144 FERC ¶ 61,132
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony Clark.

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| Golden Spread Electric Cooperative, Inc.<br>Lyntegar Electric Cooperative, Inc.<br>Farmers' Electric Cooperative, Inc.<br>Lea County Electric Cooperative, Inc.<br>Central Valley Electric Cooperative, Inc.<br>Roosevelt County Electric Cooperative, Inc.<br><br>v.<br><br>Southwestern Public Service Company | Docket No. EL05-19-004 |
| Southwestern Public Service Company | Docket No. ER05-168-003 |

OPINION NO. 501-A

ORDER ON REHEARING

(Issued August 15, 2013)

1. On May 21, 2008, Southwestern Public Service Company (SPS), Golden Spread Electric Cooperative, Inc. (Golden Spread), Cap Rock Energy Corporation (Cap Rock), Public Service Company of New Mexico (PNM), Edison Electric Institute (EEI), and the New Mexico Cooperatives[1] filed requests for rehearing of Opinion No. 501,[2] an order on exceptions to an initial decision, issued April 21, 2008, in the above-captioned dockets. Opinion No. 501 addressed SPS's practice of attributing system average fuel costs to its

[1] For the purposes of this order, the New Mexico Cooperatives consist of Central Valley Electric Cooperative, Inc. (Central Valley), Farmers' Electric Cooperative, Inc. (Farmers'), Lea County Electric Cooperative, Inc. (Lea County), and Roosevelt County Electric Cooperative, Inc. (Roosevelt County).

[2] *Southwestern Pub. Serv. Co.*, Opinion No. 501, 123 FERC ¶ 61,047 (2008).

market-based rate sales for the purposes of calculating fuel cost billings to its wholesale cost-based customers under SPS's fuel cost adjustment clause (FCAC). The order also addressed proposed changes to SPS's FCAC and a number of cost-of-service issues associated with SPS's cost-based rates for full and partial requirements service. As discussed below, the Commission grants in part and dismisses as moot in part the parties' requests for rehearing and clarification.

## I. Background

2. On November 2, 2004, several cooperatives[3] filed a complaint under section 206 of the Federal Power Act (FPA)[4] alleging that SPS had historically violated, and continued to violate, the FCAC provisions of its wholesale customers' rate schedules and the Commission's FCAC regulations.[5] The cooperatives also alleged that SPS's cost-based rates for full and partial requirements service were excessive, unjust and unreasonable, and unduly discriminatory or preferential. On the same date that the cooperatives filed their complaint, SPS filed a proposal under section 205 of the FPA to change its FCAC and to make corresponding revisions to its power supply contracts.[6]

3. On December 21, 2004, the Commission established hearing and settlement judge procedures in the cooperatives' complaint case, and set a refund effective date of January 1, 2005.[7] On December 29, 2004, the Commission accepted and suspended for a nominal period, subject to refund, SPS's proposed changes to its FCAC, effective January 1, 2005 (60 days following SPS's section 205 filing).[8] The Commission also consolidated SPS's proposed FCAC changes with the proceeding already underway in

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[3] These cooperatives included Golden Spread, Lyntegar Electric Cooperative, Inc. (Lyntegar), Farmers', Lea County, Central Valley, and Roosevelt County (collectively, complainants or cooperatives).

[4] 16 U.S.C. § 824e (2006).

[5] Complaint, Docket No. EL05-19-000 (Nov. 2, 2004).

[6] SPS Filing, Docket No. ER05-168-000 (Nov. 2, 2004).

[7] *Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,321 (2004). In accordance with FPA section 206(b) as it existed at the time of the complaint, the refund effective date was established as sixty days after the filing of the complaint.

[8] *Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,373 (2004).

the complaint case. On May 24, 2006, the Administrative Law Judge (ALJ) issued an Initial Decision in the consolidated case.[9]

4. On December 3, 2007, SPS submitted a settlement agreement (2007 Settlement Agreement) on behalf of itself, Occidental Permian Ltd. and Occidental Power Marketing, L.P. (jointly, Occidental), Golden Spread, and Lyntegar (collectively, the 2007 Settling Parties). The 2007 Settlement Agreement resolved all issues among SPS, Occidental, Golden Spread, and Lyntegar except one, which was the issue of the appropriate demand cost allocator for the SPS system.

5. On April 21, 2008, the Commission issued two orders in this proceeding. The first approved the uncontested 2007 Settlement Agreement, subject to modification based on the Commission's determination of the proper demand cost allocator for SPS.[10] The second was Opinion No. 501, which affirmed in part and reversed in part the Initial Decision. Opinion No. 501 resolved all issues among SPS and the parties not involved in the 2007 Settlement Agreement, in addition to resolving the demand cost allocator issue for all parties in the proceeding, including the 2007 Settling Parties.

6. SPS, Golden Spread, Cap Rock, PNM, and the New Mexico Cooperatives filed timely requests for rehearing of Opinion No. 501. EEI filed a late motion to intervene and request for rehearing. Occidental and the New Mexico Cooperatives filed answers to EEI's late-filed motion to intervene. The New Mexico Cooperatives filed an answer to SPS's request for rehearing. SPS filed an answer to PNM's request for rehearing. PNM filed an answer to SPS's answer, and SPS filed answers to the answers of both PNM and the New Mexico Cooperatives.

7. On July 21, 2008, SPS submitted a compliance filing, pursuant to the Commission's order in Opinion No. 501, quantifying the refunds related to SPS's cost-of-service rates and FCAC billings.

8. On January 19, 2010, SPS submitted a settlement agreement (January 2010 Settlement Agreement) on behalf of itself, the New Mexico Cooperatives, and Occidental (collectively, the January 2010 Settling Parties). The January 2010 Settlement Agreement resolved all issues among SPS, Occidental, and the New Mexico Cooperatives. Because the demand cost allocator issue was pending rehearing in this proceeding, the January 2010 Settlement Agreement contained alternative resolutions based on the demand cost allocator issue; i.e., a different resolution for each of the

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[9] *Golden Spread Elec. Coop., Inc.*, 115 FERC ¶ 63,043 (2006) (Initial Decision).

[10] *Golden Spread Elec. Coop., Inc.*, 123 FERC ¶ 61,054 (2008).

two possible outcomes on that issue. On June 22, 2010, the Commission approved the uncontested January 2010 Settlement Agreement.[11]

9. On July 7, 2010, SPS submitted a settlement agreement (July 2010 Settlement Agreement) on behalf of itself, Cap Rock, and Occidental (collectively, the July 2010 Settling Parties). The July 2010 Settlement Agreement resolved all issues among SPS, Occidental, and Cap Rock. On December 20, 2010, the Commission approved the uncontested July 2010 Settlement Agreement.[12]

## II. Procedural Issues

### A. EEI's Motion to Intervene and Request for Rehearing

10. On May 21, 2008, EEI submitted a late motion to intervene and request for rehearing of Opinion No. 501. EEI argues there is good cause for accepting its motion to intervene. EEI explains that the Commission's use of the median, rather than the midpoint, of the zone of reasonableness for determining the non-incentive return on equity (ROE) for a single utility of average risk in Opinion No. 501 will adversely affect most EEI member companies, and as the representative of those companies, EEI has a substantial interest in this proceeding. EEI states that prior to the issuance of Opinion No. 501, it could not have anticipated that the Commission would use this proceeding as the vehicle for reversing the Commission's policy on the midpoint versus median issue. EEI further notes that the Commission has previously granted late motions to intervene by EEI in appropriate circumstances.[13]

11. Occidental and the New Mexico Cooperatives filed answers to EEI's motion to intervene and request for rehearing. These parties argue that EEI has not demonstrated good cause to intervene at this late date and that granting EEI's intervention would be prejudicial to the parties and disruptive to the proceedings. Moreover, the parties argue EEI's interest with regard to the median versus midpoint issue is adequately represented by SPS.

[11] *Golden Spread Elec. Coop., Inc. v. Southwestern Pub. Serv. Co.*, 131 FERC ¶ 61,260 (2010).

[12] *Golden Spread Elec. Coop., Inc. v. Southwestern Pub. Serv. Co.*, 133 FERC ¶ 61,243 (2010).

[13] EEI's May 21, 2008 Motion to Intervene and Request for Rehearing at 4 n.18 (citing *Pub. Serv. Co. of N.H. v. N.H. Elec. Coop.*, 84 FERC ¶ 61,129 (1998); *Pub. Serv. Elec. & Gas Co.*, 63 FERC ¶ 61,200 (1993); *Pa. Elec. Co.*, 60 FERC ¶ 61,034 (1992)).

12. The Commission will deny EEI's motion to intervene out-of-time. When late intervention is sought after the issuance of a dispositive order, the prejudice to other parties and burden upon the Commission of granting the late intervention may be substantial. Thus, movants bear a higher burden to demonstrate good cause for granting such late intervention. EEI has not met this higher burden of justifying its late intervention.[14] Here, EEI has been on notice since the complaint was filed that the issue of the use of the median versus the midpoint for ROE determinations would be before the Commission in this proceeding.[15] In addition, the prejudice to other parties involved in this matter would be severe if the Commission were to grant EEI's late motion to intervene and consider the new materials and arguments contained in EEI's rehearing request.

13. In light of our decision to deny EEI's late motion to intervene, we will also dismiss EEI's request for rehearing. Because EEI is not a party to this proceeding, it lacks standing to seek rehearing of Opinion No. 501 under the FPA and the Commission's regulations.[16]

### B. Answers to Requests for Rehearing

14. Rule 713(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d) (2013), prohibits answers to requests for rehearing. Therefore, we will reject the answers filed by SPS, the New Mexico Cooperatives, PNM, and Occidental, as well as the answers to answers filed by SPS and PNM.

## III. Requests for Rehearing

15. The requests for rehearing in this proceeding can be divided into four categories: FCAC issues, the refund period, SPS's return on equity, and demand cost allocation. The New Mexico Cooperatives and Cap Rock request rehearing only on the refund period issue. Golden Spread requests rehearing only on the demand cost allocation issue, as discussed in detail below. SPS requests rehearing on the refund period, return on equity, and multiple FCAC issues. In addition, SPS seeks clarification on the calculation of

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[14] *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 61,250, at P 7 (2003).

[15] *See* Complaint, Docket No. EL05-19-000, Exhibit CCG-6 at 9-11 (Nov. 2, 2004).

[16] *See* 16 U.S.C. § 825(a) (2006); 18 C.F.R. § 385.713(b) (2013); *Southern Co. Services, Inc.*, 92 FERC ¶ 61,167 (2000).

revenue credits for requirements customers and whether PNM is entitled to refunds from SPS's FCAC charges. PNM seeks rehearing on the demand cost allocation and refund period issues. Last, as discussed in more detail below, PNM also seeks clarification, and alternatively rehearing, on whether PNM is entitled to FCAC refunds.

16. The Commission approved the 2007 Settlement Agreement, January 2010 Settlement Agreement, and July 2010 Settlement Agreement in this proceeding. Taken together, the three settlement agreements resolve, as among the settling parties, all contested issues except one: the dispute between Golden Spread and SPS over the appropriate demand cost allocator.[17]

17. The only parties that did not settle as to each other are PNM and SPS. As a result, PNM's and SPS's requests for rehearing and clarification are still pending. However, as discussed in detail below, we clarify in the instant order that PNM is not entitled to FCAC refunds. Therefore, PNM's request for rehearing on the proper refund period for SPS's FCAC charges is moot. Similarly, SPS's rehearing requests concerning the FCAC issues are also rendered moot by our clarification regarding PNM. In the aftermath of the settlement agreements, the only party that could possibly receive a refund based on our reconsideration of the FCAC issues is PNM. Thus, our clarification that PNM is not entitled to FCAC refunds moots SPS's remaining requests for rehearing and clarification concerning the FCAC issues because SPS has already settled with all parties.

18. Accordingly, we dismiss as moot all of the requests for rehearing and clarification except two. As discussed below, we provide clarification on PNM's eligibility for FCAC refunds, and we grant rehearing on the issue of the appropriate demand cost allocator for the SPS system.

## A. Refunds to PNM

### 1. Requests for Clarification

19. PNM argues that the Commission should clarify that PNM is entitled to refunds for improper FCAC billings by SPS. PNM states that the ALJ specifically ruled that PNM was entitled to refunds, and that nothing in Opinion No. 501 reverses this finding. PNM further contends that SPS conceded that if it were required to make refunds, PNM

[17] SPS, *et al.*, Dec. 3, 2007 Offer of Settlement, Explanatory Statement at 5-6; SPS, *et al.*, Jan. 19, 2010 Offer of Settlement, Explanatory Statement at 5-7; SPS, *et al.*, July 7, 2010 Offer of Settlement, Explanatory Statement at 7-8.

would be entitled to receive them.[18] However, PNM states that in the interest of clarity, the Commission should expressly state that PNM is entitled to refunds for improper FCAC billings.

20. PNM explains that it purchased power from SPS under three contracts during the applicable time period: the PNM Interruptible Contract, the 2002 PNM contract, and the 2003 PNM contract. PNM states that each of these contracts contained the same FCAC that applied to the complainants and Cap Rock in this proceeding, and thus, PNM was subject to the same illegal FCAC billing practices. PNM states that the Commission has found that when a utility is required to make refunds under its FCAC, all customers whose rates include an FCAC are entitled to refunds.[19]

21. PNM asserts that Opinion No. 501 was "concerned about market-based intersystem sales being subsidized by 'native load customers,' 'captive customers,' and 'requirements customers.'"[20] PNM argues that although it is not a native load customer or requirements customer, it is a captive customer with respect to the PNM Interruptible Contract.[21] PNM argues that the distinctions between the PNM Interruptible Contract and the 2002 and 2003 PNM contracts, as well as the distinctions between native load customers, requirements customers, and captive customers, should not matter in this case

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[18] PNM argues that SPS did not challenge in its Brief on Exceptions the ALJ's assertion that SPS acknowledged that, should it be ordered to issue refunds, PNM was entitled to them. As a result, PNM argues that SPS waived any objection to this aspect of the Initial Decision. *See* PNM Request for Rehearing at 29 (citing Initial Decision, 115 FERC ¶ 63,043 at P 240).

[19] *Id.* at 30 (citing *N.C. Elec. Membership Corp v. Carolina Power & Light, Co.*, 57 FERC ¶ 61,332, at 62,067 (1991)).

[20] PNM Request for Rehearing at 30. As explained in Opinion No. 501, "intersystem sales" and "opportunity sales" are interchangeable terms. Opinion No. 501, 123 FERC ¶ 61,047 at P 39.

[21] PNM states that the Commission recently defined "captive customer," for the purposes of its rules governing market-based rates, to include customers served under cost-based regulation, which PNM argues is the case for PNM under the PNM Interruptible Contract, although not for the 2002 and 2003 PNM contracts. *Id.* (citing *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, 72 Fed. Reg. 39,904 (July 20, 2007), FERC Stats. & Regs. ¶ 31,252 at P 478 & PP 848-850, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, 123 FERC ¶ 61,055 (2008)).

because PNM is similarly situated to SPS's requirements customers. Specifically, PNM argues it was improperly billed by SPS under the FCACs contained in all three contracts, and because the FCACs in PNM's contracts were the same as the FCACs in the complainants' and Cap Rock's contracts, PNM should receive refunds for improper FCAC billings under all three contracts. PNM argues the Commission has no grounds for treating PNM differently from the complainants and Cap Rock.

22. SPS requests clarification that PNM is not entitled to refunds. SPS states that pursuant to all three PNM contracts at issue in this proceeding, PNM was the beneficiary of average cost pricing. SPS explains that on September 15, 2005, PNM filed a separate complaint in Docket No. EL05-151-000, alleging that SPS misapplied its FCAC by using average fuel costs to price energy associated with its off-system firm power sales, including the three sales to PNM.[22] SPS states that the parties settled all cost-of-service issues in Docket No. EL05-151-000, but reserved to each party their "rights with regard to the FCAC issues currently held in abeyance in Docket No. EL05-151-000."[23] SPS argues that if PNM is entitled to any remedy, it should come from a final resolution of the proceeding in Docket No. EL05-151-000.

23. SPS further argues that although the Commission determined that Cap Rock was entitled to refunds, PNM is not in the same "customer class" as Cap Rock. SPS states that, while both Cap Rock and PNM were intervenors in this proceeding, and not complainants, the two are not similarly situated, because PNM has never taken full requirements service from SPS and, thus, it does not pay the same rates as Cap Rock.

### 2. Commission Determination

24. We clarify that PNM is not entitled to refunds for SPS's improper FCAC practices. In Opinion No. 501, the Commission explained that Cap Rock was entitled to FCAC refunds in this proceeding because Cap Rock pays the same charges as SPS's full requirements customers.[24] PNM argues that it is similarly entitled to refunds because all of the PNM contracts at issue in this proceeding contain FCAC clauses. However, it was not the Commission's intention in Opinion No. 501 to order refunds for all SPS contracts

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[22] The Commission severed the FCAC issues and held them in abeyance pending a final Commission order on the Initial Decision in this proceeding. *See Public Serv. Co. of N.M. v. Southwestern Pub. Serv. Co.*, 113 FERC ¶ 61,153 (2005).

[23] *See Pub. Serv. of N.M. v. Southwestern Pub. Serv. Co.*, 124 FERC ¶ 61,232 (2008) (approving contested partial settlement).

[24] Opinion No. 501, 123 FERC ¶ 61,047 at P 201.

with FCAC clauses. The purpose of granting refunds in that order was to compensate SPS's native load and full requirements customers for SPS's improper FCAC practices. SPS plans its resources for those customers who are obligated to pay for the construction and maintenance of these resources, with the exception of off-system customers. The customers who are obligated to pay these costs are entitled to average cost fuel pricing that excludes the incremental costs associated with opportunity sales, so they can receive the benefit of the resources for which they are obligated to pay without subsidizing SPS's use of those resources to make sales to other customers.[25] Thus, it was the rates of the native load and full requirements customers that were improperly inflated by SPS's use of the average cost of fuel for its intersystem sales in calculating FCAC billings. Cap Rock, unlike PNM, was a full requirements customer. Customers who engaged in opportunity sales with SPS, such as PNM, actually benefited from SPS's FCAC practices because they paid a lower cost of fuel, i.e., average fuel cost (which only native load customers were entitled to), than they would have paid had they been paying the appropriate cost of opportunity sales, i.e., incremental fuel cost.[26] Thus, we find that, regardless of whether PNM's contracts contained FCACs, as an off-system sales customer, PNM is not entitled to refunds for SPS's FCAC practices.

## B. Demand Allocation

25. As explained in Opinion No. 501, demand allocation refers to the method of apportioning fixed capacity costs among customer classes. The Commission typically uses a coincident peak method to allocate demand costs, through which demand costs are allocated based on the customer class's load at the time of (or coincident with) the system peak load. The coincident peak may be based, for example, on a single peak month (1 CP), the average of three peak months (3 CP), or the average of peaks in 12 months (12 CP). Typically, a company that has a relatively flat load profile throughout the year would allocate demand costs on a 12 CP basis, which assumes that a utility's load is relatively constant throughout all 12 months of the year. A summer (or winter) peaking company would allocate demand costs more typically on a 3 CP basis, which assumes the load profile peaks during three peak usage months.

### 1. Opinion No. 501

26. In Opinion No. 501, the Commission reversed the ALJ's finding that the 3 CP demand allocator proposed by SPS was the correct demand allocator for the SPS system.

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[25] *Id.* at PP 41-45. *See also Re Entergy Servs., Inc.*, 58 FERC ¶ 61,234, at 61,772 (1992).

[26] *See* Opinion No. 501, 123 FERC ¶ 61,047 at P 44.

Based upon a review of the record, the Commission concluded that load profile changes on the SPS system warranted shifting to a 12 CP demand allocation methodology.

27. The Commission also noted that historically, as part of a review of a company's operating realities, the Commission has used three separate peak load tests to determine whether the system demands are characteristic of a 3 CP system or a 12 CP system.[27] The first test is the On and Off Peak test, whereby the Commission compares the average of the system peaks during the purported peak period, as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak.[28] For the second test, the Low to Annual Peak test, the Commission calculates the lowest monthly peak as a percentage of the annual peak.[29] For the third test, the Average to Annual Peak test, the Commission computes the average of the twelve monthly peaks as a percentage of the annual peak.[30]

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[27] *Id.* P 76.

[28] The Commission has held that, in general, a 19 percentage point or less difference between these two figures indicates that using the 12 CP demand allocation methodology is appropriate. *See Illinois Power Co.*, 11 FERC ¶ 63,040, at 65,248-49 (1980) (*Illinois Power Initial Decision*), *aff'd*, 15 FERC ¶ 61,050 (1981) (comparing average summer peak of 94 percent of annual peak to eight-month average peak of 75 percent of annual peak, a difference of 19 percentage points).

[29] The Commission has held that a range of 66 percent or higher is indicative of a 12 CP system. *See id*. (approving 12 CP where lowest monthly peak as percentage of annual peak was 66 percent); *Delmarva Power & Light Co.,* 17 FERC ¶ 63,044, at 65,201 (1981) (*Delmarva Initial Decision*), *aff'd*, Opinion No. 185, 24 FERC ¶ 61,199, *reh'g denied*, Opinion No. 185-A, 24 FERC ¶ 61,380 (1983) (stating that for the Low to Annual Peak test, a low percentage indicates a load curve with a clearly defined peak, while a high percentage indicates a flatter load curve).

[30] The Commission has held that the range indicating whether a utility is to be considered a 12 CP system is 81 percent or higher. *See Illinois Power Initial Decision*, 11 FERC ¶ 63,040, at 65,249 (1980) (approving 12 CP where average monthly peak for five-year period was 81 percent); *Lockhart Power Co.*, Opinion No. 29, 4 FERC ¶ 61,337, at 61,807 (1978) (approving 12 CP where average monthly demand was 84 percent of annual system peak); *El Paso Elec. Co.*, Opinion No. 109, 14 FERC ¶ 61,082, at 61,147 (1981) (approving 12 CP where twelve-month average was 84 percent of maximum peak).

28. In Opinion No. 501, the Commission presented a table that compared ratios from the three peak load tests previously found by the Commission to be indicative of a 12 CP system to the peak load test ratios for SPS submitted by various parties in this proceeding.[31] The ratios provided by each party varied slightly, and the Commission noted that these differences could be attributed to the inclusion or exclusion by certain parties of interruptible loads, off-system sales, and the number of years used to calculate the average ratios shown below.[32] The Commission noted that comparing the results of the three peak load tests to the benchmarks set in prior cases, as the Commission did in Opinion Nos. 162[33] and 337,[34] demonstrates that SPS is a 12 CP utility.[35] The Commission noted that even the ratios of Golden Spread's witness, who testified in support of SPS remaining a 3 CP utility, meet the acceptable range for a 12 CP demand allocator.[36] The Commission also stated that Golden Spread's switch from full requirements service to partial requirements service helped contribute to the flattening of SPS's load profile.[37]

### 2. <u>Rehearing Requests</u>

29. PNM argues that the Commission erred in reversing the ALJ's decision to use the 3 CP demand allocation methodology for SPS. PNM contends that the Commission performed a mechanical review of the peak ratio calculations without considering the broader operating realities of the SPS system. PNM argues that because Commission

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[31] Opinion No. 501, 123 FERC ¶ 61,047 at P 77.

[32] *Id.*

[33] *Southwestern Pub. Serv. Co.*, Opinion No. 162, 22 FERC ¶ 61,341, *reh'g denied*, 23 FERC ¶ 61,406 (1983) (affirming the ALJ's decision that SPS was a 3 CP utility based, in part, on the results of the three peak load tests, which were performed using actual load data from 1974 to 1980, as well as projected 1981 load data).

[34] *Southwestern Pub. Serv. Co.*, Opinion No. 337, 49 FERC ¶ 61,296 (1989), *reh'g denied*, Opinion No. 337-A, 51 FERC ¶ 61,341 (1990) (affirming the ALJ's decision that SPS remained a 3 CP utility).

[35] *Id.*

[36] *Id.*

[37] *Id.* P 78.

precedent requires a company-specific evaluation of all operating realities,[38] the results of the peak load tests in cases involving other utilities are not controlling. PNM states that while there has been a modest shift in SPS's load profile, the change is insufficient to warrant a change to the 12 CP demand allocation methodology, especially in light of evidence indicating that the change in SPS's load profile is temporary.

30. Golden Spread also requests rehearing of the Commission's decision that SPS is a 12 CP utility. Golden Spread contends that in reaching this decision, the Commission failed to adhere to SPS-specific precedent regarding the proper demand allocator. Golden Spread explains that the Commission previously addressed the issue of the appropriate demand allocator for SPS in Opinion Nos. 162 and 337, and in both cases found that SPS was a 3 CP utility. Golden Spread argues that SPS-specific precedent like Opinion Nos. 162 and 337 should be the controlling precedent in this proceeding, rather than the precedent relied on by the Commission in Opinion No. 501, which involved other utilities and cases that were issued prior to Opinion No. 162.[39]

31. Golden Spread also disagrees with the Commission's statement that it applied the same analytical criterion in examining the demand allocator issue in this proceeding as it did in Opinion Nos. 162 and 337.[40] Golden Spread argues, to the contrary, that Opinion No. 501 failed to reflect the results of the peak load tests in Opinion Nos. 162 and 337. Golden Spread argues that the table in Opinion No. 501 should be modified to compare the peak load ratio determinations in Opinion No. 162 with SPS's current peak load ratios.

32. Golden Spread explains that, in Opinion No. 162, the average result for the On and Off Peak test was 22.9 percent. Golden Spread notes that the ALJ in Opinion No. 162 found that this result was higher than the highest instance in which a 12 CP methodology was adopted (19 percent in *Illinois Power*) and was therefore indicative of a 3 CP methodology. Moreover, Golden Spread states that, in Opinion No. 162, the result of the Low to Annual Peak test was 66.98 percent. According to Golden Spread, even though that result falls into the "66 percent or higher" benchmark and Opinion No. 501 stated it was indicative of a 12 CP demand methodology, the Commission in Opinion No. 162

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[38] PNM May 21, 2008 Request for Rehearing and Clarification at 26 (citing *Louisiana Power & Light Company*, Opinion No. 110, 14 FERC ¶ 61,075, at 61,128 (1981) (*Louisiana Power*)).

[39] Golden Spread May 21, 2008 Request for Rehearing at 14 (objecting to the Commission reliance on the *Louisiana Power* case).

[40] *Id.* (citing Opinion No. 501, 123 FERC ¶ 61,047 at P 77).

found that SPS was a 3 CP utility. Golden Spread further states that, in Opinion No. 162 the average result for the Average to Annual Peak test was 80.1 percent. Golden Spread explains that the ALJ found that this ratio was below the comparable figure of 81.2 percent in *Louisiana Power*, and therefore, was indicative of a 3 CP methodology.

33. Golden Spread argues that the Commission may only implement a new demand allocator if there has been a "persuasive showing" that circumstances have changed since the Commission last accepted the 3 CP demand allocator for SPS. Golden Spread explains that in 1984, one year after the issuance of Opinion No. 162, SPS filed another rate proceeding, and at the outset of that proceeding, the Commission stated that "barring a persuasive showing that circumstances may have changed in such a way as to warrant a difference, there would be no reason to relitigate …[the demand allocator] issue."[41] Golden Spread asserts that in order to measure properly whether circumstances have changed, the Commission in Opinion No. 501 should have compared the current conditions on SPS's system to the results of prior SPS decisions, such as Opinion No. 162, and not to other non-SPS precedent.

34. Golden Spread further argues that the Commission erred when determining the appropriate demand cost allocator for SPS by relying on demand data that included certain market-based opportunity sales. Golden Spread argues that including these opportunity sales in the load data used to calculate the three peak load tests is inconsistent with other parts of Opinion No. 501, in which the Commission stated that these opportunity sales should (1) have an incremental fuel cost imputed for crediting in the fuel adjustment clause, (2) be revenue credited in the cost of service and (3) be excluded from demand cost allocations to avoid double counting those sales.[42]

35. Golden Spread states that all of the data relied upon by the Commission for its analysis of the demand cost allocation issue included opportunity sales. Golden Spread asserts that the only evidence in the record that excluded these sales was proffered by Golden Spread's own witness, Mr. Linxwiler. Golden Spread explains that Mr. Linxwiler presented two forms of data in this proceeding: (1) unadjusted data that included opportunity sales; and (2) adjusted data that excluded opportunity sales. Golden Spread asserts that in the table in Opinion No. 501, the Commission used the unadjusted load data provided by Mr. Linxwiler, and then relied upon those data together with the unadjusted load data from other witnesses to reach the conclusion that all the witnesses

[41] *Id.* at 12-13 (citing *Southwestern Pub. Serv. Co.*, 29 FERC ¶ 61,056, at 61,123 (1984)).

[42] *Id.* at 15-18 (citing Opinion No. 501, 123 FERC ¶ 61,047 at sections II.A.4, III.D.4, and III.C.3).

proffered evidence to support the use of the 12 CP methodology. Golden Spread argues that the Commission should have used Golden Spread's adjusted load data, which excluded the opportunity sales.[43] Golden Spread states that when the load data are adjusted to eliminate opportunity sales, the results indicate that SPS is still a 3 CP system.

36. Golden Spread explains that its witness excluded opportunity sales from the load data because such sales would skew the load characteristics of the native load customers. Golden Spread further argues that it was proper to exclude these sales, because they have a lower priority than native-load contracts in terms of interruptibility. Moreover, Golden Spread asserts that excluding the opportunity sales from the load data is consistent with the Commission's determination that SPS failed to demonstrate that it planned, constructed, or maintained its system for these opportunity sales, as it does for cost-based requirements service.

37. Golden Spread argues that once this error is corrected and opportunity sales are excluded from the load data, and the Commission compares these data to the results of the three peak load tests in Opinion No. 162, it is clear that SPS remains a 3 CP utility. Golden Spread provides a revised version of the table in Opinion No. 501 demonstrating the comparison between SPS's load data for the 2001-2004 time period (excluding opportunity sales) and the load data in Opinion No. 162. The SPS load ratios Golden Spread uses are Mr. Linxwiler's adjusted data from Exhibit GSL-18, which are as follows: (1) Low to Annual Peak test – 66.22 percent; (2) On and Off Peak test – 21.68 percent; and (3) Average to Annual Peak test – 79.86 percent.[44] Golden Spread argues that when compared with the ratios in Opinion No. 162, these results demonstrate that a 3 CP demand cost allocator is still appropriate, and that there is no credible evidence of a substantial change to warrant a different result.

38. Golden Spread also objects to the Commission's assertion that Golden Spread's switch from full requirements service to partial requirements service is a contributing factor to SPS's flattening load. Golden Spread states that it made this change in response to the price signal provided by the 3 CP demand allocation, and the switch provides significant benefits to the SPS system.[45] Golden Spread asserts that evidence was

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[43] *Id.* at 18-21 (citing Exhibit GSL-1 and GSL-12, and the peak load test analysis in Exhibit GSL-18).

[44] *Id.* at 23.

[45] *Id.* at 25 (explaining that Golden Spread constructed a 480 MW facility in SPS's control area called the Mustang Station and entered into a Commitment and Dispatch Services Agreement with SPS that provides SPS with significant benefits).

submitted at the hearing showing that the full requirements customers have not responded to the 3 CP methodology and are contributing to the increase in peak load growth. Golden Spread contends that switching SPS from a 3 CP methodology to a 12 CP methodology would penalize Golden Spread, the only party that responded to the price signal.

39. Golden Spread also argues that the Commission should have used two additional peak load tests in examining the demand allocator issue. Golden Spread explains that in the *Carolina Power* case, the Commission used a test that counts the number of times the load in a non-peak month exceeds the load in a peak month.[46] Golden Spread states that the Commission found that if the number of times exceeds three in a year, then the 12 CP methodology was warranted. In addition, Golden Spread states that in the *Consumers Energy* Initial Decision, the Commission counted the number of times the load in a non-peak month exceeds the load in a peak month of the previous year.[47] Golden Spread states that the ALJ found that if the number exceeded 10 in a five year time period, then this was indicative of a 12 CP methodology. Golden Spread states that using its adjusted load data for SPS (or even faulty unadjusted data), the results from these two tests indicate that SPS is a 3 CP system.

40. Golden Spread further contends that the Commission failed to look beyond the peak load tests and review all of SPS's operating realities, such as scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales. Golden Spread explains that its review of SPS's scheduled maintenance indicates that SPS does most of its maintenance in the off-peak periods. In making this assertion, Golden Spread relies on Southwest Power Pool Inc.'s (SPP) 2004 State of the Market Report, which summarizes maintenance outages in SPP by month.[48] With regard to unscheduled outages, Golden Spread states that according to SPS's data, no significant amounts of generation were out of service at the time of the summer peak months, indicating that SPS plans its system to meet summer-peaking demand.[49] Golden Spread

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[46] *Id.* at 29 (citing *Carolina Power & Light Co.*, 4 FERC ¶ 61,107, at 65,147 (1978) (*Carolina Power*)).

[47] *Id.* (citing *Consumers Energy Co.*, 86 FERC ¶ 63,004 (1999), *aff'd*, 98 FERC ¶ 61,333 (2002) (*Consumers Energy*)).

[48] *Id.* at 31 (citing Exhibit GSL-4).

[49] *Id.* at 31 (citing Exhibit GSL-5). Golden Spread states that in the summer, SPS plans for only 54 MW of outages (one percent of peak load), but in all other seasons, the outages are far greater (Fall – 431 MW; Winter – 612 MW; Spring - 484 MW). *Id.*

states that when considering diversity, SPS is not a double peaking utility with a high summer peak and high winter peak, which would indicate that a 12 CP methodology is warranted. Golden Spread further states that when reviewing SPS's reserve requirements it found that SPS takes large portions of its generation off-line in non-summer months, consistent with a 3 CP system. Golden Spread further states that SPS's off-system sales have been decreasing over the 2003-2006 period,[50] and the inclusion of these sale commitments in the demand allocator analysis will skew the direction the SPS load shape may otherwise be headed. Golden Spread states it was the only party to evaluate all of these operating realities, and that doing so reinforces that SPS is a 3 CP utility.

41. Golden Spread contends that the Commission's truncated analysis of the demand allocation issue in Opinion No. 501 does not establish significant changes warranting a shift from a 3 CP methodology to a 12 CP methodology. Citing Opinion No. 162 and *Illinois Power*, Golden Spread argues that Commission precedent and sound public policy dictate that a change in demand cost allocation methodology should not be made except upon a showing of substantial and long-term change.[51] Golden Spread argues that here, the slight changes in load profile demonstrated by the three peak load tests are not enough to change the demand allocation methodology. Thus, on rehearing Golden Spread requests that the Commission vacate its decision to implement a 12 CP demand cost allocation methodology on the SPS system.

### 3. Commission Determination

42. For the reasons discussed below, we grant rehearing on the demand cost allocation issue and find that SPS is a 3 CP utility. In Opinion No. 501, the Commission determined that, for the locked-in period at issue in this proceeding, SPS was a 12 CP utility. However, upon further examination, we find that the Commission relied on improper data in reaching its determination and erroneously concluded that a supervening change had occurred since SPS's previous rate case that warranted a shift in SPS's demand cost allocator. Therefore, we reverse the decision on rehearing.

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[50] *Id.* at 33 (citing Exhibit SPS-77). Golden Spread states that SPS off-system sale commitments were 585 MW in 2003, 381 MW in 2004, 260 in 2005, and 210 MW in 2006.

[51] *Id.* at 34 (citing Opinion No. 162, 22 RFERC at 61,123; *Illinois Power Initial Decision*, 11 FERC at 65,247 (stating that a demand cost allocation methodology should not be changed absent a showing of significant new facts of changed circumstances that warrant modification)).

43. As explained above, demand cost allocation determines how much a utility will charge each class of customer based upon the class's contribution to the utility's capacity costs. The Commission has refused to endorse any single method of demand allocation for general application.[52] Instead, the Commission's determination of the appropriate allocation method rests on the facts of each case.[53]

44. In the last two SPS rate cases, the Commission determined that SPS was a summer peaking utility and a 3 CP methodology was appropriate.[54] Thus, since the early 1980s, SPS has allocated demand-related costs to its various customer classes using the 3 CP methodology.

45. The Commission has stated that substantive ratemaking principles, such as demand cost allocation, once established for a particular company, should continue to be applied in subsequent cases unless there is a supervening change in circumstances or Commission policy requiring a different conclusion.[55] The Commission has also stated that in selecting the proper method of demand cost allocation, the full range of a company's operating realities should be considered, including: (1) system demand; (2) scheduled maintenance; (3) unscheduled outages; (4) diversity; (5) reserve requirements; and (6) off-system sales commitments.[56] Based on our analysis of the full range of SPS's operating realities, we conclude that no supervening change has occurred that justifies a shift in SPS's demand cost allocator.

46. When assessing the first operating reality, system demand, the Commission looks at a utility's pattern of monthly peak demands throughout the year. A company that has a relatively flat demand curve would typically allocate demand on a 12 CP basis, which assumes that a utility's fixed costs are related to the demand throughout all 12 months of the year. On the other hand, a summer (or winter) peaking company would more

[52] *Louisiana Power*, 14 FERC ¶ 61,075, at 61,126 (1981); *Commonwealth Edison*, 15 FERC ¶ 63,048, at 65,196 (1981), *aff'd in relevant part*, 23 FERC ¶ 61,219 (1983).

[53] *Commonwealth Edison*, 15 FERC at 65,196.

[54] Opinion No. 162, 22 FERC ¶ 61,341; Opinion No. 337, 49 FERC ¶ 61,296.

[55] *Louisiana Power*, 14 FERC at 61,128.

[56] *Carolina Power*, 4 FERC at 61,230; *Illinois Power Initial Decision*, 11 FERC at 65,248.

typically allocate demand on a 3 CP basis, which relates demand to the three peak usage months.

47. As explained above, the Commission traditionally has used three peak load tests to examine these patterns – the On and Off Peak test, the Low to Annual Peak test, and the Average to Annual Peak test. Commission precedent has set certain benchmarks against which the results of these tests are compared to help determine the appropriate demand allocation for a particular utility.[57]

48. In Opinion No. 501, the Commission determined that SPS was a 12 CP utility by examining the results of the three peak load tests submitted by the experts for SPS, Cap Rock, the full requirements customers, and Golden Spread.[58] The Commission compared these results to the benchmarks set by past Commission decisions, as demonstrated in the table in Opinion No. 501.

49. On rehearing, Golden Spread argues that, rather than looking at the benchmarks established in other cases, the Commission should only consider SPS-specific precedent. We agree that how the load ratios in the instant proceeding compare to load ratios in previous SPS cases is relevant to determining whether a supervening change in circumstances has occurred. However, it is also useful to consider how SPS's load ratios compare to the benchmarks the Commission has set in other non-SPS demand allocation proceedings. Doing so gives the Commission a more complete picture of how SPS's demand profile compares not only to precedent in prior SPS-specific proceedings, but also to precedent addressing other utilities.

50. On rehearing, Golden Spread also argues that the Commission erred by relying on load ratios that were calculated with improper data. Golden Spread contends that the witnesses who proffered these data failed to exclude off-system sales when performing the indicative peak load tests. Golden Spread asserts that the Commission should have used the adjusted load data provided by Golden Spread's witness, Mr. Linxwiler, which excluded off-system sales. Golden Spread contends that because the Commission found that off-system sales should be revenue credited and not included in the demand cost allocation, it would be inconsistent to include such sales when analyzing SPS's system characteristics.

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[57] *See supra* n.28, n.29, n.30.

[58] *See* Opinion No. 501, 123 FERC ¶ 61,047 at P 77 (demonstrating in a table the results of the three peak load tests for each party's expert witness).

51. Upon further examination, we agree that the Commission's analysis of the appropriate demand allocator was flawed because opportunity sales should have been excluded from the load data used to determine the appropriate demand allocator for the SPS system. In previous cases, the Commission has stated that when determining an appropriate demand allocation, the Commission should consider the full range of a company's operating realities, including off-system sales commitments.[59] However, in those cases, the Commission did not address what should be done for off-system opportunity sales that are not included in the demand allocator, but are revenue credited. Here, SPS's opportunity sales will be revenue-credited. Therefore, we believe these sales should be excluded from the demand allocation analysis.

52. In Opinion No. 501, the Commission determined that the off-system opportunity sales at issue in this proceeding should be revenue credited, and as a result, not included in the demand allocation of SPS's rates. The Commission reasoned that only those customers for whom SPS plans its system and makes capacity additions should be included in the demand allocation for ratemaking purposes. It follows then that only these parties' loads should be included in the peak load tests to determine the appropriate demand allocation. This treatment is consistent with the principle of cost-causation, which states that the parties who cause the costs should bear the costs.[60]

53. Here, SPS engaged in the opportunity sales at issue in this proceeding in order to use the excess capacity temporarily available after Golden Spread's conversion to partial requirements service. SPS did not plan for and construct its system or make purchases to serve these transactions. As a result, including these off-system opportunity sales in the peak load tests would skew the results for other SPS customers. This is especially true given the fact that, as of 2006, the excess capacity on the SPS system was diminishing and SPS expected to make fewer off-system opportunity sales in future years.[61]

54. As Golden Spread explains in its request for rehearing, excluding SPS's off-system sales commitments from the three peak load tests results in load ratios that support the use of a 3 CP demand allocation. As explained above, the three peak load tests are as follows: (1) the On and Off Peak test, in which the Commission compares the

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[59] *E.g.*, *Carolina Power*, 4 FERC at 61,230.

[60] *See Cincinnati Gas & Electric Co.*, 71 FERC ¶ 61,380, at 62,478 n.30 (1995) (citing *Town of Norwood v. FERC*, 962 F.2d. 20 at 25 (D.C. Cir. 1992); *Union Electric Co v. FERC*, 890 F.2d 1193, at 1198 (D.C. Cir. 1989) (stating that rates should fairly track the costs for which the ratepayers are responsible)).

[61] *See* Exhibit SPS-76 at 11.

average of the system peaks during the purported peak period, as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak; (2) the Low to Annual Peak test, in which the Commission calculates the lowest monthly peak as a percentage of the annual peak; and (3) the Average to Annual Peak test, in which the Commission computes the average of the twelve monthly peaks as a percentage of the annual peak. The table below reflects the results[62] of these peak load tests calculated using SPS's load data for 2001 through 2004, excluding SPS's opportunity sales for that period.[63] When comparing the results of the three peak tests in this proceeding (calculated without SPS's opportunity sales) to the benchmarks established by the Commission in prior cases, two of the three tests indicate that SPS is a 3 CP utility. The third test – the Low to Annual Peak test – marginally indicates a 12 CP demand allocation.

| | Low to Annual Peak | On and Off Peak | Average to Annual Peak |
|---|---|---|---|
| Historical Commission range for 12 CP | 66% or higher | 19% or less | 81% or higher |
| 2001 | 69.05 | 22.16 | 80.2 |
| 2002 | 68.41 | 21.21 | 82.25 |

[62] For each of the three peak load tests, the result is calculated by applying the test to the firm loads each year over a period of years (to account for the possibility of an abnormal year) and then averaging those values.

[63] The Commission excluded from the table load data from 2000 because that was an anomalous year on the SPS system. During that year, Golden Spread converted from full requirements to partial requirements service. Thus, a portion of the load data for 2000 reflects Golden Spread's full requirements service and is not representative of the demands placed on SPS's system during the locked-in period.

The load data for the SPS system for 2005 were estimated for July through December and actual for January through June. There is some dispute between the parties about whether it is appropriate to mix actual and projected data in such a manner. The Commission finds that if the data from 2005 are included in the demand allocator analysis, the results change only minimally and still suggest that the proper demand allocator for SPS is 3 CP.

| | | | |
|---|---|---|---|
| 2003 | 65.25 | 19.8 | 79.27 |
| 2004 | 62.18 | 23.54 | 77.72 |
| Average 2001 - 2004 | 66.2 | 21.7 | 79.9 |
| 2001-2004 Trend[64] | Toward 3 CP | Mixed | Toward 3CP |

55. While the historical percentages that indicate a 12 CP utility in these peak load tests do not constitute a bright line test for determining an appropriate demand cost allocation methodology, we find it helpful to compare the test results for SPS's system with the historical threshold percentages in other proceedings. If the results are compared to the results of the same peak load tests in Opinion No. 162 (the order addressing SPS's 1983 rate case), the numbers are not significantly different. In both cases, the results of the Low to Annual Peak test narrowly indicate that a 12 CP demand allocation is appropriate, while the other two tests indicate that SPS is a 3 CP utility.

| | Low to Annual Peak | On and Off Peak | Average to Annual Peak |
|---|---|---|---|
| Historical Commission range for 12 CP | 66% or higher | 19% or less | 81% or higher |
| Average 2001 -2004 | 66.2 | 21.7 | 79.9 |
| Opinion No. 162 | 66.98 | 22.9 | 80.1 |

56. Accordingly, our analysis of the load ratios, after removing SPS's opportunity sales, supports the continued use of a 3 CP demand cost allocator. The Commission has stated that substantive ratemaking principles, such as demand cost allocation, once established for a particular company, should continue to be applied in subsequent cases unless there is a supervening change in circumstances or Commission policy requiring a different conclusion.[65] On rehearing, and after reconsidering the data discussed above,

[64] This row of the table describes the trend line that results when, for each test, the annual values from each year of the analyzed time period are plotted on a graph.

[65] Opinion No. 110, 14 FERC at 61,128.

we find that there was not a supervening change in SPS's system demand that warranted a change to a 12 CP demand cost allocator in Opinion No. 501, as the results of the peak load tests generally support a 3 CP demand cost allocator and are not significantly different from the results in Opinion No. 162, in which the Commission determined SPS was a 3 CP utility.

57. On rehearing, Golden Spread argues that the Commission should consider two additional peak load tests in the analysis of SPS's system characteristics. Because the results of the three peak load tests might not be the only indicators of a change on SPS's system, we will now consider these additional tests. The first test measures the number of times the non-summer monthly peak demand exceeds the summer monthly peak demand.[66] For SPS, the non-summer monthly peak demand was greater than the lowest summer peak month twice during the period of 2001 to 2004.[67] The second test computes the number of times the non-summer monthly peak demand exceeds the summer monthly peak demand in the preceding year.[68] In SPS's case, the occurrences of non-summer peak demand exceeding a summer peak demand of a prior year were rare during that same period, which indicates that SPS is a summer peaking utility.[69] Thus, the results of these two additional peak load tests tend to support the use of a 3 CP demand allocator for SPS.

58. Taken together, we believe that the corrected load data and the two additional peak load tests indicate that SPS is a 3 CP utility. However, system demand is only one of the operating realities the Commission must consider. We will also look at SPS's scheduled maintenance, unscheduled outages, diversity, and operating reserves during the locked-in period.

59. With regard to scheduled maintenance, the record demonstrates that during the locked-in period, more of SPS's scheduled maintenance occurred in the non-summer

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[66] Golden Spread May 21, 2008 Request for Rehearing at 29 (citing *Carolina Power*, 4 FERC ¶ 61,107, *reh'g granted on other grounds*, 5 FERC ¶ 61,081 (1978)).

[67] *See* Exhibit GSL-18 at 6.

[68] Golden Spread May 21, 2008 Request for Rehearing at 29 (citing *Consumers Energy Co.*, 86 FERC ¶ 63,004 (1999), *aff'd*, 98 FERC ¶ 61,333 (2002)).

[69] *See* Exhibit GSL-18 at 6.

months rather than during the peak summer months.[70] This is more indicative of a 3 CP company, for whom summer is a critical time for peak usage, than of a 12 CP company.

60. Most of the evidence in the record regarding unscheduled outages relates to SPS's interruptions of the PNM Interruptible contract. This evidence demonstrates that in 2003 and 2004, SPS interrupted PNM during both the summer and the winter months.[71] The parties advocating a 12 CP demand allocator argue that this indicates that SPS's peak demands are not concentrated in the summer months. However, we do not find this argument to be persuasive because the majority of the unscheduled outages for PNM still occurred during the summer months. Moreover, SPS may have interrupted PNM's service for reasons other than to reduce peak demand. By the terms of the PNM Interruptible contract, SPS may interrupt service for any reason for up to 5 percent of the energy in each month. Thus, we find that SPS's unscheduled outages for the locked-in period do not indicate that the SPS system has undergone a supervening change warranting a shift in SPS's demand cost allocator.

61. The diversity of generation upon which SPS relied during the locked-in period also does not require a shift in SPS's demand cost allocator. The record shows that base load generation represented 87.5 percent of SPS's total available capacity in 2004 and provided 84.7 percent of the energy SPS sold during that year.[72] In contrast, peaking units represented 5 percent of SPS's total available capacity in 2004 and provided 0.64 percent of the total energy SPS sold that year.[73] These data do not indicate whether SPS is a 3 CP or 12 CP utility because, with Golden Spread's switch to partial requirements service, SPS had a significant amount of excess generation capacity that would reduce its reliance on peaking units and skew the generation data.[74] However,

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[70] *See* Exhibit GSL-5 (demonstrating that the amount of planned scheduled outages in autumn of 2003 was 431 MW, winter was 612 MW and spring was 484 MW); *See also* Exhibit PNM-6 at 4:17-20; Exhibit GSL-4 (SPP State of the Market Report).

[71] *See* Exhibit PNM-7 (demonstrating that in 2003, SPS interrupted PNM three times (twice during the summer months and once in February), and in 2004, SPS interrupted PNM three times (twice in the summer months and once in January)).

[72] *See* Exhibit FRC-1 at 10:3-4, 18:21-23.

[73] *Id*.

[74] Moreover, the parties providing the generation data in the record used total energy sold during the year which would include opportunity sales. As explained above, opportunity sales should not be included in the calculation used for determining the demand allocation in this proceeding.

SPS's load profile does not exhibit the diversity that would support a 12 CP demand allocation. From a diversity perspective, basing SPS's demand cost allocation on all months equally, as under the 12 CP demand cost allocation methodology, would be inappropriate, because SPS has neither a flat load profile nor a load profile demonstrating a double peak.

62. In addition, SPS's reserve margins data for the 2004 test year indicate that SPS may have had a couple of non-summer months with unexplained low reserve margins in 2004.[75] However, the reserve margin data provided were only for one year and patterns in reserve margins can not be determined from the data. Moreover, SPS's Load and Resource documents in the record only reflect SPS's expected reserve margins for the summer period.[76] Thus, while SPS may have had a couple of months of unexplained low reserve margins in the summer of 2004, the only pattern we can ascertain from these documents is that SPS was more concerned about meeting the reserve margins during the summer period than in non-summer periods.[77] Taken as a whole, this evidence indicates that the 3 CP demand allocation is appropriate.

63. These operational realities, considered together with our revised analysis of system demand, demonstrate that a supervening change has not occurred that justifies switching to a 12 CP demand cost allocator. Moreover, in Opinion No. 501, the Commission relied on load data that included SPS's opportunity sales. Here, the Commission finds that the inclusion of SPS's opportunity sales improperly skewed the results of the peak load tests. Because no supervening change has occurred and because the demand data the Commission relied upon in Opinion No. 501 included off-system sales, we reverse our earlier decision on rehearing. The corrected load data, together with the other operational realities on SPS's system, indicate that no supervening change has occurred and that SPS continues to be a 3 CP utility. As the ALJ stated, "in order to

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[75] *See* Exhibit SPS-41. The reserve margin data indicate that the reserve margins in March and September were lower than in one peak month, June. During the non-summer months of 2004, SPS's reserve margins varied from about 8 percent to about 20 percent.

[76] SPS's Load and Resource documents reflect the total resources and the total load, including firm opportunity sales that SPS expects for a certain period. The SPS Load and Resource documents in the record for years 2001 through 2003 were titled "SPS – Summer Load and Resources." SPS's Load and Resource document for 2004 had a similar title.

[77] SPS did not submit any load and resource forecasts for any other season of the year.

justify a departure from Commission precedent, even a 20 year old precedent, more is needed than a mere step or two in the direction of a flatter curve."[78] For these reasons, we grant the requests for rehearing on the appropriate demand cost allocator for SPS and finds that SPS continues to be a 3 CP utility.

The Commission orders:

(A) The requests for rehearing regarding the proper demand allocator for the SPS system are granted, as discussed in the body of this order.

(B) SPS's request for clarification regarding refunds to PNM is granted, as discussed in the body of this order.

(C) The remaining requests for rehearing and clarification are dismissed as moot.

(D) SPS's July 21, 2008 compliance filing quantifying refunds for the locked-in period based on Opinion No. 501 is rejected.

(E) SPS is directed to file, within 30 days of the date of this order, a compliance filing quantifying refunds relating to cost of service rates for the refund period in this proceeding, i.e., January 1, 2005 through June 30, 2006.

By the Commission.

( S E A L )

Kimberly D. Bose,
Secretary.

[78] Initial Decision, 115 FERC ¶ 63,043 at P 24.