COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter Of:

The Application of the Fuel Adjustment Clause of	)	
Kentucky Power Company from November 1, 2013	)	Case No. 2014-00225
Through April 30, 2014	)	

REBUTTAL TESTIMONY OF

WILLIAM A. ALLEN

ON BEHALF OF KENTUCKY POWER COMPANY

VERIFICATION

The undersigned, William A. Allen, being duly sworn, deposes and says he is the Managing Director Regulatory Case Management for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing testimony and the information contained therein is true and correct to the best of his information, knowledge and belief

William A. Allen

STATE OF OHIO)
) Case No. 2014-00225
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by William A. Allen, this the 3rd day of November 2014.

Amanda E Owen
Notary Public

My Commission Expires: N/A

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REBUTTAL TESTIMONY OF
WILLIAM A. ALLEN, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William A. Allen, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by the American Electric Power Service Corporation (AEPSC) as Managing Director of Regulatory Case Management. AEPSC supplies engineering, financing, accounting, and planning and advisory services to the electric operating companies of the American Electric Power System, one of which is Kentucky Power Company ("Kentucky Power" or "Company").

Q. WOULD YOU PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. Yes. I received a Bachelor of Science in Nuclear Engineering from the University of Cincinnati in 1996 and a Master of Business Administration from the Ohio State University in 2004.

I was employed by AEPSC beginning in 1992 as a Co-op Engineer in the Nuclear Fuels, Safety and Analysis department and upon completing my degree in 1996 was hired on a permanent basis in the Nuclear Fuel section of the same department. In January 1997, the Nuclear Fuel section became a part of Indiana Michigan Power Company (I&M) due to a corporate restructuring. In 1999, I transferred to the Business Planning section of the Nuclear Generation Group as a Financial Analyst. In 2000, I transferred back to AEPSC into the Regulatory Pricing and Analysis section as a Regulatory Consultant. In 2003, I transferred into the Corporate Financial Forecasting department as a Senior Financial Analyst. In 2007, I was promoted to the position of Director of Operating Company Forecasts. In that role, I was primarily responsible for the supervision of the financial forecasting and analysis of the AEP System's operating companies, including Kentucky Power Company. In 2010, I transferred to the Regulatory Services Department as Director of Regulatory Case Management. I was named to my current position in January 2013.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR OF REGULATORY CASE MANAGEMENT?

A. I am primarily responsible for the supervision, oversight and preparation of major filings with state utility commissions and the Federal Energy Regulatory Commission (FERC).

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes. I have previously submitted testimony or testified before the Michigan Public Service Commission, the Indiana Utility Regulatory Commission, the Public Utilities Commission of Ohio, the West Virginia Public Service Commission and the Virginia State Corporation Commission on behalf of various electric operating companies of the American Electric Power system.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to rebut testimony of KIUC and Attorney General ("KIUC/AG") Witness Lane Kollen with regard to the consistency of Kentucky Power's no-load cost allocation methodology with FERC guidance. Contrary to Mr. Kollen's testimony, the Company's allocation methodology comports fully with FERC guidance.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring the following exhibits:

Exhibit WAA-1	FERC Wholesale Fuel Adjustment Clause Audit of Ohio Power Company
Exhibit WAA-2	FERC Wholesale Fuel Adjustment Clause Audit of Public Service Company of Oklahoma
Exhibit WAA-3	Commission Order dated December 17, 1982 in FERC Docket No. ER83-63-000
Exhibit WAA-4	FERC Opinion No. 501 dated April 21, 2008
Exhibit WAA-5	Order Accepting Proposed Rates for Filing dated May 31, 1995 in FERC Docket No. ER95-852-000

III. KENTUCKY POWER'S FAC FUEL ALLOCATION METHODOLOGY IS NOT INCONSISTENT WITH FERC GUIDANCE

Q. KIUC WITNESS KOLLEN CLAIMS THAT KENTUCKY POWER'S FUEL COST ALLOCATION APPROACH IS IMPROPER BECAUSE IT CONFLICTS WITH FERC GUIDANCE ON FUEL COST ALLOCATION. DO YOU AGREE?

A. No. Based upon my review of the FERC dockets referenced by KIUC witness Kollen as well as audits performed by the FERC Division of Audits within the Office of Enforcement, I do not believe that Kentucky Power's retail fuel allocation methodology in inconsistent with FERC guidance.

Q. DO YOU AGREE WITH MR. KOLLEN'S CONTENTION THAT KENTUCKY'S FAC REGULATION IS MODELED UPON FERC'S FUEL REGULATION, 18 CFR § 35.14?

A. Yes, I do.

Q. ARE YOU AWARE OF WHETHER THE FERC STAFF HAS AUDITED THE FUEL COSTS ASSIGNED TO WHOLESALE CUSTOMERS OF KENTUCKY POWER OR ITS AFFILIATES – INCLUDING THE COMPANY'S ALLOCATION OF NO-LOAD FUEL COSTS TO NATIVE LOAD CUSTOMERS?

A. Yes. The FERC Division of Audits within the Office of Enforcement has audited the wholesale fuel adjustment clauses of two affiliates of Kentucky power in recent years - Ohio Power Company (OPCo) and Public Service Company of Oklahoma (PSO) – to determine whether they complied with 18 CFR § 35.14.

Q. DO OPCO AND PSO'S WHOLESALE FUEL ADJUSTMENT CLAUSES TREAT THE NO LOAD COSTS CONSISTENT WITH THE METHOD THAT KENTUCKY POWER DOES?

A. Yes they do.

Q. WHAT WERE THE RESULTS OF THE AUDITS PERFORMED BY FERC STAFF?

A. As indicated in Exhibits WAA-1 and WAA-2, the audits resulted in no findings or recommendations related to the companies' wholesale fuel adjustment clauses. In both cases, the audit staff "recalculated the FAC for the test months to ensure that it was properly calculated." The results of these audits demonstrate that the treatment by Kentucky Power of no load costs in fuel clause calculations is consistent with FERC precedent and guidance.

Q. KIUC WITNESS KOLLEN'S TESTIMONY AT PAGE 19, LINE 18, THROUGH PAGE 20, LINE 3, REFERENCES A 1982 FERC ORDER. HAVE YOU REVIEWED THAT ORDER AND DO YOU HAVE ANY COMMENTS?

A. Yes, I have reviewed the entirety of the order (Exhibit WAA-3) and I think that it is important to put the limited quotation provided by witness Kollen in context. The full paragraph from the order that Mr. Kollen quotes is as follows:

> We also note that the Power Agency and ElectriCities do not question the prudence of APCO's coal purchases from its subsidiary, but limit their concern strictly to the assignment of such purchases to the interchange transaction. Because the six generating units furnishing the power for this sale are among the highest fuel cost units on the American Electric Power System, these units are precisely the ones which would be expected to provide the energy for any off-system sale to VEPCO or others, and these units form a proper basis for pricing the interchange service. We believe that it is both appropriate, and a common industry practice to assign the highest fuel cost to off-system sales, while lower fuel cost resources are reserved for the benefit of the APCO native load customers who, through their rates, provide for the construction and operation of the generating facilities.

The agreement that was the subject of the order was very different than the situation currently before this Commission and thus the Commission should not afford it any substantive weight as it evaluates the allocation of fuel costs incurred by plants owned by Kentucky Power. Under the agreement at issue in the FERC proceeding, Appalachian Power Company ("APCo") was providing energy to Virginia Electric and Power Company (VEPCO) from six specific units, only one of which was partially owned by APCo. The question at issue before FERC was the assignment of purchases by APCo from the AEP pool to a wholesale customer versus retail customers of APCo. This is a very different issue than the allocation of no load costs between full requirements customers and opportunity sales for units owned by Kentucky Power because the APCo to VEPCO sale was essentially a pass through of purchased power costs.

Q. ON PAGE 20, LINES 3 THROUGH 9, OF KIUC WITNESS KOLLEN'S TESTIMONY HE REFERENCES FERC OPINION NO. 501, DATED APRIL 21, 2008. HAVE YOU REVIEWED THAT OPINION AND DO YOU HAVE ANY COMMENTS?

A. Yes, I've reviewed the Opinion (see Exhibit WAA-4) and I do not entirely agree with the conclusions reached by witness Kollen.

Q. PLEASE EXPLAIN TO THE COMMISSION WHERE YOU AND MR. KOLLEN ARE IN AGREEMENT.

A. Witness Kollen correctly describes the approach used by Southwestern Public Service Company (SPS) to allocate fuel costs between native load customers and opportunity sales (referred to as off-system sales). The approach used was to assign the same system average fuel cost to both native and off-system sales. I also agree with witness Kollen that FERC determined that it was inappropriate to allocate costs in this manner.

Q. WHERE DOES MR. KOLLEN ERR IN HIS DESCRIPTION OF THE OPINION?

A. Witness Kollen provides his interpretation of the basis for FERC's determination by stating "because it forced native load customers to subsidize off-system sales by paying higher incremental fuel costs associated with those sales." This interpretation is not consistent with the Opinion. Nowhere in the Opinion does it state that native load customers are "paying higher incremental fuel costs."

Q, IS THE ABSENCE OF SUCH A STATEMENT IN THE OPINION THE ONLY ERROR IN MR. KOLLEN'S DESCRIPTION?

A. No. To clearly understand the implications of the Opinion the entire determination section, paragraphs 36 through 49, must be considered. In particular, Paragraph 37, included below, provides a very clear description of how fuel costs for native load customers are to be determined.

Q. PLEASE DESCRIBE THE PROCEDURE SET OUT IN THE FERC ORDER FOR DETERMINING NATIVE LOAD FUEL COSTS.

A. It is a three step process.

> 37. In order to calculate the fuel cost for native load customers under section 35.14, a utility first computes the fuel cost for all kWh sold, whether to native load customers or intersystem customers. The utility then deducts from the total fuel cost the cost of fuel recovered through intersystem sales. Native load customers pay the remainder. This "ensures that wholesale customers will not pay for fuel costs already paid for by the intersystem customers."

Thus, total fuel costs are first calculated. Second, fuel costs recovered from off-system sales are calculated. The third and final step is to subtract the fuel costs recovered from off-system sales from the total fuel cost – the amount that remains is the fuel cost attributable to native load customers. Nowhere in the equation does the concept of incremental fuel costs associated with native load customers come into play.

Q. WHERE, IF AT ALL, DOES FERC ADDRESS INCREMENTAL FUEL COSTS?

A. The concept of incremental costs comes into play when determining the level of fuel costs recovered from <u>off-system sales</u>. The <u>incremental cost</u> of fuel used for off-system sales must be calculated as part of the second step of the three step process prescribed by FERC. In Paragraph 44 of the Opinion, FECR notes that:

> 44. Imputing the incremental costs of fuel to intersystem transactions assures that native load customers pay no more for fuel than they would have had the intersystem sale not occurred…

Similarly, Paragraph 47 of the Opinion clearly states the position of the FERC in this regard.

> 47. In the instant proceeding, for market-based rate transactions, SPS' prices are limited by competition in lieu of cost-based regulation. If SPS or any other seller wishes to include a fuel price in its market-based contract, that price may be defined as average (as SPS so defined), indexed, incremental, or in any other manner. The fact that at least some of these contracts were filed with the Commission and accepted for filing is not germane because, as we stress here, the Commission is not seeking to change the contract language regarding fuel costs in market-based contracts, if fuel costs are even addressed at all. <u>The Commission is simply directing here that, in order to avoid subsidization, the incremental cost of fuel for these market-based intersystem sales must be flowed through the FCAC</u>. (emphasis added)

Thus, according to FERC, the additional, incremental fuel costs associated with making off-system sales cannot be attributed to native load customers. All other fuel costs are properly allocated to native load customers as those costs would have been incurred regardless of whether there were any off-system sales.

Q. IS KENTUCKY POWER'S APPROACH TO ALLOCATING FUEL COSTS CONSISTENT WITH THE POSITION PUT FORTH IN FERC OPINION 501?

A. Yes. As Company Witness Pearce discusses in greater detail, after the Company calculates the no load costs associated with having the units standing ready to serve native load customers, the Company calculates the incremental costs associated with the off-system sales from the Big Sandy, Mitchell, and Rockport units and subtracts those costs from the total fuel costs for those units to calculate the costs that remain and are subject to recovery from native load customers. Because the no-load costs for each unit would have been incurred regardless of whether off-system sales from that unit occurred, the Company's "top down" approach is wholly consistent with the FERC Opinion.

Q. ON PAGES 19 AND 20 OF KIUC WITNESS KOLLEN'S TESTIMONY HE TAKES THE POSITION THAT FERC HAS DETERMINED THAT IT IS INAPPROPRIATE TO PAY FUEL COSTS THAT ARE HIGHER THAN FUEL COSTS ASSIGNED TO

OFF-SYSTEM SALES. HAS FERC PROVIDED DIRECTION THAT FUEL COSTS ASSIGNED TO NATIVE LOAD CUSTOMERS MUST BE LOWER THAN FUEL COSTS ASSIGNED TO OFF-SYSTEM SALES?

A. No. As I previously indicated, the FERC Opinions and Orders cited by KIUC witness Kollen demonstrate that FERCs guidance is that fuel costs assigned to off-system sales (or non-native load) should be based upon the <u>incremental</u> cost of making the off-system sale – there is no requirement that the incremental cost be lower than the average cost or the cost to serve native load customers. In fact, FERC addressed this very issue in its Order Accepting Rates for Filing, dated May 31, 1995, in Docket No. ER95-852-000 (see Exhibit WAA-5). In this proceeding Florida Power Corporation objected to Tampa Electric Company (Tampa) providing service to a wholesale customer which included a fuel cost component reflecting an incremental fuel cost that was lower than Tampa's average fuel cost. The Order accepted the agreements filed by Tampa and rejected Florida Power position in the case.

Q. IS THIS COMMISSION BOUND BY THESE FERC OPINIONS.

A. No. Kentucky Power's retail fuel allocation methodology is regulated by this Commission. But to the extent the Commission's fuel adjustment clause is modeled on FERC methodology, these opinions are both instructive and indicate that the Company's allocation of incremental fuel costs to off-system sales is consistent with the FERC methodology.

Q. IF THE COMMISSION NEVERTHELESS ELECTS NOT TO FOLLOW FERC GUIDANCE SHOULD THIS DETERMINATION BE APPLIED RETROACTIVELY?

A. No. The Company has been using the same fuel cost allocation methodology for decades –

the result of which has been presented to this Commission, its Staff and intervenors in a number of base cases, fuel adjustment clause cases, and OSS sharing cases. If this Commission, through a contested proceeding, were to determine that a different fuel cost allocation methodology is more appropriate, such a determination should only be prospective in nature at the time that Kentucky Power establishes new base rates because it is important to ensure that the fuel cost allocation that underlies base rates is consistent with the fuel cost allocation used in the FAC. To do otherwise would result in one of two unacceptable conditions – either there are costs that are trapped costs or there are costs that are double recovered.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. FA08-16-000
July 31, 2008

Ohio Power Company
Attention: Mr. Andrew Reis
Assistant Controller
AEP Service Corporation
155 West Nationwide Blvd.
Columbus, Ohio 43215

Dear Mr. Bethel:

1. The Division of Audits within the Office of Enforcement (OE) has completed the audit of Ohio Power Company (Ohio Power) for the period from January 1, 2005 through December 31, 2007.

2. The overall objective was to evaluate Ohio Power's compliance with the Commission's accounting and reporting regulations as they relate to the calculation of the wholesale fuel adjustment clause under 18 C.F.R. § 35.14 (2007). The audit also included selective tests of Ohio Power's accounting records to validate the accuracy of the information filed with the Commission in its FERC Form No. 1 and FERC Form 580.

3. The audit did not result in any findings or recommendations that require Ohio Power to take corrective actions at this time. Docket No. FA08-16-000 is now closed.

4. The Commission delegated authority to act on this matter to the Director of OE under 18 C.F.R. § 375.314 (2007). This letter order constitutes final agency action. Ohio Power may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2007).

5. This letter order is without prejudice to the Commission's right to require hereafter any adjustments it may consider proper from additional information that may come to its attention. In addition, any instance of non-compliance not addressed herein or that may occur in the future may also be subject to investigation and appropriate remedies.

6. I appreciate the courtesies extended to the auditors. If you have any questions, please contact Mr. Bryan K. Craig, Director, Division of Audits at (202) 502-8471.

Sincerely,

Susan Court

Susan J. Court
Director
Office of Enforcement

Enclosure

Federal Energy Regulatory Commission

Wholesale Fuel Adjustment Clause Audit of Ohio Power Company

Docket No. FA08-16-000
July 31, 2008

Office of Enforcement
Division of Audits

I. Executive Summary

A. Conclusion

Audit staff has completed the audit of Ohio Power Company's (Ohio Power or Company) compliance with the Commission's accounting and reporting regulations applicable to the calculation of the wholesale fuel adjustment clause (FAC). The audit evaluated Ohio Power's compliance with the Commission's regulations[1] and whether information filed on certain pages in the FERC Form No. 1 and FERC Form 580 was accurate for the period January 1, 2005, to December 31, 2007. Based on materials provided by Ohio Power in response to data requests, interviews with Ohio Power staff members, and a review of publicly available documents, audit staff determined that there are no audit findings or recommendations that require Ohio Power to take corrective action at this time.

B. Ohio Power Company

Ohio Power is a regulated public utility that generates, transmits, and distributes electricity for sale in northwestern, east central, eastern and southern sections of Ohio. The Company served approximately 712,000 customers as of December 31, 2007. The Company owns (either fully or jointly) seven steam generating plants that burn coal. Also, as a member of the AEP Power Pool, Ohio Power engages in AEP Power Pool's sales to neighboring utilities and power marketers. In addition, the Company purchases large amounts of surplus power from Ohio Valley Electric Company and small amounts of power from Qualifying Facilities and Independent Power Producers. Ohio Power recovers wholesale fuel and purchased power costs from its sister company, Wheeling Power Company, through a fuel adjustment clause, the only customer from whom Ohio Power recovers fuel costs.

C. Fuel Cost and Purchased Economic Power Adjustment Clause

The fixed or base rates for wholesale electric service are typically derived from the estimated cost of service for a future test year. Included in the cost of service are estimates of fuel costs and purchased power expenses. The fuel clause regulations allow utilities to adjust base rates if actual fuel costs and certain actual purchased power costs differ from the projections used to set base rates.

Actual fuel costs consist of fossil and nuclear fuel consumed in the utility's plants and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased

[1] 18 C.F.R. § 35.14 (2007).

plants. Utilities can recover the actual expense of the fuel portion of all purchased power. A utility may recover non-fuel purchased power costs through the fuel clause in certain circumstances. Energy charges, including non-fuel energy charges, for energy purchased are recoverable through the fuel clause if the energy charges are less than the buyer's total avoided variable costs during the purchase period. All expenses associated with purchased power such as capacity or reservation charges or transmission or wheeling charges are recoverable through the fuel clause if the purchase is of less than twelve months duration and two conditions are met. First, the total cost of the purchase must be less than the buyer's total avoided variable cost. Second, the purpose of the purchase must be solely to displace higher cost generation. The second condition excludes from automatic recovery purchases made to maintain reserve levels or otherwise cure a capacity deficiency.

If the actual expenses are less than those forecasted in the base rates, a negative adjustment (reduction) is made to base rates; if greater, a positive adjustment (increase) is made. The effect of fuel clause adjustments is that actual fuel and (in some cases) charges associated with purchased power are recovered, regardless of the accuracy of the estimates embedded in the base rates.

II. Introduction

A. Objective

The overall objective of the audit was to evaluate Ohio Power's compliance with the Commission's accounting and reporting regulations as they relate to the calculation of wholesale fuel adjustment clause under 18 C.F.R. § 35.14 (2007). The audit also included selective tests of Ohio Power's accounting records to validate the accuracy of the information filed with the Commission in its FERC Form No. 1 and FERC Form 580.

B. Scope and Methodology

The audit covered the period from January 1, 2005 through December 31, 2007. Audit staff tested the validity of Ohio Power's recovery of fuel and purchased power costs through the wholesale FAC by the issuance of data requests, review of materials on file with the Commission and interviews with company employees. Specifically:

- Prior to commencement of the audit on October 30, 2007, audit staff reviewed publicly-available materials, including the FERC Form 580, FERC Form No.1, Electric Quarterly Reports (EQRs), and Annual Report to Stockholders. While reviewing this information audit staff looked for fuel contract buy-outs, large fluctuations of fuel stock and purchase power accounts, heat waves, price spikes and things that would affect the FAC customers.

- Audit staff tested the accuracy of the company's calculation of its billings under the wholesale FAC by comparing its calculations to the formula in the approved FAC tariff.

- Audit staff conducted interviews with Company personnel responsible for the actual calculations of FAC, fuel accounting, and the purchase power transactions to clarify how the Company computed its wholesale FAC fuel and purchased power adjustments.

- Audit staff tested the accuracy of the Company's wholesale FAC calculations against the applicable regulations and Commission precedent by reviewing the Company's calculations for a test period of three months, the months of December 2006, January 2007, and June 2007. Audit staff selected December 2006 and January 2007 because it is likely that companies would record unusual transactions during the first and the last months of the year. June 2007 was selected as this would be a high demand month during the summer. Therefore, we would see large fuel consumption and purchase power transactions. Audit staff conducted the following testing:

- Audit staff reviewed the fuel purchases, fuel transportation costs charged to Account 151, Fuel Stock by obtaining supporting invoices and journal entries charged to the account. Based on the tests performed, audit staff is assured that the charges made to Account 151 are permitted by the Commission's regulations and fuel purchases are properly accounted for. Audit staff interviewed the Manager of Fuel Accounting and ensured that the controls over fuel purchases are proper.

- Audit staff reviewed the fuel consumption amounts recorded in Account 501, Fuel that were passed though the Company 's FAC calculations by reviewing supporting worksheets and journal entries for the three sample months. Audit staff also interviewed company personnel, such as the Manager of Fuel Accounting and the Settlements Analyst responsible for accounting for fuel consumption, to ensure only the consumed amounts were passed thorough the FAC.

- Audit staff reviewed purchased power expenses recorded for the test months, reviewed the supporting invoices for these purchases, and tied these amounts to the amounts booked to Account 555, Purchased Power. Audit staff also interviewed Company personnel responsible for purchase power amounts passed through the FAC to ensure only the fuel costs were included. Additionally, audit staff reviewed purchased power invoices to ensure that only the fuel component of the purchase power costs were passed through the FAC.

- Audit staff recalculated the FAC for the test months to ensure that it was properly calculated. Also, audit staff interviewed the personnel responsible for calculating the FAC.

- Finally, audit staff tied the FAC calculations to the charges assessed to Wheeling Power Company (the only customer billed under the Company's FAC) to verify that Ohio Power charged its customer the amount shown in the FAC calculations, which tied to the books and records.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. FA09-2-000
July 2, 2009

Public Service Company of Oklahoma
Attention: Timothy Dooley,
Director, Energy Accounting and Reporting
American Electric Power
AEP Service Corporation, 1 Riverside Plaza,
Columbus, Ohio 43215-2373

Dear Mr. Dooley:

1. The Division of Audits in the Office of Enforcement (OE) has completed the audit of Public Service Company of Oklahoma (PSO) for January 1, 2006, through June 19, 2009. The audit was conducted to determine whether PSO complies with Commission accounting and reporting regulations as they relate to the calculation and assessment of the wholesale fuel adjustment clause (FAC) under 18 CFR § 35.14 of the Commission's regulations and PSO's FAC tariff on file with the Commission for the Oklahoma Municipal Power Authority (OMPA), the Town of South Coffeyville (TSC) and Western Farmers Electric Cooperative (WFEC). Also the audit included selective tests of PSO's accounting records to validate the accuracy of information filed with the Commission in its FERC Form No. 1 and FERC Form No. 580.

2. The audit resulted in no findings or recommendations that require PSO to take corrective actions at this time. Docket No. FA09-2-000 is now closed.

3. The Commission delegated authority to act on this matter to the Director of OE under 18 C.F.R. § 375.314 (2009). This letter order constitutes final agency action. PSO may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2009).

4. This letter order is without prejudice to the Commission's right to require hereafter any adjustments it may consider proper from additional information that may come to its attention. In addition, any instance of non-compliance not addressed herein or that may occur in the future may also be subject to investigation and appropriate remedies.

5. I appreciate the courtesies extended to our auditors. If you have questions, please contact Athula Gunaratne at (202) 502-8230 or via e-mail at athula.gunaratne@ferc.gov or Beth Taylor at (202) 502-8826 or via e-mail at elizabeth.taylor@ferc.gov.

Sincerely,

Bryan K. Craig, Director
Division of Audits

Enclosure

Federal Energy Regulatory Commission

Wholesale Fuel Adjustment Clause Audit of Public Service Company of Oklahoma

Docket No. FA09-2-000
July 2, 2009

Office of Enforcement
Division of Audits

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I. Executive Summary

A. Overview

The Division of Audits within the Office of Enforcement (OE) has completed an audit of the Public Service Company of Oklahoma (PSO). The audit was initiated to evaluate whether PSO complies with the Commission’s accounting and reporting regulations as they relate to the calculation of the wholesale fuel adjustment clause (FAC) under 18 C.F.R. §35.14 and its FAC tariff on file with the Federal Energy Regulatory Commission (Commission). The audit covered the period from January 1, 2006 through June 19, 2009.

B. Public Service Company of Oklahoma

PSO is a regulated public utility engaged in the generation, transmission and distribution of electric power to approximately 525,000 retail customers in eastern and southwestern Oklahoma. PSO owns six coal power plants, one combustion-turbine power plant, and one combined-cycle power plant. In 2008, PSO generated 14.9 million megawatt-hours (Mwh) of power and purchased 6.4 million Mwh. All PSO power plants burn natural gas, coal or oil. PSO is a member of the Southwest Power Pool. PSO also supplies and markets electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. PSO participates in the day-ahead and real-time market. AEP Service Corporation (AEPSC), as agent for PSO, provides forecasts of PSO's load, and offers PSO's generation resource capabilities to the SPP per SPP market guidelines.

PSO is one of 11 public utility companies owned by Columbus, OH-based American Electric Power (AEP). On June 15, 2000, AEP merged with Central and South West Corporation (CSW) (now known as AEP Utilities, Inc.). Through this merger, PSO became a wholly owned public utility AEP subsidiary.

C. Fuel Adjustment Clause

During the audit period, PSO had three FAC customers; Oklahoma Municipal Power Authority (OMPA), South Coffeyville, OK, and Western Farmers Electric Cooperative (WFEC). PSO’s FAC with these customers became effective March 12, 1985, January 15, 1996, and August 4, 1985 respectively. Effective December 31, 2007, PSO terminated its FAC with OMPA.

The Commission has approved electric-service rates that usually contain two components: a demand charge to recover a utility's fixed (capacity-related) costs and an energy charge to recover a utility's variable costs, primarily for fuel. The energy charge is further divided into two components.

In addition, the energy charge has two elements. The first element is the "basic energy rate" which recovers the "base cost" of fuel. The basic energy rate must be approved in advance by the Commission. The second element is the "fuel adjustment" charge. This charge is based on a formula designed to recover the difference (plus or minus) between the projected cost of fuel and the actual cost of fuel incurred over time. A utility's FAC formula must be approved by the Commission because it is part of the utility's filed rate. Since the FAC is approved by the Commission, the monthly charge that results from application of the formula need not be filed with the Commission for approval. This enables utilities to keep their rates in line with the current cost of their fuel without continually having to file for rate increases and decreases.

II. Introduction

A. Objective

Audit objectives were to determine whether PSO complies with Commission accounting and reporting regulations as they relate to the calculation and assessment of the wholesale fuel adjustment (FAC) clause under 18 CFR § 35.14 of Commission regulations and PSO's FAC tariff on file with the Commission for the OMPA, Town of South Coffeyville, OK, (TSC) and Western Farmers Electric Cooperative (WFEC). Also, the audit included selective tests of PSO accounting records to validate the accuracy of information filed with the Commission.

B. Scope and Methodology

The audit covered January 1, 2006 through June 19, 2009. Audit staff tested the validity of PSO's recovery of fuel and purchased-power costs through the wholesale FAC by issuing formal and informal data requests, reviewing materials filed with the Commission, and interviews with PSO employees. Specifically, audit staff:

- Prior to audit commencement on November 6, 2008, reviewed publiclyavailable materials, including FERC Form No. 580, FERC Form No. 1, Electric Quarterly Reports (EQRs), and PSO's Annual Report to Stockholders. While reviewing this information, audit staff looked for fuel contract buy-outs, large fluctuations in fuel stock and purchase-power accounts, and other events that may affect FAC customers.

- Tested the accuracy of PSO's calculation of its billings under the wholesale FAC by comparing its calculations to the formula in the approved FAC tariff.

- Interviewed PSO employees responsible for calculations of FAC, fuel accounting, and purchase-power transactions to clarify how PSO computed its wholesale FAC fuel and purchase-power adjustments.

- Randomly selected three months to test the accuracy of PSO's wholesale FAC calculations against applicable regulations and Commission precedent. Audit staff reviewed PSO's calculations for December 2006, and January and September 2007. In testing, audit staff :

    - Reviewed fuel on hand (natural gas, coal, or oil), fuel purchases, and fuel transportation costs charged to Account 151, Fuel Stock by obtaining

- Reviewed purchase-power expenses recorded for test months, reviewed supporting invoices for these purchases, and tied these amounts to those booked to Account 555, Purchased Power. Also, audit staff interviewed PSO employees responsible for purchase-power amounts passed through the FAC to ensure that only fuel costs were included. In addition, purchased-power invoices were reviewed to ensure that the fuel component of purchase-power costs were passed through the FAC according to Commission regulations. Further, invoices from independent power producers (wind energy) were reviewed to ensure these cost (nonfuel energy charges) were allowed to be passed through the FAC based on Commission regulations.

- Reviewed fuel consumption amounts in Account 501, Fuel, which were passed through PSO's FAC calculations by reviewing supporting worksheets and journal entries for the sample months. Also, audit staff interviewed employees, such as the fuels analyst responsible for accounting for fuel consumption, to ensure only consumed amounts were passed through the FAC.

- Recalculated the FAC for the test months to ensure that it was properly calculated. Also, audit staff interviewed the manager of fuel accounting, who is responsible for FAC calculation.

- Audit staff reviewed PSO's intersystem sales (also known as opportunity sales) to ensure that wholesale requirement customers were not subsidizing these sales. Audit staff recalculated the FAC to ensure that wholesale requirement customers were not damaged by PSO opportunity sales.

- Finally, audit staff tied the FAC calculations to customer invoices to verify that the PSO charged to customers is consistent with the amount shown in FAC calculations.

Appalachian Power Company

Docket No. ER83-63-000

FEDERAL ENERGY REGULATORY COMMISSION - Commission

21 F.E.R.C. P61,309; 1982 FERC LEXIS 1804

December 17, 1982

ACTION:
[**1]

Order Accepting Rates for Filing, Granting Intervention and Terminating Docket

JUDGES:

Before Commissioners: Georgiana Sheldon, Acting Chairman; J. David Hughes, A. G. Sousa and Oliver G. Richard III.

OPINION:
[*61,812]

On October 26, 1982, the American Electric Power Service Corporation, on behalf of Appalachian Power Company (APCO), tendered for filing Modification No. 19, Service Schedule I, to an existing Interconnection Agreement between APCO and Virginia Electric and Power Company (VEPCO). n1

n1 *See* Appendix A for rate schedule designation.

APCO currently provides VEPCO with 600 MW of power and associated energy from its Tanners Creek Unit Nos. 1 through 3; its Gavin Unit Nos. 1 and 2; and its Amos Unit No. 3 under an Interconnection Agreement which expires on December 31, 1982. The instant filing establishes a replacement service for the expiring service. APCO states that the new service will give VEPCO greater flexibility in purchasing capacity and energy than was provided under the expiring Service Schedule H. The modified agreement will provide 600 MW of capacity and energy to VEPCO for a two-year period beginning January 1, 1983, the proposed effective date, [**2] and expiring on December 31, 1984.

The filing provides that APCO will charge VEPCO a fixed monthly demand charge of $2.8 million which will be effective for the entire two-year contract period. Energy will be provided in two parts: (1) Part I energy equal to 150 MWh per hour on a take-or-pay basis, and (2) Part II energy of up to 450 MWh per hour at VEPCO's discretion. Part I energy will be billed at 1 mill per kWh plus the average monthly fuel cost at the Tanners Creek Unit Nos. 1, 2, and 3 during the billing month, as adjusted for transmission losses. Part II energy will be billed at 1 mill per kWh plus the average monthly fuel cost at Amos Unit No. 3 and at Gavin Unit Nos. 1 and 2 during the billing period again adjusted for transmission losses. This proposed service is considered firm except for two contingencies associated with the sellers' coal supply. The purpose of the purchase by VEPCO is for the displacement of oil-fired power with cheaper coal-fired power.

Notice of the filing was published in the Federal Register with comments due on or before November 22, 1982. A motion to intervene and request for a one day suspension was filed by the North Carolina Eastern Municipal [**3] Power Agency (Power Agency) and the ElectriCities of North Carolina (ElectriCities).

These entities seek a one day suspension and a hearing so that an investigation of the rates and charges may be conducted and the amounts collected will be subject to refund. The Power Agency is a partial requirements customer of VEPCO while ElectriCities' members are full requirements VEPCO customers. The customers contend that any purchased power contracts entered into by VEPCO will ultimately be reflected in their wholesale rates. Specifically, the intervenors contend that they must be assured that APCO [*61,813] is properly assigning the high-cost coal developed from subsidiary resources, and that APCO is not assigning all such fuel costs to interchange transactions such as that contemplated by the instant filing.

On December 7, 1982, Appalachian filed a pleading objecting to intervention by the Power Agency and ElectriCities. Appalachian contends that these movants have not alleged any interest that cannot be adequately represented by VEPCO. Appalachian also opposes the request for suspension and a refund obligation.

Discussion

Under Rule 214 of the Commission's Rules of Practice [**4] and Procedure (*18 CFR § 385.214*), the Commission will grant the motion to intervene filed by the Power Agency and ElectriCities. Despite Appalachian's contentions, it appears that the interest of these parties may not be identical to those of their wholesale supplier--VEPCO.

With respect to the intervenors' request for suspension and a hearing based on their desire to be assured that APCO is not assigning all of the high-cost coal from its subsidiaries as fuel costs in this purchased power transaction, we find that the intervenors have not raised an issue which warrants suspension or hearing. Our analysis indicates that in 1981, the six designated operating units supplying power to VEPCO were only partially fueled by subsidiary coal. In addition, the power purchased by VEPCO will be priced at the average monthly cost of fuel consumed at the supplying generating units. Consequently, we believe that the intervenors' concern that the subsidiary coal will be assigned exclusively to the VEPCO sale is unwarranted and does not serve as a basis for initiating a hearing.

We also note that the Power Agency and ElectriCities do not question the prudence of APCO's [**5] coal purchases from its subsidiary, but limit their concern strictly to the assignment of such purchases to the interchange transaction. Because the six generating units furnishing the power for this sale are among the highest fuel cost units on the American Electric Power System, n2 these units are precisely the ones which would be expected to provide the energy for any off-system sale to VEPCO or others, and these units form a proper basis for pricing the interchange service. We believe that it is both appropriate, and a common industry practice to assign the highest fuel cost to off-system sales, while lower fuel cost resources are reserved for the benefit of the APCO native load customers who, through their rates, provide for the construction and operation of the generating facilities.

n2 APCO is an operating company within the AEP system.

Since the Power Agency and ElectriCities have raised no issues of law or fact which would warrant an evidentiary hearing, and furthermore, since our analysis indicates that the rates tendered for filing by APCO are not excessive, APCO's submittal will be accepted for filing to become effective on January 1, 1983, as requested.

The Commission [**6] *orders* :

(A) Appalachian Power Company's submittal in this docket is hereby accepted for filing to become effective on January 1, 1983, without suspension.

(B) The motion to intervene filed by the North Carolina Eastern Municipal Power Agency and ElectriCities of North Carolina is hereby granted subject to the Commission's Rules of Practice and Procedure.

(C) The request by North Carolina Eastern Municipal Power Agency and ElectriCities of North Carolina to suspend APCO's filing for one day and initiate a hearing is hereby denied.

(D) Docket No. ER83-63-000 is hereby terminated.

(E) The Secretary shall promptly publish this order in the Federal Register.

APPENDIX:

Appendix A

Appalachian Power Company

Supplement No. 16 to

Rate Schedule FPC No. 16

(Supersedes Supplement No. 11)

Legal Topics:

For related research and practice materials, see the following legal topics:
Energy & Utilities LawElectric Power IndustryRatesRetail RatesEnergy & Utilities LawElectric Power IndustryState RegulationGeneral OverviewEnergy & Utilities LawPurchase ContractsTake or PayGeneral Overview

123 FERC ¶ 61,047
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 501

Golden Spread Electric Cooperative, Inc. Lyntegar Electric Cooperative, Inc. Farmers' Electric Cooperative, Inc. Lea County Electric Cooperative, Inc. Central Valley Electric Cooperative, Inc. Roosevelt County Electric Cooperative, Inc. v. Southwestern Public Service Company	Docket No. EL05-19-002
Southwestern Public Service Company	Docket No. ER05-168-001

Issued: April 21, 2008

123 FERC ¶ 61,047
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Golden Spread Electric Cooperative, Inc.
Lyntegar Electric Cooperative, Inc.
Farmers' Electric Cooperative, Inc.
Lea County Electric Cooperative, Inc.
Central Valley Electric Cooperative, Inc.
Roosevelt County Electric Cooperative, Inc.

v. Docket No. EL05-19-002

Southwestern Public Service Company

Southwestern Public Service Company Docket No. ER05-168-001

OPINION NO. 501

OPINION AND ORDER ON INITIAL DECISION

(Issued April 21, 2008)

Table of Contents

Paragraph Number

I. Introduction

1. This case arises in part out of a complaint, filed on November 2, 2004, by several cooperatives (the Cooperative Customer Group, CCG, or complainants).[1] These cooperatives purchase requirements service from Southwestern Public Service Company (SPS).[2] SPS, a subsidiary of Xcel Energy Inc., is an operating utility engaged primarily in the generation, transmission, distribution and sale of electricity. SPS serves approximately 386,000 electric customers in portions of Texas and New Mexico, and also operates in Oklahoma and Kansas.

2. The complaint, filed under section 206 of the Federal Power Act (FPA),[3] alleges that SPS has historically violated, and continues to violate, the fuel cost adjustment clause (FCAC) provisions of its wholesale customers' rate schedules and the Commission's FCAC regulations. Complainants assert that SPS may be flowing through

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[1] When the complaint was filed, CCG included Golden Spread Electric Cooperative, Inc. (Golden Spread), Lyntegar Electric Cooperative, Inc. (Lyntegar), Farmers' Electric Cooperative, Inc. (Farmers'), Lea County Electric Cooperative, Inc. (Lea County), Central Valley Electric Cooperative, Inc. (Central Valley), and Roosevelt County Electric Cooperative, Inc. (Roosevelt County). However, since that time, Golden Spread and Lyntegar have resolved with SPS all issues except one in a settlement filed on December 3, 2007 (Settlement Agreement). Therefore, in this order, CCG will only include Farmers', Lea County, Central Valley, and Roosevelt County.

[2] All of the cooperatives involved in this proceeding are full requirements customers, except Golden Spread, which is a partial requirements customer.

[3] 16 U.S.C. § 824e (2000).

its FCAC virtually all energy-related purchased power costs, and that some of the costs are not permissible under the filed rate or the Commission's regulations. Complainants also expressed concern that SPS was not appropriately crediting the FCAC (and as a result, its requirements customers) with the cost associated with incremental fuel when it makes intersystem sales. That is, complainants argue that intersystem sales are opportunity sales and that the intersystem customers should have higher cost incremental fuel attributed to their transactions for purposes of computing the FCAC. They also argue that lower cost energy purchases incurred to meet SPS' requirements customers' needs have been allocated to intersystem sales, resulting in requirements customers subsidizing SPS' marketing function. Complainants asked the Commission to investigate FCAC charges dating back to the last Commission audit of SPS under section 205(f) of the FPA,[4] or at least from 1994. We address the issue of how to treat fuel costs under market-based contracts when determining the FCAC for wholesale requirements customers in section II of this order.

3. The complainants also allege that SPS' cost-based rates for full and partial requirements service are excessive, unjust and unreasonable, and unduly discriminatory or preferential for a number of reasons as explained below.[5] SPS' cost-based rates are addressed in section III of this order.

4. On the same date that CCG filed its complaint against SPS,[6] SPS filed a proposal under section 205 of the FPA[7] to change its FCAC and to make corresponding revisions to SPS' power supply contracts.[8] SPS stated that it filed the revised FCAC to conform to the Commission's current fuel cost and purchased economic power adjustment clause regulations,[9] and also to account for expenses and revenues associated with SPS' participation in the Southwest Power Pool, Inc. (SPP) Open Access Transmission Tariff (OATT). Under the revised FCAC, SPS would collect the net difference between the amounts SPS pays to SPP for transmission losses and the amounts that SPP distributes to

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[4] *Id.* § 824d(f).

[5] *See e.g.* CCG's April 10, 2006, Initial Brief at Issue I (Cost of Service Issues).

[6] Docket No. EL05-19-000.

[7] 16 U.S.C. § 824d (2000).

[8] Docket No. ER05-168-000. SPS' proposed FCAC that is discussed in section V of this order is contained in the November 2, 2004, filing.

[9] *See* 18 C.F.R. § 35.14 (2007); *Treatment of Purchased Power in the Fuel Cost Adjustment Clause for Electric Utilities*, Order No. 352, FERC Stats. & Regs. ¶ 30,525 (1983), *reh'g denied*, Order No. 352-A, 26 FERC ¶ 61,266 (1984) (Order No. 352).

SPS to compensate it for supplying energy to cover transmission losses. Issues pertaining to SPS' former FCAC are addressed in section IV of this order. Issues pertaining to SPS' proposed FCAC are addressed in section V.

5. On December 21, 2004, the Commission established hearing and settlement judge procedures in response to the CCG complaint, and set a refund effective date of January 1, 2005, for damages arising from the complaint.[10] On December 29, 2004, the Commission accepted and suspended, for a nominal period, subject to refund (also effective January 1, 2005, sixty days following the filing of the FPA section 205 proposal), SPS' proposed changes to the FCAC.[11] The Commission also consolidated SPS' proposed FCAC changes with the proceeding already underway in the complaint case before an administrative law judge (ALJ).

6. On May 24, 2006, the ALJ issued an Initial Decision.[12] Briefs on Exceptions were filed by SPS, CCG,[13] Central Valley, Trial Staff, Occidental Permian Ltd. and Occidental Power Marketing, L.P. (collectively, Occidental), Public Service Company of New Mexico (PNM), and Cap Rock Energy Corporation (Cap Rock) on June 23, 2006. Briefs Opposing Exceptions were filed by SPS, CCG, Trial Staff, Occidental, PNM, and Golden Spread on July 13, 2006.[14]

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[10] *Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,321 (2004) (order on complaint establishing hearing and settlement judge procedures). In accordance with FPA section 206(b) as it existed at the time of the complaint, the refund effective date in complaint proceedings shall not be earlier than the date sixty days after the filing of a complaint, nor later than five months after the expiration of such sixty-day period. Here the refund effective date is sixty days after the filing of the complaint.

[11] *Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,373 (2004) (order accepting and suspending proposed fuel adjustment clause changes, establishing hearing and settlement judge procedures, and consolidating proceedings).

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

[13] As noted above, at the time Briefs on Exceptions and Briefs Opposing Exceptions were filed, CCG included Golden Spread and Lyntegar.

[14] Due to the Settlement Agreement, we will not discuss the briefs of Golden Spread and Occidental in this order.

7. Between July and November 2007, the parties filed three motions asking the Commission to defer action on the Initial Decision to permit additional time for settlement discussions.[15] The Commission granted all of these motions.

8. On December 3, 2007, SPS submitted a Settlement Agreement on behalf of itself, Golden Spread, Lyntegar, and Occidental (collectively, the Settling Parties). The Settlement Agreement resolves all issues between the Settling Parties except one, which is the issue of the appropriate demand cost allocator for use on the SPS system. On January 18, 2008, the Settlement Judge certified the Settlement Agreement to the Commission as uncontested.[16]

9. On March 14, SPS, Golden Spread, and Lyntegar filed a motion requesting that the Commission promptly approve the Settlement Agreement. PNM, Occidental, Central Valley, Farmers', and Roosevelt County filed answers to the Settling Parties' motion stating that they do not oppose the motion, but request that the Commission also promptly issue an order on the Initial Decision.

10. This order resolves all issues between the non-settling parties. In addition, because the Settlement Agreement does not resolve the demand cost allocator issue, this order also resolves that issue as it applies to both the Settling Parties and the non-settling parties.

11. This order affirms in part, and reverses in part, the Initial Decision. Broadly speaking, the dispute addressed by this order involves intersystem sales and how they relate to the FCAC, a range of cost of service issues associated with SPS' cost-based rates for full and partial requirements service, and SPS' former FCAC and proposed FCAC.

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[15] On July 17, 2007, SPS and Golden Spread filed a joint motion asking the Commission to defer action on the Initial Decision to permit additional time for settlement discussions. On September 17, 2007, SPS, Golden Spread, Lyntegar, Farmers', Lea County, Central Valley, Roosevelt County, and Cap Rock, filed another joint motion asking the Commission to defer action on the Initial Decision for the same reason. On November 14, 2007, Golden Spread, Lyntegar, and Occidental filed a third joint motion requesting more time to engage in settlement discussions.

[16] *Southwestern Public Service Co.*, 122 FERC ¶ 63,003 (2008). In an order issued contemporaneously with this order, the Commission approved the Settlement Agreement, subject to modification. *Golden Spread Elec. Coop., Inc.*, 123 FERC ¶ 61,054 (2008) (Order Approving Uncontested Partial Settlement Subject to Modifications).

II. Intersystem Sales and the FCAC

12. The most significant aspect of this case involves how the FCAC operates under section 35.14 of the Commission's regulations with respect to market-based rate transactions. CCG argues that SPS' allocation of average fuel cost for market-based sales impermissibly subsidizes intersystem sales at the expense of native load customers. It is not disputed that SPS' market-based sales contracts provide that SPS recovers the average cost of fuel, not the incremental cost as complainants would prefer.

A. The Commission's Fuel and Purchased Power Cost Adjustment Regulations, 18 C.F.R. § 35.14(a)(2)(v) (2006)[17]

13. Rates for electric service generally have two components; a "demand charge" to recover the utility's fixed (capacity related) costs and an "energy charge" to recover the utility's variable costs, primarily cost of fuel.

14. The energy charge is further composed of two elements. The first element is the "basic energy rate." This recovers the "base cost" of fuel. The basic energy rate must be approved in advance by the Commission. The second element is the "fuel adjustment" charge. This charge is based on a formula designed to recover the difference between the base cost of fuel and the actual cost of fuel incurred over time. A utility's fuel adjustment formula must be approved by the Commission, for it is part of the utility's filed rate. The monthly charge that results from application of the formula, which is an approved rate, thus need not be filed for Commission approval. The fuel adjustment clauses enable utilities to keep their rates in line with the current cost of their fuel without continually having to file for rate increases and decreases.

15. Section 35.14(a)(2) of the Commission's regulations provides in pertinent part as follows:

> 35.14 – Fuel cost and purchased economic power adjustment clauses
> (a)(2) – Fuel and purchased economic power costs shall be the cost of:
> (i)-(iv) – [various costs and charges]
> (v) – *And less* the cost of fossil and nuclear fuel recovered through all intersystem sales. (Emphasis in original).

[17] Unless otherwise stated, all references to section 35.14 are to the 2006 version (in earlier years, subsection (a)(2)(v) was (a)(2)(iv)).

SPS' FCAC largely tracks the Commission's *pro forma* FCAC. SPS submitted into evidence a sample of its wholesale fuel cost and economic purchased power adjustment clause, which provides in relevant part as follows:

> 2. Fuel costs (*F*), measured in $, shall be the cost of:
>
> (i) fossil and nuclear fuel consumed in Company's own plants . . . .
>
> * * *
>
> (viii) less, the cost of fossil and nuclear fuel and the costs of energy purchases recovered through all inter-system sales.[18]

16. As the Commission has explained before, "[t]he fuel adjustment clause is intended to keep utilities whole with respect to changes in the cost of their fuel. It allows utilities to pass through to their ratepayers increases or decreases in the cost of their fuel, without having to make separate rate filings to reflect each change in fuel cost, and without having to obtain Commission review of each change in fuel cost."[19]

17. The FCAC issues in this proceeding fall into two categories: those raised in the complaint against SPS in Docket No. EL05-19 concerning the SPS FCAC that was in effect prior to the effective date of the proposed FCAC (January 1, 2005) and those in Docket No. ER05-168 concerning the FCAC that SPS proposed in the FPA section 205 filing that is also part of this proceeding.[20] In the following section we address the

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[18] Ex. SPS-2 at 1-2 (Southwestern Public Service Company FERC Electric Rate Schedule No. 118, First Revised Sheet No. 16).

[19] *Missouri Pub. Serv. Co.*, Opinion No. 327, 48 FERC ¶ 61,011, at 61,078 (1989) (Opinion No. 327) (citing *Fuel Adjustment Clauses in Wholesale Rate Schedule*, Order No. 517, 52 FPC 1304 (1974) (FPC Order No. 517)); *see also Public Utils. Comm'n of California v. FERC*, 254 F.3d 250, 256 n.6 (D.C. Cir. 2001) (citing Opinion No. 327 for proposition that intent of fuel adjustment clause is to keep utilities whole with respect to changes in cost of fuel).

[20] *Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,321 (2004) (order on complaint establishing hearing and settlement judge procedures), *with Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,373 (2004) (accepting and suspending proposed FCAC and consolidating with complaint proceeding).

general question of how fuel costs recovered from intersystem sales should be allocated per the FCAC under section 35.14(a)(2)(v) when the intersystem sales are market-based rate transactions.

1. **Initial Decision**

18. The ALJ concluded that SPS' FCAC practices are not permissible. The ALJ first noted that SPS had a long-standing practice of allocating system average fuel and purchased energy costs to firm system capacity sales.[21] The ALJ further observed that in recent years, as the industry has evolved from cost-based to market-based rates, SPS did not reexamine its practice of allocating system average fuel and purchased energy costs to its capacity sales, regardless of whether such sales were opportunity-type sales made under a market-based tariff or traditional requirements sales made under a cost-based tariff.

19. In finding that the sales in question were intersystem opportunity sales, the ALJ characterized them as having a "lesser status" than native load sales, and the ALJ distinguished the intersystem sales from native load sales in that intersystem opportunity sales do not require the same amount of capacity planning, construction, or maintenance.[22]

20. The ALJ stated that the Commission's policy has been "that opportunity sales are generally priced to reflect incremental fuel cost, so that the risk of recovery would fall upon the utility, not other customers."[23] Recognizing the converse, i.e., that wholesale requirements customers pay the average fuel cost, the ALJ also stated that "the record supports the view that this policy was well understood in the industry, as [Golden Spread's witness] suggested, when he stated that other utilities believed that system average fuel belonged to 'the regulated customers, being native load customers, retail, long-term wholesale, those that are considered native or captive customers within their jurisdiction.'"[24]

21. In response to Trial Staff's argument that wholesale requirements customers do not have a superior claim to service than a non-requirements customer, the ALJ stated that "to charge market-based rate customers system average fuel costs should not bind

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[21] Initial Decision at P 133 (citing Ex. SPS-12 at 15); *id.* P 146.

[22] *Id.* P 33.

[23] *Id.* P 148.

[24] *Id.* (citing Tr. 962-63 (Wise)).

non-signatory wholesale customers and the Company's retail customers to subsidize such sales through the FCAC by failing to recover from the opportunity sale customers the real incremental fuel costs associated with the market-based sales."[25] The ALJ referenced *Heartland Energy Services, Inc.*,[26] *Entergy Services, Inc.*,[27] and *Consumers Energy Co.*[28] for the proposition that cost-based requirements customers should not subsidize a utility's market-based activities, and the ALJ also noted that other utilities avoided situations such as the one that SPS entered into.[29]

22. The ALJ concluded that:

> The plain facts are that SPS improved its competitive position in making market-based sales by charging market-based customers lower system average fuel costs, and collected the difference from the Company's cost-based customers, who were forced to cover their own fuel costs and the difference between average costs and the incremental fuel costs associated with the market-based sales.[30]

23. The ALJ directed SPS to make a compliance filing "designed to restore its wholesale customers to the position in which they would have been had they been paying a just and reasonable rate, i.e., one calculated to assign incremental fuel costs to market-based customers from 1999 to 2004."[31]

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[25] *Id.* P 149.

[26] 68 FERC ¶ 61,223, at 62,062-63 (1994) (prohibiting transfer of benefits from captive customers of a franchised public utility to affiliates and shareholders) (*Heartland*).

[27] 58 FERC ¶ 61,234, at 61,772 (1992) (requiring Entergy to charge at least incremental cost to intersystem customers to avoid subsidizing native load customers) (*Entergy*).

[28] 94 FERC ¶ 61,180, at 61,623 (2001) (directing utility to amend wholesale contracts to credit cost of fuel recovered at the hourly system incremental cost for sales to affiliates, or to make revisions accomplishing the same) (*Consumers*).

[29] Initial Decision at P 149.

[30] *Id.* P 150.

[31] *Id.* P 252.

2. **Briefs on Exception**

24. On this issue, SPS disagrees with the ALJ on two general principles. First, SPS argues the ALJ erred in concluding that SPS' contested market-based rate sales were intersystem opportunity sales. Second, SPS argues the ALJ erred in concluding that the incremental fuel and purchased power costs attributable to those market-based sales should be credited against the costs of fuel and purchased power recovered from the CCG members and Cap Rock.[32]

25. SPS contends that the market-based sales at issue were neither opportunity nor intersystem sales. Rather, SPS describes the sales as "firm system capacity sales."[33] SPS argues that among the salient characteristics of these contracts, most were for periods of one year or more, and many of these contracts contained the "standard SPS FCAC." Furthermore, SPS states that many of these contracts were filed with the Commission. Although these contracts were made under SPS' market-based rate authority, SPS asserts that the rates were designed to recover SPS' average imbedded costs. The rates included a negotiated demand charge that was no lower than the demand charge assessed on SPS' cost-based partial requirements customers operating within the SPS control area. The rates also incorporated SPS' standard FCAC mechanism to recover average fuel and purchased power costs, which SPS alleges is the same mechanism used to recover such costs from the CCG members.[34]

26. SPS argues that, based on the Commission's statements in cases such as *Wisconsin Public Power, Inc. v. Wisconsin Power & Light Co.*,[35] the disputed sales should not be classified as opportunity or intersystem sales.[36] Citing *Kentucky Utilities Company*,[37] SPS characterizes opportunity sales as non-firm and for limited terms. SPS describes firm service as being available on an as-needed basis, being continuously available, and being priced on a fully-allocated cost basis. SPS cites *Commonwealth Edison Company* as support for this proposition.[38] SPS argues that the disputed sales are not opportunity

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[32] SPS Brief on Exceptions at 21-42.

[33] *Id.* at 22-23.

[34] *Id.* at 22.

[35] 98 FERC ¶ 61,293, at 62,279 (2002), *reh'g denied*, 104 FERC ¶ 61,244 (2003) (*Wisconsin*).

[36] SPS Brief on Exceptions at 22-28.

[37] 22 FERC ¶ 63,011, at 65,024 (1983).

[38] 21 FERC ¶ 61,096, at 61,294 (1982).

sales because SPS' sales "were continuously available to the customer from the Company's generation resources, which include capacity purchases made to meet planning reserves," were multi-year sales, and were considered in performing annual system planning.[39] SPS states that "[t]he Presiding Judge's conclusion that the firm system capacity sales made by SPS to neighboring utilities are 'fundamentally different from sales to SPS' cost of service customers' is not well founded."[40]

27. SPS argues that neither its FCAC nor the Commission's fuel clause regulations contemplate the attribution of incremental fuel costs to intersystem sales.[41] SPS states that its FCAC, which is on file with the Commission, provides that SPS shall reduce the fuel and purchased costs that it recovers in monthly FCAC billings by "the cost of fossil and nuclear fuel *recovered through inter-system sales* . . . ."[42] SPS further argues that "there is no basis . . . to impute, attribute or otherwise ascribe to such sales an incremental cost for purposes of making monthly FCAC calculations."[43]

28. SPS next argues that the Initial Decision violates the filed rate doctrine by retroactively amending SPS' filed FCAC provisions.[44] Specifically, SPS invokes the filed rate doctrine in response to the ALJ's order that SPS "restore its wholesale customers to the position in which they would have been had they been paying a just and reasonable rate, i.e., one calculated to assign incremental fuel costs to market-based rate customers from 1999 to 2004."[45] SPS states that FPA section 206(b)[46] limits the Commission to ordering prospective relief, which may take effect no earlier than the

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[39] SPS Brief on Exceptions at 24. SPS also cites Ex. CCG-8, CRE-32, and Tr. at 1042:5-9 in support of its argument that it plans for these intersystem sales.

[40] *Id.* at 27.

[41] *Id.* at 28-29.

[42] *Id.* at 28 (emphasis in original).

[43] *Id.* at 29.

[44] *See id.* at 30-32; *see also id.* at 37-41 (asserting that Initial Decision constitutes impermissible collateral attack on SPS' filed rates).

[45] *Id.* at 30 (quoting Initial Decision at P 252). As stated above, the Commission's order on setting the complaint for hearing, *Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,321 (2004), established January 1, 2005, as the refund effective date pursuant to FPA section 206.

[46] 16 U.S.C. § 824e(b) (2000).

refund effective date established when the complaint proceeding begins.[47] SPS also argues that rates established in power sales contracts filed with and accepted by the Commission are binding on the parties even when it is alleged that the selling utility committed fraud on the purchaser.[48]

29. SPS states that the average cost energy rates were the appropriate basis for pricing the disputed sales.[49] SPS argues that the Commission has approved the sale of firm energy priced on the basis of average system energy costs when the transaction was labeled an opportunity sale, but the sale was firm in nature.[50]

30. SPS also argues that nothing in the power sales agreements, under which SPS serves its wholesale requirements customers, gives them preference rights to SPS' most efficient energy production.[51]

31. Trial Staff argues that SPS was correct in attributing average costs to long-term market-based sales.[52] Specifically, Trial Staff focuses on whether sales for more than one year should be called opportunity sales and treated the same as short-term opportunity sales of one year or less.[53] Trial Staff also argues that "[t]he real problem is that SPS' FCAC practices become less objectionable, the longer the term of the long-term contract, to the extent that SPS would be planning, acquiring, constructing and operating capacity and energy to meet its system-wide load requirements, including these long-term sales."[54] Thus, Trial Staff concludes that the ALJ should have approved of SPS' charging of average fuel cost to long-term market-based rate transactions.

[47] SPS Brief on Exceptions at 30-31.

[48] *Id.* at 31 (citing *Montana-Dakota Utils. Co. v. Northwestern Pub. Serv. Co.*, 341 U.S. 246, 251-52 (1951)).

[49] *Id.* at 32-37.

[50] *Id.* at 33 (citing *Public Serv. Co. of New Mexico*, 43 FERC ¶ 61,469, at 62,145, *reh'g denied*, 45 FERC ¶ 61,034 (1988).

[51] *Id.* at 41-42.

[52] Trial Staff Brief on Exceptions at 18-31.

[53] *Id.* at 19.

[54] *Id.* at 19-20.

3. **Briefs Opposing Exceptions**

32. CCG argues that the Initial Decision correctly finds that incremental fuel costs should be attributed to SPS' market-based sales.[55] CCG further states that SPS should be required to recalculate the FCAC billings to account differently for SPS' intersystem market-based sales, and that the Commission is permitted to do this under the filed rate doctrine.[56] According to CCG, the Commission has stated that whenever a public utility acts inconsistently with Commission-filed tariffs or with specific requirements in its rate authorizations, the Commission may order refunds to rectify such action.[57] CCG further argues that such refunds are not retroactive ratemaking, but rather serve to ensure that only the filed rate is charged. With formula rates such as the FCAC, argues CCG, the formula itself is the filed rate, and consequently any misapplication of it is a violation of the CCG members' filed rates which the Commission can and should remedy.[58] CCG accordingly asks the Commission to affirm the ALJ and award refunds.[59]

33. CCG states that SPS' sales at issue involve "improper, coerced subsidization by SPS' native load" and that the ALJ properly decided that the policy of protecting wholesale customers from subsidization is an important principle that should be applied here.[60] CCG argues that the filed rate doctrine does not protect SPS because SPS never obtained authorization to engage in a new pricing scheme affecting market-based rate sales that, in turn, could modify the formula applied to cost-of-service based customers.[61]

34. CCG illustrates a distinction between long-standing cost-of-service customers and market-based customers by arguing that CCG and SPS have a regulatory compact to serve and receive service at cost-based rates, as well as the corollary obligation to pay for

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[55] CCG Brief on Exceptions at 19-24.

[56] CCG Brief Opposing Exceptions at 29-34.

[57] *Id.* at 9 (citing *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Servs.*, 96 FERC ¶ 61,120, at 61,508 (2001); *Washington Water Power Co.*, 83 FERC ¶ 61,282, at 62,169 (1998)).

[58] CCG Brief Opposing Exceptions at 9.

[59] *Id.* at 29-34.

[60] *Id.* at 20.

[61] *Id.* at 24-25.

embedded capacity resources over the life of those resources.[62] CCG notes that this compact substantially predates the advent of SPS' market-based rate authority in 1995.[63]

35. PNM argues that "[t]he basic problem with the paradigm advanced by SPS and Staff is that under their theory, the terms of SPS' market-based contracts would control the manner in which the Commission applies its regulations governing automatic recovery of fuel costs. If this is so . . . the amount of fuel costs billed under the market-based contract would control, no matter how little such amounts contributed to recovery of actual fuel costs."[64] PNM also argues that SPS' cost-of-service customers were not on notice of SPS' FCAC practice.[65]

4. Commission Determination

36. Given that SPS' FCAC largely tracks section 35.14 of the Commission's regulations, a review of that section is instructive in understanding how SPS' FCAC should be interpreted. When section 35.14 of the Commission's regulations was changed to roughly its present form in 1974 (as otherwise modified since), the Federal Power Commission (FPC) explained that "the purpose of this fuel cost adjustment clause is to keep the utilities whole with regard to changes in the fuel costs per [kWh] sold" by "pass[ing] on to customers the increases or decreases in the fuel costs actually incurred."[66]

37. In order to calculate the fuel cost for native load customers under section 35.14, a utility first computes the fuel cost for all kWh sold, whether to native load customers or intersystem customers.[67] The utility then deducts from the total fuel cost the cost of fuel recovered through intersystem sales.[68] Native load customers pay the remainder. This

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[62] *Id.* at 28-29.

[63] *Id.*

[64] PNM Brief Opposing Exceptions at 31.

[65] *Id.* at 29; *see generally id.* at 28-32.

[66] FPC Order No. 517, 52 FPC 1304, 1305-06; *accord Pennsylvania Power & Light Co.*, Opinion No. 34, 6 FERC ¶ 61,036, at 61,078 (1979) (*Pennsylvania P&L*).

[67] *See, e.g., Pennsylvania P&L*, 6 FERC ¶ 61,036 at 61,077.

[68] *Id.* (explaining that this prevents a utility from recovering from its native load customer fuel costs recovered elsewhere).

"ensures that wholesale customers will not pay for fuel costs already paid for by the intersystem customers."[69]

38. In the past, most utilities were vertically integrated entities that generated, transmitted, and distributed energy to customers in a defined region, known as the utility's native load. Those customers paid for the construction and maintenance of the utility's infrastructure and, in return, the utility served that native load.

39. At times, however, a utility may have available excess generation not already committed to native load customers, providing the utility with an opportunity to sell this capacity to buyers outside its home area. These sales are called opportunity sales or intersystem sales. Duration is not necessarily the determining factor in distinguishing opportunity sales from wholesale requirements sales. Opportunity sales "are simply transactions that are entered into from time to time for . . . an immediate economic benefit reason."[70]

40. In *Minnesota Power & Light Co.*, the Commission stated that in considering how to apply the fuel cost of intersystem sales to the requirements customers' FCACs, requirements customers "are credited with the cost of fuel recovered from the off-system customer."[71] In that case, the Commission also explained that the "[u]tilities generally price the fuel component of intersystem sales on the basis of the cost of the incremental fuel used in meeting intersystem load. Pricing an intersystem sale by reference to the incremental fuel cost assures that the requirements customers pay no more than they would have paid had the off-system sale never occurred."[72]

41. The Commission has clearly sought to prevent the subsidization of shareholders at the expense of captive customers.[73] It would be unreasonable for SPS' intersystem

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[69] *Id.* at 61,079. The total amount a utility can collect under the FCAC is limited to the amount spent; the Commission explained that "[w]hile we believe that a utility should be made 'whole for increased fuel costs,' we do not believe that a utility should be made whole and plus some." *Id.*

[70] Tr. at 284:19-21 (Daniel).

[71] 47 FERC ¶ 61,064, at 61,184 (1989) (denying petition for declaratory order that it is just and reasonable to assign to intersystem sales lower cost fuel than to requirements customers, but also stating that such an assignment is not *per se* unjust and unreasonable).

[72] *Id.* at 61,183 n.2; *see also id.* at 61,184.

[73] *See, e.g.*, *Heartland*, 68 FERC at 62,062-63 (prohibiting transfer of benefits from captive customers of a franchised public utility to affiliates and shareholders).

customers to be subsidized by wholesale requirements customers through an FCAC mechanism based on average fuel cost. Preventing such subsidization was the original reason for requiring that utilities price opportunity sales at a price that, at a minimum, made wholesale requirements customers economically indifferent to the sales.

42. In this case, the Commission must consider the workings of a market-based intersystem sale on a FCAC. Market-based rate transactions may take many forms: prices can be fixed by the contract, based on an index, or derived by some other formula. By definition, such prices may have no basis in actual cost.[74] Consequently, fuel cost must be imputed for these transactions for purposes of the utility's fuel cost clause.

43. The Commission finds that because the market-based intersystem transactions do not necessarily have a basis in actual cost, and to avoid the possibility of subsidization of these transactions by the wholesale requirements customers, the Commission must impute an appropriate fuel rate to the fuel cost calculation in order to avoid native load customers overpaying as a result of intersystem transactions under market-based rate contracts. In reaching this conclusion, the Commission recognizes that the FCAC in SPS' cost-based contracts with respect to fuel costs for market-based intersystem sales may not have been entirely clear.

44. Imputing the incremental cost of fuel to intersystem transactions assures that native load customers pay no more for fuel than they would have paid had the intersystem sale not occurred. To impute something different from incremental costs as a surrogate for the actual fuel cost could allow market-based rate sellers to include an artificially low fuel cost into their market-based rate contracts. Imputing an artificially low fuel cost would result in unjust and unreasonable subsidization of intersystem sales by requirements customers, which is contrary to the intent of the fuel cost clause.[75]

45. Attributing incremental fuel cost is consistent with the only market-based rate case that addressed this subsidizing effect. In *Entergy Services, Inc.*,[76] the Commission acknowledged that there is "no requirement [that the utility, when making off-system

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[74] In the instant proceeding, there is no dispute that SPS' market-based contracts provide for average fuel costs. But the specification of costs in a market-based contract is not determinative for purposes of the current issue, as explained below.

[75] Because the Commission does not review fuel costs in market-based rate contracts, parties could set the fuel cost at any price, or even at zero, which would result in requirements customers compensating the utility for *all* of the utility's fuel costs incurred for sales to others.

[76] 58 FERC ¶ 61,234 (*Entergy*).

sales] sell power and energy . . . at rates that would recover at least its system incremental costs."[77] But to protect wholesale customers who had FCACs in that case, the Commission ordered Entergy to incorporate a floor into the relevant rate schedule equal to the incremental costs incurred to provide the service.[78] The same principles of protecting wholesale requirements customers from an unjust subsidization as applied in *Entergy* apply here.

46. In *Consumers Energy Company*,[79] the Commission addressed the potential for captive wholesale customers to subsidize an affiliate sale because the fuel cost clause excluded sales that Consumers made to an affiliate. The Commission found that the amounts collected by Consumers from its affiliates would have been insufficient to cover the incremental cost of the sales. Recognizing the potential for improper subsidization by captive customers, the Commission directed Consumers to amend its contracts to credit the cost of fuel recovered at the incremental cost or otherwise accomplish the same objective.

47. In the instant proceeding, for market-based rate transactions, SPS' prices are limited by competition in lieu of cost-based regulation. If SPS or any other seller wishes to include a fuel price in its market-based contract, that price may be defined as average (as SPS so defined), indexed, incremental, or in any other manner. The fact that at least some of these contracts were filed with the Commission and accepted for filing is not germane because, as we stress here, the Commission is not seeking to change the contract language regarding fuel costs in market-based contracts, if fuel costs are even addressed at all. The Commission is simply directing here that, in order to avoid subsidization, the incremental cost of fuel for these market-based intersystem sales must be flowed through the FCAC.[80]

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[77] *Id.* at 61,772.

[78] *Id.*

[79] 94 FERC ¶ 61,180 (*Consumers*).

[80] The Commission notes that it may be appropriate to allow a cost of fuel other than the incremental cost to be attributed to market-based intersystem sales where the utility provides clear evidence that it planned and constructed its system or made purchases specifically to serve particular market-based intersystem transactions. However, SPS has failed to provide any such evidence here. Instead, it has provided little more than a general statement that it engaged in such plans (Tr. 1042:5-9 (Diller)), and several load forecast charts that do not make clear what planning, if any, was done to support intersystem sales (Ex. CCG-8 and CRE-32). We are not convinced that such

(continued…)

48. Consistent with this finding, SPS itself appears to have questioned the appropriate cost treatment for market-based intersystem sales transactions. As discussed by the ALJ in the Initial Decision,[81] a former SPS employee who testified for Golden Spread[82] stated that, when he worked at SPS, he had discussions with utilities such as Oklahoma Gas & Electric and other companies in the Southwest Power Pool about utilities not offering system capacity with system fuel costs due to "regulatory risk."[83] According to this witness, whose duties varied at SPS but who described himself as "basically . . . a bulk power sales manager or representative that conducted sales negotiations [with] various wholesale . . . power purchasing entities,"[84] the regulatory risk was:

> the concern . . . that the system average fuel really belongs to the regulated customers, being native load customers, retail, long-term wholesale, those that are considered native or captive customers within their jurisdictions. So they were

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evidence demonstrates that SPS engaged in planning specifically to support its intersystem transactions.

[81] Initial Decision at P 148.

[82] Though Golden Spread settled with SPS and is not a party to the issue discussed in this section of the order, the testimony of Golden Spread's witness remains a part of the record, and as such, the Commission relied upon this testimony in making its determination.

[83] Initial Decision at P 148 (discussing the record supporting the view that opportunity sales are generally priced to reflect incremental fuel cost and citing testimony sponsored by Golden Spread that this was well-understood in the industry). *See generally* Tr. 959-66 (Wise) (redirect examination of Golden Spread witness Wise, attesting that SPS was aware of regulatory risk in offering wholesale system sales at system average fuel cost).

[84] Tr. 957:17-19 (Wise). This witness described his career at SPS more fully in testimony contained in Exhibit GSL-26 at 2-3. His positions at SPS included: Statistician; Supervisor, Market Research; Competitive Analyst; Strategic Analyst; and Regional Power Sales Manager. Ex. GSL-26 at 2-3. In his capacity as Regional Power Sales Manager, this witness states that he was "responsible for analyzing markets and developing and negotiating significant power contracts . . . including: energy, capacity, transmission and ancillary services." *Id.* He further states that he worked with electric cooperatives, municipal utilities and investor owned utilities within SPP, Electric Reliability Council of Texas, and the Northwest Power Pool. *Id.* at 3.

> very concerned, and they said they were frankly surprised that SPS was willing to offer wholesale system sales at system average fuel.[85]

The former SPS manager further testified that "the discussion about system average fuel was well known within the company . . . and it was well known throughout the company . . . there was a potential to have a regulatory treatment that was unfavorable due to it."[86] In this regard, this witness testified that SPS' wholesale power business

> included the regulatory folks . . . and the legal folks in Denver. They were a part of the line of individuals we had to get approvals for to sign any of these contracts. So they were fully aware of all of the conditions . . . .[87]

49. For the reasons discussed in the following section of this order (Time Period Concerning Historical FCAC Charges), the Commission concludes that refunds will be ordered beginning on January 1, 2005, the refund-effective date established in the December 21, 2004, order setting the complaint for hearing,[88] and SPS will be required to implement the FCAC as instructed herein.[89]

B. Time Period Concerning Historical FCAC Charges[90]

1. Initial Decision

50. The ALJ determined that the relevant period for considering the FCAC is from 1999 forward.[91] The ALJ found that FCAC implementation practices became questionable beginning in 1999, after the Commission implemented open access and market-based rate sales increased. The ALJ observed that while market participants had no basis to complain about the FCAC prior to 1999, beginning in 1999, SPS was under a

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[85] Tr. at 962:23-25 through 963:1-5 (Wise). This witness's title at Golden Spread is "Manager, Operations." Ex. GSL-26 at 1:5-6.

[86] *Id.* at 963:11-18 (Wise).

[87] *Id.* at 964:1-5 (Wise).

[88] *Golden Spread Elec. Coop.*, 109 FERC ¶ 61,321 (2004).

[89] Because the Commission is ordering refunds effective January 1, 2005, we need not address SPS' argument that contracts are binding on parties even when fraud is alleged.

[90] Initial Decision at P 120-25 (Issue II.A.1).

[91] *Id.* P 125.

duty to examine its FCAC implementation practices due to changed market conditions. Therefore, the ALJ determined that SPS would owe refunds for a period beginning in 1999 and ending in 2004.

2. Briefs on Exception

51. SPS argues the ALJ erred because law and equity demand that a decision granting refunds should only be given prospective effect. SPS contends neither SPS nor the Commission has the authority to modify SPS' contracts with SPS' market-based wholesale customers retroactively to provide for the recovery of incremental costs.[92]

3. Commission Determination

52. Sections 205 and 206 of the FPA are the statutory foundation for the filed rate doctrine and the rule against retroactive ratemaking. According to section 205(c), all rates must be on file with the Commission: "Under such rules and regulations as the Commission may prescribe, every public utility shall file with the Commission, within such time and in such form as the Commission may designate . . . schedules showing all rates and charges . . . subject to the jurisdiction of the Commission . . . ."[93] The Commission has determined that utilities engaging in market-based sales must file a tariff with the Commission so stating, but components of the price need not be broken out in the tariff. Instead, information relating to transactions must be filed in Electric Quarterly Reports,[94] and the contracts remain jurisdictional without having to be filed with us.[95]

53. In the instant proceeding, both as to SPS' prior FCAC that is the subject of a complaint and as to the FCAC that SPS proposes in its FPA section 205 filing, SPS

[92] SPS Brief on Exceptions at 9-10.

[93] 16 U.S.C. § 824d(c) (2000).

[94] 18 C.F.R. § 35.10b (2007) (directing public utilities to file updated Electric Quarterly Reports, which must be prepared in conformance with the Commission's guidance posted and available on the Commission's website).

[95] *Revised Public Utility Filing Requirements*, Order No. 2001, FERC Stats. & Regs. ¶ 31,127, at P 223 (stating that Electric Quarterly Reports are designed to satisfy the FPA section 205(c) requirement that public utilities file jurisdictional rates and charges with the Commission), *reh'g denied*, Order No. 2001-A, 100 FERC ¶ 61,074, *reh'g denied*, Order No. 2001-B, 100 FERC ¶ 61,342, *order directing filing*, Order No. 2001-C, 101 FERC ¶ 61,314 (2002), *order directing filing*, Order No. 2001-D, 102 FERC ¶ 61,334 (2003).

flowed through (and proposes to continue to flow through) its FCAC the amount of money recovered for fuel for its market-based sales based on the average cost. The Commission may take retroactive refund action to address circumstances where a seller did not charge the filed rate or violated statutory or regulatory requirements or rules in applicable rate tariffs, but SPS' FCAC is ambiguous on the issue in dispute.[96] Following consideration of all of the evidence presented, the Commission has concluded above that in order to avoid wholesale requirements customers subsidizing intersystem sales, SPS' FCAC should be construed as requiring SPS to attribute incremental costs for purposes of the FCAC.[97] However, because the interpretation of the FCACs contained within SPS' contracts with respect to such attribution may not have been clear prior to the institution of these proceedings, the Commission will apply the clarification of FCACs to take effect as of the refund effective date established in these proceedings. We note that "the breadth of agency discretion is, if anything, at zenith when the action assailed relates primarily . . . to the fashioning of policies, remedies and sanctions . . . ."[98] Accordingly, SPS is directed to make refunds starting with the refund effective date, January 1, 2005,[99] and to apply the FCAC as directed herein on a prospective basis.

III. <u>Cost of Service</u>

54. In its original complaint, CCG argues that SPS' full requirements and partial requirements rates for the period January 1, 2005 to July 1, 2006[100] are unjust and unreasonable and are unduly discriminatory and/or preferential.[101] CCG cites its

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[96] *See Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Utilities*, Order No. 697, 72 Fed. Reg. 39,904 (July 20, 2007), FERC Stats. & Regs. ¶ 31,252 (June 21, 2007), *clarifying order*, 122 FERC ¶ 61,260 (2007) (stating that the Commission is authorized to order potential retroactive refunds for tariff violations).

[97] *See supra* P 43, 49.

[98] *Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 159 (D.C. Cir. 1967) (internal citation omitted).

[99] *See Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,321 (2004) (establishing refund effective date in Docket No. EL05-19-000 under FPA section 206).

[100] In Docket No. ER06-274-000, SPS filed new rates for its full and partial requirements customers that were set for hearing and made effective July 1, 2006, subject to refund. *See Southwestern Pub. Serv. Co.*, 114 FERC ¶ 61,091 (2006). That docket has not been consolidated with the instant proceeding.

[101] CCG Complaint at P 10-16.

allocated cost-of-service analysis in arguing that SPS' current demand and energy charges and the associated revenues in the aggregate and as applicable to each of the cooperatives' members exceed prudently incurred and properly allocated costs of providing requirements power supply service. CCG concludes that SPS' "overcharges . . . will result in higher rates for the retail consumers."[102] CCG also asserts that SPS data submissions to the Commission contain inconsistencies, and that these submissions lack detail; the result, CCG claims, is that they cannot confirm the proper values to be used in a cost of service analysis. CCG also alleges that SPS' parent company, Xcel Energy Inc., allocates excessive costs to SPS. Based on the allegations raised in the complaint, the Commission set the matter for hearing and settlement judge procedures.

A. Rate of Return[103]

1. Initial Decision

55. As explained by the ALJ, the determination of a just and reasonable return on equity (ROE) is governed by two standards: (1) the rate must be sufficient to allow the regulated entity to maintain its financial integrity and to allow the utility to maintain its credit and attract investment capital; and (2) the rate must be commensurate with returns on investments in enterprises that have a corresponding risk.[104]

56. The ALJ also stated that the discounted cash flow (DCF) methodology has been favored by the Commission, and that the Commission has expressed a preference for using current market data to develop an electric utility's ROE.[105] When, as in this case, the rate under consideration is "locked-in" (the rate being litigated has been superseded or is otherwise no longer in effect), the Commission updates the equity allowance for the

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[102] *Id.* P 10.

[103] Initial Decision at P 80-107 (Issue I.*I*).

[104] *Id.* P 80 (citing *Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679, 693 (1923); *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944)).

[105] *Id.* P 80.

locked-in period based on the change in average yields on ten-year constant maturity U.S. Treasury bonds.[106]

57. The ALJ accepted Trial Staff's proxy group.[107] Using that proxy group, the ALJ determined that 9.64 percent is the just and reasonable ROE for SPS. In making this determination the ALJ used 9.20 percent, the median ROE of Trial Staff's proxy group, as a base and added seven basis points as a flotation adjustment for an ROE of 9.27 percent.[108] The ALJ then added 37 basis points to account for interest rate risk, for a total ROE of 9.64.[109]

2. <u>Briefs on Exception</u>

58. SPS argues[110] that the ALJ's reliance on Trial Staff's analysis using the median value for the zone of reasonableness was incorrect because the Commission's recent orders relating to ROE employ the midpoint, not the median, in setting the ROE for electric utilities.[111] SPS also argues that the ALJ compounded this error by adopting the ROE at the median for the zone of reasonableness established by the high and low returns of Trial Staff's four proxy companies. SPS claims that the ROE should be placed in the upper half of the zone of reasonableness because three of the four companies in Trial Staff's analysis have higher credit and bond ratings than SPS and therefore SPS presents

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[106] *Jersey Cent. Power & Light Co.*, Opinion No. 408, 77 FERC ¶ 61,001, at 61,009 (1996) (explaining "locked-in" rates); Initial Decision at 104 (citing Commission practice of updating return on equity).

[107] Initial Decision at P 104-105.

[108] Initial Decision at P 96 (description of Trial Staff's analysis); *see also id.* P 96-103 (discussing Trial Staff's arguments on ROE).

[109] *Id.* P 104.

[110] SPS Brief on Exceptions at 71-75.

[111] SPS Brief on Exceptions at 72. SPS cites *Consumers Energy Company*, 98 FERC ¶ 61,333, at 62,416 (2002), and *Southern California Edison Company*, Opinion No. 445, 92 FERC ¶ 61,070 (2000) (*Southern California Edison*), as support for using the midpoint. The Commission notes here that the midpoint of all the estimates of ROE of a proxy group is the average of the highest and lowest estimated ROE of all members of the group. The median is that point within the zone of reasonableness where half the returns have a higher value and half the returns have a lower value. The mean, or average, is the sum of the estimates of each member of the proxy group, divided by the number of estimates.

a greater financial risk.[112] SPS states that it is seen by the financial community as a company that presents relatively more risk than Trial Staff's proxy companies do, and that when faced with similar facts in *Southern California Edison Co.*,[113] the Commission found that the ROE should be above the midpoint of returns indicated for the comparison group.[114] SPS argues that the appropriate ROE in the instant case should be 10.65 percent.[115] SPS also claims that this should be adjusted upward for the increase in the 10-year constant maturity Treasury bonds for the period ending June 30, 2006, the end of the period for the rates at issue in this case.[116]

59. CCG argues the ALJ should not have rejected its proxy group based on a determination that one of the proxy group companies did not accurately reflect the risks of SPS, nor should the ALJ have concluded that a three company proxy group was insufficient to judge return in a DCF analysis. CCG also claims the ALJ should have used the Commission's long-standing methodology for locked-in rates rather than a method used for open-ended periods.[117] CCG states that it does not object to adjusting the ROE *per se*; however, it highlights the fact that the rates at issue here are for a locked-in period.[118] CCG cites several cases in support of its position that "in updating an ROE applicable to a locked-in period, the appropriate inquiry is to compare the average yield on ten-year constant maturity Treasury bonds in the period used to establish the ROE to the average yield on such bonds for the entire locked-in period."[119] Then, CCG states, the Commission should adjust the locked-in period ROE for any difference found, if the resulting ROE is still within the zone of reasonableness established in the

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[112] SPS Brief on Exceptions at 73.

[113] 92 FERC ¶ 61,070.

[114] SPS Brief on Exceptions at 73-74.

[115] *Id.* at 74-75.

[116] *Id.* at 75 n.74.

[117] CCG Brief on Exceptions at 36-39.

[118] *Id.* at 37.

[119] *Id.* at 37 (citing *Jersey Cent. Power & Light Co.*, Opinion No. 408, 77 FERC ¶ 61,001, at 61,009-10 (1996); *Indiana Mun. Distrib. Assn. v. Indiana Michigan Power Co.*, Opinion No. 373, 59 FERC ¶ 61,260, at 61,978 (1992); *Blue Ridge Power Agency v. Appalachian Power Co.*, Opinion No. 363-A, 57 FERC ¶ 61,200, at 61,371-72 (1991); *Pacific Gas & Elec. Co.*, Opinion No. 356, 53 FERC ¶ 61,146, at 61,537-38 (1990)).

record.[120] CCG contends following the locked-in method results in an adjustment of 6 basis points rather than 37, with the resulting ROE being 9.33 percent (9.27 + .06).[121]

3. **Briefs Opposing Exceptions**

60. CCG and Trial Staff object to SPS' claim that Commission policy is to use the midpoint to set the ROE for a single utility. CCG and Trial Staff cite the Commission's discussion in *Midwest Independent Transmission System Operator, Inc*.[122] as the correct policy: i.e., that the median is the appropriate measure of central tendency of a single utility. Further, CCG and Trial Staff argue that the ALJ was correct in rejecting SPS' request to place the ROE in the upper end of the range of the zone of reasonableness. CCG argues that SPS' claims of higher risk based on three of four companies having higher risk credit and bond ratings does not justify a higher ROE. This is because, in total, SPS is no greater risk than the proxy group based on an analysis of multiple credit risk factors. CCG highlights Staff's testimony that addressed three indicators of risk and concluded that SPS and the proxy group were equal in risk.[123] In its brief opposing exceptions, Trial Staff asserts that while three of the four companies in its proxy group had higher S&P Corporate Credit Ratings, SPS ignored other important risk factors. These factors are: (1) the *Value Line* Safety Rank, a comprehensive measurement of risk derived from the volatility of the stock as measured by its index of price stability relative to 1,700 other stocks over the past five years; (2) *Value Line's* Financial Strength rating of the company; and (3) S&P's Business Profile comparisons. S&P's Business Profile is a rating system that measures a company's business risk relative to an overall utility industry business risk profile.[124] Trial Staff's analysis indicated that its proxy group members and SPS' parent, Xcel Energy Inc., all had a Safety Rank of 2. In addition, SPS' S&P Business Profile number was 5 (on a scale of 1 to 10, where 1 is least risky and 10 is most risky) as opposed to Trial Staff's proxy group average of 5.5.[125] Therefore, Trial Staff argues, SPS poses no greater risk than the proxy group and SPS should be placed in the median of the zone of reasonableness.

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[120] *Id.* at 37.

[121] *Id.* at 39.

[122] *Midwest Indep. Transmission Sys. Operator, Inc.*, Order on Remand, 106 FERC ¶ 61,302, at P 12 (2004) (*Midwest ISO*).

[123] CCG Brief Opposing Exceptions at 63-66.

[124] Trial Staff Brief Opposing Exceptions at 23-25.

[125] *Id.*

61. SPS argues that the ALJ's decision rejecting CCG's proxy group was reasonable, because Energy East did not face the same business risks as SPS and therefore was not a reliable basis for an ROE determination.

4. Commission Determination

62. Based on the record in this case, we find the just and reasonable ROE to be 9.33 percent for the period beginning January 1, 2005 and ending July 1, 2006. The Commission affirms the ALJ's determination to use Trial Staff's proxy group.[126] We also affirm the ALJ's use of the median value for the zone of reasonableness to determine the just and reasonable ROE. However, as discussed below, we reverse the ALJ's finding that a 37 basis point interest rate adjustment is appropriate.

63. When deriving the ROE for an individual utility facing average risk, the Commission has held that the median best represents the central tendency in a proxy group with a skewed distribution of returns.[127] In *Midwest ISO*[128] the Commission contrasted the formula for deriving the ROE for an individual utility versus the formula for deriving the ROE for a diverse group of utilities included in the Midwest ISO.

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[126] Both Trial Staff's proxy group and CCG's proxy group result in a 9.27 percent ROE. Initial Decision at P 89 and P 96. The Commission also agrees with the ALJ's decision to reject CCG's proxy group based upon its inclusion of Energy East, because the company may not accurately reflect SPS' risks. *Id.* P 107. While a larger group is generally desirable, the group cannot include companies that are not reflective of the subject companies. Using Trial Staff's proxy group is thus preferable to CCG's proxy group because when two groups' risk profiles are interchangeable, the larger group is statistically preferable. Trial Staff's proxy group is also more representative than SPS', which the ALJ found, *inter alia*, included companies with business and related risks that are significantly different from SPS' regulated utility business and wholesale electric service. *Id*. P 106. Finally, the Commission agrees with the ALJ's rejection of SPS' proxy group because of the inclusion of Constellation, which was in the midst of merger activity at the relevant time. *Id.* P 106.

[127] *Northwest Pipeline Corp.*, 99 FERC ¶ 61,305, at 62,276 (2002). However, as discussed further below, to the extent that the Commission determines that an applicant is <u>not</u> of average risk vis-à-vis the proxy group, then the Commission's *Southern California Edison* precedent would apply to the determination of the appropriate ROE within the range of reasonableness.

[128] 106 FERC ¶ 61,302 at P 10.

> Because the ROE in this case will apply to a diverse group of companies, the entire range of results yielded by the subset is relevant here. Thus, we find that using the midpoint is the most appropriate measure for determining a single ROE for all Midwest ISO [transmission operators], since it fully considers that range. Selecting the most refined measure of central tendency, as might be achieved with use of the median, is not the Commission's goal in this case, given that we are not selecting a ROE for a single utility of average risk.[129]

64. Here, we are determining the just and reasonable ROE for a single utility of average risk and find the median to be appropriate for setting the ROE. In *Transcontinental Gas Pipe Line Corp.*,[130] the Commission determined that setting the ROE at the median of the zone of reasonableness lessens the impact of any single proxy company whose ROE is atypically high or low. While there are no concerns of extremes here, using the median also has the advantage of taking into account more of the companies in a proxy group rather than only those at the top and bottom. We decline to place SPS in the upper half of the zone of reasonableness because we conclude, based on the S&P Safety Rank and Business Profile factors, SPS does not have any higher risk than the proxy group, despite SPS' arguments to the contrary.[131] SPS cites *Southern California Edison*, a case in which the Commission placed the utility in the upper half of the zone of reasonableness because it found the company to be more risky than the proxy group.[132] Unlike in *Southern California Edison*, here we find that SPS is not more risky than the proxy group. Accordingly, we affirm the use of the median in establishing the ROE for SPS.

65. We reverse the ALJ's finding that there should be a 37 basis point interest rate adjustment. Instead, the adjustment should be 6 basis points, because the rates at issue here are for a locked-in period. Therefore, the ROE should be 9.33 percent (9.27 plus 6 basis points). As CCG correctly noted, where the rate under consideration is "locked-in" (that is, the rate being litigated has been superseded or is otherwise no longer in effect),[133]

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[129] *Midwest ISO*, 106 FERC ¶ 61,302 at P 10.

[130] 84 FERC ¶ 61,084, *aff'd* Opinion No. 414-B, 85 FERC ¶ 61,323 (1998).

[131] Trial Staff Brief Opposing Exceptions at 23-25.

[132] *Southern California Edison*, 92 FERC ¶ 61,070, at 61,266 (2000) ("[W]e find that SoCal Edison is more risky than the comparison group. Therefore, the appropriate ROE for SoCal Edison should be above the midpoint of returns indicated for the comparison group").

[133] As noted, the rates at issue here are for the locked-in period from January 1, 2005 to July 1, 2006.

the Commission updates the equity allowance for the locked-in period based on the change in average yields on ten-year constant maturity U.S. Treasury bonds.[134] Instead of following the Commission's methodology for adjustments applicable to locked-in period rates, the ALJ used the Commission's method for updating based on open-ended rates. This was inconsistent with Commission policy, as the rates at issue here were for a locked-in period. Accordingly, we adopt the adjustment required by Commission precedent for locked-in rates, 6 basis points instead of 37 basis points.

B. Coincident Peak Basis (3 CP v. 12 CP)[135]

66. 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, in which demand costs are allocated based on the customer class' demand at the time of (coincident with) the system peak demand.[136] 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 twelve months (12 CP). A company that has a relatively flat demand curve throughout the year would typically allocate demand on a 12 CP basis, which assumes that a utility's demand is relatively constant throughout all twelve months of the year. A summer (or winter) peaking company would more typically allocate demand on a 3 CP basis, which assumes demand will peak during the three peak usage months.

1. Initial Decision

67. The ALJ concluded that SPS remains a 3 CP system,[137] not a 12 CP system as Cap Rock, SPS, and CCG propose. The ALJ cited *Louisiana Power & Light Co.*,[138] in

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[134] *E.g.*, *Jersey Cent. Power & Light Co.*, Opinion No. 408, 77 FERC ¶ 61,001, at 61,009-10 (1996).

[135] Initial Decision at P 10-24 (Issue I.A). We note that the issue of the Coincident Peak Basis is the sole issue that the Settling Parties did not resolve in the Settlement Agreement. Therefore, this portion of the order applies to both the Settling Parties and non-settling parties.

[136] *See generally Delmarva Power & Light Co.*, 17 FERC ¶ 63,044, at 65,199-203 (1981), *aff'd in relevant part*, Opinion No. 185, 24 FERC ¶ 61,199 (1983) (*Delmarva Initial Decision*) (discussing method of demand cost allocation).

[137] *Cf. Southwestern Pub. Serv. Co.*, Opinion No. 162, 22 FERC ¶ 61,341, at 61,589-591, *reh'g denied*, 23 FERC ¶ 61,406 (1983) (Opinion No. 162) (affirming that SPS is a 3 CP system); *Southwestern Pub. Serv. Co.*, Opinion No. 337, 49 FERC

(continued…)

rejecting calls for changing SPS' demand allocation method. *Louisiana P&L*, the ALJ explained, states that the demand allocation method should not be changed except when there are changed circumstances or a change in policy.[139] The ALJ concluded that the data suggest modest changes but not "major shifts" in the load curve.[140] The ALJ further observed that one of the factors that may have caused the movement in the direction of a flatter demand curve – the increase in intersystem sales caused by the availability of excess power due to the shift of Golden Spread to a partial requirements customer – has run its course.[141] Moreover, the ALJ found that one cannot assume the continuation of whatever flattening of the demand curve occurred.[142]

2. **Briefs on Exceptions**

68. CCG,[143] Cap Rock,[144] and SPS[145] argue that SPS is now a 12 CP system, and they disagree with the ALJ's conclusion that SPS remains a 3 CP system. They claim that SPS' peak load ratios and other operating realities have changed substantially since the Commission last examined the SPS system in 1989. They claim that analyses by Cap Rock, SPS, and others in the proceeding take into account factors besides the availability of excess power due to the shift of Golden Spread to a partial requirements customer, such as large retail customers seeking to firm up service previously taken on an interruptible service basis and SPS' rapidly increasing growth in high load factor oil field load. They state that the evidence clearly establishes that SPS is now a 12 CP system.

69. For example, CCG states that during the hearing they introduced updated analyses of various aspects of SPS' system demand curve and other system characteristics, based on data from recent years, to show the appropriate wholesale demand cost allocator in

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¶ 61,296, at 62,132 (1989), *reh'g denied*, Opinion No. 337-A, 51 FERC ¶ 61,130 (1990) (Opinion No. 337) (same).

[138] Opinion No. 110, 14 FERC ¶ 61,075, at 61,128, *reh'g denied*, 15 FERC ¶ 61,297 (1981) (Opinion No. 110 or *Louisiana P&L*).

[139] Initial Decision at P 22.

[140] *Id.* P 24.

[141] *Id.*

[142] *Id.*

[143] CCG Brief on Exceptions at 3-23.

[144] Cap Rock Brief on Exceptions at 12-61.

[145] SPS Brief on Exceptions at 61-65.

light of current conditions, and that, in total five witnesses concluded that SPS has now become a 12 CP system.[146] CCG argues that the Initial Decision does not discuss or dispute this evidence, undermining its ruling that a 3 CP allocator should continue to be used.[147]

70. CCG, Cap Rock, and SPS also claim that the burden of proof for a change in methodology is satisfied by a just and reasonable standard, and that the ALJ broke with precedent set in *Louisiana P&L* by ruling that "there should be a strong reason for changing allocation methodologies," and parties seeking to do so must show "major shifts in the load curve."[148] They claim that Opinion No. 110[149] states that the demand allocator should not be changed "except where there are changed circumstances or a change in policy."

3. **Brief Opposing Exceptions**

71. Golden Spread argues that the Initial Decision was correct in concluding that SPS' operating realities remain consistent with a 3 CP system.[150] Golden Spread submits that its demand allocation testimony demonstrates that SPS remains a 3 CP system, and that its evidence complies with the requirements set forth in *Illinois Power Co.*[151] Golden Spread asserts that Cap Rock, CCG, and SPS failed to meet the burden of proof, and shifting to a 12 CP would impose a significant cost shift on the sole entity that has done anything of significance on the system to curtail summer demand. Golden Spread claims that the ALJ recognized its comprehensive analysis and correctly concluded that "there should be a strong reason for changing allocation methodologies, given the impact on customers' expectations and the shifting price signal effects associated with a change in methodology."[152]

72. Golden Spread claims that what little change has occurred in the SPS system in metrics can be attributed to the response by Golden Spread to the 3 CP price signal.

[146] CCG Brief on Exceptions at 4.

[147] *Id.* at 4-5, 7-11.

[148] Initial Decision at P 24.

[149] 14 FERC ¶ 61,075.

[150] Golden Spread Brief Opposing Exceptions at 17-22.

[151] *Id.* at 17 (citing *Illinois Power Co.*, 11 FERC ¶ 63,040, at 65,247-48 (1980), *aff'd in relevant part*, 15 FERC ¶ 61,050, at 61,093 (1981) (*Illinois Power*)).

[152] Initial Decision at P 24.

Golden Spread states that it built a highly efficient generating facility that tempered the growth of the SPS summer peak, limiting cost increases to the SPS ratepayers, and providing significant energy cost savings. Golden Spread states that affirming the ALJ would ensure that customers will not be penalized for merely responding to price signals and reducing the burden they impose on a summer peaking system.

73. Golden Spread points out that the Trial Staff witness who advocated the switch to 12 CP in prefiled testimony was not as certain during the hearing, and admitted that a 12 CP would probably produce a price signal that would not discourage customers to reduce their summer load, but rather have the opposite effect.[153]

4. <u>Commission Determination</u>

74. We reverse the Initial Decision's finding that the 3 CP methodology remains the correct demand cost allocator for the SPS system. Although the Commission previously determined that SPS was a 3 CP system, we find that the ALJ misapplied the *Louisiana P&L* standard and overlooked numerical data in concluding that demand changes on the SPS system do not provide a "strong reason" for shifting the demand allocator to a 12 CP methodology.[154]

75. While the Commission has not established hard and fast rules for determining whether the 3 CP or 12 CP allocation method is appropriate, we have explained that the following factors should be considered when determining which allocation to use: "[t]he full range of a company's operating realities including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments."[155]

76. Historically, the Commission has considered three tests in determining whether a system is better characterized as 3 CP or 12 CP. First, 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 – the On and Off Peak test. Generally, the Commission

[153] Tr. 2469:2-10 (Sammon).

[154] Initial Decision at P 9.

[155] *Carolina Power & Light Co.*, Opinion No. 19, 4 FERC ¶ 61,107, at 61,230 (1978); *Illinois Power*, 11 FERC ¶ 63,040 at 65,247-48; *see also Delmarva Initial Decision*, 17 FERC ¶ 63,044 at 65,199-203 ("The Commission has not adopted any one method . . . its determination of the appropriate allocation method has rested on the facts of each case.").

has held that a nineteen percentage point or less difference between these two figures supports using the 12 CP method.[156] The second test, the Low-to-Annual Peak test, involves the lowest monthly peak as a percentage of the annual peak. The Commission considers a range of sixty-six percent or higher as indicative of a 12 CP system.[157] The third test is the Average to Annual Peak test, and it computes the average of the twelve monthly peaks as a percentage of annual peak. Generally, the range for a utility to be considered 12 CP is eighty-one percent or higher.[158]

77. The Commission is persuaded by testimony and evidence submitted by SPS, Cap Rock, the full requirements customers,[159] and Golden Spread that substantive changes have occurred on the SPS system since the Commission last addressed the issue in 1989. The chart below is a comparison of previously accepted ratios from the peak tests indicative of a 12 CP system to the ratios submitted as evidence by various parties at trial regarding SPS' system. Differences in ratio values can be attributed to the inclusion or exclusion of interruptible loads, off-system sales, and the number of years used to calculate the average ratios shown below. The chart illustrates that applying the same analytical criterion that was primarily used in Opinion Nos. 162 and 337 to determine that SPS was a 3 CP system now clearly demonstrates it is a 12 CP utility. Even Golden Spread's witness Linxwiler's ratios, who testified in support of SPS remaining a 3 CP utility, meet the acceptable range.

[156] *See, e.g., Illinois Power*, 11 FERC ¶ 63,040 at 65,248-49 (comparing average summer peak of ninety-four percent of annual peak to eight-month average peak of seventy-five percent of annual peak, a difference of nineteen percentage points).

[157] *Id*. (approving 12 CP where lowest monthly peak as percentage of annual peak was sixty-six percent); *Delmarva Initial Decision*, 17 FERC ¶ 63,044 at 65,201 (stating that Commission favors 12 CP method and citing 12 CP cases with low monthly peaks).

[158] *See, e.g., Illinois Power*, 11 FERC ¶ 63,040 at 65,249 (approving 12 CP where average monthly peak for five-year period was eighty-one percent); *Lockhart Power Co.*, Opinion No. 29, 4 FERC ¶ 61,337, at 61,807 (1978) (approving 12 CP where average monthly demand was eight-four 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 eighty-four percent of maximum peak).

[159] Central Valley Electric Cooperative, Inc., Farmers' Electric Cooperative, Inc., Lea County Electric Cooperative, Inc., and Roosevelt County Electric Cooperative, Inc.

	Lowest-To-Peak	**On-Peak-Off-Peak**	**Average-To-Peak**
Historical Commission Range for 12 CP	66% or higher	19% or less	81% or higher
Heintz, SPS-37 at 16	68%	19%	82%
Saffer FRC-2 Pro Forma	70%	18%	84%
Linxwiler, GSL – 1 at 9-10	67.55%	19%	82.05%
Diller, CRE-1 at 18	70%	18%	84%

78. In addition, in the years since Opinion Nos. 162 and 337, Golden Spread switched from a full-requirements, high summer-peaking customer on SPS' system to a partial requirements customer with a year-around, fixed contract. SPS testified that this and other factors have increasingly flattened its load profile to a point inconsistent with a 3 CP utility, as illustrated by the peak ratio percentages submitted by SPS and others.[160] We agree and will reverse the ALJ's finding that SPS is a 3 CP utility and conclude that use of the 12 CP demand allocation methodology appropriately reflects SPS' system.

C. Demand Cost Allocation Factors[161] and Post Test Year Adjustments[162]

1. Initial Decision

79. The ALJ determined that the interruptible load deductions[163] issue was resolved in the Joint Trial Stipulation, and that Cap Rock is free to further pursue the matter in

[160] *See* SPS Brief on Exceptions at 64 (citing Tr. 1560:3-9).

[161] Initial Decision at P 108-113 (Issue I.J).

[162] *Id.* P 114-119 (Issue I.K).

[163] When deriving demand cost allocation factors, interruptible loads, which are wholesale and/or retail loads whose service may be interrupted in peak periods, should be removed from the demand calculation. *See Louisiana Pub. Serv. Comm'n v. Entergy Corp.*, 106 FERC ¶ 61,228 (2004) *aff'd*, 111 FERC ¶ 61,080 (2005).

Docket No. ER06-274.[164] On the question of post test year adjustments, the ALJ determined that none should be made in the instant proceeding.[165]

2. **Brief on Exception**

80. In its Brief on Exceptions, Cap Rock stated that it does not except to the Initial Decision's determination on interruptible loads to the extent it is limited to the cost of service for the test year. Rather, Cap Rock asks that the Commission clarify that the stipulation does not control the treatment of interruptible loads in the analysis of the system load characteristics used in determining demand cost allocation.[166] Cap Rock asserts that the parties did not stipulate how to treat interruptible loads for purposes of analyzing the SPS system characteristics.[167] Similarly, Cap Rock does not except to the ruling that no post-test year adjustments may be made but claims it sweeps too broadly by prohibiting the use of post-test year adjustments made solely for the purpose of analyzing SPS' system load characteristics.[168] Cap Rock also requests that the Commission rule that it is appropriate to include intersystem sales in analyzing system load characteristics.[169]

3. **Commission Determination**

81. The Commission clarifies that the stipulation does not control the treatment of interruptible loads in the analysis of the system load characteristics in determining demand cost allocation. Cap Rock argues that retail loads that are not interruptible in the non-summer months of October through May should be included for purposes of analyzing system load characteristics.[170] Doing so has the effect of further flattening the SPS load profile, which changes its load ratio measures to be more in line with a utility with a 12 CP profile. While we make this clarification, Cap Rock's request is moot because we find that SPS is a 12 CP utility even without this adjustment. Regarding Cap

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[164] Initial Decision at P 113; *see* Exhibit J-1 at I.J.(i)-(iii) (Joint Trial Stipulation).

[165] *Id.* P 119.

[166] Cap Rock Brief on Exceptions at 62.

[167] *Id.* at 62-63.

[168] *Id.* at 59-60.

[169] *Id.* at 71.

[170] Cap Rock Brief on Exceptions at 63-69 (citing Opinion Nos. 468 and 468-A; *Delmarva Power & Light Co.*, 22 FERC ¶ 63,053, at 65,204-05, *aff'd*, Opinion No. 189, 25 FERC ¶ 61,022 (1983)).

Rock's other two requests, we find that it would be inappropriate to include opportunity sales or inapplicable test year adjustments in the allocation of demand costs. To do so would, in effect, provide double credit to Cap Rock. If opportunity sales are included in the demand cost allocators and given revenue credit treatment, Cap Rock benefits twice through reduced demand rates and revenue credits from the proceeds of the off-system sales. Including post-test year results would have a similar effect. Accordingly, we deny Cap Rock's requests.

D. Revenue Crediting vs. Cost Allocation[171]

82. In a cost-based regime, revenues from intersystem sales are typically reflected in wholesale rates through either a revenue credit or an allocation in the cost of service. Under the revenue credit method, all the costs are allocated to requirements customers, and each requirements customer group is then subsequently credited with its share of intersystem demand revenues and energy revenues via demand and energy allocators, respectively. The revenue crediting method is most often used when sales are opportunity sales.[172] The Commission has expressed a preference for the use of revenue crediting for opportunity sales.[173] Under the cost allocation method, intersystem sales customers are treated as if they are a separate customer group in a cost of service study by including their monthly demands in the energy and demand cost allocator denominators. Thus, intersystem customers are allocated a share of the total system fixed and variable costs as if they were requirements customers. The Commission has found the allocation method appropriate for firm intersystem sales with a term of one year or more.[174]

[171] Initial Decision at P 25-33 (Issue I.B).

[172] *See Public Serv. Co. of New Mexico*, Opinion No. 146, 20 FERC ¶ 61,290, at 61,547 (1982) (Opinion No. 146) (crediting revenue from intersystem opportunity sales to native load customers).

[173] *See, e.g.*, *Public Serv. Co. of Oklahoma*, Opinion No. 788, 57 FPC 1041, 1050 (1977) (FPC Opinion No. 788) (crediting revenue from intersystem sales to on-system customers); Opinion No. 146, 20 FERC ¶ 61,290 at 61,546-48 ("The Commission has typically used revenue crediting for opportunity sales.").

[174] *See, e.g.*, *Boston Edison Co.*, Opinion No. 53, 8 FERC ¶ 61,077, at 61,283 (1979) (finding allocation of costs to firm services preferable to revenue credit approach).

1. **Initial Decision**

83. In the Initial Decision, the ALJ found that the nine SPS intersystem market-based sales at issue,[175] excluding the expired sales to Manitoba Hydro and Midwest Energy, are more in line with what the Commission found to be "opportunity sales" in *Florida Power & Light Co.*[176] and *Kentucky Utilities Company*,[177] rather than the type of requirements sales for which SPS is required to plan, construct, and maintain capacity.[178] The ALJ also found that the sales at issue are fundamentally different from long-term sales to SPS' cost of service customers and have a lesser status than the native load. Therefore, the ALJ determined that the revenues from these sales should be credited against the cost of serving the requirements customers whose rates are at issue in this proceeding.

2. **Briefs on Exceptions**

84. Trial Staff and SPS except to the ALJ's determination to use the revenue crediting methodology. SPS states that, consistent with *Florida P&L*, revenue credit treatment has been limited to short-term sales of less than a year, usually referred to as opportunity sales, where no system planning is involved to ensure that a firm capacity sale commitment can be met over the term of the underlying contract. Trial Staff and SPS argue that the sales in question are all long-term firm sales that are part of the "system" for which it must plan, construct, maintain, and operate its system of transmission, generation, and power resources,[179] and claim that the allocation methodology is more appropriate.

85. Trial Staff and SPS cite Order No. 2001 for the proposition that the market-based sales at issue are long-term sales.[180] They conclude that these sales should thus be treated like requirements sales for cost-of-service purposes.[181]

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[175] Ex. CCG-1 at 36.

[176] 33 FERC ¶ 61,116, at 61,247 (1985) (*Florida P&L*).

[177] 15 FERC ¶ 61,002 (1981).

[178] In these cases the Commission determined that in developing rates, fixed costs should not be allocated to services that do not cause the utility to plan, construct, or maintain capacity.

[179] Trial Staff Brief on Exceptions at 9-12; SPS Brief on Exceptions at 58-61.

[180] *Revised Public Utility Filing Requirements*, Order No. 2001, FERC Stats. & Regs. ¶ 31,127, at 30,171 (2002) (defining long-term market-based rate sale as equal to or greater than one year).

86. Trial Staff and SPS also contend that the sales in question are "firm loads" according to the Commission's analysis in Opinion No. 468,[182] and thus are not "fundamentally different" from the services rendered to SPS' cost-of-service customers.[183] Trial Staff and SPS state that SPS' generation resource planning is not done for individual customer load, but rather uses the total company firm energy and peak demand to determine the best overall generation mix to serve all customers. Furthermore, SPS states that it has no ability to refuse or curtail service to either group of firm service customers except in the case of *force majeure* or a system emergency.

87. CCG generally agrees with the ALJ's revenue crediting determination, and excepts only to the ALJ's ruling that the sales contracts to Manitoba Hydro and Midwest Energy should not be treated as revenue credits merely because the contracts expired during the 2004 test year period.[184] CCG claims that the expiration of the contracts in 2004 simply means that they should be treated as short-term and non-firm sales, which are revenue-credited.

3. **Briefs Opposing Exceptions**

88. CCG states that only its witness performed a substantive review of the specific terms and conditions of the contracts in question, and that Trial Staff relied upon SPS' incomplete and inaccurate analysis of the contracts to determine that the sales in question are not different from true requirements contracts. CCG states that its witness' analysis clearly reveals that the sales in question are substantially different from requirements contracts in that they are voluntary, market-based sales of limited duration, and only available for as long as SPS could claim that it had surplus capacity, which qualifies them as opportunity sales.[185] Furthermore, CCG claims that the contracts make clear that interruption will occur before SPS' own ultimate customers and, in contrast to true firm

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[181] Trial Staff Brief on Exceptions at 9-12; SPS Brief on Exceptions at 58-61.

[182] *Louisiana Pub. Serv. Comm'n v. Entergy Corp.*, 106 FERC ¶ 61,228, at P 74-75 (2004), *affirmed*, Opinion No. 468-A, 111 FERC ¶ 61,080 (2005) (When a utility makes a commitment to serve a firm load, it commits to serve that load at all times (absent a *force majeure* event on the system)).

[183] Initial Decision at P 33.

[184] Tr. 2088:21-2089:14 (Heintz).

[185] CCG Brief Opposing Exception at 53.

loads, relieve SPS of the requirement to deliver and the customer of the obligation to pay in the event of adverse conditions.[186]

89. CCG and PNM argue that SPS' reliance on *Wisconsin* is unfounded, and the sales must be considered opportunity sales because SPS does not "plan, construct, or maintain" the capacity in the long-run. CCG claims SPS admits that because its wholesale and retail native load requirements are growing, its marketing of opportunity sales from its generation will shrink, a core characteristic of opportunity sales as determined in *Florida P&L* and *Kentucky Utilities Co*.[187] Furthermore, CCG states the fact that SPS has had to buy short-term capacity from third parties when its own resources were insufficient demonstrates that it has not incurred long-term fixed costs to build capacity specifically to serve the 2004 market-based opportunity sales.

90. CCG states that opportunity sales are made to market temporary surplus of capacity and/or energy, and the length of a contract does not exclude it from being considered an opportunity sale. CCG states that even though the sale was for 13 years in *Public Service Co. of New Mexico*,[188] the Commission determined that it was clearly an opportunity transaction because it was undertaken to utilize idle capacity. CCG also argues that in *Tampa Elec. Co.*, the Commission found revenue crediting the cost-of-service for the underlying requirements customers to be appropriate for a 4-year and an 18-year contract to an intersystem customer.[189]

91. CCG states that the Commission has long held that opportunity sales should be revenue credited. CCG also states that Opinion No. 337 found "all of the revenues from off-system sales should be credited to the on-system customers."[190]

92. SPS supports the ALJ's conclusion to exclude the Manitoba Hydro and Midwest Energy sales from the test year for the cost of service study on the basis that neither sale was extended or replaced in 2005.[191]

[186] *Id*. at 52-53.

[187] *Id.* at 56 (citing *Florida P&L*, 33 FERC ¶ 61,116, and *Kentucky Utils. Co.*, 15 FERC ¶ 61,002, at 61,005 (1981)).

[188] *Public Serv. Co. of New Mexico*, 43 FERC ¶ 61,469 (1988).

[189] *Tampa Elec. Co.*, 71 FERC ¶ 61,245 (1995), *aff'd*, 83 FERC ¶ 61,262 (1998).

[190] Opinion No. 337, 49 FERC ¶ 61,296 at 62,133.

[191] SPS Brief Opposing Exceptions at 34-35.

4. **Commission Determination**

93. We will affirm the ALJ's determination that revenue crediting is the proper cost of service treatment for the sales at issue. This conclusion is consistent with our finding made earlier, that SPS' market-based intersystem sales are opportunity sales. The sales were entered into when SPS experienced a temporary level of excess capacity when Golden Spread changed from a full to partial requirements customer in 2000. While these sales were for firm power and some were for more than one year, SPS neither planned, constructed, or maintained its system to accommodate these sales, a general predicate to classify the sales as other than opportunity sales. And, as demonstrated by CCG, SPS' opportunity sales, while not interruptible, do get interrupted prior to the wholesale requirements customers.[192] The fact that some of the sales could be considered long-term under the Commission's market-based rate policy is not a determining factor because, as noted above, the Commission has considered sales of up to thirteen years as opportunity sales. The Commission has expressed a preference for the use of revenue crediting for opportunity sales.[193] Accordingly, we direct that SPS revenue credit these sales.

94. However, the Commission disagrees with the ALJ's exclusion of the expired sales contracts to Manitoba Hydro and Midwest Energy from revenue credit treatment. The ALJ excluded these contracts because "they have expired and whether similar sales will recur is speculative."[194]

95. The test year in this proceeding is calendar year 2004. SPS states that two "long-term firm power sales agreements that expired in 2004 . . . will not be in effect on or after January 1, 2005, when any rate changes made in this case would be made effective."[195]

Specifically, a 100 MW sale to Manitoba Hydro Energy Board (Manitoba Hydro) terminated December 31, 2004, and a 25 MW sale to MidWest Energy, Inc. (Midwest Energy) terminated May 31, 2004.[196]

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[192] CCG Brief Opposing Exceptions at 52-53.

[193] *See, e.g.*, Opinion No. 788, 57 FPC at 1050 (crediting revenue from intersystem sales to on-system customers); Opinion No. 146, 20 FERC ¶ 61,290 at 61,546-48 ("The Commission has typically used revenue crediting for opportunity sales.").

[194] Initial Decision at P 33.

[195] Ex. SPS-37 at 11:11-16.

[196] *Id.*

96. Although the contracts expired during the test year, these revenues should not be excluded simply because they expired during the test period. As the name "test period" implies, the test period costs and revenues form the basis for testing the justness and reasonableness of a rate.[197] The development of that rate involves (1) total utility expenses *for the test period*, (2) allocation of a portion of those expenses to wholesale service based upon wholesale cost responsibility *during the test period*, and (3) development of a unit charge or rate that is based upon wholesale billing determinants projected *for the test period*.[198] By synchronizing these three parameters - expenses, allocation factors, and billing determinants - the resulting unit rate should allow the utility to fully recover its cost of providing wholesale electric service. While historic test period data may be adjusted to reflect known and measurable changes that affect revenues and costs,[199] such adjustments must also be synchronized so that the resulting unit charge would not result in over- or under-recovery of the utility's cost of providing wholesale electric service.

97. Here, the fact that the two contracts expired and were not replaced with new contracts is not enough to justify elimination of the revenue credits associated with these contracts. Instead, other related factors would need to be considered, such as whether SPS reduced its production resources after the termination of its obligation to supply Manitoba Hydro and Midwest Energy, or whether, instead, the capacity previously used to supply those contracts was subsequently used to meet load growth of SPS' retail and wholesale requirements customers. Elimination of the revenue credits associated with these contracts without reflecting other related changes in expenses, allocation factors, and billing determinants, would violate the principle that these parameters must be synchronized so that the resulting rate would not result in over- or under-recovery of the utility's cost of providing wholesale electric service.

E. Cash Working Capital Allowance[200]

98. A cash working capital allowance (CWCA) is an amount included in rate base to allow a company to pay "out-of-pocket" expenses that are incurred in daily operations before the expenses are recovered through customer revenues. The Commission has used two methods to calculate CWCA, the 45-day rule, and a fully developed and reliable

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[197] *See Delmarva Power and Light Co.*, Opinion No. 262, 38 FERC ¶ 61,098, at 61,257 (1987).

[198] *Id.*

[199] *See, e.g.*, 18 C.F.R. §§ 35.13(a)(2)(D) and 35.13(d)(1)(ii) (2007).

[200] Initial Decision at P 44-52 (Issue I.D).

lead-lag study. The Commission has stated that the 45-day rule has "produced reasonable results over the years without the expense of prolonged litigation . . . [and] it affords substantial advantages from the standpoints of administrative convenience."[201] The Commission has also found that the 45-day rule avoids imposing the costs of a detailed lead-lag study on utilities, and ultimately, on their consumers.[202] The Commission also allows parties to submit fully developed and reliable lead-lag studies to develop a working capital allowance in lieu of the 45-day rule.

99. A fully developed and reliable lead-lag study's revenue lag calculation must be based on, or confirmed by, a study of the wholesale customers' actual bill paying practices. Absent this, the lead-lag study cannot be found to reflect the actual cash needs of the company.[203] However, where a study is conducted based on assumptions that payments were received on time, rather than on actual bill paying practices, and those assumptions are verified by checking the data against actual payment practices, the Commission affords the lead-lag study the same credibility as if it had been based on data derived from payments.[204]

1. Initial Decision

100. In the Initial Decision, the ALJ determined that the 45-day rule should be applied to determine SPS' CWCA.[205] The ALJ found that CCG's lead-lag study is not fully developed and reliable, stating that CCG could not provide an explanation of the sampling methodology for the lead-lag study, and that the study is based on too many assumptions that were not necessary and created the possibility of repetition error.[206]

2. Brief on Exception

101. CCG argues that the ALJ erred in ruling that a 45-day CWCA is appropriate.[207] CCG argues that the ALJ incorrectly rejected the lead-lag study merely because it was

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[201] *Carolina Power and Light Co.*, 6 FERC ¶ 61,154, at 61,295 (1979).

[202] *Id.*

[203] *Pennsylvania Power Co.*, 12 FERC ¶ 61,049, at 61,080 (1980), *aff'd, Boroughs of Ellwood City v. FERC*, 731 F.2d 959 (1984).

[204] *Cities of Aitken*, 704 F.2d 1254 (D.C. Cir. 1982).

[205] Initial Decision at P 53.

[206] *Id.* P 53-55.

[207] CCG Brief on Exceptions at 16-24.

not based on 100 percent actual data. CCG claims that the study relied on limited assumptions, and the assumptions used were advantageous to SPS and disadvantageous to CCG, the proponent of the assumptions. CCG further states that the Commission has determined that such a study may establish a utility's working capital requirements, even if the study is not based on 100 percent of actual service and payment data, if the opponent of the study fails to present persuasive evidence that the study was not reasonably illustrative of the utility's cash requirement.[208]

102. CCG claims that the ALJ applied an overly-stringent test for the "fully developed and reliable" standard. It asserts that the Commission requires lead-lag studies to be prepared only so that "the Commission can be *reasonably confident* that the study reflects the actual, rather than just an approximation of, the cash needs of the utility."[209] CCG further argues that the Commission is particularly flexible in determining what is fully developed and reliable when the study is reliable to show a negative allowance.[210] CCG claims its study produces a three to four day negative lag, and therefore it is reasonable to adopt a zero cash working capital allowance.

3. <u>Briefs Opposing Exceptions</u>

103. Trial Staff and SPS claim that none of CCG's three attempted lead-lag studies was fully developed because CCG used the contract terms to determine cash flow and made no attempt to determine the actual billing and payments of revenues and expenses.[211] SPS asserts that the information needed to determine the actual service periods was readily available, and CCG's witness did not follow through on plans to obtain it.[212] Trial Staff further states that CCG's data were indeed questioned, and CCG's claim that no party presented evidence showing substantive error is irrelevant because the study itself was insufficient.[213]

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[208] *Id.* at 21 (citing *Central Illinois Pub. Serv. Co.*, 8 FERC ¶ 63,022 (1979), *aff'd in relevant part*, 10 FERC ¶ 61,162 (1980) (*Central Illinois*)).

[209] *Pennsylvania Power Co.*, 12 FERC ¶ 61,049, at 61,080 (1980), *aff'd*, *Boroughs of Ellwood City v. FERC*, 731 F.2d 959 (1984) (emphasis added).

[210] *Minnesota Power and Light Co.*, 16 FERC ¶ 63,012, at 65,060 (1981).

[211] Trial Staff Brief Opposing Exceptions at 34; SPS Brief Opposing Exceptions at 19.

[212] SPS Brief Opposing Exception at 21.

[213] Trail Staff Brief Opposing Exception at 34.

4. Commission Determination

104. We affirm the ALJ's ruling and agree with Trial Staff and SPS that CCG's lead-lag study was not fully developed and reliable. For example, the record shows that the actual invoices were never inspected.[214] Thus, the assumptions made with regard to the service periods and payment dates were never validated against actual payment practices.[215] Therefore, we cannot be reasonably confident that the study reflects the actual rather than a mere approximation of the cash needs of the utility. Accordingly, we affirm the ALJ's ruling that the 45-day rule is appropriate and consistent with Commission policy to determine SPS' CWCA.

F. Renewable Energy Credits[216]

105. Renewable Energy Credits/Certificates (RECs) are required pursuant to some state programs intended to promote renewable energy. In furtherance of that goal, these credits may be used to offset the cost of purchasing renewable energy. The issue in this case is whether SPS should reduce, by the amount of the credit, the cost that it flows through the FCAC.

1. Initial Decision

106. In the Initial Decision, the ALJ determined that even though the Commission's regulations do not contemplate the inclusion of renewable energy credits proceeds in the FCAC, the sales of renewable energy credits should not be separated from the costs of wind energy purchases. The ALJ explained that not requiring the wind energy purchase price to be offset by the renewable energy credits overstates the cost of these purchases and could provide a windfall to SPS.[217]

2. Briefs on Exceptions

107. Trial Staff argues that the ALJ's determination that the renewable energy credits should be flowed through the FCAC should be reversed because the Commission's regulations do not allow FCAC treatment of renewable energy credits.[218]

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[214] Initial Decision at P 54 (citing Tr. 817-19 (Humphrey).

[215] *Id.* P 56.

[216] *Id.* P 73-79 (Issue I.H).

[217] *Id.* P 79.

[218] Trial Staff Brief on Exceptions at 13-14.

108. SPS excepts on the same grounds as Trial Staff and adds that the requirement to flow its renewable energy credits through its FCAC would violate the Administrative Procedure Act.[219] SPS also argues that the Commission's findings in *Cincinnati Gas & Electric Co.*,[220] where the Commission permitted the inclusion of emission allowances in the FCAC even though the Commission's regulation did not explicitly reference inclusion of such costs, does not apply here. SPS points out that the recovery of the cost of emission allowances related to power purchases was consistent with the Commission's FCAC policy, whereas the recovery of renewable energy credits is not.[221]

3. Briefs Opposing Exceptions

109. CCG argues that SPS' current revenue crediting approach for renewable energy credits would result in a significant mismatch of costs. By design, if SPS chose to avoid or defer selling renewable energy credits in a ratemaking test year, it would then reap all of the profits for sales of renewable energy credits in subsequent years. CCG adds that this problem will become magnified in future years as SPS increases its purchases from wind generation. By allowing FCAC treatment, the actual cost-recovering nature of the FCAC will be maintained, according to CCG.

110. PNM argues that the ALJ's decision is entirely consistent with the Commission's ruling in *Cincinnati Gas & Electric.* PNM concludes that the ALJ correctly ruled that offsetting the proceeds of REC sales is necessary to determine the true "total cost" of SPS' wind energy purchases for purposes of FCAC recovery.

4. Commission Determination

111. We affirm the ALJ's conclusion that not addressing the issue of renewable energy credits in the FCAC would result in overstating the total cost of wind purchases. While the Commission's regulations do not directly address FCAC treatment of renewable energy credits, the Commission's regulations do provide that the total cost of purchased economic energy must be flowed through the FCAC.[222] Therefore, when SPS sells

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[219] SPS Brief on Exceptions at 78.

[220] 71 FERC ¶ 61,083, at 61,294 (1995) (*Cincinnati Gas & Elec.*).

[221] *Id.* at n.80.

[222] Under the Commission's FCAC regulations, the "[*t*]*otal cost of the purchase* is all charges incurred in buying economic power and having such power delivered to the buyer's system. The total cost includes, but is not limited to, capacity or reservation charges, energy charges, adders, and any transmission or wheeling charges associated with the purchase." 18 C.F.R. § 35.14(a)(11)(i) (2007); *see* 18 C.F.R. § 35.14(a)(2)(iii)

(continued…)

renewable energy credits, it must subtract the proceeds of these sales from the cost of the wind energy purchases it flows through the FCAC. Otherwise, SPS would not be including in the FCAC the true total cost of the purchase of wind power.

112. In addition, we find that our determinations in *Cincinnati Gas & Electric* are applicable to the instant proceeding. The Commission's logic in requiring FCAC treatment of emission allowances, which increase the purchase cost and "constitute[] a component of the purchased power costs that are eligible for fuel adjustment clause recovery, just as other non-fuel components of purchased power costs," applies equally to renewable energy credits that decrease the purchase cost.

G. Pollution Control Construction Work in Progress[223]

113. Pollution control construction work in progress (pollution control CWIP or CWIP) refers to any expenditure of a utility in the process of constructing a pollution control facility.[224] A pollution control facility is an identifiable structure or portions of a structure that is designed to reduce the amount of pollution produced by the utility.[225] In determining if a facility qualifies as a pollution facility, the Commission considers, among other things, "evidence showing that such facilities are for pollution control."[226] Commission regulations permit a public utility to include costs of pollution control CWIP from qualifying pollution control facilities in its rate base.[227]

1. Initial Decision

114. The ALJ determined that a pollution control CWIP of $3,835,043 is properly included in SPS' rate base. The ALJ stated that the Commission's regulations permit the recovery of pollution control CWIP. Furthermore, the ALJ states that SPS submitted a

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(2007) (providing that fuel and purchased economic power costs shall be the cost of "[t]he total cost of the purchase of economic power, as defined in paragraph (a)(11) . . . .").

[223] Initial Decision at P 57-61 (Issue I.E).

[224] 18 C.F.R. § 35.25 (2007).

[225] *Id.* § 35.25 (b)(4).

[226] *Id.* § 35.25(c)(1)(c).

[227] *Id.* § 35.25 (c)(1).

list of pollution control facilities[228] it includes in its rate base as well as testimony indicating they are pollution control facilities associated with existing facilities SPS owns.[229]

2. **Brief on Exception**

115. CCG asserts that SPS has not met the requirements in 18 C.F.R. § 35.25 to include pollution control CWIP, and therefore the ALJ's determination is an exception to the rate-making principle that customers cannot be required to pay for facilities that are not used and useful during the applicable test year.[230] CCG argues that SPS made no showing that its claimed pollution control facilities are "[an] identifiable structure or portions of a structure that is designed to reduce the amount of pollution produced by the power plant"[231] as required by the Commission's regulations. CCG states that the Commission has historically rejected CWIP when a utility does not describe the facility allegedly serving a pollution control function in sufficient detail for the Commission to make a determination.[232]

116. CCG also claims SPS did not comply with the requirement to use forward-looking allocation ratios to allocate its requested total system CWIP to its customers,[233] which it states is a precondition for the inclusion of pollution control CWIP in the rate base.[234] CCG states that SPS employed a single demand allocation ratio derived from 2004 test year data for all production-related costs, including CWIP projects.[235] CCG cites Order No. 474 in asserting that this will result in an unjust "double whammy"[236] effect on a

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[228] Exhibit SPS-52.

[229] Initial Decision at P 61 (citing Tr. 2225 (Blair)).

[230] CCG Brief on Exception at 24-30.

[231] 18 C.F.R. § 35.25(b)(4).

[232] In support of its position, CCG cites *Southern California Edison Co.*, 38 FERC ¶ 61,040, at 61,109 (1987) and Opinion No. 110, 14 FERC ¶ 61,075 at 61,117.

[233] 18 C.F.R. § 35.25(c)(4) (2007).

[234] CCG cites, *inter alia*, *Maine Yankee Atomic Power Co.*, 66 FERC ¶ 61,375, at 62,252 n.7 (1994) and *South Carolina Elec. & Gas Co.*, 63 FERC ¶ 61,218, at 62,599-600 (1993) (*South Carolina*).

[235] Tr. 2194:4-15 (Heintz).

[236] *Electric Rates; Construction Work in Progress; Anticompetitive Implication*, Order No. 474, 52 Fed. Reg. 23,948 (June 26, 1987), FERC Stats. & Regs. ¶ 30,751, at

(continued…)

utility's wholesale customer by requiring that customer to pay for the costs of the utility's future facilities even though the customer may have purchased or incurred the costs to construct alternate capacity.

117. CCG claims that SPS failed to comply with section 35.25(f) of the Commission's regulations, which requires a utility to propose accounting procedures that ensure that wholesale customers will not be charged for (1) both capitalized allowance for funds used during construction (AFUDC) and corresponding amounts of CWIP proposed to be included in the rate base, and (2) any corresponding AFUDC capitalized as a result of different accounting or ratemaking treatments accorded CWIP by state or local regulatory authorities.

3. <u>Briefs Opposing Exception</u>

118. Trial Staff and SPS argue that the CWIP regulations that CCG claims the ALJ did not address apply only when a utility is seeking to initiate or change its CWIP in a section 205 rate case, and not in a section 206 complaint case.[237] Furthermore, SPS claims it has met the requirements to include pollution control CWIP in its rate even though the requirements are not applicable in this case. Trial Staff and SPS claim that SPS has provided adequate evidence that the facilities it has included are in fact pollution control facilities. SPS also states it provided assurances that SPS would not charge customers for both AFUDC and pollution control CWIP in rate base, explaining how SPS would track CWIP recovery in wholesale rates to assure that in future years there would be no AFUDC accruals recovered in a plant on this same CWIP. SPS provided an example of how the accounting would track the CWIP to ensure that customers would not be charged for the same projects both in CWIP and AFUDC.[238]

4. <u>Commission Determination</u>

119. The Commission affirms the ALJ's finding that pollution control CWIP is properly included in SPS' rate base, as it is allowable by the Commission's regulations.[239] Section 35.25(c)(1)(i) of the Commission's regulations states that "[a]ny CWIP for pollution control facilities allocable to electric power sales for resale may be

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30,702 n.5 (1987) (defining "double whammy"). CCG also cites *South Carolina*, 63 FERC ¶ 61,218, at 62,599.

[237] 18 C.F.R. § 35.25(c)(4); 18 C.F.R. § 36.26(c) (2007).

[238] Exhibits SPS-158 and SPS-159.

[239] 18 C.F.R. § 35.25(c) (2007).

included in the rate base of the public utility." SPS provided evidence and testimony indicating the facilities are properly designated as pollution control facilities. For example, Exhibit SPS-52 provides work order numbers, descriptions, and the costs for facilities and equipment that SPS included in its rate base as pollution control CWIP. SPS also submitted in Exhibits SPS-158 and 159 a description of the accounting procedures it will undertake to ensure that wholesale customers will not be charged for both AFUDC and CWIP in future years. We are persuaded by SPS' evidence that SPS will not charge customers for both pollution control CWIP and AFUDC in rate base. CCG has not provided any evidence to convince us otherwise. Accordingly, we find that SPS' pollution control CWIP is properly allowable in its rate base.

H. Undistributed Subsidiary Earnings[240]

120. Income earned by a utility's subsidiary appears in the utility's Account 216.1, Undistributed Subsidiary Earnings. These funds are only represented on paper, and not actually available for the utility to use. Once the subsidiary pays a dividend or the utility sells the subsidiary, the amount becomes available for the utility to use at its discretion. The funds from the dividend or sale are then characterized as distributed subsidiary earnings, and the amount is moved to Account 216.0, Retained Earnings. In 1997, SPS sold two subsidiaries, Utility Engineering Corp. and Quixx Corp. and recorded the proceeds as undistributed subsidiary earnings.[241]

1. Initial Decision

121. The ALJ states that although the operations of the subsidiaries at issue did not involve the provision of utility service, the $22,855,828 from the sale of the subsidiaries was properly moved to account 216.0 (Retained Earnings) in 2004.[242] Thus, the ALJ ruled that the funds are no longer undistributed subsidiary earnings, but rather retained earnings available for use by SPS to invest in its electric operations. Therefore the ALJ held that the funds are includable in SPS' equity balance under *United Gas Pipe Line*.[243]

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[240] Initial Decision at P 62-69 (Issue I.F).

[241] *Id.* P 64.

[242] Tr. 2197 (Heintz).

[243] 13 FERC ¶ 61,044, at 61,096 (1980) (stating that distributed subsidiary earnings (retained earnings) are available to the utility for rate base investment (or retirement of debts previously used for rate base investment) and are therefore properly includable in capitalization) (*United Gas Pipe Line*).

2. <u>Brief on Exceptions</u>

122. CCG argues that it was erroneous for the ALJ now to allow SPS to treat the earnings as retained earnings (Account 216.0) after SPS inexplicably treated the earnings as undistributed subsidiary earnings (Account 216.1) for seven years after the sale of the subsidiaries.[244] Furthermore, CCG argues that, even assuming the shift from Account 216.1 to Account 216.0 was proper for accounting purposes, SPS has not shown that including the earnings in SPS' common equity is proper for ratemaking purposes.[245] CCG claims that the undistributed subsidiary earnings should be removed from SPS' common equity calculation because the subsidiaries are not affiliated with the electric operation of SPS, and wholesale ratepayers should not be required to pay a return on earnings derived from non-existent, non-utility operations.[246]

3. <u>Brief Opposing Exceptions</u>

123. SPS argues that CCG has inaccurately characterized the funds as undistributed subsidiary earnings, because the funds had been distributed to SPS' retained earnings account by the end of 2004 and were, thereafter, available for investment in utility rate base and no longer represented undistributed subsidiary earnings.[247] SPS claims that all retained earnings represent a return from an investment and the fact that some of SPS' retained earnings may have had their source in SPS' investment in a subsidiary is beside the point. SPS argues that by using straightforward accounting logic, it is clear the funds are available for investment in SPS' regulated utility business, and are therefore properly recognized in the test year capital structure used for rate regulation.[248]

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[244] CCG Brief on Exceptions at 31.

[245] *Id.* at 31-32 (citing letter dated March 22, 2006, from Ms. J. G. Nicholas, Chief Accountant and Director, Division of Audits and Accounting, in *Delta Energy Center, LLC*, Docket No. AC06-10-000 ("Our determination that Delta's lease is a capital lease is for accounting purposes only and does not constitute approval of the appropriate level or timing of cost recovery for ratemaking purposes. Your accounting for the lease costs should be adjusted, if appropriate, to reflect the ratemaking treatment approved by the Commission.")).

[246] CCG Brief on Exceptions at 30-31.

[247] SPS Brief Opposing Exceptions at 13.

[248] *Id.* at 13-14.

4. Commission Determination

124. We affirm the ALJ's ruling that the funds are retained earnings, not undistributed subsidiary earnings as CCG claims, and therefore includable for ratemaking purposes. In *United Gas Pipe Line*, the Commission determined that because undistributed subsidiary earnings are not available for purposes of rate base investment, they must be excluded from capitalization. Here, the funds are no longer in the control of SPS' former subsidiaries and are available for investment in SPS' regulated utility business. The fact that the amount from the sale of the subsidiaries was treated as undistributed subsidiary earnings for seven years after the sale of the subsidiaries is not relevant. SPS explained that there was a note payable over a five year term to SPS, and the note was held on the books until the note was paid.[249] While the amounts could have been transferred to Account 216.0, Retained Earnings, SPS stated that they were transferred in 2004, and therefore are now properly retained earnings includable in SPS' rate structure.

125. We also agree with SPS that the source of the retained earnings is not relevant. CCG claims that although the funds may now properly be retained earnings for accounting purposes, they may not be properly included for ratemaking purposes because the funds represent a return from an investment in a subsidiary. The Commission disagrees. Retained earnings represent a return from investment, or net profit after dividends are paid, and are a component of a firm's capitalization.[250] As stated above, the funds are properly included in the Retained Earnings Account and, therefore, are includable for ratemaking purposes.

I. Allocation of Demand Side Management Programs[251]

126. Demand response means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy. The issue here is whether SPS should be permitted to include the cost of demand side management programs in its cost of service for wholesale customers.

1. Initial Decision

127. In the Initial Decision, the ALJ determined that the costs of demand side management programs are properly allocated to wholesale customers. The ALJ

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[249] Initial Decision at P 68 (citing Tr. 2198 (Blair)).

[250] SPS Brief Opposing Exceptions at 14.

[251] *See* Initial Decision at P 70-72 (Issue I.G).

determined that SPS had provided sufficient evidence that its demand side management programs had reduced its peak generation and thereby benefited customers by reducing the cost of providing service.[252]

2. Brief on Exception

128. Trial Staff asserts that SPS did not provide enough hard data to support a finding that its wholesale customers benefited from the demand side management programs. Trial Staff argues that SPS must perform a study that demonstrates conclusively that the demand side management programs have allowed SPS to reduce load on its system to the point where SPS has been able to delay the installation of new generation capacity.[253]

3. Brief Opposing Exception

129. SPS contends that Trial Staff's assertion that SPS did not prove the benefits of its demand side management programs is incorrect. SPS states that in the past four years demand side management programs have reduced energy needs by approximately 323,000 MWh and shaved SPS' system peak generation needs by approximately 38 MW.[254] SPS argues that while it cannot claim that the demand side management programs have yet enabled it to avoid expenditures on building new generation capacity, Trial Staff has not justified a requirement that demand side management programs must delay generation capacity additions in order for their costs to be included in rate base.[255]

4. Commission Determination

130. We find sufficient justification for allocating the costs of demand side management programs to wholesale customers, because SPS has demonstrated that its demand side management programs have benefited wholesale customers by reducing energy needs by approximately 323,000 MWh and shaving SPS' system peak generation needs by approximately 38 MW.[256] We disagree with Trial Staff that there must be a conclusive demonstration that the programs have specifically delayed the installation of new generation capacity. Such a requirement is an unduly stringent standard for cost

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[252] Initial Decision at P 72.

[253] Trial Staff Brief on Exceptions at 12-13.

[254] SPS Brief Opposing Exceptions at 15 (describing capacity reduction due to DSM programs).

[255] SPS Brief Opposing Exceptions at 14-15.

[256] *See* Exhibit SPS-89.

recovery (i.e., deferral of new generation capacity additions) and may discourage companies from considering all cost-effective options in meeting customer needs, including generation, transmission and demand resources. While we agree that there must be evidence of a program's benefits, we are satisfied that, in the instant case, SPS' evidence is sufficient.[257]

IV. Issues Relating to SPS' Prior FCAC

131. The FCAC issues in this case fall into two categories, those concerning the SPS FCAC that was in effect prior to the effective date of the proposed FCAC (January 1, 2005) and those concerning the FCAC that SPS proposed in the FPA section 205 filing that is involved in the instant case.[258] Due to a settlement between SPS and its customers, disputes arising from the former FCAC are governed by Order No. 517, which was issued in 1974 by this agency's predecessor, the FPC.[259] In contrast, issues arising from the proposed FCAC are governed by this Commission's Order No. 352, issued in 1983.[260]

A. Long-Term Energy-Related Qualifying Facility (QF) Costs[261]

132. FPC Order No. 517 permitted utilities to flow through the FCAC "the net energy cost of energy purchases, exclusive of capacity or demand charges . . . when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy . . . ."[262] In 1990, SPS amended its contracts to include a fuel clause that permitted purchases from QFs at or below SPS' avoided variable energy cost to be

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[257] In the Energy Policy Act of 2005, Pub. L. No. 109-58, §§ 1261 *et seq.*, 119 Stat. 594 (2005), Congress stated that "[i]t is the policy of the United States that time-based pricing and other forms of demand response . . . shall be encouraged."

[258] *See Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,373 (2004) (accepting and suspending proposed FCAC).

[259] FPC Order No. 517, 52 FPC at 1308.

[260] *Treatment of Purchased Power in the Fuel Cost Adjustment Clause for Electric Utilities*, FERC Stats. & Regs. ¶ 30,525 (1983), *reh'g denied*, Order No. 352-A, 26 FERC ¶ 61,266 (1984) (Order No. 352).

[261] Initial Decision at P 126-131 (Issue II.A.2).

[262] FPC Order No. 517 (amending section 35.14(a)(2)(c) of the Commission's regulations).

included in the customer's FCAC. As drafted, this FCAC varied slightly from the Commission's regulations because it permitted SPS to flow through costs other than "net energy costs."

1. Initial Decision

133. The ALJ concluded that the record supports a finding that SPS was permitted, as a result of the settlement in Docket No. ER89-50-000 and subsequent agreements with its wholesale customers, to collect energy-related costs of its QF purchases at or below its avoided variable energy costs, as determined by state regulatory authorities.[263] The ALJ found that the "plain language" of the settlement permits the collection of the energy-related costs of SPS' QF purchases at or below avoided variable energy costs. The ALJ also found that the customers did nothing to complain about the inclusion of these costs in the FCAC calculations that they routinely received and reviewed.

2. Briefs on Exceptions

134. Trial Staff argues that the ALJ erred in concluding that SPS was permitted to collect through its former FCAC all energy-related costs of its QF purchases at or below its avoided variable energy costs, and that the ALJ should have found that only the net energy costs of a QF purchase made on an economic dispatch basis may be passed through.[264]

135. Trial Staff also argues that the ALJ's conclusion is correct only if the language of the settlement is considered outside of the context in which the settlement was agreed upon. However, Trial Staff points out that in 1990, when the settlement added the QF provision to the SPS FCAC, the only QF purchases SPS was making were puts.[265] Trial Staff also states that SPS did not have any QF contracts for capacity.[266]

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[263] *Id.* P 130-31.

[264] Trial Staff Brief on Exceptions at 14-18.

[265] In a put, a QF would have the right to require SPS to make a purchase under the relevant regulations.

[266] Trial Staff argues that the record shows capacity QF purchases are of more recent origin. Trial Staff Brief On Exceptions at 15. Trial Staff states that the QF contract SPS has with Borger Energy Associates, L.P. was dated May 23, 1997, and its QF contract with Sid Richardson Carbon, Ltd. was dated August 1, 2001. *Id.* at 16-17; *see also* Exhibit CCG-46 at 37-38 (Testimony of Daniel). The QF contract SPS had with Engineered Carbons, Inc. went into effect in 1989, but was modified on August 15, 1999,

(continued…)

136. Trial Staff further argues that the Commission should reject SPS' recovery through its former FCAC of energy-related costs incurred under long term QF contracts. Trial Staff argues that SPS should be required to refund monies that were improperly included in the fuel clause and that "the Commission's policy of strictly construing its FCAC regulations should be followed."[267]

137. CCG argues that the "plain language" of the settlement in Docket No. EL89-50[268] cannot be reasonably read to contemplate reliability purchases from QFs, because these transactions did not exist at the time the settlement was executed.[269] Thus, CCG states, the Commission should interpret the settlement in the context of the relevant evidence of the situation and relations of the parties. CCG adds that it is unlikely that the Commission would have sanctioned such a radical departure from the regulations established in FPC Order No. 517[270] if the Commission believed that one or both of the parties intended "purchases" to be so broad as to include the non-fuel energy components of long-term reliability purchases.

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to provide for capacity payments and increased energy purchases if the plant was expanded to produce more than twelve MW net output. *Id*.

[267] Trial Staff Brief on Exceptions at 18.

[268] The relevant section of SPS' former FCAC reads:

> 2. Fuel costs (F) shall be the cost of:
>
> (i) Fossil and nuclear fuel consumed in Company's own plants, and Company's share of fossil and nuclear fuel consumed in jointly owned or leased plants.
>
> (ii) <u>Plus</u>, the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (iii) below. *<u>Included</u> therein shall be the portion of the cost of purchases from Qualifying Facilities at or below Company's avoided variable energy cost.*

(Emphasis added by CCG).

[269] CCG Brief on Exceptions at 39-43.

[270] 52 FPC at 1308.

3. **Brief Opposing Exceptions**

138. SPS argues that nothing in the language of the prior agreements or the SPS FCAC limits recovery to "QF puts" or fuel costs associated with long-term transactions.[271] According to SPS, the agreements are unambiguous and attribute no significance to whether the purchases are associated with the purchase of firm capacity or whether they are simply energy purchases that are made at an avoided cost rate. SPS adds that although at the time the settlement agreements were negotiated SPS had no avoided capacity costs, the Commission's QF regulations then in effect clearly contemplated the obligation of electric utilities to enter into long-term agreements for the purchase of QF capacity and associated energy, which is what SPS did several years later.

139. SPS also argues that the intervenors were dilatory in contesting the recovery of QF costs given the fact that they had routinely received detailed information concerning the company's FCAC calculations. In that vein, SPS argues that where an agreement involves repeated occasions for performance by either party and the other party has knowledge of the nature of the performance and opportunity for objection, any course of performance accepted or acquiesced without objection is given great weight in the interpretation of the agreement.[272]

4. **Commission Determination**

140. The Commission agrees with the ALJ that SPS was permitted, as a result of the settlement in Docket No. EL89-50-000 and subsequent agreements with its wholesale customers, to collect energy-related costs of its QF purchases at or below its avoided variable energy costs, as determined by state regulatory authorities. The settlement makes clear that the costs should be included. While the contracts were modified after the settlement and therefore the context of the purchases was changed, the repeated performance of the contract without any objection by the customers establishes a course of performance that leads us to interpret the settlement as including such costs.[273]

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[271] SPS Brief Opposing Exceptions at 35-38.

[272] SPS Brief Opposing Exceptions at 38 (citing *Restatement (Second) of Contracts* § 202(4) (1981)).

[273] U.C.C. § 2-208. Section 2-208 states:

> Where the contract for sale involves repeated occasions for performance by either party with knowledge of the nature of the performance and opportunity for objection to it by the other, any course of performance accepted or acquiesced in without objection shall be relevant to determine

(continued…)

B. Testing of Energy Purchased Against Hourly Avoided Costs[274]

141. FPC Order No. 517 required that the net energy cost of energy purchases could be flowed through the FCAC when such energy is purchased on an "economic dispatch basis." The issue here is whether the Commission's FCAC regulations in effect at the time required an after-the-fact hourly analysis to determine if the purchased energy costs were less than the utility's actual avoided cost for that hour.

1. Initial Decision

142. The ALJ agreed with SPS that nothing in FPC Order No. 517 requires after-the-fact testing of purchases to ensure that they were on an economic basis. The ALJ found that SPS was under no obligation to evaluate purchases on any basis other than a projected estimate of avoided cost in any given hour. The ALJ points out that the Commission changed this regime in Order No. 352 to one where recovery of energy purchases would be permitted as long as the purchased energy costs are not more than total avoided variable cost, and that this method necessarily involves an after-the-fact analysis. Therefore, the ALJ concluded that SPS properly tested its energy purchases under the prior rule, and there is no need to plan a second phase of the proceeding.

2. Briefs on Exceptions

143. Trial Staff argues that the "economic dispatch basis" language in the Commission's prior rule could be interpreted to require after-the-fact testing.[275] Trial

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> the meaning of the agreement . . . . [and that] such course of performance shall be relevant to show a waiver or modification of any term inconsistent with such course of performance.

Accord Williston Basin Interstate Pipeline Co., 64 FERC ¶ 61,121, at 61,956 (1993) (course of performance is best indicator of what parties intended); *Northern Natural Gas Co.*, 43 FERC ¶ 63,015, at 65,159 (1988) (course of performance evidence tends to be indicative of actual contract meaning); *see also* 4 SAMUEL WILLISTON, A TREATISE ON THE LAW OF CONTRACTS § 623 (3d ed. 1961) ("The practical construction placed upon a contract by the parties themselves constitutes the highest evidence of their intent that whatever was done by them in the performance of the contract was done under its terms as they understood and intended same should be done").

[274] Initial Decision at P 167-173 (Issue II.A.5).

[275] Staff Brief on Exception at 54-55.

Staff argues that *Pennsylvania Power & Light Co.*[276] supports its position that any portion of an economy purchase that passes through the FCAC must be tested after-the-fact each hour to determine if it is less than the utility's actual avoided cost for that hour. While Trial Staff's witness Sammon testified that the plain meaning of the Commission's prior rule suggests before-the-fact determination, Trial Staff nevertheless argues that the Commission has required after-the-fact confirmation.[277]

144. CCG argues that the ALJ erred in accepting SPS' use of a projected estimate of avoided cost in any given hour in evaluating purchases.[278] CCG cites *Philadelphia Electric Company*,[279] in which the Commission held that under Philadelphia's FCAC "the energy charge in each hour *must be less* than Philadelphia's alternate cost *in that hour*."[280] CCG adds that if SPS were not required to make hourly comparisons of its actual costs and avoided costs, the FCAC could have generated a windfall for SPS by the use of a faulty forecast or estimate. Accordingly, CCG concludes that the Initial Decision should be reversed and the Commission should direct that an appropriate redetermination or purchase eligibility be performed based on actual hour-by-hour costs.[281]

3. <u>Brief Opposing Exceptions</u>

145. SPS argues that the reference to "purchased on an economic dispatch basis" in its former FCAC was a reference to dispatching decisions to select those resources that would provide the lowest cost of energy in the next hour.[282] Such decisions are necessarily based on a comparison of the cost quoted for an energy purchase against the *anticipated* cost of the resources that otherwise would be used to provide the same energy if the purchase were not made. Therefore, SPS asserts that Trial Staff's interpretation of the "purchased on an economic dispatch basis" language is incorrect. SPS concedes that it did not perform after-the-fact testing under its former FCAC but holds that such testing was not required. SPS adds that since CCG did not make a valid showing that SPS'

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[276] 6 FERC ¶ 61,036, at 61,078 (1979) (*Pennsylvania Power*).

[277] Trial Staff Brief on Exceptions at 55 n.164.

[278] CCG Brief on Exceptions at 43-46.

[279] 57 FERC ¶ 61,147, at 61,564-65 (1991), *reh'g denied*, 58 FERC ¶ 61,060 (1992) (*Philadelphia Electric*).

[280] 57 FERC ¶ 61,147 at 61,564-5 (emphasis added).

[281] CCG Brief on Exceptions at 45-46.

[282] SPS Brief on Exceptions at 26-29.

energy purchases were uneconomic, there is no reason why SPS should be put to the significant burden of further analyzing its past purchases under its former FCAC.[283]

4. Commission Determination

146. We affirm the ALJ's conclusion that the plain meaning of the Commission's prior rule suggests before-the-fact determination, and we reject the contention that the Commission's prior rule required after-the-fact confirmation. Specifically, the prior rule states that "[f]uel [c]osts (F) shall be the cost of . . . the net energy cost of energy purchases, exclusive of capacity or demand charges, when such energy is purchased on an economic dispatch basis." We agree with SPS that "purchased on an economic dispatch basis" implies that a dispatch decision is to be made at the time of the dispatch. Such a decision can only be made prior to dispatch and as such can only be made based on the expected costs. If after-the-fact information were required, then "economic dispatch" would not be possible. SPS followed the plain meaning of the Commission's regulations in this regard, and we are not persuaded to require a reexamination in this case.

147. Trial Staff and CCG incorrectly argue that the Initial Decision erred in finding that SPS' prior fuel clause was consistent with the Commission's prior fuel clause regulations. CCG cites two cases, *Pennsylvania Power* and *Philadelphia Electric* as undercutting the Initial Decision's determination that the prior fuel cost regulation does not require an after-the-fact determination of energy purchases against hourly avoided cost. CCG states that *Pennsylvania Power* stands for the proposition that "the purpose of [the Commission's former] fuel clause is to pass on to customers the increases or decreases in fuel costs *actually* incurred by the utility."[284] Moreover, CCG asserts that *Philadelphia Electric* can be read to require an hour-by-hour comparison of the actual cost of the purchased energy and the cost that would have been incurred in that hour if the purchase had not been made. CCG implies that this determination could only be made after-the-fact. Trial Staff similarly argues that *Pennsylvania Power* supports an after-the-fact confirmation of whether costs related to a claimed economic dispatch are recoverable under the old fuel clause. We disagree. As stated above, in interpreting the old fuel cost regulation, *Pennsylvania Power* explains that the purpose of the old

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[283] SPS notes that, in Order No. 352, the Commission specifically found that system lambda data, which CCG witness Daniel purported to use to test whether SPS' energy purchases were economic, are not an accurate measure of avoided costs. SPS Brief Opposing Exceptions at 29 (citing Order No. 352 at 30,803).

[284] CCG Brief on Exceptions at 44 (quoting *Pennsylvania Power*, 6 FERC ¶ 61,036 at 61,078 (emphasis in original)).

regulation is to ensure that utilities recover their actual fuel costs, i.e. to make them whole for increased fuel costs. It does not endorse an after-the-fact determination. Nor does *Philadelphia Electric* speak directly to the question of whether an economic dispatch decision is to be evaluated after-the-fact. In any event, the after-the-fact test to which CCG alludes and Trial Staff advocates was not adopted by the Commission until Order No. 352, which does not govern SPS' prior fuel clause.[285]

C. TUCO, Inc. Coal Contract[286]

148. CCG alleged that SPS engaged in a complex arrangement for the purchase of coal for its Harrington station that resulted in wholesale customers paying a higher amount for coal than if SPS had dealt directly with its affiliate Northern States Power Co. (NSP). Instead of procuring coal for its Harrington and Tolk stations through NSP, according to the record, SPS secured coal pursuant to long term supply contracts with TUCO, Inc. (TUCO), an unaffiliated corporation, which in turn was instructed to solicit bids on SPS' behalf. CCG contends that, although Peabody Coal Sales won the TUCO contract to supply SPS, the coal ended up coming from NSP through a swap, and that this could have been done at lower cost had SPS gone to NSP directly.

1. Initial Decision

149. The ALJ concluded that SPS adequately and convincingly explained that ratepayers paid no more than the market price for the coal that TUCO supplied.[287] The ALJ bases his conclusion on the fact that SPS had an exclusive requirements contract with TUCO for Harrington's and Tolk's coal needs, which precluded SPS from dealing directly with NSP.[288] The ALJ points out that SPS ended up benefiting from this

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[285] In contrast to FPC Order No. 517, the Commission's Order No. 352 regulations allow the recovery of the energy-related costs of a purchase, even if not economic in every hour in which the energy is purchased, so long as over the duration of the transaction the sum of the energy purchase costs are not more than the total costs of alternative energy avoided by the purchase. See 18 C.F.R. § 35.14(a)(2)(iv). "After-the-fact" comparisons of energy purchase costs to avoided costs must necessarily be made to ascertain whether the aggregate costs of energy purchased over the duration of the transaction are less than the costs that the transaction allowed the utility to avoid. This is not the case, however, under SPS' prior fuel clause.

[286] Initial Decision at P 174-178 (Issue II.A.6).

[287] *Id.* P 178.

[288] *Id.* (citing Ex. SPS-71 at 5-6).

transaction due to a reduction in the market price of the coal during the course of the transaction.[289]

2. Brief on Exceptions

150. On exception, CCG states that, although TUCO had the requirements contract to supply the stations in question, SPS had the ability to exercise significant control over TUCO in this regard.[290] The CCG explains that a single person was responsible for purchasing coal for both SPS and NSP, and that, because this person knew that SPS needed coal and NSP had contract rights to purchase coal, TUCO should have been directed to deal directly with NSP.

151. CCG argues that Peabody won the contract by bidding coal that was of a lower quality than that offered by other bidders even after SPS personnel expressed concern about the coal's quality. According to the CCG, Peabody ended up providing the very coal to which NSP had option rights, and that this set of transactions resulted in SPS paying a higher price than it would have paid had TUCO been directed to purchase the proper quality coal from NSP in the first place.[291] The CCG argues that the ALJ was incorrect in concluding that SPS did not overpay for coal because the price SPS paid included a multi-million dollar premium TUCO added to the price that NSP paid under its option.[292]

3. Brief Opposing Exceptions

152. SPS responds that CCG does not adequately explain its claim that SPS overpaid for the coal, and that the Initial Decision should be sustained.[293] SPS reiterates that TUCO is a non-affiliated coal supplier which has the exclusive right to provide coal for the stations in question. SPS explains that under these contracts, TUCO arranges for purchasing, receiving, transporting, unloading, handling, crushing, weighing, and delivery of coal to the station bunkers to meet SPS' requirements. TUCO also is responsible for negotiating and administering contracts with coal suppliers, transporters, and handlers.

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[289] *Id.*

[290] CCG Brief on Exceptions at 46-49.

[291] *Id.* at 48.

[292] *Id.* at 49.

[293] SPS Brief Opposing Exceptions at 29-33.

153. SPS explains that the transaction in dispute arose out of a coal price spike in 2000-2001. SPS states that its demand and risk analysis prompted it to encourage its coal supplier to secure coal for the coming years. SPS explains that TUCO accepted a bid from Peabody for 8475 Btu/lb coal from the Caballo mine (SPS states that Caballo coal had been used successfully at the SPS plant). Although plant personnel expressed concern about the Btu content of the coal, SPS states that the purchase was subject to a test burn and that there would be provisions in the contract should the coal cause problems. SPS states that it eventually asked TUCO to procure coal having a higher heating value at the urging of SPS plant personnel, which almost entirely replaced the original lower Btu coal.

154. SPS states that the transactions neither disadvantaged SPS' ratepayers nor effected a windfall to NSP or its parent Xcel Energy Inc. In fact, according to SPS, SPS' ratepayers benefited because by the time the swap for higher Btu coal was negotiated, prices had fallen from the time the original award was made for the lower Btu coal. This resulted in ratepayers paying the same price for higher quality coal that had originally been agreed to be paid for lower Btu coal.[294]

155. SPS further states that any margin that NSP earned on its option coal was passed on to its retail ratepayers. SPS summarizes its position by stating that it was required to purchase coal through TUCO, that TUCO prudently followed a request for proposal process. Thus, SPS concludes, the ALJ's findings were supported by substantial evidence and should be affirmed.[295]

4. Commission Determination

156. The Commission affirms the Initial Decision in this regard. In its brief on exceptions, CCG does not provide evidence demonstrating that SPS paid more through the Peabody swap than NSP could have paid at the outset. But even if the CCG did show that, in hindsight, higher quality coal could have been purchased for less, SPS' exclusive contract with TUCO obligated TUCO to solicit bids and a decision was made to purchase the lower cost Peabody coal and blend it with higher quality coal, in the hopes of a lower cost of coal. The coal decision was a judgment call that SPS and its parent corporation made, and the Commission is not persuaded to reverse the ALJ's finding that SPS' activity was just and reasonable.

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[294] *Id.* at 32.

[295] *Id.* at 33.

V. SPS' Proposed FCAC in Docket No. ER05-168-000

157. On November 2, 2004, the same date CCG filed its complaint against SPS, SPS filed a proposal under section 205 of the FPA to change its FCAC and to make corresponding revisions to SPS' power supply contracts. SPS stated that it filed the revised FCAC to conform to the Commission's current fuel cost and purchased economic power adjustment clause regulations,[296] and also to account for expenses and revenues associated with SPS' participation in the SPP OATT. The proposed FCAC is subject to the Commission's current FCAC policy as set forth in Order No. 352, *Treatment of Purchased Power in the Fuel Cost Adjustment Clause for Electric Utilities*.[297] According to Order No. 352, the Commission's *pro forma* FCAC allows electric utilities to recover all expenses associated with purchased power through fuel clause adjustments if two conditions are met. First, the total cost of the purchase must be less than the buyer's total avoided variable cost and the purchase must be of less than twelve months duration. And second, the purpose of the purchase must be solely to displace higher cost generation.[298]

158. On December 29, 2004, the Commission accepted and suspended, for a nominal period, subject to refund, SPS' proposed changes in the FCAC.[299] The Commission also consolidated SPS' proposed FCAC changes with the proceeding already underway in the complaint case before an ALJ in Docket No. EL05-19-000.

159. The following issues are in dispute regarding SPS' proposed FCAC: recovery of energy related costs (specifically long-term QF purchases, wind energy purchases); transmission costs; FCAC protocols; wind energy costs; avoided variable costs; and a separate QF provision.

A. Energy Related Costs

160. The issue here is whether the FCAC SPS proposes complies with the Commission's regulations governing the recovery of costs associated with long-term QF purchases and wind energy purchases. The ALJ determined that the proposed FCAC is consistent with the Commission's FCAC regulations.

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[296] Order No. 352.

[297] FERC Stats. & Regs. ¶ 30,525 (1983), *reh'g denied*, Order No. 352-A, 26 FERC ¶ 61,266 (1984) (Order No. 352).

[298] Order No. 352 at 30,799.

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

1. Long-Term QF Purchases[300]

a. Initial Decision

161. Noting that SPS agreed to amend its FCAC to include only energy charges associated with QF energy purchases on a going-forward basis, the ALJ concluded that this satisfactorily resolves the issue.[301] The ALJ concluded that a reading of the plain language of 18 C.F.R. § 35.14(a)(2)(iv) contemplates inclusion of energy charges if the total of such charges is less than the buyer's total avoided variable costs, with no distinction made between short and long-term contracts. In the ALJ's words, "[t]hat's what the regulation requires and that's what ought to be in the Company's FCAC."[302]

b. Briefs on Exceptions

162. CCG argues that the ALJ erred in failing to consider that Order No. 352 does not allow FCAC treatment for non-fuel energy costs or recovery of fuel costs for purchases greater than one year in duration that are maintained for reliability reasons.[303] CCG asserts that SPS' version of the FCAC improperly eliminates the limitations contemplated by Order No. 352, and that therefore the Commission should reverse the ALJ on this issue.

c. Briefs Opposing Exceptions

163. SPS cites Order No. 352, in which the Commission stated, in part, "[w]e have added the phrase "for any purchase" [to the FCAC], which allowed *energy charges only* to be recovered through fuel clause adjustments."[304] SPS argues that the Commission used the phrase "energy charges only" to distinguish the costs that were allowed to be recovered under section 35.14(a)(2)(iv) from the "total costs of the purchase of economic power" that are authorized for FCAC recovery under section 35.14(a)(2)(iii).[305] SPS argues that recoveries under the latter section are subject to two tests. First, the economic test compares the total cost of the purchase (including capacity and transmission

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[300] Initial Decision at P 179-185 (Issue II.B.1).

[301] *Id.* P 183.

[302] *Id.* P 183.

[303] CCG Brief on Exceptions at 50-55.

[304] SPS Brief Opposing Exceptions at 40 (citing Order No. 352 at 30,809) (emphasis added by SPS).

[305] *Id.* at 40.

charges)[306] to the total avoided cost over the purchase. Second, the regulation requires that the "economic power" purchase be for a period of twelve months or less.[307]

164. In contrast, SPS argues that recovery of *energy charges only* is not limited to energy purchases made under contracts with terms of twelve months or less; energy charges for *any purchase* may be recovered so long as they are less than avoided costs over the duration of the transaction, however long it may be. Therefore, SPS argues that the ALJ correctly found that "energy only costs" are eligible for recovery under section 35.14(a)(2)(iv) and are not subject to the reliability criterion.[308]

165. Trial Staff argues that the Initial Decision correctly reads Commission FCAC regulation 35.14(a)(2)(iv) and should be affirmed on this issue. The Initial Decision held that the plain language of regulation 35.14(a)(2)(iv) permits recovery of energy charges, including non-fuel energy charges, associated with purchase power contracts of one year or greater duration.[309] Indeed, section 35.14(a)(2)(iv) provides for FCAC pass through of

> Energy charges for *any purchase* if the total amount of energy charges incurred for the purchase is less than the buyer's total avoided variable cost . . . . (emphasis added by trial staff).

166. Trial Staff states that according to the Initial Decision, "any purchase" in section 35.14(a)(2)(iv) means "any purchase." That includes purchases pursuant to purchased power contracts of one year or greater duration. The regulation clearly does not say "any purchase of less than one year duration," according to Trial Staff.

d. <u>Commission Determination</u>

167. The Commission agrees with the ALJ that energy charges can be included in the FCAC as long as the total of such charges is less than the buyer's total avoided variable costs, regardless of the length of the contract. CCG's argument that Order No. 352 imposes two limitations appears to be a misunderstanding of the terms "total costs of the purchase of economic power" and "energy charges only." The Commission's regulations clearly provide that the total costs of purchases of economic power can be flowed through the FCAC only if the purchases are both economic and less than twelve months in

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[306] *Id.* (citing 18 C.F.R. § 35.14(a)(11)(ii) (2007)).

[307] *Id.* (citing 18 C.F.R. § 35.14(a)(11)(i) (2007)).

[308] *Id.* at 41.

[309] Trial Staff Brief Opposing Exceptions at 36-40.

duration. However, the purchase duration under section 35.14(a)(2)(iii) does not apply to purchases under section 35.14(a)(2)(iv). Thus, the energy charge portion (including non-fuel energy charges) of power purchases can be flowed through the FCAC regardless of the length of the contract as long as the purchased power price is less than total avoided variable costs.

2. <u>Wind Energy Purchases</u>[310]

168. The issue here is whether SPS' proposed FCAC permits SPS to recover the energy-related costs of all of its wind energy purchases.

a. <u>Initial Decision</u>

169. In its proposed FCAC, SPS originally sought to include the total cost of energy purchases, as long as they were less than the total avoided costs during the purchase period. SPS agreed to revise the language of section 2(iv) of its FCAC to refer only to energy charges incurred for wind energy purchases. The ALJ determined that this resolved the issue.

b. <u>Briefs on Exceptions</u>

170. CCG states that the record demonstrates that SPS' wind purchases are long-term purchases that are factored into SPS' planning forecasts as capacity resources. CCG points out that in SPS' proposed FCAC, SPS seeks FCAC recovery of energy costs associated with all wind energy purchases "without limitation" of total energy costs and "over the term of the purchase."[311] CCG asserts that Order No. 352 states that "purchases

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[310] Initial Decision at P 186-190 (Issue II.B.2). This section also addresses Issue II.B.5 of the Initial Decision, at P 200 (Should SPS be permitted to recover the energy-related cost associated with long-term (one year or more) purchases if such purchase costs are less than the avoided cost over the term of the contract?).

[311] Ex. SPS-2, section 2(iv) (emphasis added) provides:

> [E]nergy charges for any *purchase including*, *without limitation*, *the total energy costs associated with purchases from any wind energy projects* to the extent that the energy related charges incurred for the purchase *over the term of the purchase* are less than the Company's total avoided variable costs. For energy purchases greater than one year, the Company will measure the monthly purchase price relative to the Company's total monthly avoided variable cost. The Company will only include in the FCA the lesser of the

(continued…)

longer than a year are bound to have some reliability benefits . . . . We want only purchase expenses made solely for economy purposes to be passed through the fuel clause . . . [E]xpenses for purchases longer than one year can be estimated in rate cases."[312]

171. CCG argues that because SPS' wind purchases are long-term, SPS should not be permitted to recover energy costs associated with these purchases through the FCAC. CCG adds that wind purchases by definition have no fossil fuel costs, so wind costs should be recovered through base rate.[313]

172. PNM argues that section 2(iv) of SPS' proposed FCAC should be modified to delete references to wind energy purchases in order to ensure that such purchases are treated consistently with other purchases for purposes of FCAC recovery.[314]

c. <u>Brief Opposing Exceptions</u>

173. SPS states that in referencing wind purchases it is only pointing out that wind purchases are part of the subset of energy purchases addressed by section 2(iv) of its proposed FCAC. SPS argues that, consistent with Order No. 352, it may recover such associated energy costs, provided that these are less than avoided variable costs over the term of the purchase. SPS believes that the ALJ's findings should be affirmed.[315]

d. <u>Commission Determination</u>

174. In considering above the issue of SPS' recovery of the energy related costs of purchases from QFs under long-term contracts under SPS' proposed FCAC, we agreed with the ALJ that energy charges can be included in the FCAC only where the total of such charges is less than the buyer's total avoided variable costs, regardless of the length of the contract. Similarly, the Commission agrees with the ALJ that SPS' recovery of the energy-related costs of all wind energy purchases is permissible when the total of such charges is less than the buyer's total avoided variable cost.

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cumulative purchase price or the total avoided variable cost incurred through the term of the purchase to date.

[312] CCG Brief on Exceptions at 51 (citing Order No. 352 at 30,802).

[313] *Id.* at 55-57.

[314] PNM Brief on Exceptions at 5-7.

[315] SPS Brief on Exceptions at 41-42.

175. In addition, with regard to whether SPS should be permitted to recover the energy-related costs associated with long-term (one year or more) purchases if such purchase costs are less than the avoided cost over the term of the contract, we also find that SPS is permitted to recover the energy-related costs as long as they are less than the avoided variable costs as governed by section 35.14(a)(2)(iv). We reach this conclusion because the regulation states that energy charges for any purchase may be included as long as those charges are less than the total avoided variable costs.

3. Aggregation of Wind Energy Purchases[316]

176. CCG asserts that SPS attempts to enhance its treatment of wind energy purchases by not testing each single wind purchase, or any "forward purchase," on a purchase-by-purchase basis, but bundling them together for economic evaluation in its after-the-fact analysis.[317] CCG claims that this is a violation of the Commission's FCAC regulations which, CCG asserts, requires that the purchases be measured individually.

177. Section 35.14(a)(2)(iv) reads as follows:

> 2. Fuel costs (*F*), measured in $, shall be the cost of:
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> * * *
>
> (iv) Energy charges for any purchase if the total amount of energy charges incurred for the purchase is less than the buyer's total avoided variable cost[318]

a. Initial Decision

178. The ALJ found that, due to the time-consuming nature of doing individual contractual analysis, SPS' practice of aggregating the wind purchases for economic test purposes is justified.[319] The ALJ adds that while a literal reading of the Commission's FCAC regulations does not contemplate aggregation of wind purchases, the use of "short-cuts" to avoid the unnecessary expense and burden of implementing certain provisions is acceptable, especially when there is no specific prohibition of such practices.[320]

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[316] Initial Decision at P 191-194 (Issue II.B.3).

[317] Initial Joint Brief of CCG at 64.

[318] 18 C.F.R. § 35.14(a)(2)(iv) (2007).

[319] Initial Decision at P 194.

[320] *Id.*

b. Briefs on Exceptions

179. Trial Staff argues that the regulation clearly intends that wind energy purchases must be evaluated on a purchase-by-purchase basis to qualify for FCAC treatment. According to Trial Staff, the plain language of Commission regulation 35.14(a)(2)(iv) states that added to energy charges passed through the FCAC will be "energy charges for *any purchase* if the total amount of energy charges incurred for *the purchase* is less than the buyer's total avoided variable cost."[321] Trial Staff argues that the use of the singular number demonstrates that the regulation intends that each individual purchase be evaluated against SPS' total avoided variable cost. Therefore, Trial Staff concludes that aggregating purchases for evaluation purposes violates the regulation.[322]

180. CCG states that the Commission's regulations contemplate that utilities will make economic decisions about each of their purchases, consistent with the requirements of FPA section 205(f).[323] CCG states that neither SPS nor the Initial Decision cited precedent or regulation that supports aggregation of purchases.[324]

181. PNM also argues that the language in section 35.14(a)(2)(iv) of the Commission's regulations indicates that, in order to evaluate whether a given purchase may be flowed through the FCAC, it is necessary to examine whether that purchase—in and of itself, and not in conjunction with other purchases—is economic. Therefore, PNM asserts that the Initial Decision permitting aggregation should be reversed.[325]

c. Brief Opposing Exceptions

182. SPS argues that the practical implementation of its FCAC provisions by aggregating wind energy purchases was sensible and not in violation of the Commission's regulations. SPS adds that in any month typically wind energy costs will be substantially less than avoided costs. Therefore, SPS asserts, the ALJ was correct in

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[321] 18 C.F.R. § 35.14(a)(2)(iv) (2007) (emphasis added).

[322] Staff Brief on Exceptions at 60.

[323] 16 U.S.C. § 824d(f) (2000) (requiring that "not less than every four years the Commission shall make a thorough review of automatic adjustment clauses in public utility rates").

[324] CCG Brief on Exceptions at 59.

[325] PNM Brief on Exceptions at 7-9.

determining that SPS' practice of aggregating wind energy purchases would reduce expense and burden in administering its FCAC, and this determination should be affirmed.[326]

d. **Commission Determination**

183. The Commission will reverse ALJ on this issue. The language of our regulation refers in the singular to "any purchase" and "the purchase."[327] This regulation thus requires a purchase-by-purchase analysis, as opposed to aggregate analysis. Administrative convenience notwithstanding, counting purchases individually serves a purpose that aggregation would not. This is illustrated by the following scenario:

> Assume that SPS purchases 100 MWh of wind energy at $30/MWh in a month when avoided costs are $40/MWh. Under the Initial Decision approach, SPS in effect would bank $1,000 ($10/MWh times 100 MWh hours) that it could net against future purchases that would otherwise be uneconomic and therefore ineligible for fuel clause recovery. Were this to happen for the first six months of a contract, SPS would have banked $6,000. In subsequent months, SPS would be able to purchase well above avoided costs but nevertheless recover all of its costs through the FCAC by aggregating over the contract life. For example, in the next six months SPS could purchase 100 MWh at $50/MWh, assuming avoided costs remain at $40, and still flow costs through the FCAC.[328]

The Commission's interpretation prevents abuse of the system which could occur if a utility was permitted to aggregate purchases. Further, we do not believe that performing a purchase-by-purchase analysis as required by the FCAC would place an undue administrative burden on SPS.

184. When the Commission interprets its own regulations, "a court must necessarily look to the administrative construction of the regulation if the meaning of the words used

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[326] SPS Brief Opposing Exceptions at 43-44.

[327] *Cf.* Holder v. Hall, 512 U.S. 874, 918 (1994) (Thomas, J., concurring) (explaining that the words "any citizen" refers to individual citizens).

[328] Occidental Brief on Exceptions at 10. While Occidental settled with SPS in this proceeding, Occidental's Brief on Exceptions is still a part of the record and as such, the Commission relied upon the brief in making its decision.

is in doubt. . . . The ultimate criterion is the administrative interpretation, which becomes of controlling weight unless it is plainly erroneous or inconsistent with the regulation."[329]

B. Transmission Costs[330]

185. SPS proposes to recover, through its proposed FCAC, the cost of transmission losses purchased from SPP, less the payments for transmission losses that it receives from SPP. It claims the right to do this by virtue of 18 C.F.R. § 35.14(a)(4), which provides that "[t]he adjustment factor developed according to this procedure shall be modified to properly allow for losses (estimated if necessary) associated only with wholesale sales for resale."

1. Initial Decision

186. In the Initial Decision, the ALJ determined that it would be unfair to allow SPS to recover the cost of transmission losses purchased from SPP, less the payments for transmission losses that it receives from SPP, through its proposed FCAC because SPS cannot ensure that they are related to the wholesale sales.[331] No briefs on exceptions were filed on this issue.

2. Commission Determination

187. We affirm the ALJ's ruling to prohibit SPS from recovering net transmission losses through the FCAC for the reasons given by the ALJ as described above. Section 35.14(a)(4) of the Commission's regulations provides that the FCAC adjustment factor "shall be modified to properly allow for losses (estimated if necessary) associated only with wholesale sales for resale." Because SPS admittedly cannot identify each transaction for which SPS is charged a loss, we agree with CCG that SPS has failed to demonstrate that the losses paid actually relate to services provided to the customers at issue or any wholesale sales.

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[329] *Udall v. Tallman*, 380 U.S. 1, 16-17 (1965).

[330] Initial Decision at P 195-199 (Issue II.B.4).

[331] Tr. 1966 (Hudson).

C. **FCAC Protocols**[332]

1. **Initial Decision**

188. The ALJ found that there should be a set of protocols as part of the filed rate that explain in detail how SPS will implement its proposed FCAC on a monthly basis.[333] To accomplish this, the ALJ recommended that the parties form a study group to identify the new information and protocols that will provide the additional support for the FCAC calculations and billings necessary to obtain a greater understanding of the costs included in the charges.

2. **Brief on Exceptions**

189. SPS argues that the protocols requirement modifies and amends the Commission's FCAC regulations and that this would necessitate a notice and comment rulemaking to implement the FCAC protocol requirement.[334] SPS cites *American Federation of Government Employees, Local 3090 v. Federal Labor Relations Authority*[335] and *Consumer Energy Council of America v. FERC*[336] in support of its position.[337] SPS also argues that the evidence does not support the need for the addition of elaborate protocols to the FCAC provisions of SPS' wholesale rate schedules. SPS states that the evidence cited by the ALJ in support of the protocols does not actually support the ALJ's decision.[338] In fact, SPS argues, the discovery of the error in the preparation of one month's FCAC by a Golden Spread employee actually demonstrates SPS' customers' thorough understanding of SPS' FCAC charges as they would not have caught the error otherwise.

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[332] Initial Decision at P 201-204 (Issue II.B.5).

[333] *Id.* P 204 (adopting CCG's position as described in P 201).

[334] SPS Brief on Exceptions at 75-76.

[335] 777 F.2d 751, 759-60 (D.C. Cir. 1985).

[336] 673 F.2d. 425, 446 (D.C. Cir. 1982).

[337] SPS Brief on Exceptions at 75-76.

[338] The evidence cited includes: (1) an error in the preparation of one month's fuel clause calculations related to the inadvertent exclusion of clearly eligible costs; and (2) the restatement of fuel charges for another month in order to take into account new information not available at the time of the original calculation.

190. Lastly, SPS argues that it already provides extensive information to its wholesale customers detailing the FCAC calculations. SPS states that its practice is to provide information in a timely manner whenever customers contact SPS with questions or concerns about its FCAC calculations.

3. Briefs Opposing Exceptions

191. Trial Staff argues that the Initial Decision correctly ruled that SPS and its customers should form a study group to develop and recommend to the Commission detailed protocols to clarify and complete the proposed FCAC rate schedule at issue in this case. Trial Staff points out that section 205(c) of the FPA imposes an obligation upon SPS to ensure that its rate schedules are in a form that facilitates inspection and monitoring by the public and investigation by the Commission's auditors.[339] Unclear and incomplete rate schedules frustrate those rights. In particular, Trial Staff states that when SPS uses a complex computer model to determine whether the energy charges of a purchase that it has "incurred" are valid under the proposed FCAC – a determination that the current FCAC regulation requires – it is reasonable to conclude that the operation of the model should be explained in the rate schedule. The explanation should be in protocols, according to Trial Staff. The Initial Decision, therefore, should be affirmed.

4. Commission Determination

192. The Commission will not adopt the ALJ's recommendation that SPS be required to file detailed protocols as part of its proposed FCAC. Because the rates established in the instant proceeding are for a locked-in period (January 1, 2005 to July 1, 2006), the issue of SPS establishing protocols to explain how it will implement its proposed FCAC on a monthly basis is moot. SPS recently filed a rate case in Docket No. ER08-749-000 and it included protocols in that filing. The Commission will have the opportunity to address the adequacy of SPS's protocols in that proceeding.

193. However, as a safeguard, we will direct that SPS make an informational filing two years from implementation of its new FCAC. SPS should include sufficient detail through narrative and comparative numbers to enable the Commission to evaluate SPS' treatment of fuel for its market-based rate sales for compliance with the Commission's directives herein and to assure the Commission that it is not aggregating its wind energy purchases (as discussed above) for the purpose of fuel clause calculations to its wholesale customers. While we will not mandate fuel clause protocols, we encourage SPS to be responsive to any customers' concerns with respect to implementation of the FCAC.

[339] 16 U.S.C. § 824d(c) (2000).

D. Wind Energy Costs[340]

1. Initial Decision

194. The ALJ determined that SPS' mention of wind energy costs in its FCAC is consistent with the Commission's FCAC regulation, which allows energy charges associated with any purchase to be recovered through the FCAC if such charges are less than the buyer's total avoided cost over the purchase period. No briefs on exception were filed.

2. Commission Determination

195. For the reasons stated above, we affirm the ALJ's ruling that section 2(iv) of the proposed FCAC is, as amended, consistent with our regulations.

E. Avoided Variable Costs[341]

1. Initial Decision

196. The ALJ found that in order for section 2(v) of SPS' proposed FCAC to be consistent with the Commission's current FCAC regulations, SPS must conduct an after-the-fact comparison of actual avoided costs against the purchase costs.[342] No briefs on exceptions were filed.

2. Commission Determination

197. The Commission affirms the ALJ's conclusion because our FCAC regulations permit the flow through of "avoided variable costs," and an after-the-fact test is necessary to make this determination.

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[340] Initial Decision at P 208-212 (Issue II.B.10).

[341] *Id.* P 213-217 (Issue II.B.11).

[342] *Id.* P 217.

F. Separate QF Provision[343]

1. Initial Decision

198. The ALJ determined that there was nothing wrong with SPS' inclusion of a separate provision regarding QF purchases in its proposed FCAC because the energy-related costs of any purchase are eligible for FCAC recovery, so long as they are less than the buyer's total avoided variable cost. The ALJ found fault with the language used by SPS in the proposed FCAC regarding the appropriate test to ensure that the energy-related costs of the QF purchases are less than the buyer's total avoided variable costs. The ALJ determined that SPS must change its language to specify an after-the-fact analysis to support recovery of such costs via the FCAC. No briefs on exception were filed.

2. Commission Determination

199. In considering above the issue of SPS' recovery of the energy related costs of purchases from QFs under long-term contracts under SPS' proposed FCAC, the Commission agreed with the ALJ that energy charges can be included in the FCAC if the total of such charges is less than the buyer's total avoided variable costs, regardless of the length of the contract. Therefore, the Commission agrees with the ALJ that SPS' inclusion in its proposed FCAC of a separate provision regarding QF purchases is consistent with the Commission's regulations.

200. With regard to the language in the FCAC referring to the buyer's total avoided variable cost, the Commission agrees with the ALJ that SPS must change its language to specify an after-the-fact analysis to support recovery of such costs via the FCAC, instead of using state authority estimates.

VI. Refunds to Cap Rock

201. Because Cap Rock is not a formal complainant but an intervenor in this docket, the question arises as to its rights to refunds as a full requirements customer of SPS.[344]

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[343] *Id.* P 218-221 (Issue II.B.12).

[344] On December 2, 2004, Cap Rock filed a pleading captioned "Motion to Intervene" in the complaint docket, but in the body of the motion it wrote that it was submitting the motion also as a complaint under section 206 of the FPA. The Commission granted Cap Rock intervenor status in its order establishing hearing and settlement procedures. Cap Rock subsequently requested clarification of its intervenor status. In an order issued May 2, 2006, the Commission clarified that Cap Rock is an

(continued…)

Even though Cap Rock is not a complainant, this neither prevents Cap Rock from receiving refunds, nor does it prevent its rates from being subject to the full requirements rates after the refund effective date. When the same customer class and the same rates are at issue, a separate complaint is not required for refunds to apply to all customers served under that rate.[345] Cap Rock pays the same charges that the full requirements customers pay and SPS admits that it groups them with the other full requirements customers when setting rates.[346] Accordingly, Cap Rock is entitled to refunds consistent with the outcome of the compliance phase in this case.

VII. Post-Hearing Motions

A. Background

202. On June 23, 2006, the day that briefs on exceptions to the Initial Decision were due, West Texas Municipal Power Agency (West Texas) filed a Motion to Intervene Out-of-Time. Citing section 214(d) of the Commission's Rules of Practice and Procedure,[347] West Texas states that it meets the Commission's standards for late intervention, namely: (1) West Texas has good cause for not seeking to intervene earlier; (2) West Texas' intervention will cause no disruption in this proceeding; (3) it has become apparent that West Texas' interests are not being adequately represented by any other party to this proceeding; and (4) West Texas' intervention will not prejudice, or impose additional burdens on, any party.[348] West Texas states that it is a long-term firm power supply purchaser from SPS, with fuel costs calculated on an average system basis for many years and, in this respect, is similarly situated to the complaining cooperatives in this proceeding.[349]

203. On July 10, 2007, PNM filed an answer in opposition to West Texas' motion to intervene. PNM asks the Commission to deny West Texas' motion citing the late stage

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intervenor, not a party complainant. That order did not address whether any relief that might eventually be granted would apply to Cap Rock. *See Golden Spread Elec. Coop., Inc.*, 115 FERC ¶ 61,136 (2006).

[345] *See, e.g., North Carolina Elec. Membership Corp.*, 57 FERC ¶ 61,332, at 62,067 (1991).

[346] Initial Decision at P 234.

[347] 18 C.F.R. § 385.214(d) (2007).

[348] West Texas Motion to Intervene at 1.

[349] *Id.* at 4.

of the proceeding, the prejudice to parties who intervened and participated in a timely manner, and West Texas' failure to articulate a reason why it should be permitted to intervene at this stage or why it failed to do so earlier.

204. On July 17, 2006, SPS filed an answer to the answers opposing West Texas' motion to intervene. SPS restates West Texas' arguments.[350]

205. On the same day that West Texas filed its motion, El Paso Electric Company (El Paso), filed a four-page letter to the Commission commenting on the Initial Decision. On June 30, 2006, CCG filed a motion to reject El Paso's comments, arguing that El Paso lacks standing to make a filing because it is not a participant, as defined by rule 711 of the Commission's Rules of Practice and Procedure,[351] and thus is not permitted to file what is essentially a brief on exceptions. On July 10, 2006, PNM filed a motion to strike El Paso's submission. PNM argues that El Paso is a non-party to this proceeding and that El Paso's letter is "in blatant disregard for the Commission's rules governing the submission of evidence" and "will violate the due process rights of parties" to this proceeding.[352]

206. On July 17, 2006, SPS filed an answer in support of El Paso's comments. SPS reiterates El Paso's comments, and argues that the letter should be considered a proper submission "by a member of the public."[353] SPS further argues that there is no prohibition on the Commission "merely receiving extra-record communications, as long as they are made available to the public and served on the parties."[354] SPS moves that the Commission reopen the record to accept El Paso's comments as a response to hearsay and to permit a response by PNM.[355]

207. On August 1, 2006, PNM filed a motion for leave to respond and a response to SPS' answer. PNM argues that El Paso's comments are not proper comments submitted by a member of the public, that the letter is not a proper response to alleged hearsay testimony, and that the record should not be reopened under rule 716.

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[350] SPS Answer at 5-6.

[351] 18 C.F.R. § 385.711 (2007).

[352] PNM Motion at 1.

[353] SPS Answer at 6.

[354] *Id.* at 6-7.

[355] *Id.* at 7-8.

B. **Commission Determination**

208. The Commission will reject West Texas' motion to intervene out-of-time.[356] West Texas filed its motion after issuance of the Initial Decision, but fails to present an adequate reason why, for a year and a half since this proceeding began, it remained silent and relied on others to defend its interests. West Texas is not free to now change its mind and conclude that the participants in the case did not live up to its expectations. West Texas cannot remain inactive throughout and then enter the proceeding following the conclusion of a full evidentiary hearing and all that it entails.[357] As we have long held, the failure of one's interests to be adequately represented can be blamed on no one but oneself.[358] West Texas made a conscious decision not to intervene earlier. It cannot be permitted to intervene at this late date and raise an issue which will cause delay in the culmination of this proceeding.[359]

209. The Commission will reject El Paso's submittal because El Paso is not a participant in this proceeding and therefore, under Rule 711, El Paso lacks the standing to make such a filing.

The Commission orders:

(A) The Initial Decision is affirmed in part and reversed in part, as described in the body of this order.

(B) 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 and FCAC billings. This filing shall include a cost of service analysis and rate design consistent with the Joint Stipulation and the Commission's findings herein.

(C) Cap Rock is entitled to refunds as described in the body of this order, with such refunds to be effective January 1, 2005.

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[356] *E.g., Connecticut Yankee Atomic Power Co.*, Opinion No. 449, 92 FERC ¶ 61,269, at 61,899 (2000) (denying motion to intervene filed after issuance of initial decision for failure to demonstrate good cause and to prevent undue burden on active participants).

[357] *See, e.g., DiVito v. Fidelity & Deposit Co.*, 361 F.2d 936, 939 (7th Cir. 1966) (stating that "equity aids the vigilant").

[358] *See, e.g., Southwestern Pub. Serv. Comm'n*, 22 FERC ¶ 61,341, at 61,593 (1983).

[359] *Id.*

(D) The motion to intervene out-of-time by West Texas is denied for the reasons described in the body of this order.

(E) The filing by El Paso is rejected as described in the body of this order.

By the Commission. Commissioners Wellinghoff and Kelly dissenting in part jointly with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Golden Spread Electric Cooperative, Inc. Lyntegar Electric Cooperative, Inc. Farmers' Electric Cooperative, Inc. Lea County Electric Cooperative, Inc. Central Valley Electric Cooperative, Inc. Roosevelt County Electric Cooperative, Inc.	Docket No. EL05-19-002
v.	
Southwestern Public Service Company	
Southwestern Public Service Company	Docket No. ER05-168-001

(Issued April 21, 2008)

WELLINGHOFF and KELLY, Commissioners, *dissenting in part*:

In the initial decision in this proceeding, the Administrative Law Judge (ALJ) found that

> [t]he plain facts are that SPS improved its competitive position in making market-based sales by charging market-based customers lower system average fuel costs, and collected the difference from the Company's cost-based customers, who were forced to cover their own fuel costs and the difference between average costs and the incremental fuel costs associated with the market-based sales.[[360]]

The ALJ stated that the "complainants should not be foreclosed from pursuing an investigation back in time, so long as it is reasonably bounded."[361] The ALJ then determined that the relevant period for considering Southwestern Public Service Company's (SPS) fuel cost adjustment clause (FCAC) is from 1999 forward.[362]

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[360] *Golden Spread Elec. Coop., Inc.*, 115 FERC ¶ 63,043, at P 150 (2006) (Initial Decision).

[361] Initial Decision, 115 FERC ¶ 63,043 at P 125.

[362] *Id.*

Despite the ALJ's determination, today's order directs SPS to make refunds starting with the refund effective date of January 1, 2005, based on a finding that SPS' FCAC is ambiguous on the issue in dispute. We do not agree with the order's assertion that SPS' FCAC language was ambiguous as to the fact that SPS should credit incremental fuel and purchased power costs attributable to intersystem sales, rather than system average fuel costs, against the cost of fuel and purchased power recovered through the FCAC. As today's order correctly states, the Commission may "take retroactive refund action to address circumstances where a seller did not charge the filed rate or violated statutory or regulatory requirements or rules in applicable rate tariffs . . . ."[363] Therefore, we agree with the ALJ's determination, based upon his careful review of the extensive record in this proceeding, that we should direct SPS to pay refunds from 1999 to 2004. Further, consistent with the ALJ's determination, we believe that today's order should have directed SPS to make a compliance filing in order to allow the Commission to quantify what, if any, refunds are due for the period beginning January 1, 2005.[364]

Accordingly, we dissent in part from this order.

Jon Wellinghoff Commissioner	Suedeen G. Kelly Commissioner

[363] *Golden Spread Elec. Coop., Inc.*, 123 FERC ¶ 61,047, at P 53 (2008) (citation omitted).

[364] Initial Decision, 115 FERC ¶ 63,043 at P 239, 254.

Document Content(s)

71 FERC P 61245 (F.E.R.C.), 1995 WL 325881

FEDERAL ENERGY REGULATORY COMMISSION
****1** Commission Opinions, Orders and Notices

Tampa Electric Company

Docket No. ER95-852-000
Order Accepting Proposed Rates for Filing
(Issued May 31, 1995)

***61940** Before Commissioners: Elizabeth Anne Moler, Chair; Vicky A. Bailey, James J. Hoecker, William L. Massey, and Donald F. Santa, Jr.

Tampa Electric Company (Tampa) has filed in this proceeding a package of power sale agreements that, collectively, increase the amount of power it may sell in the future to Reedy Creek Improvement District (Reedy Creek). Florida Power Corporation (Florida Power), which both purchases power from Tampa and sells power to Reedy Creek, challenges the proposed rates, claiming that they will have the effect of increasing rates to itself and that they are unduly discriminatory (to the extent the rates are, Florida Power argues, preferential to those charged itself and other Tampa customers).

For the reasons discussed below, we will accept the proposed rates for filing without modification, suspension, or hearing. As to Florida Power's arguments, we find nothing objectionable here to a rate charged to an off-system customer that may be lower than that charged existing customers, if otherwise the utility would not be able to make a sale that benefits all of its customers.

Background

Tampa's Filing

On March 31, 1995, Tampa filed in this proceeding three agreements with Reedy Creek, a political subdivision of the State of Florida which serves Walt Disney World as a power supplier. The first, an interchange service contract, supersedes an existing contract to accommodate the establishment of a direct interconnection between Tampa and Reedy Creek. (Reedy Creek currently is directly interconnected only with Florida Power, from which it purchases most of its requirements.) The second, an amendment of an existing power sale agreement, provides for the sale of capacity and energy from the coal-fired generating resources at Tampa's Big Bend Station. The third agreement, a new power sale agreement, ***61941** provides for the sale, on a firm basis, of up to 75 megawatts of capacity and associated energy from Tampa's system resources through the year 2017.

Taken together, the package of agreements filed by Tampa increase both the amount of power it may sell to Reedy Creek and the duration of its power sales. The rates charged under the agreements are based on those already on file for existing Tampa services. In this regard, Tampa explains that it will sell power under the amended power sale agreement between 1995 and 1999 at rates (demand and energy charges) that are identical to those currently charged for existing transactions. Tampa further explains that it will sell power under the new power sale agreement at rates that are identical to those in its existing partial requirements tariff (which includes a fuel adjustment clause reflecting average system fuel costs). Nevertheless, Reedy Creek is entitled to a lower energy charge under the amended power sale agreement if the spot Big Bend fuel cost is lower than the average Big Bend fuel cost, as well as a lower energy charge under the new power sale agreement if Tampa's system incremental fuel cost in any hour is lower than the system average fuel cost.

****2** Tampa requests that the three agreements be made effective on June 1, 1995.

Notice and Responsive Pleadings

Notice of Tampa's filing was published in the *Federal Register*, 60 Fed. Reg. 19245 (1995), with comments, protests or interventions due on or before April 26, 1995.

On April 26, 1995, Florida Power filed a motion to intervene in this proceeding and to protest Tampa's filing. Florida Power states that it purchases power and energy from Tampa under Tampa's partial requirements tariff to accommodate service to the City of Sebring, Florida. Florida Power also states that it currently is Reedy Creek's primary supplier of power and that it provides transmission for all of Reedy Creek's current purchases from other suppliers. As a customer of Tampa, Florida Power expresses concern that Tampa's proposal to sell power to Reedy Creek on the basis of incremental fuel costs when those fuel costs are lower than Tampa's average fuel costs will result in higher fuel charges to Florida Power and other Tampa requirements customers. As a current supplier to Reedy Creek (and Tampa customer), Florida Power argues that it is discriminatory for Tampa to offer Reedy Creek a rate for long-term sales that is based on incremental, rather than average, fuel costs.

On May 11, 1995, Tampa filed a motion for leave to file an answer to Florida Power's motion to intervene and protest. While Tampa does not oppose Florida Power's intervention in this proceeding, it challenges Florida Power's argument that its pricing proposal to Reedy Creek somehow will increase rates to other customers or is unduly discriminatory in comparison with rates charged other Tampa customers. On May 22, 1995, Florida Power filed a response to Tampa's May 11, 1995 pleading.[1]

We discuss the parties' arguments in greater detail in the following portions of this order.

Discussion

Under rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §385.214 (1994), the timely, unopposed motion to intervene of Florida Power serves to make it a party to this proceeding. While answers to protests generally are not permitted under our Rules, *see* 18 C.F.R. §385.213(a)(2), we find that consideration of Tampa's responsive arguments is necessary to allow for resolution of the issues raised. Accordingly, we find good cause to accept Tampa's May 11, 1995 answer.

Standard of Commission Review

As an initial matter, Tampa argues that it does not bear the burden of proof to support the proposed rates in the amended power sale agreement. (Tampa does not make the same argument for the other two filed agreements.) Tampa claims that, because the amended power sale agreement amends an existing contract only as to the amount and length of service, and provides for rates that are based on the rates on file for existing services, we must review Florida Power's protest to the amended agreement as a challenge to an existing rate. Tampa further argues in this regard that, under section 206 of the FPA, Florida Power must support its position by showing that the existing rate is unjust and unreasonable.

****3** We reject Tampa's position. The amended power sale agreement provides for new sales of Big Bend unit power for a longer period of time (10-30 MW between January 1, 1996 and December 31, 1999), though to an existing customer. The Commission previously has not reviewed any cost support for the extra volumes or the additional years of service. Accordingly, we find that the amended power sale agreement, because it expands available service to an existing customer, represents a change in rates that we review, and as to which Tampa holds the burden of proof, under section ***61942** 205 of the FPA. *See, e.g.*, *Nevada Power Company*, 55 FERC P 61,379, at p. 62,152 (1991); *Southwestern Electric Power Company*, 39 FERC P 61,099, at p. 61,293 (1987).

Florida Power's Objections

Florida Power objects to the proposed energy charge in the amended and new power sale agreements, which is designed to reflect incremental fuel costs if lower than Tampa's average fuel costs. Specifically, Florida Power asserts that: (1) the rates for Reedy Creek are discriminatory because they are more favorable than those Florida Power pays; and (2) Tampa's decision to offer Reedy Creek energy based on a fuel cost lower than average cost will increase Florida Power's fuel clause billings, based on average fuel cost, for its purchases from Tampa.

Florida Power further contends that, while it may be appropriate to price short-term sales on the basis of incremental cost, it is discriminatory to offer this pricing to Reedy Creek for a long-term purchase. Florida Power asks that the Commission institute an investigation of Tampa's proposal and the effect that it will have on customers served under Tampa's fuel clause. Florida Power also requests that the investigation consider past instances when Tampa has priced energy on the basis of incremental fuel costs which were lower than the system average.

Tampa responds that the Commission already has held that, when off-system sales are priced on the basis of incremental cost, the credit in the fuel clause for the cost of fuel recovered in the off-system sales should reflect that incremental cost.[2] Tampa concludes that, because it properly has determined the incremental fuel cost for pricing this off-system sale, there is no need for further investigation.

Tampa further contends that Florida Power improperly has focused only on the fuel pricing component of the transaction and that this does not capture the entire economic impact of the Reedy Creek transaction. Tampa notes that the Reedy Creek also pays fixed demand charges which contribute to Tampa's recovery of its fixed costs. Tampa explains that the benefit of the additional demand charge revenues, to the advantage of all of Tampa's requirements customers, will far exceed the impact of the fuel clause revenues. Tampa requests that we summarily reject Florida Power's request for hearing and accept the filing without modification.

We agree with Tampa in this regard. Reedy Creek apparently indicated that it would only increase its purchases from Tampa if Tampa would agree to charge Reedy Creek incremental fuel costs.

****4** So long as Reedy Creek pays incremental fuel costs, a discount below the average cost rate charged Tampa's other customers will not harm those customers. Indeed, Tampa's agreement to the Reedy Creek incremental cost pricing option may, in fact, result in Florida Power and other Tampa customers paying less (as a result of the increased demand charge revenues from sales to Reedy Creek). Accordingly, no investigation of Tampa's fuel clause billings is warranted.

Florida Power also raises the issue of discrimination. Florida Power and others purchase requirements service on a long-term basis under the same base rates as those proposed for Reedy Creek, yet they do not have the option of paying an energy charge that is based on a fuel cost that may be lower than average fuel cost. We have no basis to disagree with Tampa's suggestion, however, that without incremental rates, it would not be able to attract additional service commitments from Reedy Creek.[3]

As competition in the electric power industry increases, customers with different generation supply options will demand lower rates. When Florida Power's existing contract expires in the year 2011 (six years before Reedy Creek's), Tampa may have to offer Florida Power a discounted rate to keep its business. That discounted rate may result in overall rate benefits to Tampa customers other than Florida Power, just as the instant discount (as explained above) benefits Tampa customers other than Reedy Creek. Therefore, Tampa has provided an adequate justification for the rate difference, and we reject Florida Power's request for an investigation of the proposed rates on the basis of any undue discrimination.[4]

***61943** *Acceptance of Rates*

The proposed rates have not been shown to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise excessive. Accordingly, we will accept the interconnection agreement and the amended and new power sale agreements for filing, without hearing or suspension, and deny Florida Power's request for rejection, modification, or investigation of the proposed rates.

The Commission orders:

(A) Tampa's motion for leave to file an answer to Florida Power's protest is hereby granted.

(B) Florida Power's response to Tampa's answer is hereby rejected.

(C) The agreements filed by Tampa in this proceeding are hereby accepted for filing, without suspension or investigation, to become effective as of June 1, 1995.

(D) The parties are hereby informed of the rate schedule designations shown on the Attachment to this order.

Attachment

Rate Schedule Designations

Designation—Descriptions

(1) Rate Schedule FERC No. 54 (Supersedes Rate Schedule FERC No. 31)—Interchange Agreement

(2) Supplement No. 1 to Rate Schedule FERC No. 54—Service Schedule A-Emergency Interchange Service

(3) Supplement No. 1 to Supplement No. 1 to Rate Schedule FERC No. 54—Cap on Service Charge Under Service Schedule A

(4) Supplement No. 2 to Rate Schedule FERC No. 54—Service Schedule B-Scheduled/Short-Term Firm Interchange Service

****5** (5) Supplement No. 1 to Supplement No. 2 to Rate Schedule FERC No. 54—Schedule H-Daily Capacity Charge Calculation

(6) Supplement No. 2 to Supplement No. 2 to Rate Schedule FERC No. 54—Cap on Service Charge Under Service Schedule B

(7) Supplement No. 3 to Rate Schedule FERC No. 54—Service Schedule C-Economy Energy Interchange Service

(8) Supplement No. 4 to Rate Schedule FERC No. 54—Service Schedule D-Long-Term Interchange Service

(9) Supplement No. 1 to Supplement No. 4 to Rate Schedule FERC No. 54—Letter of Commitment Dated October 16, 1991

(10) Supplement No. 1 to Supplement No. 1 to Supplement No. 4 to Rate Schedule FERC No. 54—Letter Agreement Dated March 16, 1991

(11) Supplement No. 2 to Supplement No. 1 to Supplement No. 4 to Rate Schedule FERC No. 54—Letter Agreement Dated March 29, 1995

(12) Supplement No. 5 to Rate Schedule FERC No. 54—Service Schedule J-Negotiated Interchange Service

(13) Supplement No. 1 to Supplement No. 5 to Rate Schedule FERC No. 54—Letter of Commitment Dated September 22, 1992

(14) Supplement No. 1 to Supplement No. 1 to Supplement No. 5 to Rate Schedule FERC No. 54—Letter Agreement Dated November 4, 1994

(15) Supplement No. 2 to Supplement No. 1 to Supplement No. 5 to Rate Schedule FERC No. 54—Transmittal Letter Dated February 8, 1995

(16) Supplement No. 6 to Rate Schedule FERC No. 54—Service Schedule X-Extended Economy Interchange Service

(17) Rate Schedule FERC No. 55—Resale Service Contract

(18) Supplement No. 1 to Rate Schedule FERC No. 55—Schedule 1-Maximum Fuel Energy Charge

(19) Supplement No. 2 to Rate Schedule FERC No. 55—Schedule 1-Minimum Fuel Energy Charge

Footnotes

1 Florida Power's response is an answer to an answer. *See* 18 C.F.R. § 385.213(a)(2) (1994). It will therefore be rejected.

2 Tampa cites the Commission's order in *Minnesota Power & Light Company*, 47 FERC P 61,064 (1989), for this proposition.

3 In an increasing number of cases, the Commission has accepted for filing discounted rates offered for particular customers when necessary to respond to competitive pressures. *See Public Service Co. of Oklahoma*, 54 FERC P 61,021, at p. 61,032 (1992); *Oklahoma Gas & Electric Co.*, 54 FERC P 61,212, at pp. 61,629-30, *reh'g denied*, 55 FERC P 61,142 (1992).

4 In this regard, we note that we recently rejected an argument by Reedy Creek, in Docket No. ER95-457-000, that the rates it is charged by Florida Power are unduly discriminatory simply because they are different than those charged other Florida Power customers (which, unlike Reedy Creek, entered into a pre-filing agreement with Florida Power). *See Florida Power Corporation*, 70 FERC P 61,321 (1995).

71 FERC P 61245 (F.E.R.C.), 1995 WL 325881

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