ripe because the FERC had determined that questions regarding costs above $4.4 million (i.e., the costs over and above those in the second SIS) would be addressed in future proceedings. The court rejected these arguments because the FERC order at issue conclusively shifted any costs above $4.4 million from Neptune to PJM, and also required PJM to proceed with the interconnection agreement. *PSEG*, 485 F.3d at 1168.

103. Chevron U.S.A., Inc. v. NRDC, 467 U.S. 837, 842-43 (1984).

104. *PSEG*, 485 F.3d at 1168.

105. *Id.* at 1168-1169.

106. *Id*. at 1169.

FERC's interpretation "helps provide workability, certainty and predictability in the interconnection process."[107]

E. Creditworthiness

In *Gas Transmission Northwest Corp. v. FERC*,[108] the Court of Appeals for the District of Columbia Circuit upheld a series of FERC orders[109] in which the FERC found that interstate pipelines' proposed tariffs were unjust and unreasonable because they proposed to increase the collateral requirements for shippers from three months to twelve months of reservation charges.

The petitioner pipelines argued that the FERC orders at issue were inconsistent with FERC policy, as the FERC had permitted other pipelines to require twelve months of reservation charges as collateral. The FERC acknowledged that certain pipeline tariffs required twelve months of reservation charges, but that these instances were not contrary to or inconsistent with FERC policy. According to the FERC, in the absence of protests, it had simply accepted unchallenged filings without examining whether they conformed to Commission policy and precedent.[110]The court agreed with the FERC that the "FERC's acceptance of a pipeline's tariff sheet does not turn every provision of the tariff into 'policy' or 'precedent.'"[111] Moreover, it found that when a proposed tariff with a collateral requirement of more than three months' reservation charges has been challenged, the FERC had required the pipeline to amend its filing to comply with the Commission's three-month rule.[112] The FERC further emphasized that it made an exception to the three-month rule for newly-constructed facilities, which were permitted to impose a twelve-month collateral requirement. The court rejected petitioners' arguments that this policy was arbitrary and capricious and agreed with the FERC that "pipelines and their financing institutions' reliance interests for new investment justify the longer collateral requirement."[113]

The pipelines further argued that three months of reservation charges did not cover their remarketing risk, i.e., the risk that the pipeline could not find a replacement for the defaulting shipper that would pay the same or higher price for the unused capacity. The court agreed with the FERC's response that such remarketing risk is an ordinary business risk that could be factored into the pipeline's rate of return and found that the FERC had in fact considered remarketing risk as a factor in at least one other instance.[114] Moreover, the court

107. *Id.* at 1169.

108. Gas Transmission Nw. Corp. v. FERC, 504 F.3d 1318 (D.C. Cir. 2007) (*GTN*).

109. *Pac. Gas & Elec. Transmission*, 101 F.E.R.C. ¶ 61,280 (2002); *e prime, Inc. v. Pac. Gas & Elec. Transmission*, 102 F.E.R.C. ¶ 61,062 (2003); *North Baja Pipeline, LLC*, 102 F.E.R.C. ¶ 61,239 (2003); *e prime, Inc. v. Pac. Gas & Elec. Tranmission.*, 102 F.E.R.C. ¶ 61,289 (2003); *Pac. Gas & Elec. Transmission*, 103 F.E.R.C. ¶ 61,137 (2003); *e prime, Inc.* v. *Pac. Gas & Elec. Transmission*, 104 F.E.R.C. ¶ 61,026 (2003); *North Baja Pipeline, LLC*, 105 F.E.R.C. ¶ 61,374 (2003); *Pac. Gas & Elec. Transmission*, 105 F.E.R.C. ¶ 61,382 (2003); *North Baja Pipeline, LLC*, 115 F.E.R.C. ¶ 61,141 (2006); *North Baja Pipeline, LLC*, 117 F.E.R.C. ¶ 61,146 (2006).

110. *GTN*, 504 F.3d at 1320 (citing *North Baja Pipeline, LLC*, 117 F.E.R.C. ¶ 61,146 (2006)).

111. *GTN*, 504 F.3d at 1320.

112. *Id.* (citing *Valero Interstate Transmission Co.*, 62 F.E.R.C. ¶ 61,197 (1993)).

113. *GTN*, 504 F.3d at 1320.

114. *Id.* at 1321-22 (citing *Ozark Gas Transmission Sys.*, 68 F.E.R.C. ¶ 61,032 (1994)).

agreed that it was reasonable for the FERC to impose the three-month rule pursuant to its "open access" policy, i.e., it was reasonable for the FERC to "promote this policy by encouraging the non-creditworthy marginal shipper's entry into the market."[115] Although some remarketing risk may be spread to creditworthy shippers, the court found that the FERC had determined that these costs were justified by the benefits of encouraging entry and concluded that this cost-benefit analysis "strikes us as the sort of policy call entrusted to [the FERC]—not to us."[116]

Finally, the court rejected the pipelines' argument that they faced unique challenges based on the high rates of default and the fact that their primary markets (Northern California and the Pacific Northwest) were likely to experience slower growth in the future. The court noted that the FERC had found that these defaults were due to the Western energy crisis and that petitioner pipeline had failed to show that its markets will not be steady or continue to grow. The court found that it had no reason to second guess the FERC's factual determinations and that it was proper for the court to defer to the FERC's policy determinations and expertise in evaluating complex market conditions.[117]

F. Market Behavior Rules

In *Colorado Office of Consumer Counsel v. FERC*,[118] the Court of Appeals for the District of Columbia rejected challenges to the FERC's Market Behavior Rules.[119] According to the court, the FERC initially promulgated the rules in response to a finding that certain anticompetitive and manipulative practices rendered rates unjust and unreasonable. Petitioner argued that the FERC, having found rates unjust and unreasonable, violated FPA section 206 by failing also to "fix" a new rate and that in fixing a new rate, the FERC must reject all market-based rates.[120]

The FERC first argued that subsequent events had rendered petitioner's claims moot; specifically, the FERC had rescinded certain Market Behavior Rules and codified others in its regulations. The court disagreed, finding that this did not render these claims moot because the FERC never rescinded its determination that market-based rates had become unjust and unreasonable, and if petitioner's legal theory were correct, they would have been entitled to relief.[121]

Nevertheless, the court denied petitioner's claims on the merits because it found that FPA section 206 "does not require the Commission, having found only one aspect of the tariffs to be unjust or unreasonable, to revisit all elements

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115. *GTN*, 504 F.3d at 1321.

116. *Id.*

117. *Id.* at 1321-22.

118. Colorado Office of Consumer Counsel v. FERC, 490 F.3d 954 (D.C. Cir. 2007) (*Colorado OCC*).

119. *See Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 103 F.E.R.C. ¶ 61,349 (2003), *order on reh'g*, 105 F.E.R.C. ¶ 61,218 (2003).

120. *Colorado OCC*, 490 F.3d at 955.

121. *Id.* at 956.

of its market-based rate tariffs."[122] The court emphasized that any FPA section 206 complaint "'*shall state the change or changes to be made*'. . . and mandating that the Commission '*specify the issues to be adjudicated*.'"[123] According to the court, FPA section 206 makes clear that such "proceedings are designed to identify and address such discrete issues."[124] The court found that this is what the FERC did here by initiating an FPA section 206 investigation and prohibiting practices it had determined were unjust and unreasonable.[125]

III. Natural Gas Act

A. Proxy Groups

In *Petal Gas Storage, L.L.C. v. FERC*,[126] the court addressed consolidated appeals by two interstate natural gas pipeline companies challenging the FERC's ratemaking orders. Both pipelines objected to the composition of the proxy groups used by the FERC in establishing the pipelines' allowed returns on equity, disputing the FERC's *inclusion* of diversified natural gas companies with gas distribution operations, as well as the FERC's *exclusion* of master limited partnerships (MLPs) engaged in interstate transportation of natural gas. The pipelines also maintained that the FERC erred in setting their respective equity returns in the middle of the range of returns calculated from the proxy companies, arguing that an equity return at the high end of the range was appropriate to reflect the fact that the range had been derived from a proxy group that included gas distribution companies with lower risk than interstate natural gas pipelines.

Agreeing with petitioners, the court concluded that there was a lack of "adequate support for the contention that the Commission's proxy group arrangements were risk-appropriate."[127] The FERC had not adequately explained why its chosen proxy companies were risk-comparable to the pipelines, the court reasoned, particularly in view of the FERC's exclusion of gas distribution companies from the proxy group in previous decisions.[128] The court also found fault with the FERC's rationale for setting the pipelines' equity returns in the middle of the range of returns calculated for the proxy group. In this regard, the FERC had "reli[ed] on the 'assumption that pipelines generally fall into a broad range of average risk . . . as compared to other pipelines,'"[129] but such an assumption could be "decisive only given a proxy group composed of other pipelines."[130] The court observed that "[i]f gas distribution companies generally face lower risks than gas pipeline companies (as seems likely), a risk-appropriate placement would be at the high end of the group."[131] While vacating

122. *Id.*

123. *Id.*

124. *Id.* (quoting 16 U.S.C. § 824e (2000)).

125. *Colorado OCC*, 490 F.3d at 956.

126. Petal Gas Storage, L.L.C. v. FERC, 496 F.3d 695 (D.C. Cir. 2007).

127. *Id.* at 699.

128. *Id.* at 699-700.

129. *Id.* at 700 (quoting *High Island Offshore Sys., L.L.C.*, 110 F.E.R.C. ¶ 61,043 at P 154 (2005)).

130. *Petal Gas Storage*, 496 F.3d at 700.

131. *Id.*

and remanding the FERC's decision on the proxy group issue, the court did not dictate any particular proxy group arrangement.[132] The court suggested that the FERC might include distribution companies in the proxy group and place the equity returns at the top of the range, or it might include MLPs and set the returns in the middle of the range.[133] The FERC might even reach the same result, the court noted, "albeit explained and justified in very different terms."[134] The court observed that, on remand, the overall proxy group arrangement must "make[] sense in terms of relative risk,"[135] and "in terms of the statutory command to set 'just and reasonable' rates, 15 U.S.C. § 717c, that are 'commensurate with returns on investments in other enterprises having corresponding risks' and 'sufficient to assure confidence in the financial integrity of the enterprise . . . [and] maintain its credit and . . . attract capital.'"[136]

Separately, the court affirmed the FERC on a number of other issues raised by one of the pipelines. In particular, the court found that the FERC had not acted arbitrarily and capriciously in rejecting an uncontested rate settlement filed by the pipeline where the settlement would have resulted in rates "half again as high" as the rates that had been approved by an administrative law judge, and where the settlement would have awarded a multi-million dollar payment exclusively to the active parties in the case.[137] Rejecting the argument that the FERC had excessively scrutinized the uncontested settlement, the court observed, "we see only the independent consideration of fairness, reasonableness and public interest the Commission is duty-bound to give."[138] The court also upheld the FERC's rulings as to the appropriate depreciation rates and management fee to be used in calculating the pipeline's rates.[139]

B. Alaska Natural Gas Pipeline Act

In *Exxon Mobil Corporation v. FERC,*[140] the court denied petitions seeking pre-enforcement review of two FERC regulations promulgated pursuant to the Alaska Natural Gas Pipeline Act (ANGPA).[141] Petitioners argued that the regulations contained in sections 157.36 and 157.37 of Title 18 of the Code of Federal Regulations purported to give the FERC authority to condition a certificate of public convenience and necessity for an Alaskan natural gas pipeline upon the project sponsor's willingness to increase the capacity or expandability of the project, in contravention of the ANGPA and section 7(a) of the Natural Gas Act.[142]

After finding that the issues presented were ripe for judicial review, the court concluded that the challenged regulations were not facially invalid. The

132. *Id.*
133. *Id.*
134. *Id.*
135. *Id.*
136. *Id*. (quoting FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944)) (alterations in the original).
137. *Petal Gas Storage*, 496 F.3d at 701.
138. *Id.* at 701.
139. *Id.* at 702-03.
140. Exxon Mobil Corp. v. FERC, 501 F.3d 204 (D.C. Cir. 2007).
141. 15 U.S.C. §§ 720-720n (2000).
142. 15 U.S.C. § 717f(a) (2000).

court found that the regulations in 18 C.F.R. § 157.36 merely gave the FERC authority to *allocate* pipeline capacity that the sponsor proposed to add of its own accord, and not, as petitioners contended, the authority to compel expansion of the pipeline.[143] The petitioners objected to 18 C.F.R. § 157.37 on the grounds that the FERC's authority to "require changes in project design" under the regulation could allow the FERC to condition a certificate upon the sponsor building a pipeline with more capacity than originally proposed. The court found that the FERC had not adopted this "highly strained" reading of the regulation.[144] Moreover, because 18 C.F.R. § 157.37 otherwise would be capable of valid application (e.g., to require design changes involving routing, cost allocation, or the design of initial rates), the court concluded that the rule "obviously is not invalid on its face."[145]

C. Accounting

In *Interstate Natural Gas Association of America v. FERC*[146] the court denied Interstate Natural Gas Association of America's (INGAA) petition for review of FERC's issuance of an accounting order pertaining to the expensing of certain costs associated with the Pipeline Safety Improvement Act of 2002 (PSIA).[147] INGAA sought review of the order arguing that certain costs incurred to implement PSIA should be capitalized and not expensed because they were non-recurring costs. The court denied the petition for review, finding that the Commission had provided a reasoned explanation for the expensing of PSIA costs and had adequately responded to all of INGAA's arguments.

The PSIA required operators of natural gas pipelines to adopt and implement a written integrity management program to monitor and reduce the risks inherent with pipeline segments located in areas of high population density. The integrity management programs were to include two components. First, pipeline operators were to conduct integrity assessments for all pipeline segments in high population density areas by year-end 2012. Second, each high population area segment was to be retested at least once every seven years unless the pipeline operator was granted a waiver.[148]

Pursuant to its authority under the Natural Gas Act, and after issuing a Proposed Accounting Release,[149] the FERC issued an Accounting Order[150] responding to comments received per the Proposed Release and definitively establishing that the PSIA testing costs associated with the integrity management program were to be expensed and not capitalized. The FERC distinguished its treatment of PSIA testing costs in the Accounting Release from earlier precedent

143. *Exxon Mobil Corp.*, 501 F.3d at 210.

144. *Id.*

145. *Id.*

146. Interstate Natural Gas Ass'n of Am., v FERC, 494 F.3d 1092 (D.C. Cir. 2007).

147. Pipeline Safety and Improvement Act of 2002, Pub. L. No. 107-355, 116 Stat. 2985 (2002).

148. 49 U.S.C. §§ 60109 (c)–(d) and 60109(c)(3)(B), (5) (2000).

149. Notice of Proposed Accounting Release, *Accounting for Pipeline Assessment Costs*, 69 Fed. Reg. 67,727 (2004).

150. *Jurisdictional Public Utilities and Licensees, Natural Gas Companies, and Oil Pipeline Companies*, 111 F.E.R.C. ¶ 61,501 (2005).

set in *Northwest Pipeline Corp*. (NPC)[151] noting that in *NPC* the costs incurred were part of a "major pipeline rehabilitation projects involving significant replacements and modifications of facilities" that extended the useful life of the pipeline.[152] The FERC found the PSIA testing, however, was part of on-going maintenance. INGAA's request for rehearing arguing that all implementation and testing costs associated with start-up of the PSIA integrity management program should be capitalized as non-recurring costs was denied. INGAA petitioned for judicial review.

The court reviewed the FERC Accounting Order under 15 U.S.C. § 717r(b) requiring that accounting orders meet § 717r(b)'s "aggrievement" condition,[153] noting that the "FERC is 'free to fashion individual accounting rules' as long as they are not arbitrary or capricious."[154] INGAA offered two arguments on the merits of the Accounting Order. The first argument was that the FERC had departed from the *NPC* precedent without providing a reasoned explanation. The second was that the FERC had failed to reasonably respond to INGAA's comments on both the Proposed Accounting Release and the Accounting Order.

After finding that INGAA had standing as an association, the court rejected INGAA's first argument, finding that the FERC's interpretation of the *NPC* precedent was consistent with the Accounting Order in that *NPC* did not cover PSIA testing because such testing did not, on its own, extend the useful life of the pipeline asset or improve its efficiency.[155] The court found reasonable the FERC's conclusion that PSIA testing did not meet the *NPC* test and therefore the costs were not eligible for capitalization because the primary goal of integrity management programs was to maintain the integrity of the pipeline, not to increase efficiency or capacity of a pipeline.

The court also rejected INGAA's arguments that the FERC failed to adhere to its own precedent without providing explanation by failing to respond to INGAA's arguments regarding the Accounting Order. In response to INGAA's arguments, the court found that the FERC had sufficiently responded to arguments put forth by INGAA and had further provided a reasoned explanation "for its decision not to treat *NPC* as governing."[156]

D. FERC Jurisdiction

1. Authority to Order Remedies

The FERC order on review in *Transcontinental Gas Pipeline Corporation v.*

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151. *Northwest Pipeline Corp.*, No. AC94-149-000 (FERC Apr. 30, 1996).

152. Notice of Proposed Accounting Release, *Accounting for Pipeline Assessment Costs*, 69 Fed. Reg. 67,727 (2004).

153. *See* CNG Transmission Corp. v. FERC, 40 F.3d 1289 (D.C. Cir. 1994).

154. Interstate Natural Gas Ass'n of Am. V. FERC, 494 F.3d 1092, 1095 (citing Anaheim v. FERC, 669 F.2d 799, 806 (D.C. Cir. 1981)) (internal quotation marks omitted); *see also* 5 U.S.C. § 706(2) (2000); Sithe/Independence Power Partners v. FERC, 169 F.3d 944, 948 (D.C. Cir. 1999).

155. The FERC interpreted *NPC* as permitting capitalization of testing meeting three criteria: (1) testing was in connection with a major rehabilitation project involving significant replacements and modifications of facilities; (2) "extended the overall pipeline system's useful life and serviceability or otherwise benefited future accounting periods; and (3) was not associated with any on-going maintenance programs." *NPC*, 494 F.3d at 1095. *See also,* Williams Gas Processing--Gulf Coast Co. v. FERC, 373 F. 3d 1335, 1341 (D.C. Cir. 2004).

156. *NPC*, 494 F.3d at 1097.

FERC,[157] involved a 1992 Settlement between Transcontinental Gas (Transco) and Sunoco for gathering and transportation services after Transco's unbundling pursuant to FERC Order No. 636. Prior to unbundling, Transco had provided gas sales and transportation to Sunoco. The settlement resulted from Transco's attempts to divide its pre-unbundling "take or pay" liabilities between itself and its customers and Sunoco's filing of a complaint with the FERC. In the 1992 Settlement Transco agreed to provide transportation services to Sunoco for twenty years at Transco's maximum FT rate. The transportation service was to also include gathering.

In 2000, Transco petitioned for and received approval to abandon its gathering facilities by sale to its affiliate Williams Gas Processing (Williams). After spinning down its gathering facilities, the subject facilities became non-jurisdictional. In 2002 Sunoco challenged the spin-down arguing that the costs it paid for the services provided pursuant to the 1992 Settlement would significantly increase. In response to the complaint, the FERC ordered Transco to assign capacity (now belonging to Williams) to Sunoco at the 1992 Settlement rate, thus ensuring that Sunoco would continue to receive the settlement services at the agreed-to price. Upon confirmation in several unrelated orders that the FERC had no authority to regulate gathering services, the Commission vacated the 2002 remedy it had imposed. The new remedy ordered by the Commission requiring Transco to reimburse Sunoco for the additional costs incurred as a result of Transco's violation of the 1992 Settlement[158] resulted in the instant petition.

Transco's principle argument was that the FERC lacked jurisdiction to impose the remedy because the gathering services became non-jurisdictional when they were transferred to Williams. Transco claimed that the FERC was indirectly regulating the rates of its affiliate Williams by forcing Transco to reimburse Sunoco for the costs of the gathering services. Transco offered eight additional arguments pertaining to the interpretation of the 1992 Settlement. The court rejected each of Transco's additional arguments finding none persuasive in light of the "high degree of deference" the court gives to Commission interpretations of settlement agreements.[159]

With regard to its primary argument that the FERC lacked jurisdiction to order the reimbursement, the court disagreed finding that the FERC's order did not regulate Williams's gathering services "in any way,"[160] but was expressly directed at Transco for causing Sunoco's costs to increase. After a review of the applicable case law, the court concluded that case law demonstrated the FERC had jurisdiction to order the reimbursement remedy. It further found that each case cited by Transco was distinguishable and not applicable. As the settlement agreement covered gathering services that were within the jurisdiction of the FERC at the time of the settlement agreement with Sunoco, the court ruled that the FERC's order remedied the violation of a contract regarding jurisdictional services despite being issued after the facilities became non-jurisdictional.

157. Transcontinental Gas Pipe Line Corp. v. FERC, 485 F. 3d 1172 (D.C. Cir. 2007).

158. *Sunoco, Inc. v. Transcon. Gas Pipe Line Corp*., 111 F.E.R.C. ¶ 61,400 at P 12 (2005).

159. *Transcontinental*, 485 F. 3d at 1178.

160. *Id*. at 1178.

2. Offshore Gathering

Jupiter Energy Corporation (Jupiter) petitioned the Fifth Circuit for review of FERC orders rejecting Jupiter's request that the FERC find two of its pipelines to be non-jurisdictional gathering lines.[161] The FERC had previously determined that the Jupiter pipelines performed a transportation function.[162] In 2003 Jupiter requested that the Commission find that the two pipelines which originated offshore and carried unprocessed gas to two onshore pipelines be declared as performing a non-jurisdictional gathering function rather than a transportation function, arguing that the small diameter lines met the criteria of the modified primary function test.[163] After denying Jupiter's request for a finding that the pipelines performed a transportation function, and denying rehearing, Jupiter petitioned the Fifth Circuit for review. Upon review the court vacated the 2003 FERC order regarding Jupiter's jurisdictional status and remanded to the FERC for further consideration.[164] The Commission reaffirmed its jurisdiction over Jupiter's lines and again denied Jupiter's request for rehearing. In its second petition for review of the FERC's determination, Jupiter argued that the FERC placed too much emphasis on location of the jurisdictional point of delineation at Platform 39A offshore and ignored other factors in its determination of Jupiter's jurisdictional status.

After finding that the standard of review for FERC's orders was the arbitrary and capricious standard, the court determined it would uphold the Commission's application of the primary function test only as long as the Commission provided "reasoned consideration to each of the pertinent factors and articulates factual conclusions that are supported by substantial evidence in the record."[165] The Commission argued that Jupiter was not able to meet its burden of proving the Commission's determination that Platform 39A was the "central point" was patently unreasonable. The Commission also stated that it had reasonably reaffirmed its functional analysis.

The court found that the FERC's determination of Jupiter's jurisdictional status did not comport with the *Sea Robin* precedent requiring that the Commission not discount any of the factors of the primary function test without reasoned analysis.[166] Finding that the Commission had ignored factors such as the pipeline's length, diameter, and operating pressure with no reasoned analysis as to why these factors were negated, the Fifth Circuit vacated the Commission's order and remanded to the Commission for further consideration consistent with the court's opinion.

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161. Jupiter Energy Corp. v. FERC, 482 F.3d 293, 294 (5th Cir. 2007).

162. *The Jupiter Corp.*, 35 F.P.C. 1091 (1966).

163. *Sea Robin Pipeline Co.*, 92 F.E.R.C. ¶ 61,072 (2000).

164. Jupiter Energy Corp. v. FERC, 407 F.3d 346 (5th Cir. 2005).

165. *Jupiter Energy Corp*, 482 F.3d at 296 (citing ExxonMobil Gas Mktg. Co. v. FERC, 297 F.3d 1071, 1084 (D.C. Cir. 2002) (citing Lomak Petroleum, Inc. v. FERC, 206 F.3d 1193, 1197 (D.C. Cir. 2000)).

166. *Jupiter Energy Corp*, 482 F.3d at 297.

E. Tariffs

The court's decision in *North Baja Pipeline, LLC* (North Baja)[167] concerned a tariff filing by North Baja in which the pipeline proposed to share the cost of *force majeure* interruptions with shippers. North Baja based its formula for sharing costs on two similar tariff provisions approved by the Commission in *Texas Eastern Transmission Corp.* (Texas Eastern)[168] and *Natural Gas Pipeline Company of America* (Natural).[169] However, the methods followed by Texas Eastern and Natural (the "Tennessee policy") were not identical. North Baja proposed a hybrid of the two policies by combining the no-refund period from *Texas Eastern* (no-refund in the first ten days of force majeure event) with the percentage refund under the *Tennessee* policy (percentage refund over the entire outage period). The resulting formula proposed by North Baja was no refunds with respect to the first ten days of a *force majeure* event and a percentage refund thereafter. North Baja further proposed to include scheduled maintenance as a *force majeure* event because its lack of excess capacity meant North Baja could not avoid interrupting service to perform necessary maintenance. The FERC rejected both items in the proposal and upheld its decision on rehearing, citing its longstanding policy of excluding scheduled maintenance from the definition of *force majeure*.[170]

On appeal, the court reviewed the Commission's orders under the arbitrary and capricious standard applicable to administrative agencies.[171] Finding that the approved *Texas Eastern* and *Tennessee* formulas evenly balanced risk between shippers and the pipeline, the court determined that North Baja had "cherry-picked" the aspects of each policy most favorable to it by combining the no-refund period with the percentage refund after the first ten days of the interruption.[172] The court agreed with the FERC that North Baja's proposal did not equitably balance the risk of a *force majeure* interruption, and that it was reasonable for the FERC to compare North Baja's proposal to previously approved policies such as *Texas Eastern* and *Tennessee*. The court upheld the Commission's determination, ruling that the FERC had reasonably rejected North Baja's proposal as inconsistent with the FERC policy on both the proposed cost sharing formula and the inclusion of scheduled maintenance as a force majeure event.

IV. INTERSTATE COMMERCE ACT: OIL PIPELINES

A. Reparations

In *ExxonMobil Oil Corp. v. FERC*,[173] Petitioners sought review, *inter alia*, of the Commission's denial of their claim for reparations for the transportation

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167. North Baja Pipeline, LLC v. FERC, 483 F.3d 819 (D.C. Cir. 2007).

168. *Texas E. Transmission Corp.*, 62 F.E.R.C. ¶ 61,015 (1993).

169. *Natural Gas Pipeline Co. of Am.*, 106 F.E.R.C. ¶ 61,310 (2004).

170. *See Florida Gas Transmission Co.*, 107 F.E.R.C. ¶ 61,074 (2004); *Alliance Pipeline L.P.*, 84 F.E.R.C. ¶ 61,239 (1998); and *El Paso Natural Gas Co*., 105 F.E.R.C. ¶ 61,262 (2003).

171. *See* 5 U.S.C. § 706(2)(A) (2000).

172. *North Baja Pipeline*, 483 F.3d at 822.

173. ExxonMobil Oil Corp. v. FERC, 487 F.3d 945 (D.C. Cir. 2007).

rates they had paid to use SFPP, L.P.'s (SFPP) East Line since August 1, 2000. The issue before the court was whether the Supreme Court's ruling in *Arizona Grocery Co. v. Atchison, T. & S.F. Ry. Co.*[174] precluded payment of reparations otherwise due Petitioners. The Supreme Court held in *Arizona Grocery* that once the Commission has prescribed a lawful (just and reasonable) rate, it may not later subject a carrier to reparations (as opposed to prospective relief) based on a revised determination of the rate's reasonableness.[175]

The Petitioners argued that *Arizona Grocery* did not preclude payment of reparations in this case because the Commission had yet to prescribe or approve a final rate for service on the East Line. The Commission argued that reparations were not warranted because SFPP proposed the rates in response to a Commission order. The Commission accepted the rates on an interim basis, and at the time the rates were accepted, the Commission explicitly recognized the Petitioners' right to appropriate refunds pending the Commission's finalization of just and reasonable rates. According to the Commission, the interim rates, minus potential refunds, constituted an "approved or prescribed" rate under *Arizona Grocery* and therefore, Petitioners were not entitled to reparations.[176]

The court agreed with the Petitioners. It found that when the Commission accepts a pipeline's proposed tariff subject to suspension and refund without even establishing the methodology for determining the final rate, "the Commission cannot properly be considered to have prescribed a just and reasonable rate until the proposed tariff is approved at the completion of the compliance proceedings."[177] The court questioned how pipelines could have relied upon the Commission's determination regarding the rates, when the Commission failed to approve, prescribe, or even declare a definitive methodology by which pipelines were to compute reasonable rates.[178] The court found that "[t]o extend *Arizona Grocery* protection to such unsettled rates retroactively would itself amount, potentially, to retroactive ratemaking."[179]

B. Failure to Investigate

In *ExxonMobil Oil Corp. v. FERC*,[180] Petitioners sought review of a Commission order refusing to investigate Petitioners' claims, under section 15(7) of the Interstate Commerce Act.[181] Petitioners had protested the indexed rates filed by SFPP, L.P., alleging that the index increase was substantially in excess of any actual cost increases incurred.

The court dismissed the petitions in a terse, four-paragraph judgment, declaring that it was "without jurisdiction to review the Commission's failure to investigate," based on the Supreme Court's decision in *Southern Railway Co. v. Seaboard Allied Milling Corp.*[182] There, the Supreme Court held that former

174. Arizona Grocery Co. v. Atchison, T. & S.F. Ry. Co., 284 U.S. 370 (1932).
175. *Id.* at 390.
176. *ExxonMobil Oil Corp.*, 487 F.3d at 962-63.
177. *Id.* at 968.
178. *Id.*
179. *Id.*
180. ExxonMobil Oil Corp. v. FERC, 219 F. App'x 3 (D.C. Cir. 2007).
181. 49 U.S.C. app. § 15(7) (1988).
182. Southern Railway Co. v. Seaboard Allied Milling Corp., 442 U.S. 444, 454 (1979).

section 15(8)(a) of the Interstate Commerce Act,[183] a derivative of section 15(7), precluded judicial review of an agency's decision not to order a hearing. Section 15(7), the court pointed out, is a statute that "precludes judicial review."[184] The court concluded that there was "no basis for distinguishing *Southern Railway* and petitioners have offered none."[185] Although the court ruled that the issues presented did not warrant a published opinion under D.C. Circuit Rule 36, the ruling clarifies that the court lacks jurisdiction to review Commission decisions not to investigate indexed rate filings by oil pipelines.

V. BONNEVILLE POWER ADMINISTRATION

Bonneville Power Administration (BPA) sells power to preference customers, direct-service industrial users (DSIs), and investor-owned utilities (IOUs).[186] BPA's activities and rates are controlled by the Northwest Electric Power Planning and Conservation Act (NWPA), 16 U.S.C. §§ 839-839h.[187] BPA's power comes from hydroelectric projects in the Columbia River Basin and from market purchases.[188] BPA is required to charge preference customers cost-based rates subject to certain limitations.[189] In 2001 BPA adopted rates, to be effective beginning in 2002, for preference customers that included (1) the cost of power generated by the hydroelectric facilities (Base Costs), (2) the cost of purchased power that would not have been necessary but for the sales to DSIs (PPA Costs), (3) the cost of a settlement with IOUs implementing the Residential Exchange Program (REP) provided for by section 5(c) of the NWPA (REP Costs),[190] and (4) the estimated cost of fish and wildlife operations (ESA Costs).[191] Preference customers challenged the inclusion of the PPA Costs and the REP Costs in their rates.[192] Confederated Tribes of the Umatilla Indian Reservation and the Yakama Nation (Tribes) asserted that the ESA Costs were inadequate to satisfy BPA's fish and wildlife obligations.[193]

BPA may charge preference customers the costs of the portion of the Federal base system (FBS) resources needed to satisfy their loads.[194] The Court found that FBS resources include purchased power sufficient to replace reductions in capability of the hydroelectric facilities, and that BPA had the authority to impose rates on preference customers based on the average cost of FBS resources including the PPA Costs.[195] Section 7(b)(2) of the NWPA

183. 49 U.S.C. § 15(8)(a) (1976).

184. *ExxonMobil Oil Corp.*, 219 F. App'x 3.

185. *Id.*

186. Golden Nw. Aluminum, Inc. v. Boonville Power Admin., 501 F.3d 1037, 1041 (9th Cir. 2007) (Preference customers are public utilities, cooperatives, and federal agencies).

187. *Id.*

188. *Id*. at 1041-42.

189. *Id.* at 1041.

190. The REP is a mechanism to ensure IOUs to have access to low-cost power. IOU's may sell a certain amount of power to BPA at their average system cost and purchase the same amount from BPA at a lower price. *Id.* at 1047.

191. *Id*. at 1040-42.

192. *Id.* at 1040-41.

193. *Id*. at 1041.

194. *Id.* at 1045.

195. *Id*. at 1045-47.

requires BPA to calculate rates charged to preference customers as if no residential exchange program transactions were made.[196] BPA classified the REP Costs as ordinary costs of doing business that it could collect from all customers.[197] The Court found that BPA's classification violated section 7(b)(2) of the NWPA and remanded to BPA to set preference customer rates appropriately.[198] BPA conducted a public process that resulted in its estimated ESA Costs in 1998.[199] In that process, the Tribes offered evidence of changed circumstances that they claimed demonstrated that BPA's estimated ESA Costs were too low.[200] BPA discounted and minimized the Tribes' evidence and refused to recalculate estimated ESA Costs in setting its rates.[201] The Court held that BPA's estimates and subsequent rates were not supported by substantial evidence and that exclusion of information was contrary to law.[202] BPA was ordered to set rates in accordance with the opinion of the 9th Circuit.

196. *Id.* at 1048.

197. *Id*.

198. *Id.* at 1048, 1053. *See also* Portland Gen. Elec. v. Boonville Power Admin., 501 F.3d 1009 (9th Cir. 2007).

199. *Golden Northwest*, 501 F.3d at 1049.

200. *Id.* at 1049-50.

201. *Id*. at 1051-52.

202. *Id.* at 1052.

JUDICIAL REVIEW COMMITTEE