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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for declaratory statement regarding eligibility for Standard Offer contract and payment thereunder by Florida Power Corporation.	**Docket No. 950110-EQ** **Submitted for filing: September 19, 1995**

APPENDIX TO FLORIDA POWER CORPORATION'S MEMORANDUM IN OPPOSITION TO MOTION TO DISMISS

DOCUMENT NO. 09227-95
9-19-95

ORIGINAL FILE COPY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for declaratory statement regarding eligibility for Standard Offer contract and payment thereunder by Florida Power Corporation.

Docket No. 950110-EQ

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INDEX TO THE APPENDIX OF FLORIDA POWER CORPORATION'S MEMORANDUM IN OPPOSITION TO MOTION TO DISMISS

1) Florida Power Corporations Petition for declaratory statement regarding eligibility for Standard Offer contract and payment thereunder by Florida Power Corporation, filed January 25, 1995.

2) *In re: Petition for Authority for Florida Power Corporation to Refuse all Standard Offer Contracts Except that submitted by Panda Kathleen, L. P.*, Docket No. 911142-EQ, Order No. PSC-92-1202-FOF-EQ, dated October 22, 1992.

3) Federal Energy Regulatory Commission Order No. 69, <u>Small Power Production and Cogeneration Facilities, Regulations implementing Section 210 of the Public Utility Regulatory Policies Act of 1978</u>, 45 Fed.Reg. 12211 (1980).

4) *Policy Statement Regarding the Commission's Enforcement Role Under Section 210 of the Public Utility Regulatory Policy Act of 1978*, 23 FERC ¶ 61,304 (1983).

5) *North Little Rock Cogeneration, L.P. and Power Systems, Ltd. v. Entergy Services, Inc. and Arkansas Power Light Co.*, ____ FERC ¶ ____ (Sept. ____, 1995). This is a Draft Order that was approved at the Commission Agenda on September 13, 1995.

6) *Southern California Edison Co. San Diego Gas & Electric*, 71 FERC ¶ 61,269 (1995).

7) *In re: Petition for determination that implementation of contractual pricing mechanism for energy payments to qualifying facilities complies with Rule 25-17.0832, of the Florida Administrative Code, by Florida Power Corporation*, Docket No. 940771-EQ, Order No. PSC-95-0210-FOF-EQ, dated February 15, 1995.

8) *In re: Petition for resolution of a cogeneration contract dispute with Orlando Cogen Limited, L.P., by Florida Power Corporation*, Docket No. 940357-EQ, Order No. PSC-95-0209-FOF-EQ, dated February 15, 1995.

9) Orlando Cogen Limited's Motion to Dismiss FPC's Amended Petition, Docket No. 940771-EQ, filed November 28, 1994.

10) *In Re: Petition for approval to the extent required, of certain actions relating to approved cogeneration contracts by Florida Power Corporation*, Docket No. 940797-EQ, Order No. PSC-95-0540-FOF-EQ, dated May 2, 1995.

11) Letter dated July 27, 1994, from Ted Hollon of Panda to David Gammon of FPC.

12) *In re: Petition of Tampa Electric Company for Declaratory Statement Regarding Conserv Cogeneration Agreement*, Order No. 14207, Docket No. 840438-EI, dated March 21, 1985.

13) *In re: Petition of Polk Power Partners for a Declaratory Statement Regarding Eligibility for Standard Offer Contracts*, Order No. PSC-92-0683-DS-EQ, Docket No. 920556-EQ, dated July 21, 1992.

14) *West Penn Power Co.*, 71 FERC ¶ 61,153 (1995).

15) *American Cogen Technology, Inc. v. Pacific Gas and Electric Co.*, 1989 Cal. PUC LEXIS 813 (Nov. 22, 1989).

16) *In the Matter of the Petition of Rosemont Cogeneration Joint Venture, et al. for an order Resolving a Dispute with Northern States Power Co.*, 1989 Minn. PUC LEXIS 107 (May 11, 1989).

17) *Fulton Cogeneration Associates v. Niagara Mohawk Power Corp.*, 1995 U.S. Dist. LEXIS 7249 (March 28, 1995).

18) *Erie Energy Associates*, 1992 N.Y. PUC LEXIS 52 (March 4, 1992).

19) *Armco Advanced Materials Corporation v. Pennsylvania Public Utility Commission*, 1995 Pa. Commw. LEXIS 344 (July 20, 1995).

Florida Power
CORPORATION

September 8, 1994

Mr. Kyle Woodruff
Project Manager
Panda-Kathleen L. P.
4100 Spring Valley, Suite 1001
Dallas, Texas 75244

Re: Standard Offer Contract for the Purchase of Firm Capacity and Energy from a Qualifying Facility Less Than 75 MW or a Solid Waste Facility between Panda-Kathleen, L. P. and Florida Power Corporation

Dear Kyle:

This is in response to your letter of August 10, 1994.

First, your letter indicates that Panda will be consulting with the PSC regarding its planned configuration which will produce 115 MW. As you know, Florida Power Corporation (FPC) has expressed concerns about that configuration's ability to comply with the 75 MW limitations imposed on standard offer contracts and, therefore, is pleased to see that Panda intends to consult with the Florida Public Service Commission (FPSC).

With respect to what will happen after the FPSC responds to your project proposal, Florida Power will not speculate at this time on how FPSC actions may or may not affect the rights and obligations under our contract with Panda. We will be happy to address this matter after FPSC actions.

Sincerely,

Robert D. Dolan
Manager, Cogeneration Contracts and Administration

RDD/mag

cc: M. B. Foley Jr.
J. P. Fama

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PEC10610

JOHNSON AND ASSOCIATES
ATTORNEYS AND COUNSELORS

BARRETT G. JOHNSON

KARA TOLLETT OAKLEY

315 SOUTH CALHOUN ST., SUITE 350
TALLAHASSEE, FL 32301
(904) 222-2693

MAILING ADDRESS:
P.O. BOX 1308
TALLAHASSEE, FLORIDA
32302
FAX (904) 222-2702

August 23, 1994

Joseph D. Jenkins
Director, Electric & Gas Division
Florida Public Service Commission
101 East Gaines Street
Tallahassee, Florida 32399

Dear Joe:

The purpose of this letter is to confirm the discussion on August 15, 1994 between you, Bob Trapp and Tom Ballenger of your staff and Bill Nordlund, Brian Dietz and myself regarding the Panda Kathleen cogeneration plant and Panda's standard offer contract with Florida Power Corporation.

As we discussed, Panda's contractual obligation is to be able to produce 74.9 MW under all site conditions for the life of the unit. Panda recently informed FPC by letter of the equipment configurations which will enable Panda to meet its contractual obligation while complying with its various environmental requirements. A copy is attached for your information. We also discussed the fact that under certain site conditions the ABB 11 N 1 and GE Frame 7EA will produce more than 74.9 MW. Since Panda Kathleen's contractual requirement is to be able to produce 74.9 MW under worst case conditions, such as right before a major overhaul and during a heat wave, it is necessarily true that the unit be capable of more than 74.9 MW under best case conditions. As we discussed, under optimal conditions these units can produce in the 115 MW range. Of course, this energy is quite a bargain for the rate payers since it carries no capacity costs to FPC under the Standard Offer Contract.

We also discussed the fact that the operation of Panda-Kathleen in the manner described in this letter and the attached letter to FPC is consistent with Panda's standard offer contract and is not a contract change that would require Florida Public Service Commission approval. Please advise immediately if this is incorrect or if you have any questions.

Sincerely,

Barrett

Barrett G. Johnson

PEC10611

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State of Florida

DIVISION OF ELECTRIC & GAS
JOSEPH D. JENKINS
DIRECTOR
(904) 488-8501

Public Service Commission

August 24, 1994

Mr. Barrett G. Johnson
Johnson and Associates
315 South Calhoun Street
Suite 350
Tallahassee, Florida 32301

Dear Mr. Johnson:

This is to confirm receipt of your letter dated August 23, 1994 concerning Panda Kathleen's plans to begin satisfying its contractual obligation with Florida Power Corporation by installing the units described in your letter. Based on the representations, I foresee no reason why this is any type of contract change that should come before the Commission for approval. I discussed this briefly with Florida Power's Bob Dolan and he concurred.

Sincerely,

Joseph D. Jenkins

Joseph D. Jenkins
Director
Division of Electric and Gas

JDJ/ms

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APPENDIX C
RATES

SCHEDULE 2
GENERAL INFORMATION FOR 1997 COMBUSTION TURBINE UNIT

GENERAL
YEAR OF AVOIDED UNIT = 1997
AVOIDED UNIT REFERENCE PLANT = BARTOW CT UNITS

INVESTMENT DATA
TOTAL COST, DIRECT + AFUDC, IN 1/91 $'s = $398.88/KW
ANNUAL ESCALATION RATE OF PLANT COSTS = 5.10%
ECONOMIC PLANT LIFE = 20 YEARS

OPERATING DATA
AVOIDED UNIT FIXED O&M COSTS IN 1/91 $'s = $6.18/KW/YR
AVOIDED UNIT VARIABLE O&M COSTS IN 1/91 $'s = $1.83/MWH
ANNUAL ESCALATION RATE OF O&M COSTS = 5.10%
MINIMUM ON-PEAK CAPACITY FACTOR = 90.0%
MINIMUM TOTAL CAPACITY FACTOR = 42.0%
SYSTEM VARIABLE O&M COSTS IN 1/91 $'s = $0.673/MWH
AVOIDED UNIT HEAT RATE = 11,610 BTU/KWH
TYPE OF FUEL = DISTILLATE

ON-PEAK HOURS
(1) FOR THE CALENDAR MONTHS OF NOVEMBER THROUGH MARCH,
ALL DAYS: 6:00 A.M. TO 12:00 NOON, AND
5:00 P.M. TO 10:00 P.M.
(2) FOR THE CALENDAR MONTHS OF APRIL THROUGH OCTOBER,
ALL DAYS: 11:00 A.M. TO 10:00 P.M.

FINANCIAL DATA
K FACTOR (MID YEAR) = 1.5259
UTILITY DISCOUNT RATE = 9.96%

ISSUED BY: S. F. Nixon, Jr., Director Rate Department

EFFECTIVE DATE: September 20, 1991

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PEC10613

PANDA-KATHLEEN L.P.

A Panda Company

August 10, 1994

Mr. Robert D. Dolan, P. E.
Manager, Cogeneration Contracts
Florida Power Corporation
3201 34th Street South
St. Petersburg, FL 33711

RE: Standard Offer Contract For The Purchase Of Firm Capacity And Energy From A Qualifying Facility Less Than 75 MW Or A Solid Waste Facility Between Panda-Kathleen L. P. and Florida Power Corporation

Dear Mr. Dolan:

The purpose of this letter is to advise Florida Power Corporation (FPC) of Panda's intention to install either a GE Frame 7EA or an ABB 11 N1 combustion turbine in a combined cycle configuration for the Lakeland cogeneration Qualifying Facility since they are the only gas turbines commercially available which can produce at least 74.9 MW each day over the life of the 30 year contract term, taking into account equipment degradation, site weather conditions, steam host needs, and environmental requirements. Panda plans to discuss equipment configuration with the Florida Public Service Commission (FPSC) to determine whether or not FPSC approval is required.

Assuming that the FPSC determines that its approval for such equipment configuration is not required, then it is Panda's understanding that the following shall apply:

1. In the event that any energy is produced in excess of 74.9 MW, FPC will pay Panda for energy produced above 74.9 MW at FPC's as-available energy price.

2. FPC will purchase the energy produced above 74.9 MW, if any, at all times when available except when system operating conditions will not permit such; i.e. at minimum load conditions as reasonably defined by FPC.

Sincerely,

Kyle Woodruff

Kyle Woodruff
Project Manager

4100 Spring Valley, Suite 1001 • Dallas, Texas • 75244 • 214/980-7159 • Fax 980-6815

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1ST CASE of Level 1 printed in FULL format.

In Re: Petition not to Accept Standard Offer Contract of Polsky Energy Corporation, by Tampa Electric Company

DOCKET NO. 940193-EQ; ORDER NO. PSC-**94-0488**-FOF-EQ

Florida Public Service Commission

94 FPSC 4:364

April 25, 1994

PANEL:
[*1]

The following Commissioners participated in the disposition of this matter: J. TERRY DEASON, Chairman; SUSAN F. CLARK, JULIA L. JOHNSON, DIANE K. KIESLING

OPINION:
NOTICE OF PROPOSED AGENCY ACTION ORDER GRANTING PETITION NOT TO ACCEPT STANDARD OFFER CONTRACT SUBMITTED BY POLSKY ENERGY CORPORATION TO TAMPA ELECTRIC COMPANY

BY THE COMMISSION:

Notice is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for formal proceeding pursuant to Rule 25-22.029, Florida Administrative Code.

Pursuant to Rules 25-17.0832 (3) (c)&(d), Florida Administrative Code, Tampa Electric Company (TECO) has petitioned the Commission to allow TECO to not accept the Standard Offer Contracts presented to TECO by Polsky Energy Corporation (PEC) on January 28, 1994. On December 20, 1993 TECO filed with the Commission a Petition to Close Standard Offer Contract which was assigned Docket Number 931218-EQ. On January 26, 1994 TECO filed a petition for Approval of Standard Offer Contract for Cogenerators and Small Power Producers which was assigned Docket **[*2]** Number 940094-EQ. The "replacement" standard offer contract delays the in-service date of TECO's next avoided unit by two years. Commission consideration of these two petitions is pending.

TECO, in its Petition to not accept the Standard Offer Contract, alleged that the PEC proposal should really be considered a request for a negotiated contract. PEC made changes to the Standard Offer Contract as follows: At paragraph 2.0 (page 8.346) they changed the minimum Monthly Availability Factor (MAF) from 90% to 80%; at paragraph 2.4 (page 8.347) they changed the MAF from 90% to 80%; at paragraph 3.0 (page 8.348) they changed the MAF from 90% to 80%; at paragraphs 4.2.4.1 COMPLETION SECURITY, 4.2.4.2 PERFORMANCE SECURITY, and 4.2.4.3 LIQUIDATED DAMAGES (pages 8.400, 8.410 and 8.411) they crossed out the entire paragraphs.

In accord with Rule 25-17.0832(3)(c), Florida Administrative Code, a Standard Offer Contract is to be used in lieu of an negotiated contract. Like

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any unilateral contract, no changes can be made to a Standard Offer Contract without the consent of the utility. Any changes to the Standard Offer Contract would necessitate negotiation which would negate the **[*3]** use of the Standard Offer Contract.

Therefore we find that Tampa Electric Company's (TECO) petition to not accept the Standard Offer Contract by Polsky Energy Corporation (PEC) should be granted.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Tampa Electric Company's (TECO) petition to not accept the Standard Offer Contract by Polsky Energy Corporation (PEC) shall be granted. It is further

ORDERED that if there is no protest to this proposed agency action within the time frame set forth below, this docket shall be closed.

By ORDER of the Florida Public Service Commission, this 25th day of April, 1994.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for declaratory statement regarding eligibility for Standard Offer contract and payment thereunder by Florida Power Corporation.	Docket No. ________ Submitted for filing: January 25, 1995

PETITION FOR DECLARATORY STATEMENT

Florida Power Corporation ("Florida Power" or "the Company") hereby submits this Petition for Declaratory Statement pursuant to Section 120.565, F.S., and Rule 25-22.020, F.A.C. Florida Power seeks a declaration that the Standard Offer Contract for the Purchase of Firm Capacity and Energy from a Qualifying Facility Less than 75 MW or a Solid Waste Facility between Panda-Kathleen L.P. and Florida Power Corporation dated November 25, 1991 (the "Standard Offer Contract") is not available to Panda-Kathleen L.P. ("Panda") if it constructs a facility configuration, as it currently proposes to do, with the capacity to produce 115 megawatts ("MW"). In addition, if the Standard Offer Contract is available to Panda, Florida Power seeks a further declaration that it has no obligation to make capacity or energy payments under the Standard Offer Contract after the December, 2016.

INTRODUCTION

1. The name of the Petitioner and its business address is:

Florida Power Corporation
3201 - 34th Street South
Post Office Box 14042
St. Petersburg, FL 33733-4042

2. All notices, pleadings and correspondence should be directed to:

James P. Fama
James A. McGee
Post Office Box 14042
St. Petersburg, FL 33733-4042
Telephone: (813) 866-5184
Facsimile: (813) 866-4931

DISCUSSION

A. Availability of the Standard Offer Contract.

3. On November 25, 1991, Panda and Florida Power entered into the Panda Standard Offer Contract (Exhibit 1) pursuant to Rule 25-17.032(3)(a) and (c), Florida Administrative Code. That rule provides for standard offer contracts involving "small qualifying facilities less than 75 megawatts. . . ." The Panda Standard Offer Contract is expressly titled "Standard Offer Contract for the Purchase of Firm Capacity and Energy from a Qualifying Facility Less Than 75 MW or a Solid Waste Facility."

4. The Commission has expressly considered the application of Rule 25-17.032 to projects which have a total net generating capacity in excess of 75 MW, and ruled that such projects do not qualify to take advantage of standard offer contracts. Order No. PSC-92-0683-DS-EQ, dated July 21, 1992. (Exhibit 2). In so ruling, the Commission entered an Order Granting Declaratory Statement In The Negative on a request by Polk Power Partners to take advantage of a standard order contract for a facility that had a net generating capacity in excess of the 75 MW cap. See also, Order No. PSC-94-1306-FOF-EQ, dated October 24, 1994 ("the Commission's current Rule 25-17.0832(3)(a) . . . limits the availability of Standard Offer Contracts to Qualified Cogeneration Facilities (QF) under 75 MW.") (Exhibit 3).

5. Despite the 75 MW cap identified both in Rule 25-17.032(3)(a) and in the Panda Standard Offer Contract, Panda proposes to install either a GE Frame 7 EA or an ABB 11 N1 combustion turbine in a combined cycle configuration for its cogeneration project. This configuration would produce 115 MW or more, in violation of the 75 MW cap imposed by Rule 25-17.0832 and the Panda Standard Offer Contract itself.

6. FPC has repeatedly expressed its belief to Panda that this Standard Offer Contract is not available with respect to Panda's proposed facility. (See, e.g., Exhibit 4). FPC further advised Panda that it should obtain a ruling from this Commission on this issue and that FPC would comply with the Commission's ruling thereon. It was FPC's understanding that Panda intended to obtain such a ruling from the FPSC.

7. However, Panda has not sought a decision from the Commission regarding the availability of, and its rights under, the Panda Standard Offer Contract in light of the project's 115 MW size. Rather, Panda has simply discussed the matter on an informal basis with FPSC staff. Its discussions are described in the letter from Barrett G. Johnson to Joseph D. Jenkins dated August 23, 1994. (Exhibit 5). Mr. Jenkins responded by letter of August 24, 1994, to Barrett G. Johnson, (Exhibit 6), and Panda has asserted that this letter constitutes approval of their proposed action.

8. FPC believes that the Commission's express rulings in Order Nos. PSC-92-0683-DS-EQ and 94-1306-FOF-EQ, as well as the express terms of both Rule 25-17.0832 and the Panda Standard Offer Contract, clearly prohibit the availability of the Standard Offer Contract to a facility producing more than 75 MW. However, since Panda has not sought a ruling from the Commission as to

the availability of the Standard Offer Contract for this proposed facility, Florida Power accordingly requests the Commission to declare the applicability of its rules and orders governing standard offer contracts to Panda's proposed 115 MW cogeneration facility.

B. Determination of the Panda Standard Offer Contract's Payment Terms.

9. Under the terms of the Panda Standard Offer Contract, Florida Power's capacity payment obligations terminate at the end of 20 years, which will be December 2016. Among other things, Appendix C, Schedule 2 of the Contract states that the economic life of the avoided unit is 20 years, and the capacity payments were calculated on that explicit basis. (Exhibit 7). Had the contract been for a term of 30 years, the monthly capacity payments would have been correspondingly reduced. Moreover, it is for this reason that all payment schedules in the Appendices are defined only through the year 2016, a twenty year period.

10. Despite these contractual provisions and limiting terms, Panda attempted to modify the term of its Standard Offer Contract by writing in an expiration date of March, 2025. On that basis, Panda now takes the position that FPC is obligated to make capacity payments in some unspecified amount under the Panda Standard Offer Contract for an additional ten years after the year 2016. See letter dated August 10, 1994 from Kyle Woodruff, Project Manager of Panda to Robert D. Dolan, P.E., Manager, Cogeneration Contracts of Florida Power. (Exhibit 8). Panda may also take the position that Florida Power is obligated by contract to purchase as available energy after the year 2016.

PEC10514

11. This attempt by Panda to modify the Standard Offer Contract is improper and conflicts with the terms of the contract that was presented to it by Florida Power and which explicitly contemplated a contract term and contract payments not to exceed 20 years. As the Commission ruled in Order No. PSC-94-0488-FOF-EQ: "Like any unilateral contract, no changes can be made to a Standard Offer Contract without the consent of the utility. Any changes to the Standard Offer Contract would necessitate negotiation which would negate the use of the Standard Offer Contract." (Exhibit 9). In so ruling, the Commission granted the petition of Tampa Electric Company not to accept the standard offer contract of Polsky Energy Corporation because Polsky had made changes to that contract.

NEED FOR DECLARATORY STATEMENT

12. Florida Power has a real and immediate need for the requested declaratory statement as it relates to its own particular circumstances only. The Commission's declaratory statement as to the correct application of Rule 25-17.0832, F.A.C., and its orders establishing the availability of Standard Offer Contracts and the ability of Panda to change the terms of this Standard Offer Contract will ensure that Florida Power and its customers will only pay for capacity and energy from facilities properly configured to take advantage of this Standard Offer Contract, and that FPC and its customers will, in addition, have no contractual obligation to pay for capacity and energy purchased from Panda other than as expressly provided for in that Standard Offer Contract. A timely resolution of these essential questions will enable Florida Power to plan its needs and its financial obligations to this QF in an orderly manner.

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WHEREFORE, Florida Power Corporation requests that the Commission enter an order declaring that the Panda Standard Offer Contract is not available to Panda-Kathleen L.P. if it configures its facility to have a capacity of 75 MW or more; and, if the Standard Offer Contract is nevertheless available to Panda, to declare that Florida Power has no obligation under the Contract to make any energy or capacity payments to Panda after December 2016.

Respectfully submitted,

OFFICE OF THE GENERAL COUNSEL
FLORIDA POWER CORPORATION

By ______________________

James P. Fama
James A. McGee
Post Office Box 14042
St. Petersburg, FL 33733-4042
Telephone: (813) 866-5184
Facsimile: (813) 866-4931

h:\jam\panda-ds.pet

PEC10516

Standard Offer
For Purchase Of Firm Capacity and Energy
From A Qualifying Facility Less Than 75 MW Or A Solid Waste Facility

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ISSUED BY: S. F. Nixon, Jr., Director Rate Department

EFFECTIVE: September 20, 1991

EXHIBIT

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**STANDARD OFFER CONTRACT FOR THE
PURCHASE OF FIRM CAPACITY AND ENERGY
FROM A QUALIFYING FACILITY
LESS THAN 75 MW OR A SOLID WASTE FACILITY**

between

PANDA-KATHLEEN L.P.

and

FLORIDA POWER CORPORATION

ISSUED BY: S. F. Nixon, Jr., Director Rate Department
EFFECTIVE: September 20, 1991

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ISSUED BY: S. F. Nixon, Jr., Director Rate Department
EFFECTIVE: September 20, 1991

ISSUED BY: S. F. Nixon, Jr., Director Rate Department
EFFECTIVE: September 20, 1991

STANDARD OFFER CONTRACT FOR THE PURCHASE OF FIRM CAPACITY AND ENERGY FROM A QUALIFYING FACILITY LESS THAN 75 MW OR A SOLID WASTE FACILITY

This Agreement ("Agreement") is made and entered by and between Panda-Kathleen, L.P., a Delaware Limited Partnership, having its principal place of business at 4100 Spring Valley #1001 Dallas, TX 75244 (hereinafter referred to as the "QF"), and Florida Power Corporation, a private utility corporation organized under the laws of the State of Florida, having its principal place of business at St. Petersburg, Florida (hereinafter referred to as the "Company"). The QF and the Company may be hereinafter referred to individually as a "Party" and collectively as the "Parties."

WITNESSETH:

WHEREAS, the QF desires to sell, and the Company desires to purchase, electricity to be generated by the Facility and made available for sale to the Company, consistent with FPSC Rules 25-17.080 through 25-17.091 in effect as of the Execution Date; and

WHEREAS, the QF will engage in interconnected operation of the QF's generating facility with ~~xxxxx~~ the Company ~~xx xxxx xxxxxxxxxx~~ system (hereinafter referred as the "Transmission Service Utility") which is directly interconnected at one or more points with the Company.

NOW, THEREFORE, for mutual consideration, the Parties covenant and agree as follows:

ISSUED BY: S. F. Nixon, Jr., Director Rate Department
EFFECTIVE: September 20, 1991

ARTICLE I: DEFINITIONS

As used in this Agreement and in the Appendices hereto, the following capitalized terms shall have the following meanings:

1.1 Appendices means the schedules, exhibits and attachments which are appended hereto and are hereby incorporated by reference and made a part of this Agreement.

1.1.1 Appendix A sets forth the Company's Interconnection Scheduling and Cost Procedures.

1.1.2 Appendix B sets forth the Company's Parallel Operating Procedures.

1.1.3 Appendix C sets forth the Company's Standard Offer Rates for Purchase of Firm Capacity and Energy from a Qualifying Facility less than 75 MW or a Solid Waste Facility.

1.1.4 Appendix D sets forth the Company's Transmission Service Standards.

1.1.5 Appendix E sets forth FPSC Rules 25-17.080 through 25-17.091 in effect as of the Execution Date.

1.2 Avoided Unit Fuel Reference Plant means that Company unit(s) whose delivered price of fuel shall be used as a proxy for the fuel associated with the avoided unit is defined in Appendix C.

1.3 Avoided Unit Heat Rate means the average annual heat rate associated with the unit in million BTU per KWH as it is defined in Appendix C.

1.4 Avoided Unit Variable O & M means the variable operation and maintenance expense associated with the unit type selected in section 8.2.1 hereof in dollars per KWH as it is defined in Appendix C.

1.5 BTU means British thermal unit.

1.6 Capacity Account means that account which complies with the procedure in section 8.6 hereof.

1.7 Capacity Payment Adjustment means the value calculated pursuant to Appendix C.

1.8 Commercial In-Service Status means (i) that the Facility is in compliance with all applicable Facility permits; (ii) that the Facility has maintained an hourly KW output, as metered at the Point of Delivery, equal to or greater than the Committed Capacity for a consecutive twenty-four (24) hour period or during the On-Peak Hours specified in Appendix C of two consecutive days; and (iii) that such twenty-four (24) hour period is reasonably reflective of the Facility's day to day operations.

1.9 Committed Capacity means the KW capacity, as defined in Article VI hereof, which the QF has agreed to make available on a firm basis at the Point of Delivery.

1.10 Company's Interconnection Facilities means all equipment which is constructed, owned, operated, and maintained by the Company located on the Company's side of the Point of Delivery, including without limitation, equipment for connection, switching, transmission, distribution, protective relaying and safety provisions which, in the Company's reasonable judgment, is required to be installed for the delivery and measurement of electric energy into the Company's system on behalf of the QF, including all metering and telemetering equipment installed for the measurement of such energy regardless of its location in relation to the Point of Delivery.

1.11 <u>Contract In-Service Date</u> means the date, as specified in Article IV hereof, by which the QF has agreed to achieve Commercial In-Service Status.

1.12 <u>Construction Commencement Date</u> means the date on which work on the concrete foundation for the turbine generator begins and substantial construction activity at the Facility site thereafter continues.

1.13 <u>Control Area</u> means a utility system capable of regulating its generation in order to maintain its interchange schedule with other utility systems and contribute its frequency bias obligation to the interconnection.

1.14 <u>Execution Date</u> means the date on which the Company executes this Agreement.

1.15 <u>Facility</u> means all equipment, as described in this Agreement, used to produce electric energy and, for a cogeneration facility, used to produce useful thermal energy through the sequential use of energy and all equipment required for parallel operation with the interconnected utility.

1.16 <u>FERC</u> means the Federal Energy Regulatory Commission and any successor.

1.17 <u>Florida-Southern Interface</u> means the points of interconnection between the electric Control Areas of (1) Florida Power & Light Company, Florida Power Corporation, Jacksonville Electric Authority, and the City of Tallahassee and (2) Southern Company.

1.18 <u>Force Majeure Event</u> means an event or occurrence that is not reasonably foreseeable by a Party, is beyond its reasonable control, and is not caused by its negligence or lack of due diligence, including, but not limited to, natural disasters, fire, lightning, wind, perils of the sea, flood, explosions, acts of God or the public enemy, strikes, lockouts, vandalism, blockages, insurrections, riots, war, sabotage, action of a court or public authority, or accidents to or failure of equipment or machinery, including, if applicable, equipment of the Transmission Service Utility.

1.19 FPSC means the Florida Public Service Commission and any successor.

1.20 Import Capability means the capability to import power at the Florida-Southern Interface, giving consideration to the various limitations imposed upon those facilities by the electric systems to which they are directly or indirectly connected.

1.21 Interconnection Costs means the actual costs incurred by the Company for the Company's Interconnection Facilities, including, without limitation, the cost of equipment, engineering, communication and administrative activities.

1.22 Interconnection Costs Offset means the estimated costs included in the Interconnection Costs that the Company would have incurred if it were not purchasing Committed Capacity and electric energy but instead itself generated or purchased from other sources an equivalent amount of Committed Capacity and electric energy and provided normal service to the Facility as if it were a non-generating customer.

1.23 KW means one (1) kilowatt of electric capacity.

1.24 KWH means one (1) kilowatthour of electric energy.

1.25 Minimum On-Peak Capacity Factor means that value which is associated with the unit as it is defined in Appendix C.

1.26 Minimum Total Capacity Factor means that value which is associated with the unit as it is defined in Appendix C.

1.27 On-Peak Hours means those daily time periods specified in Appendix C.

1.28 On-Peak Capacity Factor means the ratio calculated pursuant to section 8.3 hereof.

1.29 Operational Event of Default means an event or circumstance defined as such in Article XV hereof.

1.30 Performance Adjustment means the value calculated pursuant to Appendix C.

1.31 Point of Delivery means the point(s) where electric energy delivered to the Company pursuant to this Agreement enters the Company's system.

1.32 Point of Metering means the point(s) where electric energy made available for delivery to the Company, subject to adjustment for losses, is measured.

1.33 Point of Ownership means the interconnection point(s) between the Facility interconnected utility.

1.34 Pre-Operational Event of Default means an event or circumstance defined as such in Article XV hereof.

1.35 Security Guaranty means the deposits or other assurances as specified in section 13.1 hereof.

1.36 Qualifying [Small Power Production or Cogeneration] Facility means a facility that meets the requirements defined in FPSC Rule 25-17.080.

1.37 Term means the duration of this Agreement as specified in Article IV hereof.

1.38 Total Capacity Factor means the ratio calculated pursuant to section 8.4 hereof.

1.39 Transmission Service Agreement means that agreement between the QF and the Transmission Service Utility which meets the requirements of Appendix D.

ARTICLE II: AVAILABILITY

2.1 The availability of this Agreement is subject to:

2.1.1 The available capacity limitations described in Schedule 1 of Appendix C; and

2.1.2 The Facility being a solid waste facility pursuant to FPSC Rule 25-17.091 or the Facility having a Committed Capacity which is less than 75,000 KW; and

2.1.3 The provisions of section 2.2.

2.2 This Agreement is available to a QF with a Facility which shall be located south of the latitude of the Company's Central Florida Substation. For a QF with a Facility located north of the latitude of the Company's Central Florida Substation, this Agreement is available provided that (i) by the Contract In-Service Date the Company can make available an amount of Import Capability equal to the diminution of Import Capability caused by the Facility during the Term of the Agreement; and (ii) the QF shall reimburse the Company for such costs incurred by the Company to make available such Import Capability. Such reimbursement shall not be considered as a reduction in the payments made by the Company to the QF for capacity and energy purchased under this Agreement.

ARTICLE III: FACILITY

3.1 The Facility shall be located in Section 20, Township 28 South, Range 23 E. The Facility shall meet all other specifications identified in the Appendices hereto in all material respects and no change in the designated location of the Facility shall be made by the QF. The Facility shall be designed and constructed by the QF or its agents at the QF's sole expense.

3.2 Throughout the Term of this Agreement, the Facility shall be a Qualifying [redacted] Facility.

3.3 Except for Force Majeure Events declared by the Facility's fuel supplier(s) or fuel transporter(s) which comply with the definition of Force Majeure Events as specified in this Agreement and occur after the Contract In-Service Date, the Facility's ability to deliver its Committed Capacity shall not be encumbered by interruptions in its fuel supply.

3.4 The QF shall either (i) arrange for and maintain standby electrical service under a firm tariff; or (ii) maintain the ability to restart and/or continue operations during interruptions of electric service; or (iii) maintain multiple independent sources of generation.

3.5 From the Execution Date through the Contract In-Service Date, the QF shall provide the Company with progress reports on the first day of January, April, July and October which describe the current status of Facility development in such detail as the Company may reasonably require.

ARTICLE IV: TERM AND MILESTONES

4.1 The Term of this Agreement shall begin on the Execution Date and shall expire at 24:00 hours on the last day of March 2025 [month, year], unless extended pursuant to section 4.2.4 hereof or terminated in accordance with the provisions of this Agreement. Upon termination or expiration of this Agreement, the Parties shall be relieved of their obligations under this Agreement except for the obligation to pay each other all monies under this Agreement, which obligation shall survive termination or expiration.

4.2 The Parties agree that time is of the essence and that: (i) the QF shall execute the Transmission Service Agreement, if applicable, which shall be approved or accepted for filing by the FERC on or before the first day of [month, year] N/A; (ii) the Construction Commencement Date shall occur on or before the first day of [month, year] 4/1/94; and (iii) the Facility shall achieve Commercial In-Service Status on or before the first day of [month, year] 4/1/95, which date shall constitute the Contract In-Service Date. These three dates shall not be modified except as follows: upon written request by the QF not more than sixty (60) days after the declaration of a Force Majeure Event by the QF, which event contributes proximately and materially to a delay in the QF's schedule, these three dates each may be extended on a day-for-day basis for each day of delay so caused by the Force Majeure Event; provided, however, that the QF shall specifically identify: (i) each date for which extension is being requested; and (ii) the expected duration of the Force Majeure Event; and provided further, that the maximum extension of any of these three dates shall in no event exceed a total of one hundred and eighty (180) days, irrespective of the nature or number of Force Majeure Events declared by the QF. If the Contract In-Service Date is extended then the Term of the Agreement may be extended for the same number of days.

ARTICLE V: QF OPERATING RESPONSIBILITIES

5.1 During the Term of this Agreement, the QF shall:

5.1.1 Have the sole responsibility to, and shall at its sole expense, operate and maintain the Facility in accordance with all requirements set forth in this Agreement.

5.1.2 Provide the Company prior to October 1 of each calendar year the estimated amounts of electricity to be generated by the Facility and delivered to the Company for each month of the following calendar year, including the time, duration and magnitude of any planned outages or reductions in capacity.

5.1.3 Promptly notify the Company of any changes to the yearly generation and maintenance schedules.

5.1.4 Provide the Company by telephone or facsimile prior to 9:00 A.M. of each day an estimate of the hourly amounts of electric energy to be delivered at the Point of Delivery for the next succeeding day.

5.1.5 Coordinate scheduled outages and maintenance of the Facility with the Company. The QF agrees to recognize and accommodate the Company's system demands and obligations by exercising reasonable efforts to schedule outages and maintenance during such times as are designated by the Company.

5.1.6 Comply with reasonable requirements of the Company regarding day-to-day or hour-by-hour communications with the Company or with the Transmission Service Utility relative to the performance of this Agreement.

5.2 The estimates and schedules provided by the QF under this Article V shall be prepared in good faith, based on conditions known or anticipated at the time such estimates and schedules are made, and shall not be binding upon either Party; provided, however, that the QF shall in no event be relieved of its obligation to deliver Committed Capacity under the terms and conditions of this Agreement.

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ARTICLE VI: PURCHASE AND SALE OF CAPACITY AND ENERGY

6.1 Commencing on the Contract In-Service Date, the QF shall commit, sell and arrange for delivery of the Committed Capacity to the Company and the Company agrees to purchase, accept and pay for the Committed Capacity made available to the Company at the Point of Delivery in accordance with the terms and conditions of this Agreement. The QF also shall sell and deliver or arrange for the delivery of the electric energy to the Company and the Company agrees to purchase, accept, and pay for such electric energy as is made available for sale to and received by the Company at the Point of Delivery.

6.2 The Committed Capacity and electric energy made available at the Point of Delivery to the Company shall be (x) net of any electric energy used on the QF's side of the Point of Ownership or ( ) simultaneous with any purchases from the interconnected utility. This selection in billing methodology shall not be changed.

6.3 If the Company is unable to receive part or all of the Committed Capacity which the QF has made available for sale to the Company at the Point of Delivery by reason of (i) a Force Majeure Event; or (ii) pursuant to FPSC Rule 25-17.086, notice and procedural requirements of Article XX or FPSC Rule 25-17.086 shall apply and the Company will nevertheless be obligated to make capacity payments which the QF would be otherwise qualified to receive, and to pay for energy actually received, if any. The Company shall not be obligated to pay for energy which the QF would have delivered but for such occurrences and QF shall be entitled to sell or otherwise dispose of such energy in any lawful manner; provided, however, such entitlement to sell shall not be construed to require the Company to transmit such energy to another entity.

6.4 The QF shall not commence initial deliveries of energy to the Point of Delivery without the prior written consent of the Company, which consent shall not be unreasonably withheld. The QF shall provide the Company not less than thirty (30) days written notice before any testing to establish the

Facility's Commercial In-Service Status. Representatives of the Company shall have the right to be present during any such testing.

ARTICLE VII: CAPACITY COMMITMENT

7.1 The Committed Capacity shall be 74,900 KW, unless modified in accordance with this Article VII. The Committed Capacity shall be made available at the Point of Delivery from the Contract In-Service Date through the remaining Term of this Agreement.

7.2 For the period ending one (1) year immediately after the Contract In-Service Date, the QF may, on one occasion only, increase or decrease the initial Committed Capacity by no more than ten percent (10%) of the Committed Capacity specified in section 7.1 hereof upon written notice to the Company before such change is to be effective; provided, however, that in no event shall the Committed Capacity exceed 75,000 KW unless the QF is a solid waste facility.

7.3 A redesignated Committed Capacity pursuant to this Article VII shall be stated to the nearest whole KW and shall be effective only on the commencement of a full billing period.

7.4 The Company shall have the right to require that the QF, not more than once in any twelve (12) month period, re-demonstrate the Commercial In-Service Status of the Facility within sixty (60) days of the demand; provided, however, that such demand shall be coordinated with the QF so that the sixty (60) day period for re-demonstration period avoids, if practical, previously notified periods of planned outages and reduction in capacity pursuant to Article V.

7.5 During a Force Majeure Event declared by the QF, the QF may temporarily redesignate the Committed Capacity for up to twenty-four (24) consecutive months; provided, however, that no more than one such temporary redesignation may be made within any twenty-four (24) month period unless otherwise agreed by the Company in writing. Within three (3) months after such Force Majeure Event is cured, the QF may, on one occasion, without penalty, designate a new Committed Capacity to apply for the remaining Term. Any temporary or final redesignation of the Committed Capacity pursuant to this section 7.5 must, in the Company's judgment, be directly attributable to the Force Majeure Event and of a magnitude commensurate with the scope of the Force Majeure Event.

ARTICLE VIII: CAPACITY PAYMENTS

8.1 Capacity payments shall not commence before the Contract In-Service Date and until the QF has achieved Commercial In-Service Status.

8.2 Capacity payments shall be based upon the following selections as described in Appendix C.

8.2.1 Payment options:
( ) Value of deferral payments
(X) Early payments
( ) Levelized payments
( ) Early levelized payments

8.2.2 If an early payment option is selected pursuant to section 8.2.1, then early payments shall not commence more than three (3) years prior to the Contract In-Service Date for the unit. For the selected early payment option, the early payments shall commence __2__ ( ) years prior to the Contract In-Service Date. (As provided in columns 5, 6, and 7 of page 2, Schedule 3, Appendix C.)

8.3 At the end of each billing month, beginning with the first full month following the Contract In-Service Date, the Company will calculate the rolling average On-Peak Capacity Factor for the most recent twelve (12) month period, including such month, or for the actual number of full months since the Contract In-Service Date if less than twelve (12) months, based on the On-Peak Hours defined in Appendix C. The On-Peak Capacity Factor shall be calculated as the electric energy actually received by the Company at the Point of Delivery during the On-Peak Hours of the applicable period divided by the product of the Committed Capacity and the number of On-Peak Hours during the applicable period. In calculating the On-Peak Capacity Factor, the Company shall exclude hours and electric energy delivered by the QF during periods in which: (i) the Company does not or cannot perform its obligations to receive all the electric energy which the QF has made available at the Point of Delivery; or (ii) the QF's payments for electric energy are being calculated pursuant to section 9.1.1 hereof.

8.4 At the end of each billing month, beginning with the first full month following the Contract In-Service Date, the Company will calculate the rolling average Total Capacity Factor for the most recent twelve (12) month period, including such month, or for the actual number of full months since the Contract In-Service Date if less than twelve (12) months. The Total Capacity Factor shall be calculated as the electric energy actually received by the Company during the hours of the applicable period divided by the product of the Committed Capacity and the number of hours during the applicable period. In calculating the Total Capacity Factor, the Company shall exclude hours and electric energy delivered by the QF during periods in which: (i) the Company does not or cannot perform its obligations to receive all electric energy which the QF has made available at the Point of Delivery; or (ii) the QF's payments for electric energy are being calculated pursuant to section 9.1.1 hereof.

8.5 The QF will be eligible for a capacity payment in any month that the Total Capacity Factor exceeds the Minimum Total Capacity Factor. The monthly capacity payment shall be equal to the product of (i) the applicable capacity payment rate; (ii) the Committed Capacity; (iii) the Capacity Payment Adjustment; and (iv) the ratio of the total number of hours in the billing period less the number of hours during which the QF is being paid for energy pursuant to section 9.1.1 to the total number of hours in the billing period.

8.6 The Parties recognize that early or early levelized capacity payments are in the nature of "early payment" for a future capacity benefit to the Company when such payments exceed value of deferral capacity payments. To ensure that the Company will receive a capacity benefit for such difference in capacity payments which have been made, or alternatively, that the QF will repay the amount of such difference in payments received to the extent the capacity benefit has not been conferred, the following provisions will apply:

8.6.1 When the QF is first entitled to a capacity payment, the Company shall establish a Capacity Account. Each month the Capacity Account shall be credited in the amount of the Company's capacity payments made to the QF pursuant to the early or levelized payment options and shall be debited in the amount which the Company would have paid for capacity in the month pursuant to the value of deferral payment option.

8.6.2 The monthly balance in the Capacity Account shall accrue interest at the annual rate of 9.96%, or 0.7944% per month.

8.6.3 The QF shall owe the Company and be liable for the credit balance in the Capacity Account. The Company agrees to notify QF monthly as to the current Capacity Account balance. Prior to receipt of accelerated capacity payments the QF shall in the form of: (i) an unconditional and irrevocable direct pay letter of credit; (ii) surety bond; (iii) other form of acceptable security; or (iv) other promise to repay such amount, (for governmental solid waste), in compliance with rule 25-17.091 F.A.C.; provided that the entity issuing such promise, the form of the promise, and the means of securing payment shall be acceptable to the Company in its sole discretion.

8.6.4 The QF's obligation to pay the credit balance in the Capacity Account shall survive termination or expiration of this Agreement.

ARTICLE IX: ENERGY PAYMENTS

9.1 For that electric energy received by the Company at the Point of Delivery each month, the Company will pay the QF an amount computed as follows:

9.1.1 Prior to the Contract In-Service Date and for the duration of an Event of Default or a Force Majeure Event declared by the QF prior to a permitted redesignation of the Committed Capacity by the QF, the QF will receive electric energy payments based on the Company's actual avoided energy costs as calculated hourly in accordance with FPSC Rule 25-17.0825; provided, however, that the calculation shall be based on such rule as it may be amended from time to time.

9.1.2 Except as otherwise provided in section 9.1.1 hereof, for each billing month beginning with the first full month following the Contract In-Service Date, the QF will receive electric energy payments calculated on an hour-by-hour basis as follows: (i) the product of the average monthly inventory chargeout price of fuel burned at the Avoided Unit Reference Plant and the Avoided Unit Heat Rate, plus the Avoided Unit Variable O & M for each hour that the Company would have had a unit with these characteristics operating; and (ii) during all other hours, the Company's actual avoided energy cost calculated in accordance with section 9.1.1.

9.1.3 Energy payments shall be equal to the sum, over all hours of the month, of the product of each hour's energy cost as determined pursuant to section 9.1.1 hereof or section 9.1.2 hereof, whichever is applicable, and the energy received by the Company at the Point of Delivery, plus the Performance

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Adjustment, if applicable. The QF ( ) elects (X) does not elect the Performance Adjustment in Appendix C.

9.2 Energy payments pursuant to sections 9.1.1 and 9.1.2 hereof shall be subject to the delivery voltage adjustment value applicable to the Facility and approved from time to time by the FPSC pursuant to Appendix C.

ARTICLE X: CREDITS & CHARGES TO THE QF

10.1 The Company shall bill and the QF shall pay or receive all charges applicable under this Agreement.

10.2 To the extent not otherwise included in the charges under section 10.1 hereof, the Company shall bill and the QF shall pay or receive a monthly charge or credit equal to any taxes, assessments or other impositions for which the Company may be liable or relieved of as a result of its installation of facilities in connection with this Agreement, its purchases of Committed Capacity and electric energy from the QF or any other activity undertaken pursuant to this Agreement. Such debit or credit shall not include any amounts; (i) for which the Company would have been liable or relieved of had it generated or purchased from other sources an equivalent amount of Committed Capacity and electric energy based on normal value of deferral payments; or (ii) which are recovered or later paid by the Company.

10.3 The QF will receive a debit or a credit equal to the difference between the way the system would have operated utilizing the avoided unit and the way the system actually operated with the QF. The value of the emission credits or debits received by the QF will be the value at the time that the credits or debits were incurred by the Company. In order to be eligible for a credit for sulfur dioxide emission reductions the energy provided by the QF must be of equal value in reducing system-wide sulfur dioxide emissions as the energy that would have been provided by the avoided unit.

ARTICLE XI: METERING

11.1 All electric energy delivered to the Company shall be capable of being measured hourly at the Point of Metering. All electric energy delivered to the Company shall be adjusted for losses from the Point of Metering to the Point of Delivery. Any additional required metering equipment to measure electric energy and the telemetering equipment necessary to transmit such measurements to a location specified by the Company shall be installed, calibrated and maintained by the Company or the Transmission Service Utility, if applicable, and all related costs shall be charged to the QF, pursuant to Appendix A, as part of the Company's Interconnection Facilities.

11.2 All meter testing and related billing corrections, for electricity sold and purchased by the Company, shall conform to the metering and billing guidelines contained in FPSC Rules 25-6.052 through 25-6.060 and FPSC Rule 25-6.103, as they may be amended from time to time, notwithstanding that such guidelines apply to the utility as the seller of electricity.

11.3 The QF shall have the right to install, at its own expense, metering equipment capable of measuring energy on an hourly basis at the Point of Metering. At the request of the QF, the Company shall provide the QF hourly energy cost data from the Company's systems; provided that the QF agrees to reimburse the Company for its cost to provide such data.

ARTICLE XII: PAYMENT PROCEDURE

12.1 Bills shall be issued and payments shall be made monthly to the QF and by the QF in accordance with the following procedures:

12.1.1 The capacity payment, if any, calculated for a given month pursuant to Article VIII hereof shall be added to the electric energy payment, if any, calculated for such month pursuant to Article IX hereof. The resulting amount, if any, shall be tendered, with cost tabulations showing the basis for payment, by the Company to the QF as a single payment. Such payments to the QF shall be due and payable twenty (20) business days following the date the meters are read.

12.1.2 When any amount is owing from the QF, the Company shall issue a monthly bill to the QF with cost tabulations showing the basis for the charges. All amounts owing to the Company from the QF shall be due and payable twenty (20) business days after the date of the Company's billing statement. Amounts owing to the Company for retail electric service shall be payable in accordance with the provisions of the applicable rate schedule.

12.1.3 At the option of the QF, the Company will provide a net payment or net bill, whichever is applicable, that consolidates amounts owing to the QF with amounts owing to the Company.

12.1.4 Except for charges for retail electric service, any amount due and payable from either Party to the other pursuant to this Agreement that is not received by the due date shall accrue interest from the due date at the rate specified in section 13.2 hereof.

ARTICLE XIII: SECURITY GUARANTIES

13.1 Within sixty (60) days after the Execution Date of this Agreement, the QF shall post a Security Guaranty with the Company equal to $10.00 per KW of Committed Capacity to ensure completion of the Facility in a timely fashion as contemplated by this Agreement. This Agreement shall terminate if the Security Guaranty is not tendered on or before the applicable due date specified herein. The QF shall either: (i) pay the Company a cash deposit in an amount equal to the Security Guaranty; or (ii) provide the Company an unconditional and irrevocable direct pay letter of credit or (iii) surety bond; or (iv) other promise to pay such amount, (for governmental solid waste facility), in compliance with rule 25-17.091 F.A.C. upon failure of the QF to perform its obligations under this Agreement; provided that the entity issuing such promise, the form of the promise, and the means of securing payment all shall be acceptable to the Company in its sole discretion.

13.2 A Security Guaranty paid to the Company shall accrue interest at a rate equal to the thirty (30) day highest grade commercial paper rate as published in the Wall Street Journal on the first business day of each month. Such interest shall be compounded monthly.

13.3 If the Facility achieves Commercial In-Service Status on or before the Contract In-Service Date, the Company shall refund to the QF any cash Security Guaranty paid to the Company and accrued interest within thirty (30) days thereafter or shall cancel any other form of Security Guaranty which the Company has accepted in lieu of a cash deposit. If this Agreement is terminated pursuant to section 15.2, the QF shall immediately forfeit and the Company, in lieu of any other remedies, shall retain the monies associated with any Security Guaranty made by the QF pursuant to section 13.1 and the interest, if applicable, pursuant to section 13.2.

ARTICLE XIV: REPRESENTATIONS, WARRANTIES AND COVENANTS

14.1 The QF makes the following additional representations, warranties and covenants as the basis for the benefits and obligations contained in this Agreement:

14.1.1 The QF represents and warrants that it is a corporation, partnership or other business entity duly organized, validly existing and in good standing under the laws of the State/Commonwealth of Delaware and is qualified to do business under the laws of the State of Florida.

14.1.2 The QF represents, covenants and warrants that, to the best of the QF's knowledge, throughout the Term of this Agreement the QF will be in compliance with, or will have acted in good faith and used its best efforts to be in compliance with, all laws, judicial and administrative orders, rules and regulations, with respect to the ownership and operation of the Facility, including but not limited to applicable certificates, licenses, permits and governmental approvals; environmental impact analyses, and, if applicable, the mitigation of environmental impacts.

14.1.3 The QF represents and warrants that it is not prohibited by any law or contract from entering into this Agreement and discharging and performing all covenants and obligations on its part to be performed pursuant to this Agreement.

14.1.4 The QF represents and warrants that there is no pending or threatened action or proceeding affecting the QF before any court, governmental agency or arbitrator that could reasonably be expected to affect materially and adversely the ability of the QF to perform its obligations hereunder, or which purports to affect the legality, validity or enforceability of this Agreement.

14.2 All representations and warranties made by the QF in or under this Agreement shall survive the execution and delivery of this Agreement and any action taken pursuant hereto.

ARTICLE XV: EVENTS OF DEFAULT; REMEDIES

15.1 PRE-OPERATIONAL EVENTS OF DEFAULT

Any one or more of the following events occurring before the Contract In-Service Date for any reason, except events caused by the Company, shall constitute a Pre-Operational Event of Default and shall give the Company the right, without limitation, to exercise the remedies specified under section 15.2 hereof:

15.1.1 The QF, without a prior assignment permitted pursuant to Article XXII hereof, becomes insolvent, becomes subject to bankruptcy or receivership proceedings, or dissolves as a legal business entity.

15.1.2 Any representation or warranty furnished by the QF to the Company is false or misleading in any material respect when made and the QF fails to conform to said representation or warranty within sixty (60) days after a demand by the Company to do so.

15.1.3 The QF has not entered into the Transmission Service Agreement, if applicable, which has been approved or accepted for filing by the FERC on or before the date specified in Article IV hereof, as extended only pursuant to said Article IV.

15.1.4 The Construction Commencement Date has not occurred on or before the date specified in Article IV hereof, as extended only pursuant to said Article IV.

15.1.5 The QF fails to diligently pursue construction of the Facility after the Construction Commencement Date.

15.1.6 The Facility fails to achieve Commercial In-Service Status on or before the Contract In-Service Date.

15.1.7 The QF fails to comply with any other material terms and conditions of this Agreement and fails to conform to said term and condition within sixty (60) days after a demand by the Company to do so.

15.2 REMEDIES FOR PRE-OPERATIONAL EVENTS OF DEFAULT

For any Pre-Operational Event of Default specified under section 15.1 hereof, the Company may terminate this Agreement and retain the Security Guaranty pursuant to section 13.3.

15.3 OPERATIONAL EVENTS OF DEFAULT

Any one or more of the following events except events caused by Force Majeure Events unless otherwise stated, occurring on or after the Contract In-Service Date shall constitute an Operational Event of Default by the QF and shall give the Company the right, without limitation, to exercise the remedies under section 15.4 hereof:

15.3.1 The QF fails upon request by the Company pursuant to section 7.4 hereof to re-demonstrate the Facility's Commercial In-Service Status to the satisfaction of the Company.

15.3.2 The QF fails for any reason, including Force Majeure Events, to qualify for capacity payments under Article VIII hereof for any consecutive twenty-four (24) month period.

15.3.3 The QF fails to perform or comply with any other material terms and conditions of this Agreement and fails to conform to said term and condition within sixty (60) days after a demand by the Company to do so.

15.3.4 The QF, without a prior assignment permitted pursuant to Article XXII hereof, becomes insolvent, becomes subject to bankruptcy or receivership proceedings, or dissolves as a legal business entity.

15.4 REMEDIES FOR OPERATIONAL EVENTS OF DEFAULT

For any Operational Event of Default specified under section 15.3 hereof, the Company may, without an election of remedies to the exclusion of other remedies, take any of the following actions:

15.4.1 Allow the QF a reasonable opportunity to cure the Operational Event of Default and suspend its capacity payment obligations upon written notice whereupon the QF shall be entitled only to energy payments calculated pursuant to section 9.1.1 hereof. Thereafter, if the Operational Event of Default is cured: (i) capacity payments shall resume and subsequent energy payments shall be paid pursuant to section 9.1.2 hereof; and (ii) the On-Peak Capacity Factor and the Total Capacity Factor shall be calculated on the assumption that the first full month after the Operational Event of Default is cured is the first month that the performance criteria are imposed.

15.4.2 Terminate this Agreement.

15.4.3 Exercise all remedies available at law or in equity.

ARTICLE XVI: PERMITS

The QF hereby agrees to seek to obtain, at its sole expense, any and all governmental permits, certificates, or other authorization the QF is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement. The Company hereby agrees, at the QF's expense, to seek to obtain any and all governmental permits, certificates, or other authorization the Company is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement.

ARTICLE XVII: INDEMNIFICATION

The QF agrees to indemnify and save harmless the Company and its employees, officers, and directors against any and all liability, loss, damage, costs or expense which the Company, its employees, officers and directors may hereafter incur, suffer or be required to pay by reason of negligence on the part of the QF in performing its obligations pursuant to this Agreement or the QF's failure to abide by the provisions of this Agreement. The Company agrees to indemnify and save harmless the QF and its employees, officers, and directors against any and all liability, loss, damage, cost or expense which the QF, its employees, officers, and directors may hereafter incur, suffer, or be required to pay by reason of negligence on the part of the Company in performing its obligations pursuant to this Agreement or the Company's failure to abide by the provisions of this Agreement. The QF agrees to include the Company as an additional insured in any liability insurance policy or policies the QF obtains to protect the QF's interests with respect to the QF's indemnity and hold harmless assurance to the Company contained in Article XVII.

ARTICLE XVIII: EXCLUSION OF INCIDENTAL, CONSEQUENTIAL, AND INDIRECT DAMAGES

Neither Party shall be liable to the other for incidental, consequential or indirect damages, including, but not limited to, the cost of replacement capacity and energy, whether arising in contract, tort, or otherwise.

ARTICLE XIX: INSURANCE

The provisions of this Article does not apply to a QF whose Facility is not directly interconnected with the Company's system.

19.1 In addition to other insurance carried by the QF in accordance with the Agreement, the QF shall deliver to the Company, at least fifteen (15) days prior to the commencement of any work on the Company's Interconnection Facilities, a certificate of insurance certifying the QF's coverage under a liability insurance policy issued by a reputable insurance company authorized to do business in the State of Florida naming the QF as a named insured and the Company as an additional named insured, which policy shall contain a broad form contractual endorsement specifically covering liabilities arising out of the interconnection with the Facility, or caused by the operation of the Facility or by the QF's failure to maintain the Facility in satisfactory and safe operating condition.

19.2 The insurance policy providing such coverage shall provide public liability insurance, including property damage, in an amount not less than $1,000,000 for each occurrence which can be exceeded by the QF. The required insurance policy shall be endorsed with a provision requiring the insurance company to notify the Company at least thirty (30) days prior the effective date of any cancellation or material change in the policy.

19.3 The QF shall pay all premiums and other charges due on said insurance policy and shall keep said policy in force during the entire period of interconnection with the Company.

ARTICLE XX: FORCE MAJEURE

20.1 If either Party because of Force Majeure Event is rendered wholly or partly unable to perform its obligations under this Agreement, other than the obligation of that Party to make payments of money, that Party shall, except as otherwise provided in this Agreement, be excused from whatever performance is affected by the Force Majeure Event to the extent so affected, provided that:

20.1.1 The non-performing Party, as soon as possible after it becomes aware of its inability to perform, shall declare a Force Majeure Event and give the other Party written notice of the particulars of the occurrence(s), including without limitation, the nature, cause, and date and time of commencement of the occurrence(s), the anticipated scope and duration of any delay, and any date(s) that may be affected thereby.

20.1.2 The suspension of performance is of no greater scope and of no longer duration than is required by the Force Majeure Event.

20.1.3 Obligations of either Party which arose before the occurrence causing the suspension of performance are not excused as a result of the occurrence.

20.1.4 The non-performing Party uses its best efforts to remedy its inability to perform with all reasonable dispatch;

provided, however, that nothing contained herein shall require the settlement of any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the affected Party, are contrary to its interests. It is understood and agreed that the settlement of strikes, walkouts, lockouts or other labor disputes shall be entirely within the discretion of the affected Party.

20.1.5 When the non-performing Party is able to resume performance of its obligations under this Agreement, that Party shall so notify the other Party in writing.

20.2 Unless and until the QF temporarily redesignates the Committed Capacity pursuant to section 7.5 hereof, no capacity payment obligation pursuant to Article VII hereof shall accrue during any period of a declared Force Majeure Event pursuant to section 20.1.1 through 20.1.5. During any such period, the Company will pay for such energy as may be received and accepted pursuant to section 9.1.1 hereof.

20.3 If the QF temporarily or permanently redesignates the Committed Capacity pursuant to section 7.5 hereof, then capacity payment obligations shall thereafter resume at the applicable redesignated level and the Company will resume energy payments pursuant to section 9.1.2 hereof.

ARTICLE XXI: FACILITY RESPONSIBILITY AND ACCESS

21.1 Representatives of the Company shall at all reasonable times have access to the Facility and to property owned or controlled by the QF for the purpose of inspecting, testing, and obtaining other technical information deemed necessary by the Company in connection with this Agreement. Any inspections or testing by the Company shall not relieve the QF of its obligation to maintain the Facility.

21.2 In no event shall any Company statement, representation, or lack thereof, either express or implied, relieve the QF of its exclusive responsibility for the Facility and its exclusive obligations, if applicable, with the Transmission Service Utility. Any Company inspection of property or equipment owned or controlled by the QF or the Transmission Service Utility, or any Company review of or consent to the QF's or the Transmission Service Utility's plans, shall not be construed as endorsing the design, fitness or operation of the Facility or the Transmission Service Utility's equipment nor as a warranty or guarantee.

21.3 The QF shall reactivate the Facility and shall arrange for the Transmission Service Utility's delivery of electric energy to the Point of Delivery at its own expense if either the Facility or the equipment of the Transmission Service Utility is rendered inoperable due to actions of the QF or its agents, or a Force Majeure Event. The Company shall reactivate the Company's Interconnection Facilities at its own expense if the same are rendered inoperable due to actions of the Company or its agents, or a Force Majeure Event.

ARTICLE XXII: SUCCESSORS AND ASSIGNS

Neither Party shall have the right to assign its obligations, benefits, and duties without the consent of the other Party, which shall not be unreasonably withheld or delayed.

ARTICLE XXIII: DISCLAIMER

In executing this Agreement, the Company does not, nor should it be construed to, extend its credit or financial support for the benefit of any third parties lending money to or having other transactions with the QF or any assignee of this Agreement, nor does it create any third party beneficiary rights. Nothing contained in this Agreement shall be construed to create an association, trust, partnership, or joint venture between the Parties. No payment by the

Company to the QF for energy or capacity shall be construed as payment by the Company for the acquisition of any ownership or property interest in the Facility.

ARTICLE XXIV: WAIVERS

The failure of either Party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights under this Agreement shall not be construed as a general waiver of any such provision or the relinquishment of any such right, but the same shall continue and remain in full force and effect, except with respect to the particular instance or instances.

ARTICLE XXV: COMPLETE AGREEMENT

The terms and provisions contained in this Agreement constitute the entire agreement between the Parties and shall supersede all previous communications, representations, or agreements, either verbal or written, between the Parties with respect to the Facility and this Agreement.

ARTICLE XXVI: COUNTERPARTS

This Agreement may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

ARTICLE XXVII: COMMUNICATIONS

27.1 Any non-emergency or operational notice, request, consent, payment or other communication made pursuant to this Agreement to be given by one Party to the other Party shall be in writing, either personally delivered or mailed to the representative of said other Party designated in this section, and shall be deemed to be given when received. Notices and other communications by the Company to the QF shall be addressed to:

Panda-Kathleen L.P.
4100 Spring Valley
Suite 1001
Dallas, TX 75244

Notices to the Company shall be addressed to:

Florida Power Corporation
P. O. Box 14042
St. Petersburg, FL 33733

27.2 Communications made for emergency or operational reasons may be made to the following persons and shall thereafter be confirmed promptly in writing.

To The Company: System Dispatcher on Duty
Title: System Dispatcher
Telephone: (813)866-5888
Telecopier: (813)384-7865

To The QF: Name Hans R. van Kuilenburg
Title: President
Telephone: (214) 980-7159
Telecopier: (214) 980-6815

27.3 Either Party may change its representatives in sections 28.1 or 28.2 by prior written notice to the other Party.

27.4 The Parties' representatives designated above shall have full authority to act for their respective principals in all technical matters relating to the performance of this Agreement. However, they shall not have the authority to amend, modify, or waive any provision of this Agreement.

ARTICLE XXVIII: SECTION HEADINGS FOR CONVENIENCE

Article or section headings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of text.

ARTICLE XXIX: GOVERNING LAW

The interpretation and performance of this Agreement and each of its provisions shall be governed by the laws of the State of Florida.

IN WITNESS WHEREOF, the QF and the Company have caused this Agreement to be executed by their duly authorized representatives on the day and year first above written.

The Qualifying Facility:
Panda-Kathleen L.P.

By: PANDA-KATHLEEN CORPORATION

Title: Robert W. Carter

Robert Carter, Chairman

Date: 10-4-91

ATTEST:

The Company:

By:

Title: PETER DAGOSTINO

VICE-PRESIDENT

Date: 11-25-91

ATTEST:

FLORIDA POWER CORP.
LEGAL DEPT.
APPROVED
Date 11/25/91
By

ISSUED BY: S. F. Nixon, Jr., Director Rate Department
EFFECTIVE: September 20, 1991

APPENDIX A

INTERCONNECTION SCHEDULING AND COST RESPONSIBILITY

1.0 Purpose.

This appendix provides the procedures for the scheduling of construction for the Company's Interconnection Facilities as well as the cost responsibility of the QF for the payment of Interconnection Costs. This appendix applies to all QF's, whether or not their Facility will be directly interconnected with the Company's system. All requirements contained herein shall apply in addition to and not in lieu of the provisions of the Agreement.

2.0 Submission of Plans and Development of Interconnection Schedules and Cost Estimates.

2.1 No later than sixty (60) days after the Execution Date, the QF shall specify the date it desires the Company's Interconnection Facilities to be available for receipt of the electric energy and shall provide a preliminary written description of the Facility and, if applicable, the QF's anticipated arrangements with the Transmission Service Utility, including without limitation, a one-line diagram, anticipated Facility site data and any additional facilities anticipated to be needed by the Transmission Service Utility. Based upon the information provided, the Company shall develop preliminary written Interconnection Costs and scheduling estimates for the Company's Interconnection Facilities within sixty (60) days after the information is provided. The schedule developed hereunder will indicate when the QF's final electrical plans must be submitted to the Company pursuant to section 2.2 hereof.

2.2 The QF shall submit the Facility's final electrical plans and all revisions to the information previously submitted under section 2.1 hereof to the Company no later than the date specified under section 2.1 hereof, unless such date is modified in the Company's reasonable discretion. Based upon the information provided and within sixty (60) days after the information is provided, the Company shall update its written Interconnection Costs and schedule estimates, provide the estimated time period required for construction of the Company's Interconnection Facilities, and specify the date by which the Company must receive notice from the QF to initiate construction, which date shall, to the extent practical, be consistent with the QF's schedule for delivery of energy into the Company's system. The final electrical plans shall include the following information, unless all or a portion of such information is waived by the Company in its discretion:

a. Physical layout drawings, including dimensions;
b. All associated equipment specifications and characteristics including technical parameters, ratings, basic impulse levels, electrical main one-line diagrams, schematic diagrams, system protections, frequency, voltage, current and interconnection distance;
c. Functional and logic diagrams, control and meter diagrams, conductor sizes and length, and any other relevant data which might be necessary to understand the Facility's proposed system and to be able to make a coordinated system;
d. Power requirements in watts and vars;
e. Expected radio-noise, harmonic generation and telephone interference factor;
f. Synchronizing methods; and
g. Facility operating/instruction manuals.
h. If applicable, a detailed description of the facilities to be utilized by the Transmission Service Utility to deliver energy to the Point of Delivery.

2.3 Any subsequent change in the final electrical plans shall be submitted to the Company and it is understood and agreed that any such changes may affect the Company's schedules and Interconnection Costs as previously estimated.

2.4 The QF shall pay the actual costs incurred by the Company to develop all estimates pursuant to section 2.1 and 2.2 hereof and to evaluate any changes proposed by the QF under section 2.3 hereof, as such costs are billed pursuant to Article XII of the Agreement. At the Company's option, advance payment for these cost estimates may be required, in which event the Company will issue an adjusted bill reflecting actual costs following completion of the cost estimates.

2.5 The Parties agree that any cost or scheduling estimates provided by the Company hereunder shall be prepared in good faith but shall not be binding. The Company may modify such schedules as necessary to accommodate contingencies that affect the Company's ability to initiate or complete the Company's Interconnection Facilities and actual costs will be used as the basis for all final charges hereunder.

3.0 Payment Obligations for Interconnection Costs.

3.1 The Company shall have no obligation to initiate construction of the Company's Interconnection Facilities prior to a written notice from the QF agreeing to the Company's interconnection design requirements and notifying the Company to initiate its activities to construct the Company's Interconnection Facilities; provided, however, that such notice shall be received not later than the date specified by the Company under section 2.2 hereof. The QF shall be liable for and agrees to pay all Interconnection Costs incurred by the Company on or after the specified date for initiation of construction.

ISSUE BY: S. F. Nixon, Jr., Director Rate Department
EFFECTIVE: September 20, 1991

3.2 The QF agrees to pay all of the Company's actual Interconnection Costs as such costs are incurred and billed in accordance with Article XII of the Agreement. Such amounts shall be billed pursuant to section 3.2.1 if the QF elects the payment option permitted by FPSC Rule 25-17.087(4). Otherwise the QF shall be billed pursuant to section 3.2.2.

3.2.1 Upon a showing of credit worthiness, the QF shall have the option of making monthly installment payments for Interconnection Costs over a period no longer than thirty six (36) months. The period selected is 36 months. Principal payments will be based on the estimated Interconnection Costs less the Interconnection Costs Offset, divided by the repayment period in months to determine the monthly principal payment. Payments will be invoiced in the first month following first incurrence of Interconnection Costs by the Company. Invoices to the QF will include principal payments plus interest on the unpaid balance, if any, calculated at a rate equal to the thirty (30) day highest grade commercial paper rate as published in the Wall Street Journal on the first business day of each month. The final payment or payments will be adjusted to cause the sum of principal payments to equal the actual Interconnection Costs.

3.2.2 When Interconnection Costs are incurred by the Company, such costs will be billed to the QF to the extent that they exceed the Interconnection Costs Offset.

3.3 If the QF notifies the Company in writing to interrupt or cease interconnection work at any time and for any reason, the QF shall nonetheless be obligated to pay the Company for all costs incurred in connection with the Company's Interconnection Facilities through the date of such notification and for all additional costs for which the Company is responsible pursuant to binding contracts with third parties.

4.0 <u>Payment Obligations for Operation, Maintenance and Repair of the Company's Interconnection Facilities</u>

The QF also agrees to pay monthly through the Term of the Agreement for all costs associated with the operation, maintenance and repair of the Company's Interconnection Facilities, based on a percentage of the total Interconnection Costs net of the Interconnection Costs Offset, as set forth in Appendix C.

APPENDIX B

PARALLEL OPERATING PROCEDURES

1.0 Purpose

This appendix provides general operating, testing, and inspection procedures intended to promote the safe parallel operation of the Facility with the Company's system. All requirements contained herein shall apply in addition to and not in lieu of the provisions of the Agreement.

2.0 Schematic Diagram

Exhibit B-1, attached hereto and made a part hereof, is a schematic diagram showing the major circuit components connecting the Facility and the Company's [substation] and showing the Point of Delivery and the Point of Metering and/or Point of Ownership, if different. All switch number designations initially left blank on Exhibit B-1 will be inserted by the Company on or before the date on which the Facility first operates in parallel with the Company's system.

3.0 Operating Standards

3.1 The QF and the Company will independently provide for the safe operation of their respective facilities, including periods during which the other Party's facilities are unexpectedly energized or de-energized.

3.2 The QF shall reduce, curtail, or interrupt electrical generation or take other appropriate action for so long as it is reasonably necessary, which in the judgment of the QF or the Company may be necessary to operate and maintain a part of either Party's system, to address, if applicable, an emergency on either Party's system.

3.3 As provided in the Agreement, the QF shall not operate the Facility's electric generation equipment in parallel with the Company's system without prior written consent of the Company. Such consent shall not be given until the QF has satisfied all criteria under the Agreement and has:

(i) submitted to and received consent from the Company of its as-built electrical specifications;

(ii) demonstrated to the Company's satisfaction that the Facility is in compliance with the insurance requirements of the Agreement; and

(iii) demonstrated to the Company's satisfaction that the Facility is in compliance with all regulations, rules, orders, or decisions of any governmental or regulatory authority having jurisdiction over the Facility's generating equipment or the operation of such equipment.

3.4 After any approved Facility modifications are completed, the QF shall not resume parallel operation with the Company's system until the QF has demonstrated that it is in compliance with all the requirements of section 4.2 hereof.

3.5 The QF shall be responsible for coordination and synchronization of the Facility's equipment with the Company's electrical system, and assumes all responsibility for damage that may occur from improper coordination or synchronization of the generator with the utility's system.

3.6 The Company shall have the right to open and lock, with a Company padlock, manual disconnect switch numbers(s)__________ and isolate the Facility's generation system without prior notice to the QF. To the extend practicable, however, prior notice shall be given. Any of the following conditions shall be cause for disconnection:

1. Company system emergencies and/or maintenance repair and construction requirements;
2. hazardous conditions existing on the Facility's generating or protective equipment as determined by the Company;
3. adverse effects of the Facility's generation to the Company's other electric consumers and/or system as determined by the Company;
4. failure of the QF to maintain any required insurance; or
5. failure of the QF to comply with any existing or future regulations, rules, orders or decisions of any governmental or regulatory authority having jurisdiction over the Facility's electric generating equipment or the operation of such equipment.

3.7 The Facility's electric generation equipment shall not be operated in parallel with the Company's system when auxiliary power is being provided from a source other than the Facility's electric generation equipment.

3.8 Neither Party shall operate switching devices owned by the other Party, except that the Company may open the manual disconnect switch(s) number(s)________ owned by the QF pursuant to section 3.6 hereof.

3.9 Should one Party desire to change the operating position of a switching device owned by the other Party, the following procedures shall be followed:

(i) The Party requesting the switching change shall orally agree with an authorized representative of the other Party regarding which switch or switches are to be operated, the requested position of each switching device, and when each switch is to be operated.

(ii) The Party performing the requested switching shall notify the requesting Party when the requested switching change has been completed.

(iii) Neither Party shall rely solely on the other party's switching device to provide electrical isolation necessary for personnel safety. Each Party will perform work on its side of the Point of Ownership as if its facilities are energized or test for voltage and install grounds prior to beginning work.

(iv) Each Party shall be responsible for returning its facilities to approved operating conditions, including removal of grounds, prior to the Company authorizing the restoration of parallel operation.

(v) The Company shall install one or more red tags similar to the red tag shown in Exhibit B-2 attached hereto and made a part hereof, on all open switches. Only Company personnel on the Company's switching and tagging list shall remove and/or close any switch bearing a Company red tag under any circumstances.

3.10 Should any essential protective equipment fail or be removed from service for maintenance or construction requirements, the Facility's electric generation equipment shall be disconnected from the Company's system. To accomplish this disconnection, the QF shall either (i) open the generator breaker number(s) ______; or (ii) open the manual disconnect switch number(s) ______.

3.10.1 If the QF elects option (i), the breaker assembly shall be opened and drawn out by QF personnel. As promptly as practicable, Company personnel shall install a Company padlock and a red tag on the breaker enclosure door.

3.10.2 If the QF elects option (ii), the switch shall be opened by QF personnel or by Company personnel and, as promptly as practicable, Company personnel will install a Company padlock and a red tag.

4.0 Inspection and Testing

4.1 The inspection and testing of all electrical relays governing the operation of the generator's circuit breaker shall be performed in accordance with manufacturer's recommendations, but in no case less than once every 12 months. This inspection and testing shall include, but not be limited to, the following:

(i) electrical checks on all relays and verification of settings electrically;

(ii) cleaning of all contacts;

(iii) complete testing of tripping mechanisms for correct operating sequence and proper time intervals; and

(iv) visual inspection of the general condition of the relays.

4.2 In the event that any essential relay or protective equipment is found to be inoperative or in need of repair, the QF shall notify the Company of the problem and cease parallel operation of the generator until repairs or replacements have been made. The QF shall be responsible for maintaining records of all inspections and repairs and shall make said records available to the Company upon request.

4.3 The Company shall have the right to operate and test any of the Facility's protective equipment to assure accuracy and proper operation. This testing shall not relieve the QF of the responsibility to assure proper operation of its equipment and to perform routine maintenance and testing.

5.0 Notification

5.1 Communications made for emergency or operational reasons may be made to the following persons and shall thereafter be confirmed promptly in writing:

To The Company: System Dispatcher on Duty
Title: System Dispatcher
Telephone: (813)866-5888
Telecopier: (813)384-7865

To The QF: Name Panda-Kathleen L.P.
Title: Robert Carter Chairman
Telephone: (214)980-7159
Telecopier: (2140)980-6815

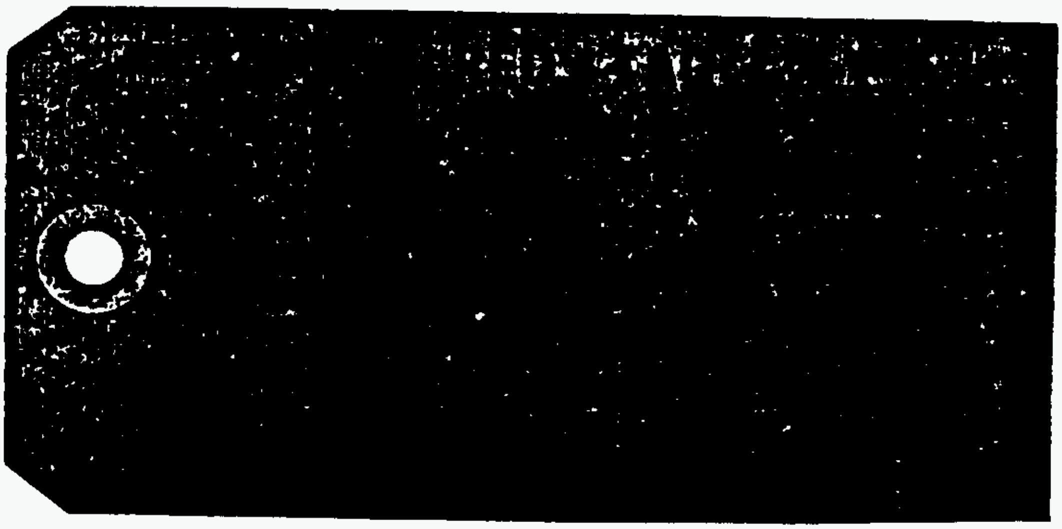
5.2 Each Party shall provide as much notification as practicable to the other Party regarding planned outages of equipment that may affect the other Party's operation.

EXHIBIT B-1

Exhibit B-1 will be unique for each Facility and must be complete prior to parallel operation with the Company.

EXHIBIT B-2

A switch or switch point (i.e., elbow, open jumpers, etc.) with a red tag attached is open and shall not be closed under any circumstances. After a switch has been red tagged, that switch cannot be closed until the red tag is removed. Red tags can only be removed when authorized by a specific written order.



ISSUED BY: S. F. Nixon, Jr., Director Rate Department
EFFECTIVE: September 20, 1991

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SCHEDULE 1
SUMMARY OF STANDARD OFFER AVAILABILITY

DESIGNATED AVOIDED UNIT	AVAILABLE CAPACITY MW	PAYMENT OPTION STARTING			
		NORMAL	EARLY	LEVELIZED	EARLY LEVELIZED
1997 Combustion Turbine	80	1997	1994-1996	1997	1994-1996

ISSUED BY: S. F. Nixon, Jr., Director Rate Department

EFFECTIVE DATE: September 20, 1991 -

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SCHEDULE 2
GENERAL INFORMATION FOR 1997 COMBUSTION TURBINE UNIT

GENERAL
YEAR OF AVOIDED UNIT = 1997
AVOIDED UNIT REFERENCE PLANT = BARTOW CT UNITS

INVESTMENT DATA
TOTAL COST, DIRECT + AFUDC, IN 1/91 $'s = $398.88/KW
ANNUAL ESCALATION RATE OF PLANT COSTS = 5.10%
ECONOMIC PLANT LIFE = 20 YEARS

OPERATING DATA
AVOIDED UNIT FIXED O&M COSTS IN 1/91 $'s = $6.18/KW/YR
AVOIDED UNIT VARIABLE O&M COSTS IN 1/91 $'s = $1.83/MWH
ANNUAL ESCALATION RATE OF O&M COSTS = 5.10%
MINIMUM ON-PEAK CAPACITY FACTOR = 90.0%
MINIMUM TOTAL CAPACITY FACTOR = 42.0%
SYSTEM VARIABLE O&M COSTS IN 1/91 $'s = $0.673/MWH
AVOIDED UNIT HEAT RATE = 11,610 BTU/KWH
TYPE OF FUEL = DISTILLATE

ON-PEAK HOURS
(1) FOR THE CALENDAR MONTHS OF NOVEMBER THROUGH MARCH,
ALL DAYS: 6:00 A.M. TO 12:00 NOON, AND
5:00 P.M. TO 10:00 P.M.
(2) FOR THE CALENDAR MONTHS OF APRIL THROUGH OCTOBER,
ALL DAYS: 11:00 A.M. TO 10:00 P.M.

FINANCIAL DATA
K FACTOR (MID YEAR) = 1.5259
UTILITY DISCOUNT RATE = 9.96%

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SCHEDULE 3
Payments for Avoided 1997 Combustion Turbine Unit

(1)	(2)	(3)	(4)
	CAPACITY PAYMENT - $/KW/MONTH		
CONTRACT	NORMAL PAYMENT OPTION		
YEAR	O&M	CAPITAL	TOTAL
1997	0.71	5.08	5.79
1998	0.75	5.33	6.08
1999	0.79	5.60	6.39
2000	0.83	5.89	6.72
2001	0.87	6.19	7.06
2002	0.91	6.51	7.42
2003	0.96	6.84	7.80
2004	1.01	7.19	8.20
2005	1.06	7.56	8.62
2006	1.11	7.95	9.06
2007	1.17	8.35	9.52
2008	1.23	8.78	10.01
2009	1.29	9.23	10.52
2010	1.36	9.69	11.05
2011	1.43	10.19	11.62
2012	1.50	10.71	12.21
2013	1.58	11.25	12.83
2014	1.66	11.83	13.49
2015	1.74	12.43	14.17
2016	1.83	13.07	14.90

NOTE:Above payments calculated in accordance with formulas set forth in FPSC Rule 25-17.0832(5). Payment shall be adjusted by multiplying factor for On-Peak Capacity Factor determined in Schedule 8.

ISSUED BY: S. F. Nixon, Jr., Director Rate Department

EFFECTIVE DATE: September 20, 1991

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SCHEDULE 3
Payments for Avoided 1997 Combustion Turbine Unit

CAPACITY PAYMENT - $/KW/MONTH

EARLY PAYMENT OPTION

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
CONTRACT	STARTING 1/96			STARTING 1/95			STARTING 1/94		
YEAR	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL
1994	-	-	-	-	-	-	0.49	3.52	4.01
1995	-	-	-	0.56	3.96	4.52	0.52	3.69	4.21
1996	0.63	4.48	5.11	0.58	4.17	4.75	0.54	3.89	4.43
1997	0.66	4.71	5.37	0.61	4.39	5.00	0.57	4.08	4.65
1998	0.69	4.96	5.65	0.65	4.60	5.25	0.60	4.29	4.89
1999	0.73	5.20	5.93	0.68	4.84	5.52	0.63	4.51	5.14
2000	0.77	5.47	6.24	0.71	5.09	5.80	0.66	4.74	5.40
2001	0.81	5.74	6.55	0.75	5.34	6.09	0.70	4.98	5.68
2002	0.85	6.04	6.89	0.79	5.62	6.41	0.73	5.24	5.97
2003	0.89	6.35	7.24	0.83	5.90	6.73	0.77	5.50	6.27
2004	0.94	6.67	7.61	0.87	6.21	7.08	0.81	5.78	6.59
2005	0.98	7.02	8.00	0.91	6.53	7.44	0.85	6.08	6.93
2006	1.03	7.38	8.41	0.96	6.86	7.82	0.90	6.38	7.28
2007	1.09	7.74	8.83	1.01	7.20	8.21	0.94	6.71	7.65
2008	1.14	8.14	9.28	1.06	7.57	8.63	0.99	7.05	8.04
2009	1.20	8.56	9.76	1.12	7.95	9.07	1.04	7.41	8.45
2010	1.26	9.00	10.26	1.17	8.37	9.54	1.09	7.79	8.88
2011	1.33	9.45	10.78	1.23	8.79	10.02	1.15	8.19	9.34
2012	1.39	9.94	11.33	1.30	9.23	10.53	1.21	8.60	9.81
2013	1.46	10.45	11.91	1.36	9.71	11.07	1.27	9.04	10.31
2014	1.54	10.97	12.51	1.43	10.21	11.64	1.33	9.51	10.84
2015	1.62	11.53	13.15	1.50	10.73	12.23	1.40	9.99	11.39
2016	1.70	12.12	13.82	1.58	11.27	12.85	1.47	10.50	11.97

NOTE: Above payments calculated in accordance with formulas set forth in FPSC Rule 25-17.0832(5). Payment shall be adjusted by multiplying factor for On-Peak Capacity Factor determined in Schedule 7.

APPENDIX C
RATES

SCHEDULE 3
Payments for Avoided 1997 Combustion Turbine Unit

(1)	(2)	(3)	(4)
	CAPACITY PAYMENT - $/KW/MONTH		
CONTRACT	LEVELIZED PAYMENT OPTION		
YEAR	O&M	CAPITAL	TOTAL
1997	0.71	7.28	7.99
1998	0.75	7.28	8.03
1999	0.79	7.28	8.07
2000	0.83	7.28	8.11
2001	0.87	7.28	8.15
2002	0.91	7.28	8.19
2003	0.96	7.28	8.24
2004	1.01	7.28	8.29
2005	1.06	7.28	8.34
2006	1.11	7.28	8.39
2007	1.17	7.28	8.45
2008	1.23	7.28	8.51
2009	1.29	7.28	8.57
2010	1.36	7.28	8.64
2011	1.43	7.28	8.71
2012	1.50	7.28	8.78
2013	1.58	7.28	8.86
2014	1.66	7.28	8.94
2015	1.74	7.28	9.02
2016	1.83	7.28	9.11

NOTE: Above payments calculated in accordance with formulas set forth in FPSC Rule 25-17.0832(5). Payment shall be adjusted by multiplying factor for On-Peak Capacity Factor determined in Schedule 7.

ISSUED BY: S. F. Nixon, Jr., Director Rate Department

EFFECTIVE DATE: September 20, 1991

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RATES

SCHEDULE 3
Payments for Avoided 1997 Combustion Turbine Unit

CAPACITY PAYMENT - $/KW/MONTH

EARLY LEVELIZED PAYMENT OPTION - $/KW/MONTH

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	STARTING 1/96			STARTING 1/95			STARTING 1/94		
CONTRACT YEAR	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL
1994	-	-	-	-	-	-	0.49	5.25	5.74
1995	-	-	-	0.56	5.84	6.40	0.52	5.25	5.77
1996	0.63	6.52	7.15	0.58	5.84	6.42	0.54	5.25	5.79
1997	0.66	6.52	7.18	0.61	5.84	6.45	0.57	5.25	5.82
1998	0.69	6.52	7.21	0.65	5.84	6.49	0.60	5.25	5.85
1999	0.73	6.52	7.25	0.68	5.84	6.52	0.63	5.25	5.88
2000	0.77	6.52	7.29	0.71	5.84	6.55	0.66	5.25	5.91
2001	0.81	6.52	7.33	0.75	5.84	6.59	0.70	5.25	5.95
2002	0.85	6.52	7.37	0.79	5.84	6.63	0.73	5.25	5.98
2003	0.89	6.52	7.41	0.83	5.84	6.67	0.77	5.25	6.02
2004	0.94	6.52	7.46	0.87	5.84	6.71	0.81	5.25	6.06
2005	0.98	6.52	7.50	0.91	5.84	6.75	0.85	5.25	6.10
2006	1.03	6.52	7.55	0.96	5.84	6.80	0.90	5.25	6.15
2007	1.09	6.52	7.61	1.01	5.84	6.85	0.94	5.25	6.19
2008	1.14	6.52	7.66	1.06	5.84	6.90	0.99	5.25	6.24
2009	1.20	6.52	7.72	1.12	5.84	6.96	1.04	5.25	6.29
2010	1.26	6.52	7.78	1.17	5.84	7.01	1.09	5.25	6.34
2011	1.33	6.52	7.85	1.23	5.84	7.07	1.15	5.25	6.40
2012	1.39	6.52	7.91	1.30	5.84	7.14	1.21	5.25	6.46
2013	1.46	6.52	7.98	1.36	5.84	7.20	1.27	5.25	6.52
2014	1.54	6.52	8.06	1.43	5.84	7.27	1.33	5.25	6.58
2015	1.62	6.52	8.14	1.50	5.84	7.34	1.40	5.25	6.65
2016	1.70	6.52	8.22	1.58	5.84	7.42	1.47	5.25	6.72

NOTE: Above payments calculated in accordance with formulas set forth in FPSC Rule 25-17.0832(5). Payment shall be adjusted by multiplying factor for On-Peak Capacity Factor determined in Schedule 7.

APPENDIX C
RATES

SCHEDULE 3
Payments for Avoided 1997 Combustion Turbine Unit

ENERGY PAYMENT - $/MWH

(1) CONTRACT YEAR	(2) (ESTIMATED) FUEL	(3) O&M	(4) TOTAL
1997	52.63	1.03	53.66
1998	55.82	1.08	56.90
1999	53.70	1.13	54.83
2000	58.78	1.19	59.97
2001	56.42	1.25	57.67
2002	62.36	1.32	63.68
2003	66.46	1.38	67.84
2004	72.25	1.45	73.70
2005	79.70	1.53	81.23
2006	83.76	1.61	85.39
2007	88.04	1.69	89.73
2008	92.53	1.77	94.30
2009	97.25	1.86	99.11
2010	102.20	1.96	104.16
2011	107.42	2.06	109.48
2012	112.90	2.16	115.06
2013	118.65	2.27	120.92
2014	124.70	2.39	127.09
2015	131.06	2.51	133.57
2016	137.75	2.64	140.39

NOTE: Information provided above is estimated. Actual payment shall be determined in accordance with FPSC Rule 25-17.0832(4).

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SCHEDULE 4
Capacity Payment Adjustment for On-Peak Capacity Factor

O.P.C.F.	CAPACITY PAYMENT ADJUSTMENT MULTIPLYING FACTOR
Greater than or Equal to the Committed O.P.C.F.	1.0
From 50.0% to the Committed O.P.C.F.	$\left[\dfrac{\text{O.P.C.F.}}{\text{Committed O.P.C.F.}}\right]^{1.5}$
Below 50.0%	0

NOTE: O.P.C.F. = On-Peak Capacity Factor

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SCHEDULE 5
Optional Performance Adjustment

If a Qualifying Facility elects the Performance Adjustment provision of Article IX in the Standard Offer Contract, the following formula shall be calculated each month after the Contract In-Service Date for all hours in the month:

$$\sum_{\text{for } i = \text{first hour}}^{\text{last hour}} PERADJ_i = [KWH_i - (CC \times 1.0 \text{ hr.} \times CF/100)] \times (EP1_i - EP2_i)$$

Where:

$PERADJ_i$ = the Performance Adjustment for hour i.

KWH_i = the hourly energy delivered to the Company by the QF during hour i.

CC = the QF's Committed Capacity in KW.

CF = if the QF's On-Peak Capacity Factor (%) is 50.0% or greater, then CF equals the lesser of (a) the avoided unit Minimum On-Peak Capacity Factor (%) or (b) the QF's On-Peak Capacity Factor (%); if the QF's On-Peak Capacity Factor is less than 50.0%, then CF equals zero.

EP1 = the energy payment in $/KWH for hour i as determined in the Standard Offer Contract for purchase of As-Available Energy.

EP2 = the energy payment in $/KWH for hour i as determined in the Standard Offer Contract for purchase of Firm Capacity and Energy.

Note:

The Performance Adjustment shall not apply to any hour in which the following condition occurs:

(a) the QF's Energy Payment is determined on the basis of the Standard Offer Contract for purchase of As-Available Energy;

(b) the Company cannot perform its obligation to receive all energy which the QF has made available for sale at the Point of Delivery;

(c) the Energy Payment as determined in the Standard Offer Contract for purchase of Firm Capacity and Energy exceeds the Energy Payment as determined in the Standard Offer Contract for purchase of As-Available Energy.

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SCHEDULE 6

Charges to Qualifying Facility

Customer Charges:

The Qualifying Facility shall be billed monthly for the costs of meter reading, billing, and other appropriate administrative costs. The charge shall be set equal to the stated Customer Charge of the Company's applicable rate schedule for service to the Qualifying Facility load as a non-generating customer of the Company.

Operation, Maintenance, and Repair Charges:

The Qualifying Facility shall be billed monthly for the costs associated with the operation, maintenance, and repair of the interconnection. These include (a) the Company's inspections of the interconnection and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company were involved.

The Qualifying Facility shall pay a monthly charge equal to 0.50% of the Interconnection Costs less the Interconnection Costs Offset. This monthly rate shall be adjusted periodically.

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SCHEDULE 7
Delivery Voltage Adjustment

The QF's energy payment will be multiplied by a Delivery Voltage Adjustment whose value will depend upon (i) the delivery voltage at the Point of Delivery and (ii) the methodology approved by the FPSC to determine the adjustment for standard offer contracts pursuant to the rule in Appendix E.

The Company's actual hourly avoided energy costs shall be adjusted according to the delivery voltage by the following multipliers as may be filed from time to time with the FPSC:

Qualifying Facility Delivery Voltage	Adjustment Factor
69 KV or greater	1.036
4 KV, 12 KV, 25 KV	1.047
600 Volts or lower	1.070

APPENDIX D

TRANSMISSION SERVICE STANDARDS

1.0 Purpose.

This appendix provides minimum standards required by the Company in the Transmission Service Agreement and applies to QF's whose Facility is not directly interconnected with the Company and who are selling firm capacity and energy to the Company.

2.0 Standards for QF's Selling Firm Capacity and Energy.

2.1 The QF shall ensure that, throughout the Term of the Agreement, the Transmission Service Utility or its lawful successors but no other party shall deliver the Committed Capacity and electric energy to the Company on behalf of the QF.

2.2 A proposed Transmission Service Agreement and any amendments thereto shall be submitted to the Company for its review and consent no less than sixty (60) days before said Transmission Service Agreement or amendment is proposed to be tendered for filing with the FERC. Such consent shall not be unreasonably withheld. No review, recommendations or consent by the Company shall be deemed an approval of any safety or other arrangements between the QF and the Transmission Service Utility nor shall it relieve the QF and the Transmission Service Utility of their responsibility with respect to the adequate engineering, design, construction and operation of any facilities other than the Company's Interconnection Facilities and for any injury to property or persons associated with any failure to perform in a proper and safe manner for any reason. Nothing contained herein shall prevent the Company from exercising any rights that it otherwise would have to participate as a full party before the

FERC when the Transmission Service Agreement or amendments thereto is tendered for filing.

2.3 To ensure the continuous availability to the Company of the Committed Capacity during the Term of the Agreement, the Transmission Service Agreement shall contain provisions satisfying the following minimum criteria:

(i) the Transmission Service Utility's transmission commitment shall be for the full amount of the Committed Capacity plus any losses assessed by the Transmission Service Utility from the Point of Metering to the Point of Delivery;

(ii) the duration of the Transmission Service Utility's transmission commitment shall be for a term at least as long as the Term of the Agreement with termination provisions that are acceptable to the Company;

(iii) the Transmission Service Utility's transmission commitment shall not be interruptible or curtailable to a greater extent than the Transmission Service Utility's transmission service to its own firm requirements customers;

(iv) The QF and the Transmission Service Utility shall not be permitted to amend the Transmission Service Agreement in a manner that adversely affects the Company's rights without the Company's prior written consent;

(v) the Company shall be provided with prompt notification of any default under the Transmission Service Agreement;

(vi) the QF and/or the Transmission Service Utility shall expressly indemnify and hold the Company harmless for any and all liability or cost responsibility in connection with the

Transmission Service Agreement and the activities undertaken thereunder, including, without limitation, any facility costs, service charges, or third party impact claims;

(vii) the Company shall be entitled to reasonable access at all times to property and equipment owned or controlled by either the QF or the Transmission Service Utility and at reasonable times to records and schedules maintained by either the QF or the Transmission Service Utility, in order to carry out the purposes of the Agreement in a safe, reliable and economical manner;

(viii) unless otherwise agreed by the Company, the Point of Delivery into the Company's system shall be defined as all points of interconnection at transmission voltages between the Company and the Transmission Service Utility pursuant to any tariffs or interchange agreements on file with the FERC and in effect from time to time;

(ix) the electric energy made available from the Facility for transmission to the Company shall be telemetered to the Company and shall be reduced for all losses assessed by the Transmission Service Agreement from the Point of Metering to the Point of Delivery; the electric energy as so adjusted shall be considered the electric energy delivered to the Company for billing purposes and shall be considered as if within the Company's Control Area, provided that the Transmission Service Utility can deliver and the Company accept the electric energy as so adjusted;

(x) As an alternative to section 2.3(ix) hereof, electric energy from the Facility shall be scheduled for delivery to the Point of Delivery by the Transmission Service Utility and such electric energy as is scheduled shall be considered as electric energy delivered to the Company for billing purposes.

(xi) The Transmission Service Utility and the Company shall coordinate with one another concerning any inability to deliver or receive the electric energy as adjusted pursuant to section 8.3 (ix) hereof. Whenever the Transmission Service Utility is unable to deliver or the Company does not accept such energy, such energy shall no longer be considered within the Company's Control Area if energy is delivered pursuant to section 2.3(ix) hereof; and

(xii) a contact person for the Transmission Service Utility shall be designated for day-to-day communications between the Transmission Service Utility and the Parties.

PART III

UTILITIES' OBLIGATIONS WITH REGARD TO COGENERATORS AND SMALL POWER PRODUCERS

25-17.080 Definitions and Qualifying Criteria.

(1) For the purpose of these rules the Commission adopts the Federal Energy Regulatory Commission Rules 292.101 through 292.207, effective March 20, 1980, regarding definitions and criteria that a small power producer or cogenerator must meet to achieve the status of a qualifying facility. Small power producers and cogenerators which fail to meet the FERC criteria for achieving qualifying facility status but otherwise meet the objectives of economically reducing Florida's dependence on oil and the economic deferral of utility power plant expenditures may petition the Commission to be granted qualifying facility status for the purpose of receiving energy and capacity payments pursuant to these rules.

(2) In general, under the FERC regulations, a small power producer is a qualifying facility if:

(a) the small power producer does not exceed 80 MW; and

(b) the primary (at least 50%) energy source of the small power producer is biomass, waste, or another renewable resource; and

(c) the small power production facility is not owned by a person primarily engaged in the generation or sale of electricity. This criterion is met if less than 50% of the equity interest in the facility is owned by a utility, utility holding company, or a subsidiary of them.

(3) In general, under the FERC regulations, a cogenerator is a qualifying facility if:

(a) the useful thermal energy output of a topping cycle cogeneration facility is not less than 5% of the facility's total energy output per year; and

(b) the useful power output plus half of the useful thermal energy output of a topping cycle cogeneration facility built after March 13, 1980, with any energy input of natural gas or oil is greater than 42.5% or 45% if the useful thermal energy output is less than 15% of the total energy output of the facility; and

(c) the useful power output of a bottoming cycle cogeneration facility built after March 13, 1980, with any energy input as supplementary firing of natural gas or oil is not less than 45% of the natural gas or oil input on an annual basis; and

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(d) the cogeneration facility is not owned by a person primarily engaged in the generation or sale of electricity. This criterion is met if less than 50% of the equity interest in the facility is owned by a utility, utility holding company, or a subsidiary of them.
Specific Authority: 366.05(9), 350.127(2), F.S.
Law Implemented: 366.05(9), F.S.
History: New 5/13/81, amended 9/4/83, formerly 25-17.80.

25-17.081 Reserved.

25-17.082 The Utility's Obligation to Purchase; Customer's Selection of Billing Method.

(1) Upon compliance by the qualifying facility with Rule 25-17.087, each utility shall purchase electricity produced and sold by qualifying facilities at rates which have been agreed upon by the utility and qualifying facility or at the utility's published tariff. Each utility shall file a tariff or tariffs and a standard offer contract or contracts for the purchase of energy and capacity from qualifying facilities which reflects the provisions set forth in these rules.

(2) Unless the Commission determines that alternative metering requirements cause no adverse effect on the cost or reliability of electric service to the utility's general body of customers, each tariff and standard offer contract shall specify the following metering requirements for billing purposes:

(a) Hourly recording meters shall be required for qualifying facilities with an installed capacity of 100 kilowatts or more.

(b) For qualifying facilities with an installed capacity of less than 100 kilowatts, at the option of the qualifying facility, either hourly recording meters, dual kilowatt-hour register time-of-day meters, or standard kilowatt-hour meters shall be installed. Unless special circumstances warrant, meters shall be read at monthly intervals on the approximate corresponding day of each meter reading period.

(3)(a) A qualifying facility, upon entering into a contract for the sale of firm capacity and energy or prior to delivery of as-available energy to a utility, shall elect to make either simultaneous purchases from the interconnecting utility and sales to the purchasing utility or net sales to the purchasing utility. Once made, the selection of a billing methodology may only be changed:

1. when a qualifying facility selling as-available energy enters into a negotiated contract or standard offer contract for the sale of firm capacity and energy; or
2. when a firm capacity and energy contract expires or is lawfully terminated by either the qualifying facility or the purchasing utility; or
3. when the qualifying facility is selling as-available energy and has not changed billing methods within the last twelve months; and
4. when the election to change billing methods will not contravene the provisions of Rule 25-17.0832 or any contract between the qualifying facility and the utility.

Firm capacity and energy contracts in effect prior to the effective date of this rule shall remain unchanged.

(b) If a qualifying facility elects to change billing methods in accordance with this rule, such change shall be subject to the following provisions:

1. upon at least thirty days advance written notice;
2. upon the installation by the utility of any additional metering equipment reasonably required to effect the change in billing and upon payment by the qualifying facility for such metering equipment and its installation; and

3. upon completion and approval by the utility of any alterations to the interconnection reasonably required to effect the change in billing and upon payment by the qualifying facility for such alterations.

(c) Should a qualifying facility elect to make simultaneous purchases and sales, purchases of electric service by the qualifying facility from the interconnecting utility shall be billed at the retail rate schedule under which the qualifying facility load would receive service as a non-generating customer of the utility; sales of electricity delivered by the qualifying facility to the purchasing utility shall be purchased at the utility's avoided energy and capacity rates, where applicable, in accordance with Rules 25-17.0825 and 25-17.0832.

(d) Should a qualifying facility elect a net billing arrangement, the hourly net energy and capacity sales delivered to the purchasing utility shall be purchased at the utility's avoided energy and capacity rates, where applicable, in accordance with Rules 25-17.0825 and 25-17.0832; purchases from the interconnecting utility shall be billed pursuant to the utility's applicable standby service or supplemental service rate schedules.

(4)(a) Payments for energy and capacity sold by a qualifying facility shall be rendered monthly by the purchasing utility and as promptly as possible, normally by the twentieth business day following the day the meter is read. The kilowatt-hours sold by the qualifying facility, the applicable avoided energy rate at which payments were made, and the rate and amount of the applicable capacity payment shall accompany the payment by the utility to the qualifying facility.

(b) Where simultaneous purchases and sales are made by a qualifying facility, avoided energy and capacity payments to the qualifying facility may, at the option of the qualifying facility, be shown as a credit to the qualifying facility's bill; the kilowatt-hours produced by the qualifying facility, the avoided energy rate at which payments were made, and the rate and amount of the capacity payment shall accompany the bill to the qualifying facility. A credit shall not exceed the amount of the qualifying facility's bill from the utility and the excess, if any, shall be paid directly to the qualifying facility in accordance with this rule.

(5) A utility may require a security deposit from each interconnected qualifying facility in accordance with Rule 25-6.097 for the qualifying facility's purchase of power from the utility. Each utility's tariff shall contain specific criteria for determining the applicability and amount of a deposit from an interconnected qualifying facility consistent with projected net cash flow on a monthly basis.

(6) Each utility shall keep separate accounts for sales to qualifying facilities and purchases from qualifying facilities.

Specific Authority: 366.051, 350.127(2), F.S.
Law Implemented: 366.051, F.S.
History: New 5/13/81, Amended 9/4/83, formerly 25-17.82, amended 10/25/90.

25-17.0825 As-Available Energy.

(1) As-available energy is energy produced and sold by a qualifying facility on an hour-by-hour basis for which contractual commitments as to the quantity, time, or reliability of delivery are not required. Each utility shall purchase as-available energy from any qualifying facility. As-available energy shall be sold by a qualifying facility and purchased by a utility pursuant to the terms and conditions of a published tariff or a separately negotiated contract.

As-available energy sold by a qualifying facility shall be purchased by the utility at a rate, in cents per kilowatt-hour, not to exceed the utility's avoided energy cost. Because of the lack of assurances as to the quantity, time, or reliability of delivery of as-available energy, no capacity payments shall be made to a qualifying facility for the delivery of as-available energy.

(a) Tariff Rates: Each utility shall publish a tariff for the purchase of as-available energy from qualifying facilities. Each utility's published tariff shall state that the rate of payment for as-available energy is the utility's avoided energy cost as defined in subsection (2) of this rule, less the additional costs directly attributable to the purchase of such energy from a qualifying facility. The additional costs directly associated with the purchase of as-available energy from qualifying facilities shall be specifically identified in the utility's tariff.

(b) *Contract Rates:* Each utility may enter into a separately negotiated contract for the purchase of as-available energy from a qualifying facility. All contracts for the purchase of as-available energy between a qualifying facility and a utility shall be filed with the Commission within 10 working days of their signing. Those qualifying facilities wishing to negotiate a contract for the sale of firm capacity and energy with terms different from those in a utility's standard offer contract may do so pursuant to Rule 25-17.0832(2). Where parties cannot agree on the terms and conditions of a negotiated contract, either party may apply to the Commission for relief pursuant to Rule 25-17.0834.

(2)(a) Avoided energy costs associated with as-available energy are defined as the utility's actual avoided energy cost before the sale of interchange energy. Avoided energy costs associated with as-available energy shall be all costs the utility avoided due to the purchase of as-available energy, including the utility's incremental fuel, identifiable variable operating and maintenance expense, and identifiable variable utility power purchases. Demonstrable utility administrative costs required to calculate avoided energy costs may be deducted from avoided energy payments. Avoided line losses reflecting the voltage at which generation by the qualifying facility is received by the utility shall also be included in the determination of avoided energy costs. Each utility shall calculate its avoided energy cost associated with as-available energy deterministically, on an hour-by-hour basis, after accounting for interchange sales which have taken place, using the utility's actual avoided energy cost for the hour, as affected by the output of the qualifying facilities connected to the utility's system. A megawatt block size at least equal to the most recent available estimate of the combined average hourly generation of all qualifying facilities making energy sales based on the utility's as-available energy rate to the utility shall be used to calculate the utility's hourly avoided energy costs associated with as-available energy. For the purpose of this subsection, interchange sales are inter-utility sales which are provided at the option of the selling utility exclusive of central pool dispatch transactions.

(b) Each utility's tariff shall include a description of the methodology to be used in the calculation of avoided energy cost implementing subsection (2) of this Rule. Each utility's implementation methodology shall specify the method by which the utility's incremental fuel and operating and maintenance costs and line losses are determined.

(3)(a) For qualifying facilities with hourly recording meters, monthly payments for as-available energy shall be made and shall be calculated based on the product of: (1) the utility's actual avoided energy rate for each hour during the month; and (2) the quantity of energy sold by the qualifying facility during that hour.

(b) For qualifying facilities with dual kilowatt-hour register time-of-day meters, monthly payments for as-available energy shall be calculated based on the average of the utility's actual hourly avoided energy rate for the on-peak and off-peak periods during the month.

(c) For qualifying facilities with standard kilowatt-hour meters, monthly payments for as-available energy shall be calculated based on the average of the utility's actual hourly avoided energy rate for the off-peak periods during the month.

(4) Each utility shall file with the Commission by the twentieth business day of the following month, a monthly report of their actual hourly avoided energy costs, the average of their actual hourly avoided energy costs for the on-peak and

off-peak periods during the month, and the average of their actual hourly avoided energy costs for the month with the Commission. A copy shall be furnished to any individual who requests such information.

(5) Upon request by a qualifying facility or any interested person, each utility shall provide within 30 days its most current projections of its generation mix, fuel price by type of fuel, and at least a five year projection of fuel forecasts to estimate future as-available energy prices as well as any other information reasonably required by the qualifying facility to project future avoided cost prices including, but not limited to, a 24 hour advance forecast of hour-by-hour avoided energy costs. The utility may charge an appropriate fee, not to exceed the actual cost of production and copying, for providing such information.

(6) Utility payments for as-available energy made to qualifying facilities pursuant to the utility's tariff shall be recoverable by the utility through the Commission's periodic review of fuel and purchased power. Utility payments for as-available energy made to qualifying facilities pursuant to a separately negotiated contract shall be recoverable by the utility through the Commission's periodic review of fuel and purchased power costs if the payments are not reasonably projected to result in higher cost electric service to the utility's general body of ratepayers or adversely affect the adequacy or reliability of electric service to all customers.

Specific Authority: 366.051, 350.127(2), F.S.
Law Implemented: 366.051, F.S.
History: New 9/4/83, formerly 25-17.82, amended 10/25/90.

25-17.083 Firm Energy and Capacity.
Specific Authority: 366.04(1), 366.05(1), 366.05(9), 350.127(2), F.S.
Law Implemented: 366.05(9), F.S.
History: New 9/4/83, formerly 25-17.83, Repealed 10/25/90.

25-17.0831 Contracts.
Specific Authority: 366.05(9), 350.127(2), F.S.
Law Implemented: 366.05(9), F.S.
History: New 5/13/81, amended 9/4/83, formerly 25-17.831, Repealed 10/25/90.

25-17.0832 Firm Capacity and Energy Contracts.

(1) Firm capacity and energy are capacity and energy produced and sold by a qualifying facility and purchased by a utility pursuant to a negotiated contract or a standard offer contract subject to certain contractual provisions as to the quantity, time and reliability of delivery.

(a) Within one working day of the execution of a negotiated contract or the receipt of a signed standard offer contract, the utility shall notify the Director of the Division of Electric and Gas and provide the amount of committed capacity and the avoided unit, if any, to which the contract should be applied.

(b) Within 10 working days of the execution of a negotiated contract for the purchase of firm capacity and energy or within 10 working days of receipt of a signed standard offer contract, the purchasing utility shall file with the Commission a copy of the signed contract and a summary of its terms and conditions. At a minimum, such a summary shall report:

1. the name of the utility and the owner and/or operator of the qualifying facility, who are signatories of the contract;
2. the amount of committed capacity specified in the contract, the size of the facility, the type of the facility its location, and its interconnection and transmission requirements;
3. the amount of annual and on-peak and off-peak energy expected to be delivered to the utility;
4. the type of unit being avoided, its size and its in-service year;
5. the in-service date of the qualifying facility; and

6. the date by which the delivery of firm capacity and energy is expected to commence.

(c) Prior to the anticipated in-service date of the avoided unit specified in the contract, a qualifying facility which has negotiated a firm capacity and energy contract or has accepted a utility's standard offer contract may sell as-available energy to any utility pursuant to Rule 25-17.0825.

(2) Negotiated Contracts. Utilities and qualifying facilities are encouraged to negotiate contracts for the purchase of firm capacity and energy. Such contracts will be considered prudent for cost recovery purposes if it is demonstrated that the purchase of firm capacity and energy from the qualifying facility pursuant to the rates, terms, and other conditions of the contract can reasonably be expected to contribute towards the deferral or avoidance of additional capacity construction or other capacity-related costs by the purchasing utility at a cost to the utility's ratepayers which does not exceed full avoided costs, giving consideration to the characteristics of the capacity and energy to be delivered by the qualifying facility under the contract. Negotiated contracts shall not be evaluated against an avoided unit in a standard offer contract, thus preserving the standard offer for small qualifying facilities as described in subsection (3). In reviewing negotiated firm capacity and energy contracts for the purpose of cost recovery, the Commission shall consider factors relating to the contract that would impact the utility's general body of retail and wholesale customers including:

(a) whether additional firm capacity and energy is needed by the purchasing utility and by Florida utilities from a statewide perspective; and

(b) whether the cumulative present worth of firm capacity and energy payments made to the qualifying facility over the term of the contract are projected to be no greater than:

1. the cumulative present worth of the value of a year-by-year deferral of the construction and operation of generation or parts thereof by the purchasing utility over the term of the contract; calculated in accordance with subsection (4) and paragraph (5)(a) of this rule, providing that the contract is designed to contribute towards the deferral or avoidance of such capacity; or
2. the cummulative present worth of other capacity and energy related costs that the contract is designed to avoid such as fuel, operation and maintenance expenses or alternative purchases of capacity, providing that the contract is designed to avoid such costs; and

(c) to the extent that annual firm capacity and energy payments made to the qualifying facility in any year exceed that year's annual value of deferring the construction and operation of generation by the purchasing utility or other capacity and energy related costs, whether the contract contains provisions to ensure repayment of such payments exceeding that year's value of deferring that capacity in the event that the qualifying facility fails to deliver firm capacity and energy pursuant to the terms and conditions of the contract; provided, however, that provisions to ensure repayment may be based on forecasted data; and

(d) considering the technical reliability, viability and financial stability of the qualifying facility, whether the contract contains provisions to protect the purchasing utility's ratepayers in the event the qualifying facility fails to deliver firm capacity and energy in the amount and times specified in the contract.

(3) Standard Offer Contracts.

(a) Upon petition by a utility or pursuant to a Commission action, each public utility shall submit for Commission approval a tariff or tariffs and a standard offer contract or contracts for the purchase of firm capacity and energy from small qualifying facilities less than 75 megawatts or from solid waste facilities as defined in Rule 25-17.091.

(b) The rates, terms, and other conditions contained in each utility's standard offer contract or contracts shall be based on the need for and equal to the avoided cost of deferring or avoiding the construction of additional generation capacity or parts thereof by the purchasing utility. Rates for payment of capacity sold by a qualifying facility shall be specified in the contract for the duration of the contract. In reviewing a utility's standard offer contract or contracts, the Commission shall consider the criteria specified in paragraphs (2)(a) through (2)(d) of this rule, as well as any other information relating to the determination of the utility's full avoided costs.

(c) In lieu of a seperately negotiated contract, a qualifying facility under 75 megawatts or a solid waste facility as defined in Rule 25-17.091(1), F.A.C., may accept any utility's standard offer contract. Qualifying facilities which are 75 megawatts or greater may negotiate contracts for the purchase of capacity and energy pursuant to subsection (2). Should a utility fail to negotiate in good faith, any qualifying facility may apply to the Commission for relief pursuant to Rule 25-17.0834, F.A.C.

(d) Within 60 days of receipt of a signed standard offer contract, the utility shall either accept and sign the contract and return it within five days to the qualifying facility or petition the Commission not to accept the contract and provide justification for the refusal. Such petitions may be based on:

1. a reasonable allegation by the utility that acceptance of the standard offer will exceed the subscription limit of the avoided unit or units; or
2. material evidence that because the qualifying facility is not financially or technically viable, it is unlikely that the committed capacity and energy would be made available to the utility by the date specified in the standard offer.

A standard offer contract which has been accepted by a qualifying facility shall apply towards the subscription limit of the unit designated in the contract effective the date the utility receives the accepted contract. If the contract is not accepted by the utility, its effect shall be removed from the subscription limit effective the date of the Commission order granting the utility's petition.

(e) Minimum Specifications. Each standard offer contract shall, at minimum, specify:

1. the avoided unit or units on which the contract is based;
2. the total amount of committed capacity, in megawatts, needed to fully subscribe the avoided unit specified in the contract;
3. the payment options available to the qualifying facility including all financial and economic assumptions necessary to calculate the firm capacity payments available under each payment option and an illustrative calculation of firm capacity payments for a minimum ten year term contract commencing with the in-service date of the avoided unit for each payment option;
4. the date on which the standard contract offer expires. This date shall be at least four years before the anticipated in-service date of the avoided unit or units unless the avoided unit could be constructed in less than four years, or when the subscription limit has been reached;
5. the date by which firm capacity and energy deliveries from the qualifying facility to the utility shall commence. This date shall be no later than the anticipated in-service date of the avoided unit specified in the contract;
6. the period of time over which firm capacity and energy shall be delivered from the qualifying facility to the utility. Firm capacity and energy shall be delivered, at a minimum, for a period of ten years, commencing with the anticipated in-service date of the avoided unit specified in the contract. At a maximum, firm capacity and energy shall be delivered for a period of time equal to the anticipated plant life of the avoided unit, commencing with the anticipated in-service date of the avoided unit;

7. the minimum performance standards for the delivery of firm capacity and energy by the qualifying facility during the utility's daily seasonal peak and off-peak periods. These performance standards shall approximate the anticipated peak and off-peak availability and capacity factor of the utility's avoided unit over the term of the contract;
8. provisions to ensure repayment of payments to the extent that annual firm capacity and energy payments made to the qualifying facility in any year exceed that year's annual value of deferring the avoided unit specified in the contract in the event that the qualifying facility fails to perform pursuant to the terms and conditions of the contract. Such provisions may be in the form of a surety bond or equivalent assurance of repayment of payments exceeding the year-by-year value of deferring the avoided unit specified in the contract.

(f) The Commission may approve contracts that specify:
1. provisions to protect the purchasing utility's ratepayers in the event the qualifying facility fails to deliver firm capacity and energy in the amount and times specified in the contract which may be in the form of an up-front payment, surety bond, or equivalent assurance of payment. Such payment or surety shall be refunded upon completion of the facility and demonstration that the facility can deliver the amount of capacity and energy specified in the contract; and
2. a listing of the parameters, including any impact on electric power transfer capability, associated with the qualifying facility as compared to the avoided unit necessary for the calculation of the avoided cost.

(g) Firm Capacity Payment Options. Each standard offer contract shall also contain, at a minimum, the following options for the payment of firm capacity delivered by the qualifying facility:
1. Value of deferral capacity payments. Value of deferral capacity payments shall commence on the anticipated in-service date of the avoided unit. Capacity payments under this option shall consist of monthly payments escalating annually of the avoided capital and fixed operation and maintenance expense associated with the avoided unit and shall be equal to the value of a year-by-year deferral of the avoided unit, calculated in accordance with paragraph (5)(a) of this rule.
2. Early capacity payments. Each standard offer contract shall specify the earliest date prior to the anticipated in-service date of the avoided unit when early capacity payments may commence. The early capacity payment date shall be an approximation of the lead time required to site and construct the avoided unit. Early capacity payments shall consist of monthly payments escalating annually of the avoided capital and fixed operation and maintenance expense associated with the avoided unit, calculated in conformance with paragraph (5)(b) of the rule. At the option of the qualifying facility, early capacity payments may commence at any time after the specified early capacity payment date and before the anticipated in-service date of the avoided unit provided that the qualifying facility is delivering firm capacity and energy to the utility. Where early capacity payments are elected, the cumulative present value of the capacity payments made to the qualifying facility over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the qualifying facility had such payments been made pursuant to subparagraph (3)(g)1 of this rule.

3. Levelized capacity payments. Levelized capacity payments shall commence on the anticipated in-service date of the avoided unit. The capital portion of capacity payments under this option shall consist of equal monthly payments over the term of the contract, calculated in conformance with paragraph (5)(c) of this rule. The fixed operation and maintenance portion of capacity payments shall be equal to the value of the year-by-year deferral of fixed operation and maintenance expense associated with the avoided unit calculated in conformance with paragraph (5)(a) of this rule. Where levelized capacity payments are elected, the cumulative present value of the levelized capacity payments made to the qualifying facility over the term of the contract shall not exceed the cumulative present value of capacity payments which would have been made to the qualifying facility had such payments been made pursuant to subparagraph (3)(g)1 of this rule, value of deferral capacity payments.

4. Early levelized capacity payments. Each standard offer contract shall specify the earliest date prior to the anticipated in-service date of the avoided unit when early levelized capacity payments may commence. The early capacity payment date shall be an approximation of the lead time required to site and construct the avoided unit. The capital portion of capacity payments under this option shall consist of equal monthly payments over the term of the contract, calculated in conformance with paragraph (5)(c) of this rule. The fixed operation and maintenance expense shall be calculated in conformance with paragraph (5)(b) of this rule. At the option of the qualifying facility, early levelized capacity payments shall commence at any time after the specified early capacity date and before the anticipated in-service date of the avoided unit provided that the qualifying facility is delivering firm capacity and energy to the utility. Where early levelized capacity payments are elected, the cumulative present value of the capacity payments made to the qualifying facility over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the qualifying facility had such payments been made pursuant to subparagraph (3)(g)1 of this rule.

(4) Avoided Energy Payments.

(a) For the purpose of this rule, avoided energy costs associated with firm energy sold to a utility by a qualifying facility pursuant to a utility's standard offer contract shall commence with the in-service date of the avoided unit specified in the contract. Prior to the in-service date of the avoided unit, the qualifying facility may sell as-available energy to the utility pursuant to Rule 25-17.0825.

(b) To the extent that the avoided unit would have been operated, had that unit been installed, avoided energy costs associated with firm energy shall be the energy cost of this unit. To the extent that the avoided unit would not have been operated, the avoided energy costs shall be the as-available avoided energy cost of the purchasing utility. During the periods that the avoided unit would not have been operated, firm energy purchased from qualifying facilities shall be treated as as-available energy for the purposes of determining the megawatt block size in Rule 25-17.0825(2)(a).

(c) The energy cost of the avoided unit specified in the contract shall be defined as the cost of fuel, in cents per kilowatt-hour, which would have been burned at the avoided unit plus variable operation and maintenance expense plus avoided line losses. The cost of fuel shall be calculated as the average market price of fuel, in cents per million Btu, associated with the avoided unit multiplied by the average heat rate associated with the avoided unit. The variable operating and maintenance expense shall be estimated based on the unit fuel type and technology of the avoided unit.

(5) Calculation of standard offer contract firm capacity payment options.

(a) Calculation of year-by-year value of deferral. The year-by-year value of deferral of an avoided unit shall be the difference in revenue requirements associated with deferring the avoided unit one year and shall be calculated as follows:

$$VAC_m = \frac{1}{12}\left[KI_n \frac{\left[1 - \frac{(1+ip)}{(1+r)} \right]}{\left[1 - \frac{(1+ip)^L}{(1+r)^L} \right]} + O_n \right]$$

Where, for a one year deferral:

VAC_m = utility's monthly value of avoided capacity, in dollars per kilowatt per month, for each month of year n;

K = present value of carrying charges for one dollar of investment over L years with carrying charges computed using average annual rate base and assumed to be paid at the middle of each year and present value to the middle of the first year;

I_n = total direct and indirect cost, in mid-year dollars per kilowatt including AFUDC but excluding CWIP, of the avoided unit with an in-service date of year n, including all identifiable and quantifiable costs relating to the construction of the avoided unit that would have been paid had the avoided unit been constructed;

O_n = total fixed operation and maintenance expense for the year n, in mid-year dollars per kilowatt per year, of the avoided unit;

i_p = annual escalation rate associated with the plant cost of the avoided unit(s);

i_o = annual escalation rate associated with the operation and maintenance expense of the avoided unit(s);

r = annual discount rate, defined as the utility's incremental after tax cost of capital;

L = expected life of the avoided unit; and

n = year for which the avoided unit is deferred starting with its original anticipated in-service date and ending with the termination of the contract for the purchase of firm energy and capacity.

(b) Calculation of early capacity payments. Monthly early capacity payments shall be calculated as follows:

$$A_m = A_c \frac{(1+ip)^{(m-1)}}{12} + A_o \frac{(1+io)^{(m-1)}}{12} \quad \text{for } m=1 \text{ to } t$$

Where: A_m = monthly early capacity payments to be made to the qualifying facility for each month of the contract year n, in dollars per kilowatt per month;

i_p = annual escalation rate associated with the plant cost of the avoided unit;

i_o = annual escalation note associated with the operation and maintenance expense of the avoided unit(s);

m = year for which early capacity payments to a qualifying facility are made, starting in year one and ending in the year t;

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t = the term, in years, of the contract for the purchase of firm capacity;

$$A_C = F \left[\frac{1 - \frac{(1 + ip)}{(1 + r)}}{1 - \left(\frac{(1 + ip)}{(1 + r)}\right)^t} \right]$$

Where: F = the cumulative present value in the year that the contractual payments will begin, of the avoided capital cost component of capacity payments which would have been made had capacity payments commenced with the anticipated in-service date of the avoided unit(s); and

r = annual discount rate, defined as the utility's incremental after tax cost of capital; and

$$A_O = G \left[\frac{1 - \frac{(1 + io)}{(1 + r)}}{1 - \left(\frac{(1 + io)}{(1 + r)}\right)^t} \right]$$

Where: G = The cumulative present value in the year that the contractual payments will begin, of the avoided fixed operation and maintenance expense component of capacity payments which would have been made had capacity payments commenced with the anticipated in-service date of the avoided unit.

(c) Levelized and early levelized capacity payments. Monthly levelized and early levelized capacity payments shall be calculated as follows:

$$P_L = \frac{F}{12} \times \frac{r}{1-(1+r)^{-t}} + O$$

Where: P_L = the monthly levelized capacity payment, starting on or prior to the in-service date of the avoided unit;

F = the cumulative present value, in the year that the contractual payments will begin, of the avoided capital cost component of the capacity payments which would have been made had the capacity payments not been levelized;

r = the annual discount rate, defined as the utility's incremental after tax cost of capital; and

t = the term, in years, of the contract for the purchase of firm capacity.

O = the monthly fixed operation and maintenance component of the capacity payments, calculated in accordance with paragraph (5)(a) for levelized capacity payments or with paragraph (5)(b) for early levelized capacity payments.

(6) Sale of Excess Firm Energy and Capacity. To the extent that firm energy and capacity purchased from a qualifying facility pursuant to a standard offer contract or an individually negotiated contract is not needed by the purchasing utility, these rules shall be construed to encourage the

purchasing utility to sell all or part of the energy and capacity to the utility in need of energy and capacity at a mutually agreed upon price which is cost effective to the ratepayers.

(7) Upon request by a qualifying facility or any interested person, each utility shall provide within 30 days its most current projections of its future generation mix including type and timing of anticipated generation additions, and at least a 20-year projection of fuel forecasts, as well as any other information reasonably required by the qualifying facility to project future avoided cost prices. The utility may charge an appropriate fee, not to exceed the actual cost of production and copying, for providing such information.

(8)(a) Firm energy and capacity payments made to a qualifying facility pursuant to a separately negotiated contract shall be recoverable by a utility through the Commission's periodic review of fuel and purchased power costs if the contract is found to be prudent in accordance with subsection (2) of this rule.

(b) Upon acceptance of the contract by both parties, firm energy and capacity payments made to a qualifying facility pursuant to a standard offer contract shall be recoverable by a utility through the Commission's periodic review of fuel and purchased power costs.

(c) Firm energy and capacity payments made pursuant to a standard offer contract signed by the qualifying facility, for which the utility has petitioned the Commission to reject, is recoverable through the Commission's periodic review of fuel and purchased power costs if the Commission requires the utility to accept the contract because it satisfies subsection (3) of this rule.

Specific Authority: 350.127, 366.04(1), 366.051, 366.05(8), F.S.
Law Implemented: 366.051, 403.503, F.S.
History: New 10/25/90.

25-17.0833 Planning Hearings.

(1) Upon petition or on its own motion, the Commission shall periodically review optimal generation and transmission plans from a statewide and individual utility perspective. In connection with these proceedings, the Commission shall consider the need for capacity from both a statewide and individual utility perspective, the adequacy of the transmission grid, and other strategic planning concerns affecting the Florida electric grid.

(2) Upon petition, or on its own motion, the Commission, as needed, shall review individual utility generation and expansion plans at any time.

Specific Authority: 366.05(8), 366.051, 350.127(2), F.S.
Law Implemented: 366.051, F.S.
History: New 10/25/90.

25-17.0834 Settlement of Disputes in Contract Negotiations.

(1) Public utilities shall negotiate in good faith for the purchase of capacity and energy from qualifying facilities and interconnection with qualifying facilities. In the event that a utility and a qualifying facility cannot agree on the rates, terms, and other conditions for the purchase of capacity and energy, either party may apply to the Commission for relief. Qualifying facilities may petition the Commission to order a utility to sign a contract for the purchase of capacity and energy which does not exceed a utility's full avoided costs as defined in 366.051, Florida Statutes, should the Commission find that the utility failed to negotiate in good faith.

(2) To the extent possible, the Commission will dispose of an application for relief within 90 days of the filing of a petition by either a utility or a qualifying facility.

(3) If the Commission finds that a utility has failed to negotiate or deal in good faith with qualifying facilities, or has explicitly dealt in bad faith with qualifying facilities, it shall impose an appropriate penalty on the utility as approved by section 350.127, Florida Statutes.
Specific Authority: 366.051, 350.127(2), F.S.
Law Implemented: 366.051, F.S.
History: New 10/25/90.

25-17.0835 Wheeling.
Specific Authority: 366.05(9), 350.127(2), F.S.
Law Implemented: 366.05(9), 366.055(3), F.S.
History: New 9/4/83, repealed 10/4/85, formerly 25-17.835.

25-17.084 The Utility's Obligation to Sell.
Upon compliance with Rule 25-17.087, each utility shall sell energy to qualifying facilities at rates which are just, reasonable, and non-discriminatory.
Specific Authority: 366.05(9), 350.127(2), F.S.
Law Implemented: 366.05(9), F.S.
History: New 5/13/81, amended 9/4/83, formerly 25-17.84.

25-17.085 Reserved.

25-17.086 Periods During Which Purchases are not Required.
Where purchases from a qualifying facility will impair the utility's ability to give adequate service to the rest of its customers or, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, or otherwise place an undue burden on the utility, the utility shall be relieved of its obligation under Rule 25-17.082 to purchase electricity from a qualifying facility. The utility shall notify the qualifying facility(ies) prior to the instance giving rise to those conditions, if practicable. If prior notice is not practicable, the utility shall notify the qualifying facility(ies) as soon as practicable after the fact. In either event the utility shall notify the Commission, and the Commission staff shall, upon request of the affected qualifying facility(ies), investigate the utility's claim. Nothing in this section shall operate to relieve the utility of its general obligation to purchase pursuant to Rule 25-17.082.
Specific Authority: 366.05(9), 350.127(2), F.S.
Law Implemented: 366.05(9), F.S.
History: New 5/13/81, Amended 9/4/83, formerly 25-17.86.

25-17.087 Interconnection and Standards.
(1) Each utility shall interconnect with any qualifying facility which:
(a) is in its service area;
(b) requests interconnection;
(c) agrees to meet system standards specified in this rule; (d) agrees to pay the cost of interconnection; and
(e) signs an interconnection agreement.
(2) Nothing in this rule shall be construed to preclude a utility from evaluating each request for interconnection on its own merits and modifying the general standards specified in this rule to reflect the result of such an evaluation.
(3) Where a utility refuses to interconnect with a qualifying facility or attempts to impose unreasonable standards pursuant to subsection (2) of this rule, the qualifying facility may petition the Commission for relief. The utility shall have the burden of demonstrating to the Commission why

interconnection with the qualifying facility should not be required or that the standards the utility seeks to impose on the qualifying facility pursuant to subsection (2) are reasonable.

(4) Upon a showing of credit worthiness, the qualifying facility shall have the option of making monthly installment payments over a period no longer than 36 months toward the full cost of interconnection. However, where the qualifying facility exercises that option the utility shall charge interest on the amount owing. The utility shall charge such interest at the 30-day commercial paper rate. In any event, no utility may bear the cost of interconnection.

(5) Application for Interconnection. A qualifying facility shall not operate electric generating equipment in parallel with the utility's electric system without the prior written consent of the utility. Formal application for interconnection shall be made by the qualifying facility prior to the installation of any generation related equipment. This application shall be accompanied by the following:

(a) Physical layout drawings, including dimensions;

(b) All associated equipment specifications and characteristics including technical parameters, ratings, basic impulse levels, electrical main one-line diagrams, schematic diagrams, system protections, frequency, voltage, current and interconnection distance;

(c) Functional and logic diagrams, control and meter diagrams, conductor sizes and length, and any other relevant data which might be necessary to understand the proposed system and to be able to make a coordinated system;

(d) Power requirements in watts and vars;

(e) Expected radio-noise, harmonic generation and telephone interference factor;

(f) Synchronizing methods; and

(g) Operating/instruction manuals.

Any subsequent change in the system must also be submitted for review and written approval prior to actual modification. The above mentioned review, recommendations and approval by the utility do not relieve the qualifying facility from complete responsibility for the adequate engineering design, construction and operation of the qualifying facility equipment and for any liability for injuries to property or persons associated with any failure to perform in a proper and safe manner for any reason.

(6) Personnel Safety. Adequate protection and safe operational procedures must be developed and followed by the joint system. These operating procedures must be approved by both the utility and the qualifying facility. The qualifying facility shall be required to furnish, install, operate and maintain in good order and repair, and be solely responsible for, without cost to the utility, all facilities required for the safe operation of the generation system in parallel with the utility's system.

The qualifying facility shall permit the utility's employees to enter upon its property at any reasonable time for the purpose of inspection and/or testing the qualifying facility's equipment, facilities, or apparatus. Such inspections shall not relieve the qualifying facility from its obligation to maintain its equipment in safe and satisfactory operating condition.

The utility's approval of isolating devices used by the qualifying facility will be required to ensure that these will comply with the utility's switching and tagging procedure for safe working clearances.

(a) Disconnect Switch. A manual disconnect switch, of the visible load break type, to provide a separation point between the qualifying facility's generation system and the utility's system, shall be required. The utility will specify the location of the disconnect switch. The switch shall be mounted separate from the meter socket and shall be readily accessible to the utility and be capable of being locked in the open position with a utility padlock. The utility may reserve the right to open the switch (i.e. isolating the qualifying facility's generation system) without prior notice to the qualifying facility. To the extent practicable, however, prior notice shall be given.

Any of the following conditions shall be cause for disconnection:

1. Utility system emergencies and/or maintenance requirements;
2. Hazardous conditions existing on the qualifying facility's generating or protective equipment as determined by the utility;
3. Adverse effects of the qualifying facility's generation to the utility's other electric consumers and/or system as determined by the utility;
4. Failure of the qualifying facility to maintain any required insurance; or
5. Failure of the qualifying facility to comply with any existing or future regulations, rules, orders or decisions of any governmental or regulatory authority having jurisdiction over the qualifying facility's electric generating equipment or the operation of such equipment.

(b) Responsibility and Liability. The utility and the qualifying facility shall each be responsible for its own facilities. The utility and the qualifying facility shall each be responsible for ensuring adequate safeguards for other utility customers, utility and qualifying facility personnel and equipment, and for the protection of its own generating system. The utility and the qualifying facility shall each indemnify and save the other harmless from any and all claims, demands, costs, or expense for loss, damage, or injury to persons or property of the other caused by, arising out of, or resulting from:

1. Any act or omission by a party or that party's contractors, agents, servants and employees in connection with the installation or operation of that party's generation system or the operation thereof in connection with the other party's system;
2. Any defect in, failure of, or fault related to a party's generation system;
3. The negligence of a party or negligence of that party's contractors, agents servants and employees; or
4. Any other event or act that is the result of, or proximately caused by, a party.

For the purposes of this subsection, the term party shall mean either utility or qualifying facility, as the case may be.

(c) Insurance. The qualifying facility shall deliver to the utility, at least fifteen days prior to the start of any interconnection work, a certificate of insurance certifying the qualifying facility's coverage under a liability insurance policy issued by a reputable insurance company authorized to do business in the State of Florida naming the qualifying facility as named insured, and the utility as an additional named insured, which policy shall contain a broad form contractual endorsement specifically covering the liabilities accepted under this agreement arising out of the interconnection to the qualifying facility, or caused by operation of any of the qualifying facility's equipment or by the qualifying facility's failure to maintain the qualifying facility's equipment in satisfactory and safe operating condition.

The policy providing such coverage shall provide public liability insurance, including property damage, in an amount not less than $300,000 for each occurrence; more insurance may be required as deemed necessary by the utility. In addition, the above required policy shall be endorsed with a provision whereby the insurance company will notify the utility thirty days prior to the effective date of cancellation or material change in the policy.

The qualifying facility shall pay all premiums and other charges due on said policy and keep said policy in force during the entire period of interconnection with the utility.

(7) Protection and Operation. It will be the responsibility of the qualifying facility to provide all devices necessary to protect the qualifying facility's equipment from damage by the abnormal conditions and operations which occur on the utility system that result in interruptions and restorations of service by the utility's equipment and personnel. The qualifying facility shall protect its generator and associated equipment from overvoltage, undervoltage, overload, short circuits (including ground fault condition), open circuits, phase unbalance and reversal, over or under frequency condition, and other injurious electrical conditions that may arise on the utility's system and any reclose attempt by the utility.

The utility may reserve the right to perform such tests as it deems necessary to ensure safe and efficient protection and operation of the qualifying facility's equipment.

(a) Loss of Source: The qualifying facility shall provide, or the utility will provide at the qualifying facility's expense, approved protective equipment necessary to immediately, completely, and automatically disconnect the qualifying facility's generation from the utility's system in the event of a fault on the qualifying facility's system, a fault of the utility's system, or loss of source on the utility's system. Disconnection must be completed within the time specified by the utility in its standard operating procedure for its electric system for loss of a source on the utility's system.

This automatic disconnecting device may be of the manual or automatic reclose type and shall not be capable of reclosing until after service is restored by the utility. The type and size of the device shall be approved by the utility depending upon the installation. Adequate test data or technical proof that the device meets the above criteria must be supplied by the qualifying facility to the utility. The utility shall approve a device that will perform the above functions at minimal capital and operating costs to the qualifying facility.

(b) Coordination and Synchronization. The qualifying facility shall be responsible for coordination and synchronization of the qualifying facility's equipment with the utility's electrical system, and assumes all responsibility for damage that may occur from improper coordination or synchronization of the generator with the utility's system.

(c) Electrical Characteristics. Single phase generator interconnections with the utility are permitted at power levels up to 20 KW. For power levels exceeding 20 KW, a three phase balanced interconnection will normally be required. For the purpose of calculating connected generation, 1 horsepower equals 1 kilowatt. The qualifying facility shall interconnect with the utility at the voltage of the available distribution or the transmission line of the utility for the locality of the interconnection, and shall utilize one of the standard connections (single phase, three phase, wye, delta) as approved by the utility.

The utility may reserve the right to require a separate transformation and/or service for a qualifying facility's generation system, at the qualifying facility's expense. The qualifying facility shall bond all neutrals of the qualifying facility's system to the utility's neutral, and shall install a separate driven ground with a resistance value which shall be determined by the utility and bond this ground to the qualifying facility's system neutral.

(d) *Exceptions.* A qualifying facility's generator having a capacity rating that can:

1. produce power in excess of 1/2 of the minimum utility customer requirements of the interconnected distribution or transmission circuit; or
2. produce power flows approaching or exceeding the thermal capacity of the connected utility distribution or transmission lines or transformers; or
3. adversely affect the operation of the utility or other utility customer's voltage, frequency or overcurrent control and protection devices; or
4. adversely affect the quality of service to other utility customers; or
5. interconnect at voltage levels greater than distribution voltages,

will require more complex interconnection facilities as deemed necessary by the utility.

(8) Quality of Service. The qualifying facility's generated electricity shall meet the following minimum guidelines:

(a) Frequency. The governor control on the prime mover shall be capable of maintaining the generator output frequency within limits for loads from no-load up to rated output. The limits for frequency shall be 60 hertz (cycles per second), plus or minus an instantaneous variation of less than 1%.

(b) Voltage. The regulator control shall be capable of maintaining the generator output voltage within limits for loads from no-load up to rated output. The limits for voltage shall be the nominal operating voltage level, plus or minus 5%.

(c) Harmonics. The output sine wave distortion shall be deemed acceptable when it does not have a higher content (root mean square) of harmonics than the utility's normal harmonic content at the interconnection point.

(d) Power Factor. The qualifying facility's generation system shall be designed, operated and controlled to provide reactive power requirements from 0.85 lagging to 0.85 leading power factor. Induction generators shall have static capacitors that provide at least 85% of the magnetizing current requirements of the induction generator field. (Capacitors shall not be so large as to permit self-excitation of the qualifying facility's generator field).

(e) DC Generators. Direct current generators may be operated in parallel with the utility's system through a synchronous invertor. The inverter must meet all criteria in these rules.

(9) Metering. The actual metering equipment required, its voltage rating, number of phases, size, current transformers, potential transformers, number of inputs and associated memory is dependent on the type, size and location of the electric service provided. In situations where power may flow both in and out of the qualifying facility's system, power flowing into the qualifying facility's system will be measured separately from power flowing out of the qualifying facility's system.

The utility will provide, at no additional cost to the qualifying facility, the metering equipment necessary to measure capacity and energy deliveries to the qualifying facility. The utility will provide, at the qualifying facility's expense, the necessary additional metering equipment to measure energy deliveries by the qualifying facility to the utility.

(10) Cost Responsibility. The qualifying facility is required to bear all costs associated with the change-out, upgrading or addition of protective devices, transformers, lines, services, meters, switches, and associated equipment and devices beyond that which would be required to

provide normal service to the qualifying facility if the qualifying facility were a non-generating customer. These costs shall be paid by the qualifying facility to the utility for all material and labor that is required. Prior to any work being done by the utility, the utility shall supply the qualifying facility with a written cost estimate of all its required materials and labor and an estimate of the date by which construction of the interconnection will be completed. This estimate shall be provided to the qualifying facility within 60 days after the qualifying facility supplies the utility with its final electrical plans. The utility shall also provide project timing and feasibility information to the qualifying facility.

(11) Each utility shall submit to the Commission, a standard agreement for interconnection by qualifying facilities as part of their standard offer contract or contracts required by Rule 25-17.0832(3).
Specific Authority: 366.051, 350.127(2), F.S.
Law Implemented: 366.051, F.S.
History: New 9/4/83, formerly 25-17.87, Amended 10/25/90.

25-17.088 Transmission Service for Qualifying Facilities.
Specific Authority: 350.127(2), 366.051, F.S.
Law Implemented: 366.051, 366.04(3), 366.055(3), F.S.
History: New 10/4/85, formerly 25-17.88, Amended 2/3/87, Repealed 10/25/90.

25-17.0882 Transmission Service Not Required for Self-Service.
Specific Authority: 350.127(2), 366.05(1), F.S.
Law Implemented: 366.05(9), 366.04(3), 366.055(3), F.S.
History: New 10/4/85, formerly 25-17.882, Repealed 10/25/90.

25-17.0883 Conditions Requiring Transmission Service for Self-service.
Public utilities are required to provide transmission and distribution services to enable a retail customer to transmit electrical power generated at one location to the customer's facilities at another location when the provision of such service and its associated charges, terms, and other conditions are not reasonably projected to result in higher cost electric service to the utility's general body of retail and wholesale customers or adversely affect the adequacy or reliability of electric service to all customers. The determination of whether transmission service for self service is likely to result in higher cost electric service may be made using cost effectiveness methodology employed by the Commission in evaluating conservation programs of the utility, adjusted as appropriate to reflect the qualifying facility's contribution to the utility for standby service and wheeling charges, other utility program costs, the fact that qualifying facility self-service performance can be precisely metered and monitored, and taking into consideration the unique load characteristics of the qualifying facility compared to other conservation programs.
Specific Authority: 366.051, 350.127(2), F.S.
Law Implemented: 366.051, F.S.
History: New 10/25/90.

25-17.089 Transmission Service for Qualifying Facilities.
(1) Upon request by a qualifying facility, each electric utility in Florida shall provide, subject to the provisions of subsection (3) of this rule, transmission service to wheel as-available energy or firm energy and capacity produced by a Qualifying Facility from the Qualifying Facility to another electric utility.

(2) The rates, terms, and conditions for transmission services as described in subsection (1) and in Rule 25-17.0883 which are provided by an investor-owned utility shall be those approved by the Federal Energy Regulatory Commission.

(3) An electric utility may deny, curtail, or discontinue transmission service to a Qualifying Facility on a non- discriminatory basis if the provision of such service would adversely affect the safety, adequacy, reliability, or cost of providing electric service to the utility's general body of retail and wholesale customers.
Specific Authority: 366.051, 350.127(2), F.S.
Law Implemented: 366.051, 366.055(3), F.S.
History: New 10/25/90.

25-17.090 Reserved.

25-17.091 Governmental Solid Waste Energy and Capacity.

(1) Definitions and Applicability:

(a) "Solid Waste Facility" means a facility owned or operated by, or on behalf of, local government, the purpose of which is to dispose of solid waste, as that term is defined in section 403.703(13), Fla. Stat. (1988), and to generate electricity.

(b) A facility is owned by or operated on behalf of a local government if the power purchase agreement is between the local government and the electric utility.

(c) A solid waste facility shall include a facility which is not owned or operated by a local government but is operated on its behalf. When the power purchase agreement is between a non-governmental entity and an electric utility, the facility is operated by a private entity on behalf of a local government if:

1. One or more local governments have entered into a long-term agreement with the private entity for the disposal of solid waste for which the local governments are responsible and that agreement has a term at least as long as the term of the contract for the purchase of energy and capacity from the facility; and
2. The Commission determines there is no undue risk imposed on the electric ratepayers of the purchasing utility, based on:
   a. The local government's acceptance of responsibility for the private entity's performance of the power purchase contract, or
   b. Such other factors as the Commission deems appropriate, including, without limitation, the issuance of bonds by the local government to finance all, or a substantial portion, of the costs of the facility; the reliability of the solid waste technology; and the financial capability of the private owner and operator.
3. The requirements of subparagraph 2 shall be satisfied if a local government described in subparagraph 1 enters into an agreement with the purchasing utility providing that in the event of a default by the private entity under the power purchase contract, the local government shall perform the private entity's obligations, or cause them to be performed, for the remaining term of the contract, and shall not seek to renegotiate the power purchase contract.

(d) This rule shall apply to all contracts for the purchase of energy or capacity from solid waste facilities entered into, or renegotiated as provided in subsection (3), after October 1, 1988.

(2) Except as provided in subsections (3) and (4) of this rule, the provisions of Rules 25-17.080 - 25-17.089, Florida Administrative Code, are applicable to contracts for the purchase of energy and capacity from a solid waste facility.

(3) Any solid waste facility which has an existing firm energy and capacity contract in effect before October 1, 1988, shall have a one-time option to renegotiate that contract to incorporate any or all of the provisions of subsection (2) and (4) into their contract. This renegotiation shall be based on the unit that the contract was designed to avoid but applying the most recent Commission-approved cost estimates of Rule 25-17.0832(5)(a), Florida Administrative Code, for the same unit type and in-service year to determine the utility's value of avoided capacity over the remaining term of the contract.

(4) Because section 377.709(4), Fla. Stat., requires the local government to refund early capacity payments should a solid waste facility be abandoned, closed down or rendered illegal, a utility may not require risk-related guarantees as required in Rule 25-17.0832, paragraph (2)(c), (2)(d), (3)(e)8, and (3)(f)1. However, at its option, a solid waste facility may provide such risk related guarantee.

(5) Nothing in this rule shall preclude a solid waste facility from electing advance capacity payments authorized pursuant to section 377.709(3)(b), F.S., which advanced capacity payments shall be in lieu of firm capacity payments otherwise authorized pursuant to this rule and Rule 25-17.0832, F.A.C. The provisions of subsection (4) are applicable to solid waste facilities electing advanced capacity payments.

Specific Authority: 350.127(2), 377.709(5), F.S.
Law Implemented: 366.051, 366.055(3), 377.709, F.S.
History: New 8/8/85, formerly 25-17.91, Amended 4/26/89, 10/25/90.

2ND CASE of Level 1 printed in FULL format.

In Re: Petition of Polk Power Partners for a Declaratory Statement Regarding Eligibility for **Standard Offer** Contracts

DOCKET NO. 920556-EQ; ORDER NO. PSC-92-0683-DS-EQ

Florida Public Service Commission

1992 Fla. PUC LEXIS 1076; 92 FPSC 7:388

July 21, 1992

PANEL:
[*1]

The following Commissioners participated in the disposition of this matter: THOMAS M. BEARD, Chairman; BETTY EASLEY; J. TERRY DEASON; SUSAN F. CLARK; LUIS J. LAUREDO

OPINION:
ORDER GRANTING DECLARATORY STATEMENT IN THE NEGATIVE

BY THE COMMISSION:

BACKGROUND

By petition filed May 28, 1992, Polk Power Partners, L.P. ("Polk") has asked for a declaratory statement that Polk Power Partners may sell additional capacity from a qualifying cogeneration facility via a **standard offer** contract, where the project's total net generating capacity exceeds 75 megawatts (MW) and where the contemplated **standard offer** contract provides for committed capacity of less than 75 MW.

Though acknowledging that Rule 25-17.0832(3)(a), F.A.C. provides for **standard offer** contracts involving "small qualifying facilities less than 75 megawatts. ", Polk theorizes an ambiguity as to whether the 75 megawatt cap speaks to the total net generating capacity n1 of the QF, as defined at 18 C.F.R. 292.202 (g) (1990) of the FERC rules implementing PURPA, or the committed capacity which the qualifying facility has contractually committed to deliver on a firm basis to the purchasing utility. It is the latter definition **[*2]** alone which would be consistent with the declaratory statement petitioned for by Polk.

n1 Total net generating capacity, or "Useful power output" of a cogeneration facility means the electric or mechanical energy made available for use exclusive of any such energy used in the power production process.

DISCUSSION

We grant Polk Power Partners' Petition for Declaratory Statement, albeit in the negative.

The mere allegation at p. 8 of the Petition that

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PEC10604

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A QF with a total net generating capacity of 95 MW that sells only 70 MW to a purchasing utility is frequently referred to as a 70 MW QF

is hardly sufficient to create authentic ambiguity in this matter in view of the context in which the operable **standard offer** rule appears. Not only Rule 25-7.0832(3)(a), previously cited, but also Rule 25-17.0832(2) states that

Negotiated contracts shall not be evaluated against an avoided unit in a **standard offer** contract, thus preserving the **standard offer** for small qualifying facilities as described in subsection (3) [e.s.]

All of the language in both rule sections relating the 75 MW cap to the goal of preserving the **standard offer** for small qualifying facilities would **[*3]** be rendered nugatory by the declaratory statement petitioned for by Polk.

If "committed" capacity, rather than total net generating capacity were the measure by which to calculate the 75 MW cap, QF's of any size could participate in **standard offer** contracts, contrary to the clear intent of the rules to preserve such participation for small QF's. It is a fundamental principle of statutory construction that statutes are not to be construed in such a manner as to render them meaningless, and that principle should govern the interpretation of rules as well.

Accordingly, we decline Polk's Petition to issue the statement requested. We state instead that the 75 MW cap referenced in Rule 25-17.0832(3)(a) refers to the total net generating capacity of the QF.

In view of the above, it is

ORDERED by the Florida Public Service Commission that Polk Power Partner's Petition for Declaratory Statement is granted in the negative. It is further

ORDERED that this docket is closed.

By Order of the Florida Public Service Commission this 21st day of July, 1992.

PEC10605

1ST CASE of Level 1 printed in FULL format.

In Re: Joint Petition for Approval of Standard Offer Contracts of FLORIDA POWER CORPORATION and AUBURNDALE POWER PARTNERS, LIMITED PARTNERSHIP

DOCKET NO. 940819-EQ; ORDER NO. PSC-**94-1306-FOF**-EQ

Florida Public Service Commission

94 FPSC 10:375

October 24, 1994

PANEL:
[*1]

The following Commissioners participated in the disposition of this matter: J. TERRY DEASON, Chairman, SUSAN F. CLARK, JOE GARCIA, JULIA L. JOHNSON, DIANE K. KIESLING

OPINION:
NOTICE OF PROPOSED AGENCY ACTION ORDER APPROVING CONTRACT MODIFICATIONS

BY THE COMMISSION:

NOTICE IS HEREBY GIVEN by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

By Order No. 21947, issued September 27, 1989, we approved a standard offer contract between Florida Power Corporation (FPC) and the Sun Bank of Tampa Bay (Sun Bank) for 8.5 MW of capacity generated by a wood waste burning cogeneration unit in Jefferson County. In Order No. 21948, a companion order issued that same date, we approved a standard offer contract between FPC and Sun Bank for 7.969 MW of capacity generated by a similar unit in Madison County.

Both standard offer contracts contained provisions that permitted assignment of the contracts with FPC's prior written approval, and in fact Sun Bank had **[*2]** already assigned both standard offer contracts to LFC Corporation (LFC) on April 14, 1989. Both standard offer contracts also contemplated a one-time adjustment of committed capacity; and on December 18, 1992, LFC increased the committed capacity for the Madison facility from 7.969 MW to 8.5 MW. The combined committed capacity of the facilities is now 17 MW. The facilities have been operational since 1990.

The standard offer contracts were assigned again by LFC to Auburndale Power Partners, Limited Partnership (Auburndale) in a "Consent and Agreement" (Consent), executed by LFC, FPC and Auburndale on April 18, 1994. By the terms of the Consent, Auburndale would generate the firm capacity and energy committed by LFC's standard offer contracts from Auburndale's own existing 150 MW natural gas fired cogeneration facility in Polk County, not from LFC's existing wood waste burning cogeneration facilities in Madison and Jefferson Counties.

EXHIBIT
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PEC10606

Auburndale already plans to sell 114 MW of firm capacity to FPC pursuant to a negotiated contract that we approved in Order No. 24634, Docket No. 910401-EQ, issued July 1, 1991. The Consent also provided that FPC could curtail energy purchases from **[*3]** Auburndale under certain circumstances. If the Consent is approved, LFC plans to discontinue operations at the Madison and Jefferson County facilities.

On August 5, 1994, Auburndale and FPC filed this Joint Petition for Expedited Approval of Contract Modifications. In the joint petition the parties have asked us to confirm that the standard offer contracts as modified continue to qualify for cost recovery and are not subject to the provisions of the Commission's current Rule 25-17.0832(3)(a), whichh limits the availability of Standard Offer Contracts to Qualified Cogeneration Facilities (QF) under 75 MW. The modifications in question include: LFC's assignment of the standard offer contracts to Auburndale; a change in location and facilities from LFC's plants in Madison and Jefferson counties to Auburndale's natural gas fired plant in Auburndale; and, curtailment provisions that permit FPC to reduce energy purchases from Auburndale during certain periods when FPC's load is reduced.

At our September 20, 1994 Agenda Conference we addressed four substantive issues raised by the joint petition:

1) Is LFC's assignment of its standard offer contracts with Florida Power Corporation **[*4]** to Auburndale Power Partners contemplated by the terms of those contracts?

2) Is the change in location from the existing LFC facilities in Madison and Jefferson counties to the Auburndale facility in Polk county, Florida contemplated pursuant to the original standard offer contracts?

3) Are the agreed upon "Off-Peak Curtailment Periods" as defined in the Consent and Agreement between Auburndale, FPC, and LFC contemplated pursuant to Sections 5(a) and 5(c) of LFC's original standard offer contract?

4) Should the joint petition for approval of contract modifications be approved?

Our decision on those issues is memorialized below.

The Assignment

The standard offer contracts in question specifically provide for assignment with the prior written approval of FPC. This requirement was met when LFC, Auburndale, and FPC entered into the Consent and Agreement. The Consent assigned the responsibility of generating the power and the rights and benefits of the standard offer contracts to Auburndale. By an amendment to the Consent, LFC has retained its original obligations to FPC. Upon consideration we find that this type of assignment was contemplated in the original standard **[*5]** offer contracts that were approved by the Commission in Order Nos. 21947 and 21948. Therefore, no further Commission approval is required.

The Change in Facilities and Location

While the terms of the standard offer contracts provided for assignment, the terms of the contracts did not provide for a change in location and facilities from the existing woodburning facilities in Madison and Jefferson counties to the Auburndale natural gas facility in Polk county.

As the name implies, a standard offer contract is just that, an "off-the-shelf" offering that has certain blank terms to be filled in when a particular QF executes the contract. Those terms include the name of the QF, the effective date of the contract, the location of the facility, the size of the facility, the term of the contract, the committed capacity, the in-service date, and the capacity payment option. Once the blanks are filled in and the standard offer is signed, those terms are not subject to negotiation or modification unless the contracts specifically provide for the modification.

Auburndale and FPC suggest that the change in location is a minor modification, because the location was originally left blank **[*6]** in the standard offer contract. The location provision of a standard offer contract is left blank because the utility does not know the location or type of a facility when it publishes its standard offer contract tariff. The fact that this information was not specified by the utility before the standard offer was executed does not mean that the information is insignificant and can be changed at will. It means that at the outset the cogenerator has the flexibility and the responsibility to provide the location information so that the purchasing utility can, from that point on, manage its purchased power contracts and plan its system accordingly. The changes in location and facilities significantly modify the project that was the subject of the original standard offers. We must evaluate the current effect of those changes on the ratepayers.

FPC indicated that the current LFC standard offer contracts are more expensive than FPC's current avoided costs by approximately $ 20 million. FPC's analysis of the benefits of the proposed changes shows a net present value benefit of approximately $ 12 million compared to the original standard offers. Auburndale and FPC state in **[*7]** their joint petition that the "new location will reduce line loss incurred in the transmission of power to the load center, provide greater reliability as the transmission distance will be significantly shortened, and increase FPC's opportunity for purchase of bargain and emergency power from the non-peninsular Florida System." At the Agenda Conference, FPC indicated that the majority of the $ 12 million benefit was the result of replacing expensive as-available energy with less expensive firm energy. We believe that in this instance there are significant benefits to be gained by FPC's ratepayers, and accordingly we approve the modification.

Curtailment

Section 4(d) of the Consent and Agreement defines "Off-Peak Curtailment Periods" as the off-peak hours, 12:00 a.m. to 6:00 a.m, for certain months of the year. These are the "[t]imes the Company shall be deemed unable to accept energy and capacity deliveries". This section relieves FPC of the obligation to purchase excess as-available energy which may not be economical.

Section 5 of LFC's standard offer contract reads as follows:

During the term of this agreement, QF agrees to:

(a) Provide The Company prior to October 1 of **[*8]** each calendar year an estimate of the amount of electricity generated by the Facility and delivered to

The Company for each month of the following calendar year, including the time, duration and magnitude of any planned outages or reductions in capacity;

(b) Promptly update the yearly generation schedule and maintenance schedule as and when any changes may be determined necessary;

(c) Coordinate its scheduled Facility outages with The Company;

(d) Comply with reasonable requirements of The Company regarding day-to-day or hour-by-hour communications between the parties relative to the performance of this Agreement; and

(e) Adjust reactive power flow in the interconnection so as to remain within the range of 85% leading to 85% lagging power factor.

Section 5 of the standard offer requires that the QF and the utility coordinate planned outages of the QF so the utility can manage its system. Typically, planned outages are for maintenance purposes for the QF. They are not to relieve minimum load problems of the utility. The "Off-Peak Curtailment Periods" provision in the Consent are intended to relieve minimum load problems that FPC contends exist, to avoid economic penalties **[*9]** associated with the continuing purchase of as-available energy during off-peak hours. The "Off-Peak Curtailment Periods" provision is a modification to the terms of the original standard offer contract that is not provided for in the contract.

Having said that, we do believe the parties have adequately demonstrated that the new curtailment provisions will provide FPC the opportunity to avoid the continuing purchase of as-available energy during off-peak hours, and thus, like the change in location and facilities, will provide benefits to FPC's ratepayers. We therefore approve the curtailment provisions. We view the question of whether current Rule 25-17.0832(3)(a), Florida Administrative Code applies to these contracts as modified to be moot.

It is, therefore,

ORDERED by the Florida Public Service Commission that the Joint Petition for Expedited Approval of Contract Modifications of Florida Power Corporation and Auburndale Power Partners, Limited Partnership is approved for purposes of cost recovery. It is further

ORDERED that this Order shall become final and this docket shall be closed unless an appropriate petition for formal proceedings is received by the Division of Records **[*10]** and Reporting, 101 East Gaines Street, Tallahassee, Florida 32399-0870, by the close of business on the date indicated in the Notice of Further Proceedings or Judicial Review.

By ORDER of the Florida Public Service Commission, this 24th day of October, 1994.

Chairman Deason and Commissioner Clark concur in the Commission's decision that the proposed modifications to the standard offer contracts are beneficial to FPC and its ratepayers and should be approved. They do not believe that it is necessary to decide whether the modifications were contemplated in the original contracts.

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1992 Fla. PUC LEXIS 1549 printed in FULL format.

In re: Petition for Authority for Florida Power Corporation to Refuse all Standard Offer Contracts Except that submitted by Panda Kathleen, L.P.

DOCKET NO. 911142-EQ; ORDER NO. PSC-92-1202-FOF-EQ

Florida Public Service Commission

1992 Fla. PUC LEXIS 1549; 92 FPSC 10:556

October 22, 1992

PANEL:
[*1]

The following Commissioners participated in the disposition of this matter: THOMAS M. BEARD, Chairman; SUSAN F. CLARK; J. TERRY DEASON; BETTY EASLEY; LUIS J. LAUREDO

OPINION:
ORDER GRANTING PETITION FOR AUTHORITY FOR FLORIDA POWER CORPORATION TO REFUSE ALL STANDARD OFFER CONTRACTS EXCEPT THAT SUBMITTED BY PANDA KATHLEEN, L.P.

BY THE COMMISSION:

CASE BACKGROUND

In Docket No. 910004-EU, the Commission determined that FPC's avoided unit for its standard offer contract was a 1997 combustion turbine. The standard offer subscription limit was set at 80 MW, with an effective date of September 20, 1991.

FPC conducted a two week "open season" from September 20, 1991, to October 4, 1991, during which potential providers were to submit standard offer contracts for evaluation. FPC received nine contracts during its "open season" and one contract after the "open season" concluded. On November 19, 1991, FPC petitioned the Commission for authority to reject the first standard offer contract it had received on September 20, 1991, from Noah IV GP, Incorporated (Noah IV). Subsequently, on November 26, 1991, FPC filed a petition with the Commission for authority to refuse all standard offer contracts [*2] except the one submitted by Panda Kathleen L.P. This petition also included rejection of Noah IV's contract. The two petitions have been combined into this single docket, Docket No. 911142-EQ.

On December 13, 1991, Noah IV and Ark Energy, Incorporated (Ark), jointly filed an Answer and Cross-Petition to FPC's petition. In the petition, Noah IV and Ark requested the Commission to reject FPC's petition and either (1) order FPC to execute the standard offer contract submitted by Noah IV to FPC or (2) set the matter for hearing. Subsequently, counsel for Noah IV and Ark agreed to permit the petition by FPC to be treated as a Proposed Agency Action. At the February 18, 1992, agenda conference, the Commission voted unanimously to approve the staff recommendation to approve FPC's petition, but to keep the standard offer open until the remaining 5.1 MW are subscribed.

Noah IV and Ark timely filed a protest to the Notice of Proposed Agency Action. A hearing was held on the matter on June 29, 1992. All parties submitted post hearing filings. In addition to its forty two page brief, ARK/NOAH IV submitted forty proposed Findings of Fact. Recommendations for rulings on each specific [*3] Finding of Fact are included in this Order as Attachment I. ARK/NOAH IV also submitted 11 proposed Conclusions of Law. We believe these conclusions are redundant in the context of a case heard by the agency head with an explicitly defined Issue List, Post Hearing briefs and a Final Order to be prepared after considering staff recommendations on the enumerated legal, policy and factual issues. This agency is under no legal duty to address each proposed conclusion in this setting. Therefore, we make no rulings on the 11 proposed Conclusions of Law submitted by ARK/NOAH IV.

We find that Commission rules do not require a "first-in-time, first-in-line" prioritization of standard offer contracts submitted to a utility. Rule 25-17.0832(d)3 does allow other methods of prioritizing contracts.

The pertinent portion of rule reads:

"Within sixty days of receipt of a signed standard offer contract, the utility shall either accept and sign the contract and return it within five days to the qualifying facility or petition the Commission not to accept the contract and provide justification for the refusal. Such petitions may be based on:

1. a reasonable allegation by the utility that acceptance [*4] of the standard offer will exceed the subscription limit of the avoided unit or units; or

2. material evidence that because the qualifying facility is not financially or technically viable, it is unlikely that the committed capacity and energy would be made available to the utility by the date specified in the standard offer." (emphasis added)

We believe that had the commission intended these two criteria to be exclusive, the words "may only" or "shall only" would appear in the place of the word "may". In reviewing the legislative history of the rule, we are unpersuaded that the Commission intended that these two explicit criteria were intended to be exclusive. The record is devoid of evidence suggesting the commission considered the possibility of an immediate over-subscription of a standard offer contract or of simultaneous delivery to the utility or of a "first day queue" as experienced by Florida Power and Light Company and referenced in testimony in this proceeding. Moreover, the deletion of one proposed explicit basis for petitioning the Commission (a change in the utilities generation expansion plan) from the proposed rule should not be construed to eliminate every possible [*5] reasonable method of evaluating standard offer contracts. In the instant case, Florida Power Corporation acted in the best interests of the ratepayers to select the contract which after a comparative evaluation was deemed by FPC to be the best available. We find that this action is consistent with the language of Rule 25-17.0832(3)(d), F.A.C.

We find that Florida Power Corporation did not violate its tariff by either petitioning for the Commission's authority to reject NOAH IV's standard offer contract on the basis of a comparative evaluation or by executing the standard offer contract delivered to FPC by Panda Kathleen on October 4, 1991.

Rule 25-17.0832 is incorporated by reference in FPC's standard offer tariff. The subject of "evaluation criteria" is not explicitly spoken to in the tariff. Any violation of the tariff is predicated on a violation of Rule 25-17.0832, F.A.C. Since we have determined that FPC's actions were consistent with the requirements of Rule 25-17.0832, F.A.C., no violation of FPC's tariff occurred.

Additionally, as recognized by Ark witness James Freeman, standard offer contracts are a unique type of tariff. Rather than selling products or services [*6] for an established price/rate, the standard offer tariff defines the terms of a utility purchase of products or services. We believe that standard offer contracts are published as tariffs as a matter of administrative convenience and are not subject to the same type scrutiny as a utility's offers to provide service. Therefore, we find that FPC did not violate its tariff by either petitioning for the Commission's authority to reject NOAH IV's standard offer contract on the basis of a comparative evaluation or by executing the standard offer contract delivered to FPC by Panda Kathleen on October 4, 1991.

We find that ARK/NOAH IV did not waive its right to object to Florida Power's evaluation process by failing to notify Staff, other respondents to the standard offer or Florida Power of Ark/Noah's position that a first-in-time acceptance was required. Prior to the Petition to Reject Standard Offer Contracts filed by FPC, ARK/NOAH IV had no clear point of entry to a Section 120.57, Florida Statutes proceeding to exercise its rights. ARK/NOAH IV were under no duty to protest FPC's chosen procedure until they were afforded a point of entry by the Commission to do so.

Rule 25-17.0832, [*7] F.A.C., does not purport to give individual parties the right to object to the evaluation method utilized by a utility in evaluating standard offer contracts. Thus, ARK/NOAH could not waive a right that it never had in the first place. ARK/NOAH were under no duty to protest FPC's chosen procedure until they were afforded a point of entry to a proceeding pursuant to Section 120.57, Florida Statutes. In protesting the Notice of Proposed Agency Action entered in this docket ARK did what the law required.

We find that as of November 19, 1991, ARK/NOAH IV's Lake County Cogeneration Project was technically viable with respect to fuel transportation capability.

On June 20, 1991, a $ 10,000 reservation deposit was made to reserve pipeline capacity for the Ark/Noah project and other Ark projects on Florida Gas Transmission's Phase III expansion. Evidently, this fact was not communicated to FPC when Ark/Noah filed its standard offer acceptance or when asked for additional information by FPC. In addition, another pipeline is projected to be constructed in Florida that could provide gas transportation for the project. Since the ARK/NOAH project will have dual fuel capability, it could [*8] use another fuel as a "bridge" measure between its in-service date and the availability of additional pipeline capacity. Therefore, we find that the Ark/Noah project appears to be technically viable with respect to fuel transportation capability.

We find that sufficient information was not provided to FPC to determine the technical viability of the proposed thermal host for ARK/NOAH IV's Lake County

Cogeneration Project.

Ark/Noah's witness Malenius argues, in part, that viability with respect to the thermal host is assured based on the following: (1) there is sufficient lead time for a competent QF developer to construct such a project; (2) Ark Energy's financial strength and established experience; and (3) Ark is presently developing a similar facility (the Mulberry Facility). However, these facts, which are very general in nature, do not establish the viability of the thermal host for the specific project proposed by Ark/Noah in this proceeding.

On October 11, 1991, FPC sent a questionnaire to seven entities who had submitted standard offer contracts during the open season. This questionnaire, among other things, asked the proposer to describe the level of commitment from [*9] the steam user, including whether it is an existing, ongoing enterprise and whether the steam user has an ownership interest in the project. The questionnaire also asked for copies of commitments by the steam user on behalf of the project. In response to this specific request, Ark referred to Attachment "H" of its September 21 [sic], 1991, standard offer submittal to FPC. Attachment "H" of Ark's standard offer submittal has not been offered into evidence in this proceeding, but FPC assigned a score of minus 1 (Poor) to the category entitled "Host" in its comparative evaluation of the project.

In a letter to Thomas Wetherington of FPC, dated November 5, 1991, William Siderewicz of Ark Energy briefly discusses the possibility of marketing its CO2 product to a wholesaler, who, in turn, will distribute the CO2 product to end users. Item 3 of that letter states, in part, "A copy of Carbonic Industries, 1990 annual report and recent communication regarding our working relationship is attached." We make the following three observations with regard to this information:

(1) the 1990 annual report of Carbonic Industries does not provide specific technical information to assess the viability [*10] of any specific thermal host;

(2) the one-page brief letter from David Fike of Carbonic Industries to William Siderewicz of Ark Energy provides almost no information on the purported "working relationship" between the two entities;

(3) the information provided does not constitute any kind of commitment to purchase the CO2 output.

Therefore, we find that sufficient information was not provided to FPC to establish technical viability of the proposed thermal host.

We find that as of November 19, 1991, ARK/NOAH IV's Lake County Cogeneration project did not have the highest likelihood of success relative to the other proposals received by Florida Power Corporation.

Although ARK/NOAH's witnesses testified that FPC's comparative evaluation system was unfair, no alternate weighting and ranking system was introduced into the record showing that the NOAH IV project would have the highest likelihood of success. The fairness and/or reasonableness of FPC's comparative evaluation procedure is not one of the issues that have been raised in this proceeding. However, we believe that the criteria used to evaluate the various proposals were valid, reasonable and fairly applied. Exhibit 1 contains [*11] the ranking criteria, ranking methodology, and the results of FPC's evaluation.

Based on our decisions in the above issues, the remainder of the issues raised in this proceeding are rendered moot.

In consideration of the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Power Corporation's Petition for authority to reject all standard offer contracts except that submitted by Panda Kathleen, L.P. is GRANTED. It is further

ORDERED that this docket shall be closed.

By ORDER of the Florida Public Service Commission this 22nd day of October, 1992.

ATTACHMENT I

SPECIFIC RULINGS ON ARK/NOAH'S PROPOSED FINDINGS OF FACT

1. Nothing in the Commission's standard offer rule addresses the comparative evaluation/open season procedure followed by Florida Power Corporation ("Florida Power") in this proceeding. [Rule 25-17.-832, F.A.C. (1991)]

RULING: Rejected as a Conclusion of Law and not a Finding of Fact.

2. Nothing in the pre-adoption history of the standard offer rule supports the use of a comparative evaluation/open season procedure for executing standard offer contracts. [ARK/NOAH Exhibit 3; Tr. 313 line 25- Tr. 317 line 3, esp. p. 316, [*12] lines 15-16]

RULING: Rejected as a Conclusion of Law and not a Finding of Fact.

3. At hearing, Florida Power introduced no evidence that the pre-adoption history of the standard offer rule supports use of a comparative evaluation/open season approach. [Tr. 12, line 11 - Tr. 142, line 2; Tr. 554, line 13 - Tr. 593, line 11].

RULING: Rejected as unnecessary to decide the factual matters at issue in this case.

4. At the September 18, 1990 agenda conference, the Commission voted to adopt Rule 25-17.0832. At that conference, prior to their vote, Commission members were advised by staff that the rule was structured so that standard offer contracts would be handled on a "first in line" basis. [ARK/NOAH Exhibit 3, Doc. 9, at 49-50]

RULING: Accepted and incorporated with the clarification that the exchange was between Chairman Wilson and Ms. Harvey; and was not sworn testimony in any proceeding.

5. Prior to adoption of the rule, members of the Commission considered establishing three criteria for rejecting a standard offer contract, then

reduced the criteria to the two now contained in Rule 25-17.0832(3). [ARK/NOAH Exhibit 3, Doc. 5, pp. 93-103].

RULING: Accepted [*13] and incorporated with the clarification that the criteria are not exclusive.

6. The conversation with Jennifer Harvey described by Florida Power at hearing was informal, not noticed, and entirely off the record. [Tr. 66, line 17 - Tr. 67, line 8].

RULING: Rejected as unnecessary to decide the matters at issue in the proceeding.

7. ARK/NOAH were the first to accept Florida Power's standard offer to purchase firm capacity and energy from a QF. [Tr. 21, lines 18-19; FPC Exhibit 1, pp. 19,30]

RULING: Accepted and incorporated.

8. ARK/NOAH were the only QF to accept Florida Power's standard offer tariff on September 20, 1991, and no other QF accepted until September 26, 1991. [Tr. 21, lines 18-19; FPC Exhibit 1, pp. 19,30]

RULING: Accepted and incorporated, with the clarification that ARK/NOAH were the first to file documents responsive to the tariff.

9. At hearing Florida Power introduced no evidence to demonstrate that the ARK/NOAH project was not viable. [Tr. 12, line 11 - Tr. 142, line 2; Tr. 554, line 13 - Tr. 593, line 11].

RULING: Rejected as unsupported by the evidence, FPC expressed concerns about the viability of the steam host which could affect [*14] the viability of the project. However, the evidence neither proves nor disproves the viability of the project.

10. At hearing Florida Power's witness conceded that had the ARK/NOAH project been the only project under consideration, he did not know whether he would have petitioned to reject. [Tr. 26, line 10 - Tr. 27, line 2]

RULING: Rejected. At one point in his testimony he did not know. On redirect he indicated that FPC would have petitioned to reject the contract.

11. At hearing, Florida Power's witness admitted that Florida Power "would have had a difficult time" in proving that ARK/NOAH could not bring their project on line in five years. [Tr. 31, lines 15-24]

RULING: Accepted and incorporated.

12. Florida Power's witness admitted that it is possible to build a facility such as ARK/NOAH's Lake County cogeneration facility. [Tr. 30, lines 17-18].

RULING: Accepted and incorporated.

13. Under Florida Power's comparative evaluation analysis, ARK/NOAH were

rated "very good" as a developer [Tr. 137, lines 24-25].

RULING: Accepted and incorporated.

14. The ARK/NOAH project was rated as "good" or "very good" on 7 of 8 viability-related criteria. [Tr. [*15] 138, line 6 - Tr. 139, line 12; FPC Exhibit 1, p. 19]

RULING: Accepted and incorporated.

15. The ARK/NOAH project was ranked fourth overall under Florida Power's comparative evaluation. [Tr. 26, lines 7-8; FPC Exhibit 1, p. 19].

RULING: Accepted and incorporated.

16. As of November 19, 1991, the ARK/NOAH Lake County Cogeneration project was a viable project. [Tr. 540, line 1 - Tr. 541, line 10; Tr. 184, line 11 - Tr. 186, line 9].

RULING: Rejected as unsupported by the greater weight of the evidence. FPC had concerns about the security of the steam host. [Tr. 556-557; page 22, FPC Exhibit 1]. The viability of the steam host could affect the viability of the project.

17. ARK Energy, through Polk Power Partners, L.P., is also developing the Mulberry Cogeneration Facility, a cogeneration facility in Polk County, Florida, that is nearly identical to the Lake County Cogeneration Facility being developed by ARK/NOAH. [Tr. 535, lines 3-14].

RULING: Rejected as irrelevant.

18. The Mulberry Cogeneration Facility is approximately on schedule. [Tr. 535, lines 15-16; Tr. 538, line 18 - Tr. 539, line 4].

RULING: Rejected as irrelevant.

19. Florida Power's [*16] standard offer tariff, Sheets Nos. 9.500 through 9.900, was required to be filed on September 6, 1991. [PSC Order No. 24989, p. 70, 73].

RULING: Accepted and incorporated.

20. Florida Power's standard offer tariff did not mention a comparative evaluation/open season process. [Tr. 34, line 5 - Tr. 35, line 3]

RULING: Accepted with the modification that FPC's standard offer tariff does not mention any evaluation method.

21. Florida Power's standard offer tariff was approved on September 12, 1991, and became effective on September 20, 1991. [Tr. 33, lines 4-6; FPC Exhibit 1, Section X, Memo from R. D. Dolan to File: See Tr. 72, lines 9-12]

RULING: Accepted and incorporated.

22. Florida Power's comparative evaluation/open season process was never reviewed or approved by the Commission. [Tr. 34, line 5 - Tr. 35, line 3]

RULING: Accepted with the clarification that prior approval of the comparative evaluation/open season was not required under the rule and by our decision in this matter is explicitly approved.

23. ARK/NOAH accepted the standard offer tariff at 7:35 a.m. on September 20, 1991 by hand-delivery of a completed standard offer contract to Florida [*17] Power in St. Petersburg, Florida. [Tr. 464, lines 10-13].

RULING: Accepted and incorporated.

24. Once ARK/NOAH accepted Florida Power's standard offer contract on September 20, only 10 MW remained to be subscribed, under the Commission's rule and the terms of Florida Power's tariff. [FPC Exhibit 1, Standard Offer Contract Tariff, Original Reissue Sheets Nos. 9.511 and 9.710]

RULING: Rejected as a Conclusion of Law, however we accepted as fact that ARK/NOAH offered to provide 70 MW of the 80 MW subscription limit.

25. ARK/NOAH contacted Florida Power prior to the standard offer contract's effective date, and inquired where to file the contract and how early the office would open on September 20. [Tr. 463, line 18 - Tr. 464, line 3; Tr. 502, line 25 - Tr. 503, line 9].

RULING: Accepted and incorporated.

26. As of November 19, 1991, ample capacity remained in FGT's Phase III pipeline expansion to serve ARK/NOAH's fuel requirements. [Tr. 437, 541, line 19 - Tr. 542, line 8]

RULING: Accepted and incorporated.

27. On June 20, 1991 the appropriate reservation deposit was made on behalf of ARK to reserve Phase III capacity for the ARK/NOAH project and other [*18] ARK projects in Florida. [Tr. 441, lines 11-12]

RULING: Accepted and incorporated.

28. ARK/NOAH have numerous options available to it for fuel supply in 1997. [Tr. 188, lines 2-11; Tr. 437, line 14 - Tr. 438, line 2; Tr. 542, line 14 - Tr. 543, line 1].

RULING: Rejected to the extent that numerous is too indefinite.

29. ARK/NOAH's cogeneration facility will have dual fuel capability, so if necessary, ARK/NOAH will use an alternative fuel as a bridge measure. [Tr. 188, lines 6-11; Tr. 437, line 20 - Tr. 438, line 22; Tr. 542, line 20 - Tr. 543, line 1].

RULING: Accepted and incorporated.

30. Florida Power rated ARK/NOAH's Lake County project "good" with respect

to fuel transportation. [FPC Exhibit 1, p. 19,25].

RULING: Accepted and incorporated.

31. Liquid carbon dioxide plants are widely recognized as viable thermal hosts for qualifying cogeneration facilities. [Tr. 535, line 19 - 536, line 3].

RULING: Accepted and incorporated without the word "widely."

32. Florida Power itself has sought and obtained approval of a negotiated contract for a cogeneration facility with a carbon dioxide plant as its thermal host. [Tr. 189, line 21 - Tr. 194, [*19] line 2].

RULING: Accepted and incorporated.

33. The Florida Power plant referred to in the above Proposed Finding of Fact is scheduled to be built in less than half the time available to ARK/NOAH for the Lake County project. [Tr. 192, line 16 - Tr. 193, line 13; Tr. 543, line 17 - Tr. 544, line 10]

RULING: Accepted and incorporated.

34. Florida Power produced no evidence that the plant referred to in Proposed Finding 32 will be unable to come on line because of lack of a CO2 thermal host. [Tr. 97, line 18 - Tr. 98, line 11].

RULING: Rejected as irrelevant.

35. The sum total of Florida Power's allegation that ARK/NOAH's project is not viable is Florida Power's subjective rating of the project as "poor" with respect to thermal host, because of the absence of a letter of intent to construct the CO2 plant, and undocumented "doubts" concerning ARK/NOAH's ability to access the CO2 market. [FPC Exhibit 1, p. 22; Tr. 97, lines 7-18].

RULING: Rejected as argument rather than a finding of fact.

36. ARK/NOAH have a ready market for the carbon dioxide produced at its Lake County Facility, and has already granted a "right of first refusal" to a CO2 marketer. [Tr. [*20] 546, line 14-24]

RULING: Rejected as unsupported by the evidence of record.

37. Florida Power never formally advised potential QF's of its comparative evaluation/open season. [Tr. 119, line 6 - Tr. 123, line 14]

RULING: Rejected. The term "formally" is not adequately defined.

38. Florida Power's evaluation and scoring criteria never made a part of the record of Docket No. 910004-EU.

RULING: Rejected as irrelevant, based on our determination that the open season was proper under the rule.

39. ARK/NOAH had no communication with Panda Kathleen prior to filing its

acceptance of the standard offer contract. [Tr. 152, line 18 - Tr. 153, line 20]

RULING: Accepted and incorporated.

40. Panda made its decision when to file based on the representations of Florida Power and allegedly others, but not on any representations or communication by ARK/NOAH. [Tr. 152, line 18 - Tr. 153, line 20]

RULING: Accepted and incorporated.

3

structural failure of the airframe. accomplish a comprehensive inspection of all areas modified by The Raisbeck Group. as follows:

A. Before further flight. inspect for deviations from the supplemental type design in accordance with Paragraphs I through IV. and VI. of FAA approved Raisbeck Service Bulletin No. 25. Inspect for discrepancies such as:

1. Plugged holes
2. Oblong. eggshaped. oversized. or irregular holes
3. Tapered holes
4. Excess holes
5. Inadequate edge distances
6. Gouges
7. Improper fasteners (type and number)
8. Improper clearances
9. Any other irregularities which are not consistent with standard aircraft practice.

B. Before accumulation of 2.000 flight hours time-in-service after modification by STC SA667NW inspect the horizontal stabilizer and elevator in accordance with Paragraphs V(A) and V(B) of FAA approved Raisbeck Service Bulletin No. 25. Repeat this inspection at intervals not exceeding 5.000 flight hours time-in-service thereafter.

C. Before accumulation of 2.000 flight hours time-in-service after modification by STC SA667NW or STC SA847NW. inspect the wing leading edge in accordance with Paragraph V(D) of FAA approved Raisbeck Service Bulletin No. 25. Repeat this inspection at intervals not exceeding 5.000 flight hours time-in-service thereafter.

D. Before accumulation of 10.000 flight hours time-in-service after modification by STC SA667NW or STC SA847NW. inspect the overwing modification in accordance with Paragraph V(C) of FAA approved Raisbeck Service Bulletin No. 25. Repeat this inspection at intervals not exceeding 10.000 flight hours time-in-service thereafter.

E. Inspections are to be conducted at facilities specifically authorized by the Chief. Engineering and Manufacturing Branch. FAA Northwest Region.

F. Discrepancies discovered as a result of the inspections are to be reported to the Chief. Engineering and Manufacturing Branch. FAA Northwest Region. Repair or modifications required because of these problems are to be FAA approved by the Chief. Engineering and Manufacturing Branch. FAA. Northwest Region or specifically authorized DERs.

G. Airplanes may be ferried. in accordance with FAR 21.199. to a maintenance base. for the purpose of complying with this AD.

H. The inspections noted herein may be accomplished as noted or in a manner approved by the Chief. Engineering and Manufacturing Branch. FAA. Northwest Region.

I. Areas previously inspected in accordance with Amendment 39–3660 may be excluded from the inspections required by this AD.

The manufacturer's specifications and procedures identified and described in this directive are incorporated herein and made a part hereof pursuant to 5 U.S.C. 552(a)(1).

All persons affected by this directive who have not already received these documents from the manufacturer, may obtain copies upon request to The Raisbeck Group. 7777 Perimeter Road. Seattle. Washington 98108.

This amendment becomes effective upon publication in the Federal Register and was effective earlier to all recipients of the telegraphic AD T80–NW–2 dated January 17. 1980.

(Secs. 313(1). 601. and 603. Federal Aviation Act of 1958. as amended (49 U.S.C. 1354(a). 1421. and 1423) and Section 6(c) of the Department of Transportation Act (49 U.S.C. 1655(c)); and 14 CFR 11.89)

Note.—The FAA has determined that this document involves a regulation which is not considered to be significant under the provisions of Executive Order 12044 and as implemented by Department of Transportation Regulatory Policies and Procedures (44 FR 11034: February 26. 1979).

Issued in Seattle. Washington. on February 13. 1980.

Note.—The incorporation by reference provisions in the document were approved by the Director of the Federal Register on June 19. 1967.

C. B. Walk. Jr.,

Director. Northwest Region.

[FR Doc. 80-[illegible] Filed 2-22-80; 8:45 am]

BILLING CODE 4910-13-M

OFFICE OF THE UNITED STATES TRADE REPRESENTATIVE

15 CFR Chapter XX

CFR Chapter Heading and Nomenclature Change

February 19. 1980.

AGENCY: Office of the United States Trade Representative.

ACTION: Final rule.

SUMMARY: This rule changes Chapter XX of Title 15. Code of Federal Regulations. from "Office of the Special Representative for Trade Negotiations" to "Office of the United States Trade Representative." Within the body of the Chapter XX. all references to the "Office of the Special Representative for Trade Negotiations". to the "Special Representative for Trade Negotiations" and to the "Special Representative" or "Deputy Special Representative" are changed to the "Office of the United States Trade Representative". to "the United States Trade Representative". and the "Trade Representative" or "Deputy Trade Representative" respectively. These changes are authorized as part of Reorganization Plan No. 3 of 1979 (44 FR 69273) which was implemented by Executive Order No. 12188 of January 2. 1980 (45 FR 989).

EFFECTIVE DATE: February 25. 1980.

FOR FURTHER INFORMATION CONTACT: Alice Zalik. General Council's Office. Office of the United States Trade Representative. 1800 G Street. NW., Washington. D.C. 20506. (202) 395-34[illegible]

Accordingly. each reference to "the Office of the Special Representative for Trade Negotiations" contained within Chapter XX of Title 15 of the Code of Federal Regulations. including the heading. is changed to "the Office of the United States Trade Representative". Each reference to "the Special Representative for Trade Negotiations" contained within the chapter is changed to "the United States Trade Representative". Each reference to the "Special Representative" and to the "Deputy Special Representative" is changed to the "Trade Representative" and to the "Deputy Trade Representative" respectively.

Robert C. Cassidy,

General Counsel.

[FR Doc. 80-[illegible] Filed 2-22-80; 8:45 am]

BILLING CODE 3190-01-M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 292

[Docket No. RM79–55, Order No. 69]

Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations that implement section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). The rules require electric utilities to purchase electric power from and sell electric power to qualifying cogeneration and small power production facilities. and provide for the exemption of qualifying facilities from certain federal and State regulation. Implementation of these rules is reserved to State regulatory authorities and nonregulated electric utilities.

EFFECTIVE DATE: March 20. 1980.

FOR FURTHER INFORMATION CONTACT:

Ross Ain. Office of the General Counsel. Federal Energy Regulatory Commission. 825 North Capitol Street. N.E.. Washington D.C. 20426. 202–357–8446.

John O'Sullivan. Office of the General Counsel. Federal Energy Regulatory Commission. 825 North Capitol Street. N.E. Washington. D.C. 20426. 202–357–8477

Adam Wenner. Office of the General Counsel. Federal Energy Regulatory Commission. 825 North Capitol Street. N.E. Washington. D.C. 20426. 202–357–8033

Bernard Chew, Office of Electric Power Regulation, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-376-9294.

SUPPLEMENTARY INFORMATION:

Issued February 19, 1980.

Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) requires the Federal Energy Regulatory Commission (Commission) to prescribe rules as the Commission determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from and sell electric power to cogeneration and small power production facilities. Additionally, section 210 of PURPA authorizes the Commission to exempt qualifying facilities from certain Federal and State law and regulation.

Under section 201 of PURPA, cogeneration facilities and small power production facilities which meet certain standards and which are not owned by persons primarily engaged in the generation or sale of electric power can become qualifying facilities, and thus become eligible for the rates and exemptions set forth under section 210 of PURPA.

Cogeneration facilities simultaneously produce two forms of useful energy, such as electric power and steam. Cogeneration facilities use significantly less fuel to produce electricity and steam (or other forms of energy) than would be needed to produce the two separately. Thus, by using fuels more efficiently, cogeneration facilities can make a significant contribution to the Nation's effort to conserve its energy resources.

Small power production facilities use biomass, waste, or renewable resources, including wind, solar and water, to produce electric power. Reliance on these sources of energy can reduce the need to consume traditional fossil fuels to generate electric power.

Prior to the enactment of PURPA, a cogenerator or small power producer seeking to establish interconnected operation with a utility faced three major obstacles. First, a utility was not generally required to purchase the electric output, at an appropriate rate. Secondly, some utilities charged discriminatorily high rates for back-up service to cogenerators and small power producers. Thirdly, a cogenerator or small power producer which provided electricity to a utility's grid ran the risk of being considered an electric utility and thus being subjected to State and Federal regulation as an electric utility.

Sections 201 and 210 of PURPA are designed to remove these obstacles. Each electric utility is required under section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which obtain qualifying status under section 201 of PURPA. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, in the public interest, and which do not discriminate against cogenerators or small power producers. Section 210 also requires electric utilities to provide electric service to qualifying facilities at rates which are just and reasonable, in the public interest, and which do not discriminate against cogenerators and small power producers. Section 210(e) of PURPA provides that the Commission can exempt qualifying facilities from State regulation regarding utility rates and financial organization, from Federal regulation under the Federal Power Act (other than licensing under Part I), and from the Public Utility Holding Company Act.

I. Procedural History

On June 26, 1979, in Docket No. RM79-54,[1] the Commission issued proposed rules to determine which cogeneration and small power production facilities may become "qualifying" cogeneration or small power production facilities under section 201 PURPA. Such qualifying facilities are entitled to avail themselves of the rate and exemption provisions under section 210 of PURPA; and qualifying cogeneration facilities are eligible for exemption from incremental pricing under Title II of the Natural Gas Policy Act of 1978.[2] The Commission will soon issue a final rule in Docket No. RM79-54.

As part of the rulemaking process in this docket, the Commission issued a Staff Discussion Paper[3] on June 27, 1979, addressing issues arising under section 210 of PURPA.

Public hearings on RM79-54 and the Staff Discussion Paper (RM79-55) were held in San Francisco on July 23, 1979, Chicago on July 27, 1979, and Washington, D.C. on July 30, 1979. Written comments were also received.

On October 18, 1979, the Commission issued a Notice of Proposed Rulemaking under Section 210 of PURPA in Docket No. RM79-55.[4] On October 19, 1979, the Commission made available its preliminary Environmental Assessment (EA) of the proposed rules in Docket Nos. RM79-54 and RM79-55. In a Request for Further Comments,[5] the Commission requested further public comment on both proposed rules, and on the findings set forth in the preliminary EA. In order to obtain the data, views, and arguments of interested parties, the Commission Staff held public hearings in Seattle on November 19, 1979, in New York on November 28, 1979, in Denver on November 30, 1979, and in Washington, D.C. on December 4 and 5, 1979. The Commission also received written comment.

After consideration of the comments, the Commission Staff made available a final draft rule on January 29, 1980. State public utility commissioners were invited to comment on the draft at a public meeting held on February 5, 1980. Representatives of electric utilities were invited to comment at a public meeting held on February 6, 1980. The Commission Staff also made itself available to any other interested parties who wished to comment. All of the comments were considered in the formulation of this final rule.

In the Staff Discussion Paper and the Request for Further Comments, it was stated that any environmental effects attributable to this program would result from the combined effect of these two rulemaking proceedings. As noted previously, the Commission intends to issue final rules in Docket No. RM79-54 in the near future. At that time, the Commission will also make available its final Environmental Assessment.

II. Summary

These rules provide that electric utilities must purchase electric energy and capacity made available by qualifying cogenerators and small power producers at a rate reflecting the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers. To enable potential cogenerators and small power producers to be able to estimate these avoided costs, the rules require electric utilities to furnish data concerning present and future costs of energy and capacity on their systems.

These rules also provide that electric utilities must furnish electric energy to qualifying facilities on a nondiscriminatory basis, and at a rate that is just and reasonable and in the public interest; and that they must provide certain types of service which may be requested by qualifying facilities to supplement or back up those facilities' own generation.

[1] 44 FR 38873, July 3, 1979.

[2] 44 FR 65744, November 15, 1979.

[3] 44 FR 38863, July 3, 1979.

[4] 44 FR 61190, October 24, 1979.

[5] 44 FR 61977, October 29, 1979.

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The rule exempts all qualifying cogeneration facilities and certain qualifying small power production facilities from certain provisions of the Federal Power Act, from all of the provisions of the Public Utility Holding Company Act of 1935 related to electric utilities, and from State laws regulating electric utility rates and financial organization.

The implementation of these rules is reserved to the State regulatory authorities and nonregulated electric utilities. Within one year of the issuance of the Commission's rules, each State regulatory authority or nonregulated utility must implement these rules. That implementation may be accomplished by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the Commission's rules.

III. Section-by-Section Analysis

Subpart A—General Provisions

§ 292.101 Definitions.

This section contains definitions applicable to this part of the Commission's rules. Paragraph (a) provides that terms defined in PURPA have the same meaning as they have in PURPA, unless further defined in this part of the Commission's regulations. The definitions in PURPA are found in section 3 of that Act.

Subparagraph (1) defines a qualifying facility as a cogeneration or small power production facility which is a qualifying facility under Subpart B of the Commission's regulations. Those regulations implement section 201 of PURPA, and are the subject of Docket No. RM79-54.

Subparagraph (2) defines "purchase" as the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

Subparagraph (3) defines "sale" as the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

In the proposed rule, subparagraph (4) defined "system emergency" as a condition on a utility's system "which is likely to result in disruption of service to a significant number of customers or is likely to endanger life or property." In response to comments noting the difficulty in determining what constitutes a "significant number" of customers, the Commission has amended the definition to "a condition on an electric utility's system which is likely to result in imminent significant disruption of service to customers, or is imminently likely to endanger life or property." The emphasis is placed on the significance of the disruption of service, rather than on the number of customers affected.

Subparagraph (5) defines "rate" as any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

In the proposed rule, subparagraph (6) defined "avoided costs" as the costs to an electric utility of energy or capacity or both which, but for the purchase from a qualifying facility, the electric utility would generate or construct itself or purchase from another source. This definition is derived from the concept of "the incremental cost to the electric utility of alternative electric energy" set forth in section 210(d) of PURPA. It includes both the fixed and the running costs on an electric utility system which can be avoided by obtaining energy or capacity from qualifying facilities.

The costs which an electric utility can avoid by making such purchases generally can be classified as "energy" costs or "capacity" costs. Energy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel, and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities.

If, by purchasing electric energy from a qualifying facility, a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for a purchase from a qualifying facility is to be based on those energy costs which the utility can thereby avoid. If a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility, then the rates for such a purchase will be based on the avoided capacity and energy costs.

The Commission has added the term "incremental" to modify the costs which an electric utility would avoid as a result of making a purchase from a qualifying facility. Under the principles of economic dispatch, utilities generally turn on last and turn off first their generating units with the highest running cost. At any given time, an economically dispatched utility can avoid operating its highest-cost units as a result of making a purchase from a qualifying facility. The utility's avoided incremental costs (and not average system costs) should be used to calculate avoided costs. With regard to capacity, if a purchase from a qualifying facility permits the utility to avoid the addition of new capacity, then the avoided cost of the new capacity and not the average embedded system cost of capacity should be used.

Many comments noted that the definition of "avoided cost" in the proposed rule failed to link the capacity costs which a utility might avoid as a result of purchasing electric energy or capacity or both from a qualifying facility with the energy costs associated with the new capacity. If the Commission required electric utilities to base their rates for purchases from a qualifying facility on the high capital or capacity cost of a base load unit and, in addition, provided that the rate for the avoided energy should be based on the high energy cost associated with a peaking unit, the electric utilities' purchased power expenses would exceed the incremental cost of alternative electric energy, contrary to the limitation set forth in the last sentence of section 210(b).

One way of determining the avoided cost is to calculate the total (capacity and energy) costs that would be incurred by a utility to meet a specified demand in comparison to the cost that the utility would incur if it purchased energy or capacity or both from a qualifying facility to meet part of its demand, and supplied its remaining needs from its own facilities. The difference between these two figures would represent the utility's net avoided cost. In this case, the avoided costs are the excess of the total capacity and energy cost of the system developed in accordance with the utility's optimal capacity expansion plan,[6] *excluding* the qualifying facility, over the total capacity and energy cost of the system (before payment to the qualifying facility) developed in accordance with the utility's optimal capacity expansion plan *including* the qualifying facility.[7]

Subparagraph (7) defines "interconnection costs" as the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and

[6] An optimal capacity expansion plan is the schedule for the addition of new generating and transmission facilities which, based on an examination of capital, fuel, operating and maintenance costs, will meet a utility's projected load requirements at the lowest total cost.

[7] Throughout the rule and preamble, the phrase "energy or capacity" is used. This phrase is intended to include the capacity and energy costs associated with the capacity, if the purchase involves both energy or capacity.

administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

The Commission has clarified this definition to include distribution and administrative costs associated with the interconnected operation, in response to comments indicating that the proposed rule was vague in these respects. This definition is designed to provide the State regulatory authorities and nonregulated electric utilities with the flexibility to ensure that all costs which are shown to be reasonably incurred by the electric utility as a result of interconnection with the qualifying facility will be considered as part of the obligation of the qualifying facility under § 292.306. These costs may include, but are not limited to, operating and maintenance expenses, the costs of installation of equipment elsewhere on the utility's system necessitated by the interconnection, and reasonable insurance expenses. However, the Commission does not expect that litigation expenses incurred by the utility involving this section will be considered a legitimate interconnection cost to be borne by the qualifying facility.

Certain interconnection costs may be incurred as a result of sales from a utility to a qualifying facility. The Commission notes that the Joint Explanatory Statement of the Committee of Conference (Conference Report) prohibits the use of "unreasonable rate structure impediments, such as unreasonable hook up charges or other discriminatory practices . . ." [7] This prohibition is reflected in § 292.306(a) of these rules, which provides that interconnection costs must be assessed on a nondiscriminatory basis with respect to other customers with similar load characteristics.

A qualifying facility which is already interconnected with an electric utility for purposes of sales may seek to establish interconnection for the purpose of utility purchases from the qualifying facility. In this case, the qualifying facility may have compensated the utility for its interconnection costs with respect to sales to the qualifying facility, either as part of the utility's demand or energy charges, or through a separate customer charge. If this is the case, the interconnection costs associated with the purchase include only those additional interconnection expenses incurred by the electric utility as a result of the purchase, and do not include any portion of the interconnection costs for which the qualifying facility has already paid through its retail rates.

One comment recommended that the definition be revised to cover "all identifiable costs, including but not limited to, the costs of interconnection . . . resulting from interconnected operation". The Commission rejects this suggestion in order to maintain consistency with its initial determination to separate the utility's avoided costs with regard to purchases from qualifying facilities, from the costs incurred as a result of interconnection with a qualifying facility. Accordingly, legitimate costs not recovered pursuant to this section can be netted out in the calculation of avoided costs.

This definition also incorporates the concept from the proposed rule, as clarified in an erratum notice,[8] that these costs are limited to the net increased interconnection costs imposed on an electric utility compared to those interconnection costs it would have incurred had it generated the energy itself or purchased an equivalent amount of energy or capacity from another source.

This section of the rule contains definitions of "supplementary power", "back-up power", "interruptible power", and "maintenance power" which did not appear in the proposed rule.

Subparagraph (8) defines "supplementary power" as electric energy or capacity, supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

Subparagraph (9) defines "back-up power" as electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

Subparagraph (10) defines "interruptible power" as electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

Subparagraph (11) defines "maintenance power" as electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

Subpart C—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978

§ 292.301 *Scope.*

Section 292.301(a) describes the scope of Subpart C of Part 292 of the Commission's rules. Subpart C applies to sales and purchases of electric energy or capacity between qualifying cogeneration or small power production facilities and electric utilities, and actions related to such sales and purchases. Section 292.301(b)(1) provides that this subpart does not preclude negotiated agreements between qualifying cogenerators or small power producers and electric utilities which differ from rates, or terms or conditions which would otherwise be required under the subpart. Paragraph (b)(2) states that this subpart does not affect the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.[10]

Paragraph (b)(1) reflects the Commission's view that the rate provisions of section 210 of PURPA apply only if a qualifying cogenerator or small power production facility chooses to avail itself of that section. Agreements between an electric utility and a qualifying cogenerator or small power producer for purchases at rates different than rates required by these rules, or under terms or conditions different from those set forth in these rules, do not violate the Commission's rules under section 210 of PURPA. The Commission recognizes that the ability of a qualifying cogenerator or small power producer to negotiate with an electric utility is buttressed by the existence of the rights and protections of these rules.

Some comments stated that paragraph (b)(2) would unfairly penalize cogenerators and small power producers who, prior to the promulgation of these regulations, entered into binding contracts with electric utilities under less favorable terms than might be obtainable under these rules. The Commission interprets its mandate under section 210(a) to prescribe "such rules as it determines necessary to encourage cogeneration and small

[7] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 95th Cong., 2d Sess. (1978).

[8] 44 FR 63114, November 2, 1979.

[10] The term "purchase" is defined in § 292.101(b)

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power production * * *" to mean that the total costs to the utility and the rates to its other customers should not be greater than they would have been had the utility not made the purchase from the qualifying facility or qualifying facilities. That a cogeneration or small power production facility entered into a binding contractual arrangement with an electric utility indicates that it is likely that sufficient incentive existed, and that the further encouragement provided by these rules was not necessary. As a result, the Commission has not revised this provision.

§ 292.302 *Availability of electric utility system cost data.*

As the Commission observed in the Notice of Proposed Rulemaking, in order to be able to evaluate the financial feasibility of a cogeneration or small power production facility, an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility. This return will be determined in part by the price at which the qualifying facility can sell its electric output. Under § 292.304 of these rules, the rate at which a utility must purchase that output is based on the utility's avoided costs, taking into account the factors set forth in paragraph (e) of that section. Section 292.302 of these rules is intended by the Commission to assist those needing data from which avoided costs can be derived. It requires electric utilities to make available to cogenerators and small power producers data concerning the present and anticipated future costs of energy and capacity on the utility's system.

In the preamble to the proposed rule, the Commission stated that most electric utilities will have prepared data containing some of this information in compliance with the Commission's rules implementing section 133 of PURPA. Several commenters observed that the marginal cost data required to be provided pursuant to section 133 cannot be directly translated into a rate for purchases. The Commission has clarified paragraph (b) to emphasize that these data are not intended to represent a rate for purchases from qualifying facilities. Rather, these data are to be considered the first step in the determination of such a rate.

The Commission has also revised this section so that the rates for purchases can be more readily calculated from the data produced. The Commission has changed paragraph (b)(3) to provide that a utility shall submit the associated energy cost of each planned unit expressed in kilowatt-hours (kWh) along with the estimated capacity cost of planned capacity additions. This change is intended to ensure that the calculation of avoided costs includes the lower energy costs that might be associated with the new capacity. The Commission points out that the determination of a rate for purchases from a qualifying facility which enables a utility to defer or avoid the addition of a new unit must also reflect the hours of expected use of the deferred or avoided capacity addition.

The coverage under paragraph (a) of this section is the same as that provided pursuant to section 133 of PURPA and the Commission's rules implementing that section.[11] As noted in the Notice of Proposed Rulemaking, section 133 of PURPA applies to each electric utility whose total sales of electric energy for purposes other than resale exceeded 500 million kWh during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

Paragraph (b) provides that each regulated electric utility meeting the requirements of paragraph (a) must furnish to its State regulatory authority, and maintain for public inspection, data related to the costs of energy and capacity on the electric utility's system. Each nonregulated electric utility also must maintain such data for public inspection.

In response to comments received, the Commission has extended the date by which these data must be first provided to November 1, 1980, and changed the second date to May 31, 1982, to conform to the dates required by the Commission's regulations implementing section 133 of PURPA. The Commission has added paragraph (d) to allow a State regulatory authority or nonregulated utility to use a different approach than that provided in paragraph (b). As part of that substitute program, a State regulatory authority or nonregulated electric utility could provide that cost data be updated more frequently than every two years.

Subparagraph (1) of paragraph (b) requires each electric utility to provide the estimated avoided cost of energy on its system for various levels of purchases from qualifying facilities. The levels of purchases are to be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than ten percent of system peak demand for systems less than 1000 megawatts. This information is to be stated on a cents per kilowatt-hour basis, for daily and seasonal peak and off-peak periods, for the current calendar year and for each of the next five years.

Subparagraph (2) of paragraph (b) requires each electric utility to provide its schedule for the addition of capacity, planned purchases of firm energy and capacity, and planned capacity retirements for each of the next ten years.

Subparagraph (3) of paragraph (b) has been revised, as discussed previously, so that the costs of planned capacity additions include the associated energy costs.

The Commission received comment noting that some States have implemented or are planning to implement alternative methods by which electric utilities' system cost data would be made available. In order to prevent the preparation of duplicative data where the alternative method substantially deviates from the Commission approach, the Commission has added paragraph (d). This paragraph provides that any State regulatory authority or nonregulated electric utility may, after providing public notice in the area served by the utility and after opportunity for public comment, require data different than that which are otherwise required by this section if it determines that avoided costs can be derived from such data. Any State regulatory authority or nonregulated utility shall notify the Commission within 30 days of any determination to sustitute data requirements.

If a qualifying facility finds that the alternative requirements do not provide sufficient data from which avoided costs may be derived, the qualifying facility may seek court review of the matter as it can with regard to any other aspect of the State's implementation of this program.

A qualifying facility may wish to sell energy or capacity to an electric utility which is not subject to the reporting requirements of paragraph (b). In that event, paragraph (c) provides that, upon request of a qualifying facility, an electric utility not otherwise covered by paragraph (b) must provide data sufficient to enable the cogenerator or small power producer to estimate the utility's avoided costs. If such utility does not supply the requested data, the qualifying facility may apply to the State regulatory authority which has ratemaking authority over the utility or to this Commission for an order requiring that the information be supplied. The consideration of such applications should take into account the burden imposed on the small utilities.

[11] 44 FR 58687 October 11, 1979

An electric utility which is legally obligated to obtain all of its requirements for electric energy and capacity from another utility may provide the data provided by its supplying utility and the rates at which it currently purchases such energy and capacity for any period during which this obligation will continue. The wholesale rates may require adjustment in order to reflect properly the avoided costs. This is discussed later in this preamble under § 292.303. In the case of small, non-generating utilities, the requirements of this section will be considered to have been satisfied if these cost data are readily available from the supplying utility.

Numerous comments mentioned that the proposed rule did not address the issue of validation of the data to be provided pursuant to this section. As a result, the Commission has added paragraph (e) which provides that any data submitted by an electric utility under this section shall be subject to review by its State regulatory authority. Paragraph (e)(2) places the burden of providing support for the data on the utility supplying the data.

§ 292.303 Electric utility obligations under this subpart.

Section 210(a) of PURPA provides that the Commission prescribe rules requiring electric utilities to offer to purchase electric energy from qualifying facilities. The Commission interprets this provision to impose on electric utilities an obligation to purchase all electric energy and capacity made available from qualifying facilities with which the electric utility is directly or indirectly interconnected, except during periods described in § 292.304(f) or during system emergencies.

A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load. These rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale.

§ 292.303(a) Obligation to purchase from qualifying facilities.

§ 292.303(d) Transmission to other electric utilities. All-Requirement Contracts

Several commenters noted that the obligation to purchase from qualifying facilities under this section might conflict with contractual commitments into which they had entered requiring them to purchase all of their requirements from a wholesale supplier. One commenter noted that, with regard to all-requirements rural electric cooperatives, any impairment of the obligation to obtain all of a cooperative's requirements from a generation and transmission cooperative might affect the financing ability of the generation and transmission cooperative. The Commission observes that, in general, if it permitted such contractual provisions to override the obligation to purchase from qualifying facilities, these contractual devices might be used to hinder the development of cogeneration and small power production. The Commission believes that the mandate of PURPA to encourage cogeneration and small power production requires that obligations to purchase under this provision supersede contractual restrictions on a utility's ability to obtain energy or capacity from a qualifying facility.

The Commission has, however, provided an alternate means by which any electric utility can meet this obligation. Under paragraph (d), if the qualifying facility consents, an all-requirements utility which would otherwise be obligated to purchase energy or capacity from the qualifying facility would be permitted to transmit the energy or capacity to its supplying utility. In most instances, this transaction would actually take the form of the displacement of energy or capacity that would have been provided under the all-requirements obligation. In this case, the supplying utility is deemed to have made the purchase and, as a result the all-requirements obligation is not affected.

In addition, if compliance with the purchase obligation would impose a special hardship on an all-requirements customer, the Commission may consider waiving such purchase obligation pursuant to the procedures set forth in § 292.403.

Transmission to Other Facilities

There are several circumstances in which a qualifying facility might desire that the electric utility with which it is interconnected not be the purchaser of the qualifying facility's energy and capacity, but would prefer instead that an electric utility with which the purchasing utility is interconnected make such a purchase. If, for example, the purchasing utility is a non-generating utility, its avoided costs will be the price of bulk purchased power ordinarily based on the average embedded cost of capacity and average energy cost on its supplying utility's system. As a result the rate to the qualifying facility would be based on those average costs. If, however, the qualifying facility's output were purchased by the supplying utility its output ordinarily will replace the highest cost energy on the supplying utility's system at that time, and its capacity might enable the supplying utility to avoid the addition of new capacity. Thus, the avoided costs of the supplying utility may be higher than the avoided cost of the non-generating utility.

This would not appear to be the case if the qualifying facility offers to supply capacity and energy in a situation in which the supplying utility is in an excess capacity situation. Since the supplying utility has excess capacity, its avoided costs would include only energy costs. On the other hand, if the avoided cost were based on the wholesale rate to the all-requirements utility, the avoided cost would include the demand charge included in the wholesale rate, which would usually reflect an allocation of a portion of the fixed charges associated with excess capacity.

Use of the unadjusted wholesale rate fails to take into account the effect of reduced revenue to the supplying utility, as a result of the substitute of the qualifying facility's output for energy previously supplied by the supplying utility. As the level of purchase by the all-requirements utility decreases, the supplying utility's fixed costs will have to be allocated over a smaller number of units of output. In effect, the loss in revenue to the supplying utility will cause the demand charges to the supplying utility's customers (including the all-requirements customers interconnected with the qualifying facility) to increase. Under the definition of "avoided costs" in this section, the purchasing utility must be in the same financial position it would have been had it not purchased the qualifying facility's output. As a result, rather than allocating its loss in revenue among all of its customers, in this situation the supplying utility should assign all of these losses to the all-requirements utility. That utility should, in turn, deduct these losses from its previously calculated avoided costs, and pay the qualifying facility accordingly.

Under these rules, certain small electric utilities are not required to provide system cost data, except upon request of a qualifying facility. If, with the consent of the qualifying facility, a small electric utility chooses to transmit energy from the qualifying facility to a second electric utility, the small utility can avoid the otherwise applicable requirements that it provide the system cost data for the qualifying facility and that it purchase the energy itself. However, the ability to transmit a purchase to another utility is not limited to these smaller systems: it applies to any utility.

Accordingly, paragraph (d) provides that a utility which receives energy or capacity from a qualifying facility may, with the consent of the qualifying facility, transmit such energy to another electric utility. However, if the first facility does not agree to transmit the purchased energy or capacity, it retains the purchase obligation. In addition, if the qualifying facility does not consent to transmission to another utility, the first utility retains the purchase obligation. Any electric utility to which such energy or capacity is delivered must purchase this energy under the obligations set forth in these rules as if the purchase were made directly from the qualifying facility.

One commenter stated that this provision could result in energy being transmitted to a utility which has little or no information regarding the reliability of the qualifying facility. The Commission believes that, prior to these transactions occurring, it will be in the interest of the qualifying facility to inform any utility to which energy or capacity is delivered, of the nature of those deliveries, so that such energy or capacity can be usefully integrated into that utility's power supply.

Several other commenters believed that this provision went beyond the authority of section 210 of PURPA—namely, that the Commission cannot require the first utility to wheel the power nor the second utility to buy the power. First, the Commission notes that this transmission can only occur with the consent of the utility to which energy or capacity from the qualifying facility is made available. Thus, no utility is forced to wheel. Secondly, section 210 does not limit the obligation to purchase to any particular utility: rather, it is a generally applicable requirement.

Paragraph (d) provides that charges for transmission are not a part of the rate which an electric utility to which energy is transmitted is obligated to pay the qualifying facility. In the case of electric utilities not subject to the jurisdiction of this Commission, these charges should be determined under applicable State law or regulation which may permit agreement between the qualifying facility and any electric utility which transmits energy or capacity with the consent of the qualifying facility. For utilities subject to the Commission's jurisdiction under Part II of the Federal Power Act, these charges will be determined pursuant to Part II.

The electric utility to which the electric energy is transmitted has the obligation to purchase the energy at a rate which reflects the costs that it can avoid as a result of making such a purchase. In cases in which electricity actually travels across the transmitting utility's system, the amount of energy delivered will be less than that transmitted, due to line losses. When this occurs, the rate for purchase can reflect these losses. In other cases, the energy supplied by the qualifying facility will displace energy that would have been supplied by the purchasing utility to the transmitting utility. In those cases, a unit of energy supplied from the qualifying facility may replace a greater amount of energy from the purchasing utility. In that case, the rate for purchase should be increased to reflect the net gain. These provisions are also set forth in paragraph (d).

§ 292.303(b) Obligation to sell to qualifying facilities.

Paragraph (b) sets forth the statutory requirement of section 210(a) of PURPA that each electric utility offer to sell electric energy to qualifying facilities. The Commission observed in the Notice of Proposed Rulemaking that State law ordinarily sets out the obligation of an electric utility to provide service to customers located within its service area. In most instances, therefore, this rule will not impose additional obligations on electric utilities.

It is possible that a qualifying facility located outside the service area of an electric utility might require back-up, maintenance, or other types of power. The Commission believes that the instructions of section 210(a) of PURPA that it issue rules "as it determines necessary to encourage cogeneration and small power production * * *" mandate that it assure that such facilities are able to fulfill their needs for service.

However, the Commission also recognizes that State and local law limits the authority of some electric utilities to construct lines outside of their service area. Accordingly, the Commission requires electric utilities to serve any qualifying facility, and, subject to the restriction contained therein, to interconnect with any such facility as required in paragraph (c). However, an electric utility is only required to construct lines or other facilities to the extent authorized or required by State or local law. As a result, a qualifying facility outside the service area of a utility may be required to build its line into the service area of the utility.

§ 292.303(c) Obligation to interconnect.

In the Notice of Proposed Rulemaking the Commission used the interpretation set forth in the Staff Discussion Paper that the obligation to interconnect with a qualifying facility is subsumed within the requirement of section 210(a) that electric utilities offer to sell electric energy to and purchase electric energy from qualifying facilities. The Commission observed that to hold otherwise would mean that Congress intended to require that qualifying facilities go through the complex procedures simply to gain interconnection, contrary to the mandate of section 210 of PURPA to encourage cogeneration and small power production.

During the comment period, this question was further explored, and it was suggested that the Commission has ample authority under the general mandate of section 210(a) of PURPA—namely, that it prescribe rules necessary to encourage cogeneration and small power production—to require interconnection.

While these interpretations received substantial support in the comments submitted, they were at the same time criticized on the theory that section 210(e)(3) of PURPA does not provide that a qualifying facility may be exempted from section 210 of the Federal Power Act (added by section 202 of PURPA and providing certain interconnection authority) and that this interconnection section specifically includes qualifying cogenerators and small power producers in its applicability. These commenters contended that since section 210 of the Federal Power Act deals explicitly with the subject of interconnections between qualifying facilities and electric utilities, no other section of that Act can be interpreted as also granting authority on that subject, as such an interpretation would render the express provision "surplusage".

With regard to these criticisms, the Commission observes that this argument might be tenable in the situation in which the section of the legislation which deals explicitly with the subject does not contain an express provision that it is *not* to be considered the exclusive authority on the subject. The Commission notes that section 212 of the Federal Power Act (as added by section 204 of PURPA) sets forth certain determinations that the Commission must make before it can issue an order under either section 210 or 211 of the Federal Power Act

Section 212(e) states that no provision of section 210 of the Federal Power Act shall be treated "(1) as requiring any person to utilize the authority of such section 210 or 211 in lieu of any other authority of law, or (2) as limiting, impairing, or otherwise affecting any other authority of the Commission under any other provision of law." Thus, the Federal Power Act, as amended, expressly provides that the existence of authority under section 210 of the Federal Power Act to require interconnection is not to be interpreted as excluding any other interconnection authority available under any other law. The Commission emphasizes that the limitation is not restricted to the Federal Power Act, but rather extends to include other authority of law, such as the authority contained in the Public Utility Regulatory Policies Act of 1978, of which section 210 is a part. Clearly, the existence of this provision refutes the contention that section 210 of the Federal Power Act represents the exclusive method by which interconnection can be obtained. As a result, the comment that the direction contained in section 210(e)(3) of PURPA that no qualifying facility can be exempted from section 210 or 212 of the Federal Power Act is not persuasive.

The Commission finds that to require qualifying facilities to go through the complex procedures set forth in section 210 of the Federal Power Act to gain interconnection would, in most circumstances, significantly frustrate the achievement of the benefits of this program. The Commission does not feel that the legal interpretation set forth in the Staff Discussion Paper and the Notice of Proposed Rulemaking is the exclusive theory by which it may require interconnections under this program without resort to sections 210 and 212 of the Federal Power Act. The interpretation brought out during the comment period—that section 210(a) of PURPA provides a general mandate for the Commission to prescribe rules necessary to encourage cogeneration and small power production—provides, in the Commission's view, sufficient authority to require interconnection. The Commission believes that a basic purpose of section 210 of PURPA is to provide a market for the electricity generated by small power producers and cogenerators. The Commission believes that accomplishment of this purpose would be greatly hindered if it were to require qualifying facilities to utilize section 210 of the Federal Power Act as the exclusive means of obtaining interconnection. It therefore concludes that such a restrictive interpretation of the law is not supportable.

Paragraph (c)(1) thus provides that an electric utility must make any interconnections with a qualifying facility which may be necessary to permit purchases from or sales to the qualifying facility. A State regulatory authority or nonregulated electric utility must enforce this requirement as part of its implementation of the Commission's rules.

In addition, several commenters contended that, if the obligation to interconnect is required under section 210(a) PURPA, the limitation provided in section 212 of the Federal Power Act would not be available. That limitation provides that an electric utility which complies with an interconnection order under section 210 of the Federal Power Act would not be subject to the jurisdiction of the Federal Energy Regulatory Commission for any purposes other than those specified in the interconnection order.

After consideration of this concern, the Commission has added paragraph (c)(2) to provide that no electric utility is required to interconnect with any qualifying facility, if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act. This exception is provided because the Commission notes that, in balance, the encouragement of cogeneration and small power production would not be furthered if, by virtue of interconnection with a qualifying facility, a previously nonjurisdictional utility were reluctantly to become subject to federal utility regulation.

§ 292.303(e) Parallel operation.

In the Notice of Proposed Rulemaking, the Commission provided that each electric utility must offer to operate in parallel with a qualifying facility, *provided that the qualifying facility* complies with standards established by the State regulatory authority or nonregulated electric utility with regard to the protection of system reliability pursuant to § 292.308. By operating in parallel, qualifying facilities are enabled to export automatically any electric energy which is not consumed by its own load. The comments submitted have not set forth any convincing reasons for changing the proposed rule. Paragraph (e) thus continues to require each electric utility to offer to operate in parallel with a qualifying facility.

§ 292.304 Rates for purchases.

Section 210(b) of PURPA provides that in requiring any electric utility to purchase electric energy from a qualifying facility, the Commission must ensure that the rates for the purchase be just and reasonable to the electric consumers of the purchasing utility, in the public interest, and nondiscriminatory to qualifying facilities, but that they not exceed the incremental costs of alternative electric energy (the costs of energy to the utility, which, but for the purchase, the utility would generate itself or purchase from another source).

Relation to State Programs

The Commission has become aware that several States have enacted legislation requiring electric utilities in that State to purchase the electrical output of facilities which may be qualifying facilities under the Commission's rules at rates which may differ from the rates required under the Commission's rules implementing section 210 of PURPA.

This Commission has set the rate for purchases at a level which it believes appropriate to encourage cogeneration and small power production, as required by section 210 of PURPA. While the rules prescribed under section 210 of PURPA are subject to the statutory parameters, the States are free, under their own authority, to enact laws or regulations providing for rates which would result in even greater encouragement of these technologies. However, State laws or regulations which would provide rates lower than the federal standards would fail to provide the requisite encouragement of these technologies, and must yield to federal law.

If a State program were to provide that electric utilities must purchase power from certain types of facilities, among which are included "qualifying facilities," at a rate higher than that provided by these rules, a qualifying facility might seek to obtain the benefits of that State program. In such a case, however, the higher rates would be based on State authority to establish such rates, and not on the Commission's rules.

A facility which provides energy or capacity to a utility under State authority may nevertheless seek to obtain exemption from the Federal Power Act, the Public Utility Holding Company Act, and State regulation of electric utilities as available under section 210(e) of PURPA. The Commission notes that the States lack the authority to exempt a facility from the Federal Power Act or Public Utility Holding Company Act. The Commission finds no inconsistency in a facility's taking advantage of section 210 in order to obtain one of its benefits, while relying on other authority under which to buy from or sell to a utility.

§ 292.304(a) Rates for purchases.

Paragraph (a) sets forth the statutory requirement that rates for purchases be just and reasonable to the electric consumers of the electric utility and in the public interest, and not discriminate against qualifying cogeneration and small power production facilities.

In the proposed rule, the Commission stated that there is a rebuttable presumption that the rate for purchases is acceptable if it reflects the avoided cost resulting from a purchase on the basis of system cost data set forth pursuant to § 292.302 (b) or (c). Many of the comments received stated that this section was ambiguous.[12] The Commission has therefore provided that the rate for purchases meets the statutory requirements if it equals avoided costs, and has eliminated the reference to the "rebuttable presumption".

Some comments recommended that, as a matter of policy, this section be revised to provide that a State regulatory authority or nonregulated utility has discretion to establish the relationship between the avoided cost and the rate for purchases. Other commenters contended that the Commission should specify that the rate for purchase must equal the avoided cost resulting from such a purchase. In addition, several suggested that the Commission adopt a "split-the-savings" approach.

It is possible that developers of technologies which may be included as qualifying facilities may produce and make available power to electric facilities even though their cost of producing this power is greater than the utility's avoided costs. In most instances, however, purchases of energy or capacity from qualifying facilities will only occur when the cost to the qualifying cogenerator or small power producer of producing the energy or capacity is lower than the utility's avoided costs. Only if this is the case will payment by the utility of its avoided costs provide economic benefit for the cogenerator or small power producer.

When one electric utility can provide energy more cheaply than could another electric utility, the two utilities will often exchange power on a "split-the-savings" basis. In that type of transaction, the two utilities split the difference between the incremental costs incurred and the incremental costs that the purchasing utility would have incurred had it generated the power itself. Several commenters argued that rates for purchases from qualifying facilities should be based upon this same general principle. The effect of such a pricing mechanism would be to transfer to the utility's ratepayers a portion of the savings represented by the cost differential between the qualifying facility and the purchasing electric utility. Several utilities contend that by so allocating these savings, the Commission would provide an incentive for the electric utility to enter into purchase transactions with qualifying cogeneration and small power production facilities.

These commenters also noted that they had previously engaged in purchases from facilities which might become qualifying facilities under the Commission's rules, and they had paid prices for these purchases based on a "split-the-savings" methodology. These commenters observed that if the Commission's rules now require the payment of full avoided cost for these types of purchases, the purchased power expenses of the electric utility would increase.

Moreover, several utilities commented that, for the forseeable future, they are inextricably tied to the use of oil to produce electricity. They contend that unless they are permitted to purchase energy and capacity from qualifying facilities at a rate somewhere between the qualifying facilities' costs and their own costs, they and their ratepayers will be subject to the continually increasing world price of oil.

Commenters opposing this allocation of savings to parties other than the qualifying facility noted that this section of PURPA is intended to encourage the development of cogeneration and small power production. They noted that in providing for this encouragement, the Commission may not set rates for purchases at a level which exceeds the incremental cost of alternative energy. Therefore, they observed that, under the full avoided cost standard, the utilities' customers are kept whole, and pay the same rates as they would have paid had the utility not purchased energy and capacity from the qualifying facility.

Although use of the full avoided cost standard will not produce any rate savings to the utility's customers, several commenters stated that these ratepayers and the nation as a whole will benefit from the decreased reliance of scarce fossil fuels, such as oil and gas, and the more efficient use of energy.

The Commission notes that, in most instances, if part of the savings from cogeneration and small power production were allocated among the utilities' ratepayers, any rate reductions will be insignificant for any individual customer. On the other hand, if these savings are allocated to the relatively small class of qualifying cogenerators and small power producers, they may provide a significant incentive for a higher growth rate of these technologies.

Another concern with the use of a split-the-savings rate for purchases is that it would require a determination of the costs of production of the qualifying facility. A major portion of this legislation is intended to exempt qualifying facilities from the cost-of-service regulation by which electric utilities traditionally have been regulated. The Conference Report noted that:

> It is not the intention of the Conferees that cogenerators and small power producers become subject . . . to the type of examination that is traditionally given to electric utility rate applications to determine what is the just and reasonable rate that they should receive for their electric power.[13]

Thus, section 210(e) of PURPA provides that the Commission shall exempt qualifying facilities from the Public Utility Holding Company Act, from the Federal Power Act and from State law and regulation respecting utility rates or financial organization, to the extent that the Commission determines that such exemption is necessary to encourage cogeneration or small power production.

Several commenters have contended that a determination of the qualifying facility's costs can be made without the detail required by cost-of-service regulation. However, the Commission believes that the basis for the determination of rates for purchases should be the utility's avoided costs and should not vary on the basis of the costs of the particular qualifying facility.

Several commenters recommended that rather than using a split-the-savings approach, the Commission should set rates for purchases at a fixed percentage of avoided costs. The Commission notes that, in most situations, a qualifying cogenerator or small power producer will only produce energy if its marginal cost of production is less than the price he receives for its output. If some fixed percentage is used, a qualifying facility

[12] The relationship between the utility system cost data and the rate for purchases is discussed under § 292.302 and § 292.304(b).

[13] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. [illegible], 95th Cong., 2d Sess. (1978).

may cease to produce additional units of energy when its costs exceed the price to be paid by the utility. If this occurs, the utility will be forced to operate generating units which either are less efficient than those which would have been used by the qualifying facility, or which consume fossil fuel rather than the alternative fuel which would have been consumed by the qualifying facility had the price been set at full avoided costs.

§ 292.304(b) Relationship to avoided costs.

"New Capacity"

The proposed rule differentiated between "old" and "new" production in connection with simultaneous purchases and sales. The proposed rule required an electric utility to purchase at its avoided cost the total output of a facility, construction of which was commenced after the date of issuance of these rules, even if the utility simultaneously sells energy to the facility at its retail rate. The effect of this proposed rule was to separate the production aspect of a qualifying facility from its consumption function. Under this approach, the electrical output of a facility is viewed independently of its electrical needs. Thus, if a cogeneration facility produces five megawatts, and consumes three megawatts, it is treated the same as another qualifying facility that produces five megawatts, and that is located next to a factory that uses three megawatts.

The Commission continues to believe that permitting simultaneous purchase and sale is necessary and appropriate to encourage cogeneration and small power production. The limitation contained in the proposed rule was intended to prevent a cogenerator or small power producer, which had found it economical to produce power for its own consumption prior to the issuance of these rules, from receiving the economic rent that might result from the purchase of its entire output at a utility's full avoided cost after that date without new investment on the part of the qualifying facility.

The same reasoning applies to any facility which was in existence prior to the enactment of PURPA, whether or not it seeks to purchase and sell simultaneously. That construction of the facility was commenced prior to that date may indicate that appropriate economic returns were available without the further incentives provided by section 210.

The Commission is aware that in some instances, if a previously existing qualifying facility were not permitted to receive full avoided costs for its entire output, it would no longer have sufficient incentive to continue to produce electric power. The cost of production may have risen so as to render the previous rate insufficient to cover the costs of production, or permit an appropriate return.

Thus, with regard to facilities, construction of which commenced on or after the date of enactment of PURPA (November 9, 1978), the Commission has determined it appropriate to provide that rates for purchases shall equal full avoided costs. For facilities, construction of which commenced before the enactment of PURPA, the Commission will permit the State regulatory authorities and nonregulated electric utilities to establish rates for purchases at full avoided costs, or at a lower rate, if the State regulatory authority or nonregulated electric utility determines that the lower rate will provide sufficient encouragement of cogeneration and small power production. Thus, if a previously existing facility shows that it requires rates for purchases based on full avoided costs to remain viable, or to increase its output, the State regulatory authority or nonregulated electric utility is required to establish such rates. This distinction is intended to reflect the need for further incentives and the reasonable expectations of persons investing in cogeneration or small power production facilities prior to or subsequent to the enactment of this law.

Paragraph (b)(1) defines "new capacity" as any purchase of capacity from a qualifying facility, construction of which was commenced on or after November 9, 1978. Subparagraph (2) provides that for new capacity, utilities must pay a rate which equals their avoided cost.

A utility must therefore purchase all of the output from a qualifying facility. However, as explained above, for any portion of that output which is not "new capacity," the State regulatory authority or nonregulated electric utility, as provided in paragraph (b)(3), may provide for a lower rate, if it determines that the lower rate will provide sufficient incentive for cogeneration.

Paragraph (b)(4) requires electric utilities to pay full avoided costs for purchases from new capacity made available from a qualifying facility, regardless of whether the electric utility is simultaneously making sales to the qualifying facility.

§ 292.304(c) Standard rates for purchases.

The Notice of Proposed Rulemaking required electric utilities on request of a qualifying facility to establish a tariff or other method for establishing rates for purchase from qualifying facilities of 10 kw or less. Upon consideration of the comments received, the Commission has determined that the concept of requiring a standard rate for purchases should be retained. Several comments stated that this requirement could similarly be applied to facilities of up to 100 kw or less.

The Commission is aware that the supply characteristics of a particular facility may vary in value from the average rates set forth in the utility's standard rate required by this paragraph. If the Commission were to require individualized rates, however, the transaction costs associated with administration of the program would likely render the program uneconomic for this size of qualifying facility. As a result, the Commission will require that standardized tariffs be implemented for facilities of 100 kw or less.

In addition, some commenters pointed out that standard tariffs can be used on a technology specific basis, to reflect the supply characteristics of the particular technology. Some commenters also observed that the proposed rule did not require that standard rates for purchases from these small facilities be based on the purchasing utility's avoided cost. This omission might have permitted a utility to pay less than that rate for purchases.

The Commission has accordingly revised paragraph (c) to require each State regulatory authority or nonregulated electric utility to cause to be put into effect standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less. The revised rule requires that standard rates for purchases equal the purchasing utility's avoided cost pursuant to paragraphs (a), (b), and (e).

Several commenters noted that standard rates for purchases can also be usefully applied to larger facilities. The Commission believes that the establishment of standard rates for purchases can significantly encourage cogeneration and small power production, provided that these standard rates accurately reflect the costs that the utility can avoid as a result of such purchases. Accordingly, the Commission has added subparagraph (2) which permits, but does not require, State regulatory authorities and nonregulated electric utilities to put into effect a standard rate for purchases from qualifying facilities with a design capacity greater than 100 kilowatts. These rates must equal avoided cost pursuant to paragraphs (a), (b), and (e).

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Many commenters at the Commission's public hearings and in written comments recommended that the Commission should require the establishment of "net energy billing" for small qualifying facilities. Under this billing method, the output from a qualifying facility reverses the electric meter used to measure sales from the electric utility to the qualifying facility. The Commission believes that this billing method may be an appropriate way of approximating avoided cost in some circumstances, but does not believe that this is the only practical or appropriate method to establish rates for small qualifying facilities. The Commission observes that net energy billing is likely to be appropriate when the retail rates are marginal cost-based, time-of-day rates. Accordingly, the Commission will leave to the State regulatory authorities and the nonregulated electric utilities the determination as to whether to institute net energy billing.

Paragraph (c)(3)(i) provides that standard rates for purchase should take into account the factors set forth in paragraph (e). These factors relate to the quality of power from the qualifying facility, and its ability to fit into the purchasing utility's generating mix.

Paragraph (e)(vi) is of particular significance for facilities of 100 kW or less. This paragraph provides that rates for purchase shall take into account "the individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system . . .". Several commenters presented persuasive evidence showing that an effective amount of capacity may be provided by dispersed small systems, even in the case where delivery of energy from any particular facility is stochastic. Similarly, qualifying facilities may be able to enter into operating agreements with each other by which they are able to increase the assured availability of capacity to the utility by coordinating scheduled maintenance and providing mutual back-up service. To the extent that this aggregate capacity value can be reasonably estimated, it must be reflected in standard rates for purchases.

Several commenters observed that the patterns of availability of particular energy sources can and should be reflected in standard rates. An example of this phenomenon is the availability of wind and photovoltaic energy on a summer peaking system. If it can be shown that system peak occurs when there is bright sun and no wind, rates for purchase could provide a higher capacity payment for photovoltaic cells than for wind energy conversion systems. For systems peaking on dark windy days, the reverse might be true. Subparagraph (3)(ii) thus provides that standard rates for purchases may differentiate among qualifying facilities on the basis of the supply characteristics of the particular technology.

§§ 292.304 (b)(5) and (d) Legally enforceable obligations.

Paragraphs (b)(5) and (d) are intended to reconcile the requirement that the rates for purchases equal the utilities' avoided cost with the need for qualifying facilities to be able to enter into contractual commitments based, by necessity, on estimates of future avoided costs. Some of the comments received regarding this section stated that, if the avoided cost of energy at the time it is supplied is less than the price provided in the contract or obligation, the purchasing utility would be required to pay a rate for purchases that would subsidize the qualifying facility at the expense of the utility's other ratepayers. The Commission recognizes this possibility, but is cognizant that in other cases, the required rate will turn out to be lower than the avoided cost at the time of purchase. The Commission does not believe that the reference in the statute to the incremental cost of alternative energy was intended to require a minute-by-minute evaluation of costs which would be checked against rates established in long term contracts between qualifying facilities and electric utilities.

Many commenters have stressed the need for certainty with regard to return on investment in new technologies. The Commission agrees with these latter arguments, and believes that, in the long run, "overestimations" and "underestimations" of avoided costs will balance out.

Paragraph (b)(5) addresses the situation in which a qualifying facility has entered into a contract with an electric utility, or where the qualifying facility has agreed to obligate itself to deliver at a future date energy and capacity to the electric utility. The import of this section is to ensure that a qualifying facility which has obtained the certainty of an arrangement is not deprived of the benefits of its commitment as a result of changed circumstances. This provision can also work to preserve the bargain entered into by the electric utility; should the actual avoided cost be higher than those contracted for, the electric utility is nevertheless entitled to retain the benefit of its contracted for, or otherwise legally enforceable, lower price for purchases from the qualifying facility. This subparagraph will thus ensure the certainty of rates for purchases from a qualifying facility which enters into a commitment to deliver energy or capacity to a utility.

Paragraph (d)(1) provides that a qualifying facility may provide energy or capacity on an "as available" basis, i.e., without legal obligation. The proposed rule provided that rates for such purchases should be based on "actual" avoided costs. Many comments noted that basing rates for purchases in such cases on the utility's "actual avoided costs" is misleading and could require retroactive ratemaking. In light of these comments, the Commission has revised the rule to provide that the rates for purchases are to be based on the purchasing utility's avoided costs estimated at the time of delivery.[14]

Paragraph (d)(2) permits a qualifying facility to enter into a contract or other legally enforceable obligation to provide energy or capacity over a specified term. Use of the term "legally enforceable obligation" is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility.

Many commenters noted the same problems for establishing rates for purchases under subparagraph (2) as in subparagraph (1). The Commission intends that rates for purchases be based, at the option of the qualifying facility, on either the avoided costs at the time of delivery or the avoided costs calculated at the time the obligation is incurred. This change enables a qualifying facility to establish a fixed contract price for its energy and capacity at the outset of its obligation or to receive the avoided costs determined at the time of delivery.

A facility which enters into a long term contract to provide energy or capacity to a utility may wish to receive a greater percentage of the total purchase price during the beginning of the obligation. For example, a level payment schedule from the utility to the qualifying facility may be used to match more closely the schedule of debt service of the facility. So long as the total payment over the duration of the contract term does not exceed the estimated avoided costs, nothing in these rules would prohibit a State regulatory authority or non-regulated electric utility from approving such an arrangement.

[14] In addition to the avoided costs of energy, these costs must include the prorated share of the aggregate capacity value of such facilities.

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§ 292.304(c) Factors affecting rates for purchases.

Capacity Value

An issue basic to this paragraph is the question of recognition of the capacity value of qualifying facilities.

In the proposed rule, the Commission adopted the argument set forth in the Staff Discussion Paper that the proper interpretation of section 210(b) of PURPA requires that the rates for purchases include recognition of the capacity value provided by qualifying cogeneration and small power production facilities. The Commission noted that language used in section 210 of PURPA and the Conference Report as well as in the Federal Power Act supports this proposition.

In the proposed rule, the Commission cited the final paragraph of the Conference Report with regard to section 210 of PURPA:

> The conferees expect that the Commission, in judging whether the electric power supplied by the cogenerator or small power producer will replace future power which the utility would otherwise have to generate itself either through existing capacity or additions to capacity or purchase from other sources, will take into account the reliability of the power supplied by the cogenerator or small power producer by reason of any legally enforceable obligation of such cogenerator or small power producer to supply firm power to the utility.[15]

In addition to that citation, the Commission notes that the Conference Report states that:

> In interpreting the term "incremental costs of alternative energy", the conferees expect that the Commission and the States may look beyond the costs of alternative sources which are instantaneously available to the utility.[16]

Several commenters contended that, since section 210(a)(2) of PURPA provides that electric utilities must "purchase electric energy" from qualifying facilities, the rate for such purchases should not include payments for capacity. The Commission observes that the statutory language used in the Federal Power Act uses the term "electric energy" to describe the rates for sales for resale in interstate commerce. Demand or capacity payments are a traditional part of such rates. The term "electric energy" is used throughout the Act to refer both to electric energy and capacity. The Commission does not find any evidence that the term "electric energy" in section 210 of PURPA was intended to refer only to fuel and operating and maintenance expenses, instead of all of the costs associated with the provision of electric service.

In addition, the Commission notes that to interpret this phrase to include only energy would lead to the conclusion that the rates for sales *to* qualifying facilities could only include the energy component of the rate since section 210 also refers to "electric energy" with regard to such sales. It is the Commission's belief that this was not the intended result. This provides an additional reason to interpret the phrase "electric energy" to include both energy and capacity.

In implementing this statutory standard, it is helpful to review industry practice respecting sales between utilities. Sales of electric power are ordinarily classified as either firm sales, where the seller provides power at the customer's request, or non-firm power sales, where the seller and not the buyer makes the decision whether or not power is to be available. Rates for firm power purchases include payments for the cost of fuel and operating expenses, and also for the fixed costs associated with the construction of generating units needed to provide power at the purchaser's discretion. The degree of certainty of deliverability required to constitute "firm power" can ordinarily be obtained only if a utility has several generating units and adequate reserve capacity. The capacity payment, or demand charge, will reflect the cost of the utility's generating units.

In contrast, the ability to provide electric power at the selling utility's discretion imposes no requirement that the seller construct or reserve capacity. In order to provide power to customers at the seller's discretion, the selling utility need only charge for the cost of operating its generating units and administration. These costs, called "energy" costs, ordinarily are the ones associated with non-firm sales of power.

Purchases of power from qualifying facilities will fall somewhere on the continuum between these two types of electric service. Thus, for example, wind machines that furnish power only when wind velocity exceeds twelve miles per hour may be so uncertain in availability of output that they would only permit a utility to avoid generating an equivalent amount of energy. In that situation, the utility must continue to provide capacity that is available to meet the needs of its customers. Since there are no avoided capacity costs, rates for such sporadic purchases should thus be based on the utility system's avoided incremental cost of energy. On the other hand, testimony at the Commission's public hearings indicated that effective amounts of firm capacity exist for dispersed wind systems, even though each machine, considered separately, could not provide capacity value. The aggregate capacity value of such facilities must be considered in the calculation of rates for purchases, and the payment distributed to the class providing the capacity.

Some technologies, such as photovoltaic cells, although subject to some uncertainty in power output, have the general advantage of providing their maximum power coincident with the system peak when used on a summer peaking system. The value of such power is greater to the utility than power delivered during off-peak periods. Since the need for capacity is based, in part, on system peaks, the qualifying facility's coincidence with the system peak should be reflected in the allowance of some capacity value and an energy component that reflects the avoided energy costs at the time of the peak.

A facility burning municipal waste or biomass may be able to operate more predictably and reliably than solar or wind systems. It can schedule its outages during times when demand on the utility's system is low. If such a unit demonstrates a degree of reliability that would permit the utility to defer or avoid construction of a generating unit or the purchase of firm power from another utility, then the rate for such a purchase should be based on the avoidance of both energy and capacity costs.

In order to defer or cancel the construction of new generating units, a utility must obtain a commitment from a qualifying facility that provides contractual or other legally enforceable assurances that capacity from alternative sources will be available sufficiently ahead of the date on which the utility would otherwise have to commit itself to the construction or purchase of new capacity. If a qualifying facility provides such assurances, it is entitled to receive rates based on the capacity costs that the utility can avoid as a result of its obtaining capacity from the qualifying facility.

Other comments with regard to the requirement to include capacity payments in avoided costs generally track those set forth in the Staff Discussion Paper and the proposed rule. The thrust of these comments is that, in order to receive credit for capacity and to comply with the requirement that rates for purchases not exceed the incremental cost of alternative energy, capacity payments can only be required when the availability of capacity from a qualifying facility or facilities actually permits the purchasing utility to reduce

[15] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 95th Cong., 2d Sess. (1978).

[16] *Id.*, pp. 98–9.

its need to provide capacity by deferring the construction of new plant or commitments to firm power purchase contracts. In the proposed rule, the Commission stated that if a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating plant, to enable it to build a smaller, less expensive plant, or to purchase less firm power from another utility than it would otherwise have purchased, then the rates for purchases from the qualifying facility must include the avoided capacity and energy costs. As indicated by the preceding discussion, the Commission continues to believe that these principles are valid and appropriate, and that they properly fulfill the mandate of the statute.

The Commission also continues to believe, as stated in the proposed rule, that this rulemaking represents an effort to evolve concepts in a newly developing area within certain statutory constraints. The Commission recognizes that the translation of the principle of avoided capacity costs from theory into practice is an extremely difficult exercise, and is one which, by definition, is based on estimation and forecasting of future occurrences. Accordingly, the Commission supports the recommendation made in the Staff Discussion Paper that it should leave to the States and nonregulated utilities "flexibility for experimentation and accommodation of special circumstances" with regard to implementation of rates for purchases. Therefore, to the extent that a method of calculating the value of capacity from qualifying facilities reasonably accounts for the utility's avoided costs, and does not fail to provide the required encouragement of cogeneration and small power production, it will be considered as satisfactorily implementing the Commission's rules.

§ 292.304(e) Factors affecting rates for purchases.

As noted previously, several commenters observed that the utility system cost data required under § 292.302 cannot be directly applied to rates for purchase. The Commission acknowledges this point and, as discussed previously, has provided that these data are to be used as a starting point for the calculation of an appropriate rate for purchases equal to the utility's avoided cost. Accordingly, the Commission has removed the reference to the utility system cost data from the definition of rates for purchases and has inserted the reference to these data in paragraph (e), as one factor to be considered in calculating rates for purchases. Subparagraph (1) states that these data shall, to the extent practicable, be taken into account in the calculation of a rate for purchases.

Subparagraph (2) deals with the availability of capacity from a qualifying facility during system daily and seasonal peak periods. If a qualifying facility can provide energy to a utility during peak periods when the electric utility is running its most expensive generating units, this energy has a higher value to the utility than energy supplied during off-peak periods, during which only units with lower running costs are operating.

The preamble to the proposed rule provided that, to the extent that metering equipment is available, the State regulatory authority or nonregulated electric utility should take into account the time or season in which the purchase from the qualifying facility occurs. Several commenters interpreted this statement as implying that, by refusing to install metering equipment, an electric utility could avoid the obligation to consider the time at which purchases occur. This is not the intent of this provision. Clearly, the more precisely the time of purchase is recorded the more exact the calculation of the avoided costs, and thus the rate for purchases, can be. Rather than specifying that exact time-of-day or seasonal rates for purchases are required, however, the Commission believes that the selection of a methodology is best left to the State regulatory authorities and nonregulated electric utilities charged with the implementation of these provisions.

Clauses (i) through (v) concern various aspects of the reliability of a qualifying facility. When an electric utility provides power from its own generating units or from those of another electric utility, it normally controls the production of such power from a central location. The ability to so control power production enhances a utility's ability to respond to changes in demand, and thereby enhances the value of that power to the utility. A qualifying facility may be able to enter into an arrangement with the utility which gives the utility the advantage of dispatching the facility. By so doing, it increases its value to the utility. Conversely, if a utility cannot dispatch a qualifying facility, that facility may be of less value to the utility.

Clause (ii) refers to the expected or demonstrated reliability of a qualifying facility. A utility cannot avoid the construction or purchase of capacity if it is likely that the qualifying facility which would claim to replace such capacity may go out of service during the period when the utility needs its power to meet system demand. Based on the estimated or demonstrated reliability of a qualifying facility, the rate for purchases from a qualifying facility should be adjusted to reflect its value to the utility.

Clause (iii) refers to the length of time during which the qualifying facility has contractually or otherwise guaranteed that it will supply energy or capacity to the electric utility. A utility-owned generating unit normally will supply power for the life of the plant, or until it is replaced by more efficient capacity. In contrast, a cogeneration or small power production unit might cease to produce power as a result of changes in the industry or in the industrial processes utilized. Accordingly, the value of the service from the qualifying facility to the electric utility may be affected by the degree to which the qualifying facility ensures by contract or other legally enforceable obligation that it will continue to provide power. Included in this determination, among other factors, are the term of the commitment, the requirement for notice prior to termination of the commitment, and any penalty provisions for breach of the obligation.

In order to provide capacity value to an electric utility a qualifying facility need not necessarily agree to provide power for the life of the plant. A utility's generation expansion plans often include purchases of firm power from other utilities in years immediately preceding the addition of a major generation unit. If a qualifying facility contracts to deliver power, for example, for a one year period, it may enable the purchasing utility to avoid entering into a bulk power purchase arrangement with another utility. The rate for such a purchase should thus be based on the price at which such power is purchased, or can be expected to be purchased, based upon bona fide offers from another utility.

Clause (iv) addresses periods during which a qualifying facility is unable to provide power. Electric utilities schedule maintenance outages for their own generating units during periods when demand is low. If a qualifying facility can similarly schedule its maintenance outages during periods of low demand, or during periods in which a utility's own capacity will be adequate to handle existing demand, it will enable the utility to avoid the expenses associated with providing an equivalent amount of

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capacity. These savings should be reflected in the rate for purchases.

Clause (v) refers to a qualifying facility's ability and willingness to provide capacity and energy during system emergencies. Section 292.307 of these regulations concerns the provision of electric service during system emergencies. It provides that, to the extent that a qualifying facility is willing to forego its own use of energy during system emergencies and provide power to a utility's system, the rate for purchases from the qualifying facility should reflect the value of that service. Small power production and cogeneration facilities could provide significant back-up capability to electric systems during emergencies. One benefit of the encouragement of interconnected cogeneration and small power production may be to increase overall system reliability during such emergency conditions. Any such benefit should be reflected in the rate for purchases from such qualifying facilities.

Another related factor which affects the capacity value of a qualifying facility is its ability to separate its load from its generation during system emergencies. During such emergencies an electric utility may institute load shedding procedures which may, among other things, require that industrial customers or other large loads stop receiving power. As a result, to provide optimal benefit to a utility in an emergency situation, a qualifying facility might be required to continue operation as a generating plant, while simultaneously ceasing operation as a load on the utility's system. To the extent that a facility is unable to separate its load from its generation, its value to the purchasing utility decreases during system emergencies. To reflect such a possibility, clause (v) provides that the purchasing utility may consider the qualifying facility's ability to separate its load from its generation during system emergencies in determining the value of the qualifying facility to the electric utility.

Clause (vi) refers to the aggregate capability of capacity from qualifying facilities to displace planned utility capacity. In some instances, the small amounts of capacity provided from qualifying facilities taken individually might not enable a purchasing utility to defer or avoid scheduled capacity additions. The aggregate capability of such purchases may, however, be sufficient to permit the deferral or avoidance of a capacity addition. Moreover, while an individual qualifying facility may not provide the equivalent of firm power to the electric utility, the diversity of these facilities may collectively comprise the equivalent of capacity.

Clause (vii) refers to the fact that the lead time associated with the addition of capacity from qualifying facilities may be less than the lead time that would have been required if the purchasing utility had constructed its own generating unit. Such reduced lead time might produce savings in the utility's total power production costs, by permitting utilities to avoid the "lumpiness," and temporary excess capacity associated therewith, which normally occur when utilities bring on line large generating units. In addition, reduced lead time provides the utility with greater flexibility with which it can accommodate changes in forecasts of peak demand.

Subparagraph (3) concerns the relationship of energy or capacity from a qualifying facility to the purchasing electric utility's need for such energy or capacity. If an electric utility has sufficient capacity to meet its demand, and is not planning to add any new capacity to its system, then the availability of capacity from qualifying facilities will not immediately enable the utility to avoid any capacity costs. However, an electric utility system with excess capacity may nevertheless plan to add new, more efficient capacity to its system. If purchases from qualifying facilities enable a utility to defer or avoid these new planned capacity additions, the rate for such purchases should reflect the avoided costs of these additions. However, as noted by several commenters, the deferral or avoidance of such a unit will also prevent the substitution of the lower energy costs that would have accompanied the new capacity. As a result, the price for the purchase of energy and capacity should reflect these lower avoided energy costs that the utility would have incurred had the new capacity been added.

This is not to say that electric utilities which have excess capacity need not make purchases from qualifying facilities: qualifying facilities may obtain payment based on the avoided energy costs on a purchasing utility's system. Many utility systems with excess capacity have intermediate or peaking units which use high-cost fossil fuel. As a result, during peak hours, the energy costs on the systems are high, and thus the rate to a qualifying utility from which the electric utility purchases energy should similarly be high.

Subparagraph (4) addresses the costs or savings resulting from line losses. An appropriate rate for purchases from a qualifying facility should reflect the cost savings actually accruing to the electric utility. If energy produced from a qualifying facility undergoes line losses such that the delivered power is not equivalent to the power that would have been delivered from the source of power it replaces, then the qualifying facility should not be reimbursed for the difference in losses. If the load served by the qualifying facility is closer to the qualifying facility than it is to the utility, it is possible that there may be net savings resulting from reduced line losses. In such cases, the rates should be adjusted upwards.

§ 292.303(f) Periods during which purchase are not required.

The proposed rule provided that an electric utility will not be required to purchase energy and capacity from qualifying facilities during periods in which such purchases will result in net increased operating costs to the electric utility. This section was intended to deal with a certain condition which can occur during light loading periods. If a utility operating only base load units during these periods were forced to cut back output from the units in order to accommodate purchases from qualifying facilities, these base load units might not be able to increase their output level rapidly when the system demand later increased. As a result, the utility would be required to utilize less efficient, higher cost units with faster start-up to meet the demand that would have been supplied by the less expensive base load unit had it been permitted to operate at a constant output.

The result of such a transaction would be that rather than avoiding costs as a result of the purchase from a qualifying facility, the purchasing electric utility would incur greater costs than it would have had it not purchased energy or capacity from the qualifying facility. A strict application of the avoided cost principle set forth in this section would assess these additional costs as negative avoided costs which must be reimbursed by the qualifying facility. In order to avoid the anomalous result of forcing a qualifying utility to pay an electric utility for purchasing its output, the Commission proposed that an electric utility be required to identify periods during which this situation would occur, so that the qualifying facility could cease delivery of electricity during those periods.

Many of the comments received reflected a suspicion that electric utilities would abuse this paragraph to circumvent their obligation to purchase from qualifying facilities. In order to minimize that possibility, the Commission has revised this paragraph to provide that any electric utility which seeks to cease purchasing from qualifying facilities must notify each affected qualifying facility prior to the occurrence of such a period, in time for the qualifying facility to cease delivery of energy or capacity to the electric utility. This notification can be accomplished in any reasonable manner determined by the State regulatory authority. Any claim by an electric utility that such a light loading period will occur or has occurred is subject to such verification by its State regulatory authority as the State authority determines necessary or appropriate either before or after its occurrence. Moreover, any electric utility which fails to provide adequate notice or which incorrectly identifies such a period will be required to reimburse the qualifying facility for energy or capacity supplied as if such a light loading period had not occurred.

The section has also been modified to clarify that such periods must be due to operational circumstances.

The Commission does not intend that this paragraph override contractual or other legally enforceable obligations incurred by the electric utility to purchase from a qualifying facility. In such arrangements, the established rate is based on the recognition that the value of the purchase will vary with the changes in the utility's operating costs. These variations ordinarily are taken into account, and the resulting rate represents the average value of the purchase over the duration of the obligation. The occurrence of such periods may similarly be taken into account in determining rates for purchases.

Tax Issues

The Conference Report states that:

> * * * the examination of the level of rates which should apply to the purchase by the utility of the cogenerator's or the small power producer's power should not be burdened by the same examination as are utility rate applications to determine what is the just and reasonable rate that they should receive for their electric power.[17]

The Commission notes that section 301(b)(2) of the Energy Tax Act of 1978[18] makes certain energy property eligible for increased business investment tax credit. Some of this property is commonly used in cogeneration and small power production. However, section 301(b)(2)(B) excludes from such eligibility property "which is public utility property (within the meaning of section 46(f)(5) of the Internal Revenue Code of 1954)."[19] As a result, if the property of a qualifying facility which was otherwise eligible for the credit were to be classified as public utility property under section 46(f)(5) of the Internal Revenue Code, it would not be eligible for the increased investment tax credit.

The Commission notes that the Treasury Department's regulations provide that the definition of "public utility property" does not include property used in the business of the furnishing or sale of electric energy if the rates are not subject to regulation that fixes a rate of return on investment.[20] On this basis, the Commission believes that property of a qualifying facility that would otherwise be eligible for the energy tax credit would not be excluded from that eligibility under the public utility property exclusion.

First, this Commission is exempting property of qualifying facilities from regulation under Part II of the Federal Power Act, and from similar State and local laws and regulatory programs. Secondly, the Commission observes that the rates a qualifying facility will receive for sales of power to utilities are *not* based on a regulatory scheme which fixes a rate of return on investment of the qualifying facility.

As a result, the Commission believes that energy property of qualifying facilities should not be barred from eligibility for the tax credit by reason of the public utility property exclusion. The Commission wishes to express its opinion on this matter in an effort to further encourage cogeneration and small power production by means of this rulemaking process.

§ 292.305 Rates for sales.

Section 210(c) of PURPA provides that the rules requiring utilities to sell electric energy to qualifying facilities shall ensure that the rates for such sales are just and reasonable, in the public interest, and nondiscriminatory with respect to qualifying cogenerators or small power producers. This section contemplates formulation of rates on the basis of traditional ratemaking (*i.e.*, cost-of-service) concepts.

Paragraph (a) expresses the statutory requirement that such rates be just and reasonable and in the public interest. Paragraph (a) also provides that rates for sales from electric utilities to qualifying facilities not be discriminatory against such facilities in comparison to rates to other customers served by the electric utility.

A qualifying facility is entitled to purchase back-up or standby power at a nondiscriminatory rate which reflects the probability that the qualifying facility will or will not contribute to the need for and the use of utility capacity. Thus, where the utility must reserve capacity to provide service to a qualifying facility, the costs associated with that reservation are properly recoverable from the qualifying facility, if the utility would similarly assess these costs to non-generating customers.

In the proposed rule, paragraph (b) required electric utilities to provide energy and capacity and other services to any qualifying facility at a rate at least as favorable as would be provided to a customer who does not have his own generation. The comments received concerning this paragraph noted that this provision might be interpreted as requiring an electric utility to provide service to a qualifying facility at its most favorable rate, even if the qualifying facility would not be eligible for such a rate if it did not have its own generation. It is not the Commission's intention that, for example, an industrial cogenerator receive service at a rate applicable to residential customers; rather, such a customer should be charged at a rate applicable to a non-generating industrial customer unless the electric utility shows that a different rate is justified on the basis of sufficient load or other cost-related data. Accordingly, this section now provides that for qualifying facilities which do not simultaneously sell and purchase from the electric utility, the rate for sales shall be the rate that would be charged to the class to which the qualifying facility would be assigned if it did not have its own generation.

Subparagraph (2) provides that if, on the basis of accurate data and consistent system-wide costing principles, the utility demonstrates that the rate that would be charged to a comparable customer without its own generation is not appropriate, the utility may base its rates for sales upon those data and principles. The utility may only charge such rates on a nondiscriminatory basis, however, so that a cogenerator will not be singled out to lose any interclass or intraclass subsidies to which it might have been entitled had it not generated part of its electric energy needs itself.

In situations where a qualifying facility simultaneously sells its output to an electric utility and purchases its requirements from that electric utility, as a bookkeeping matter, the facility's

[17] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 95th Cong., 2d Sess. (1978).

[18] Pub. L. No. 95-618, 26 U.S.C. §§ 46, 48, November 9, 1978.

[19] 26 U.S.C. § 46(e)(3)(b).

[20] Treasury Reg. § 1.46-3(g)(2), T.D. 7602 (March 23, 1979).

electrical output will not serve its own load, but rather will be supplied to the grid. As a result, the facility's electric load is likely to have the same characteristics as the load of other non-generating customers of the utility. If the utility does not provide data showing otherwise, the appropriate rate for sales to such a facility is the rate that would be charged to a comparable customer without its own generation.

Paragraph (b)(2) of the rule sets forth certain types of service which electric utilities are required to provide qualifying facilities upon request of the facility. These types of service are supplementary power, back-up power, interruptible power and maintenance power. In response to comments, these terms are defined in the text of the rules, as well as in this preamble.

Back-up or maintenance service provided by an electric utility replaces energy or capacity which a qualifying facility ordinarily supplies to itself. These rules authorize certain facilities to purchase and sell simultaneously. The amount of energy or capacity provided by an electric utility to meet the load of a facility which simultaneously purchases and sells will vary only in accordance with changes in the facility's load; interruptions in the facility's generation will be manifested as variations in purchases from the facility. In such a case, sales to the qualifying facility will not be back-up or maintenance service, but will be similar to the full-requirements service that would be provided if the facility were a non-generating customer.

Supplementary power is electric energy or capacity used by a facility in addition to that which it ordinarily generates on its own. Thus, a cogeneration facility with a capacity of ten megawatts might require five more megawatts from a utility on a continuing basis to meet its electric load of fifteen megawatts. The five megawatts supplied by the electric utility would normally be provided as supplementary power.

Back-up power is electric energy or capacity available to replace energy generated by a facility's own generation equipment during an unscheduled outage. In the example provided above, a cogeneration facility might contract with an electric utility for the utility to have available ten megawatts, should the cogenerator's units experience an outage.

Maintenance power is electric energy or capacity supplied during scheduled outages of the qualifying facility. By pre-arrangement, a utility can agree to provide such energy during periods when the utility's other load is low, thereby avoiding the imposition of large demands on the utility during peak periods.

Interruptible power is electric energy or capacity supplied to a qualifying facility subject to interruption by the electric utility under specified conditions. Many utilities have utilized interruptible service to avoid expensive investment in new capacity that would otherwise be necessary to assure adequate reserves at time of peak demand. Under this approach utilities assure the adequacy of reserves by arranging to reduce peak demand, rather than by adding capacity. Interruptible service is therefore normally provided at a lower rate than non-interruptible service.

During the Commission's public hearings on this rulemaking, one commenter stated that utilities which have excess capacity do not save any costs by providing interruptible service. The commenter contended that the Commission should not require a utility with excess capacity to offer interruptible service. If a utility is not adding capacity (whether by construction or purchase) to meet anticipated increases in peak demand, the rates charged for interruptible service might appropriately be the same as for non-interruptible services.

The Commission believes that these matters involving the provision of interruptible rates are best handled through the pricing mechanism. However, if as discussed above, interruptible customers provide no savings to the electric utility, the rate for interruptible service need not be lower than the rate for firm service. In such a case, the Commission would consider granting a waiver from this paragraph, under the provisions of § 292.403.

Some comments noted that certain electric utilities do not have any generating capacity, and to require the services listed in subparagraph (1) might place an undue burden on the electric utility. In light of these comments, the State regulatory authorities or the Commission, as the case may be, will allow a waiver of these requirements upon a finding after a showing by the utility to the State regulatory authority or Commission, as the case may be, that provision of these services will impair the utility's ability to render adequate service to its customers or place an undue burden on the electric utility. Notice must be given in the area served by the electric utility, opportunity for public comment must be provided, and an application must be submitted to the State regulatory authority with respect to any electric utility over which it has ratemaking authority or the Commission with respect to any nonregulated electric utility.

Paragraph (c)(1) provides that rates for sales of back-up or maintenance power shall not be based, without factual data, on the assumption that forced outages or other reductions in output by each qualifying facility on an electric utility's system will occur either simultaneously or during the system peak. Like other customers, qualifying facilities may well have intraclass diversity. In addition, because of the variations in size and load requirements among various types of qualifying facilities, such facilities may well have interclass diversity.

The effect of such diversity is that an electric utility supplying back-up or maintenance power to qualifying facilities will not have to plan for reserve capacity to serve such facilities on the assumption that every facility will use power at the same moment. The Commission believes that probabilistic analyses of the demand of qualifying facilities will show that a utility will probably not need to reserve capacity on a one-to-one basis to meet back-up requirements. Paragraph (c)(1) prohibits utilities from basing rates on the assumption that qualifying facilities will impose demands simultaneously and at system peak unless supported by factual data.

The rule provides that utilities may refute these assumptions on the basis of factual data. These data need not be in the form of empirical load data. It might be the case that within certain geographic areas, weather data and performance data would constitute a sufficient basis to refute the assumption relating to the coincidence of the demands imposed, for example, by windmills or photovoltaics, with respect to their need for back-up power.

Paragraph (c)(2) provides that rates for sales shall take into account the extent to which a qualifying facility can usefully coordinate periods of scheduled maintenance with an electric utility. If a qualifying facility stays on line when the utility will need its capacity, and schedules maintenance when the utility's other units are operative, the qualifying facility is more valuable to the utility, as it can reduce its capacity requirements.

§ 292.306 Interconnection costs.

Paragraph (a) states that each qualifying facility must reimburse any electric utility which purchases capacity or energy from the qualifying facility for any interconnection costs, on a nondiscriminatory basis with respect to other customers with similar load characteristics. The Commission finds merit in those comments which suggested that the basis of comparison for nondiscriminatory practices in the proposed rule to "any other customer" was too broad, and that the correct reference for nondiscrimination is the practice of the utility in relation to customers in the same class who do not generate electricity. As noted previously, the interconnection costs of a facility which is already interconnected with the utility for purposes of sales are limited to any additional expenses incurred by the utility to permit purchases.

Several commenters expressed their concern that some protection should be provided to qualifying facilities from potential harassment by utilities in the form of requiring unnecessary safety equipment. As discussed above, the State regulatory authorities (with respect to electric utilities over which they have ratemaking authority) and nonregulated electric utilities have the responsibility and authority to ensure that the interconnection requirements are reasonable, and that associated costs are legitimately incurred.

For qualifying facilities with a design capacity of 100 kW or less, the Commission noted that interconnection costs could be assessed on a class basis, and the standard rates for purchases established for classes of facilities of this size pursuant to § 292.304(c)(1) might incorporate these costs. State regulatory authorities (with respect to electric utilities over which they have ratemaking authority) or nonregulated electric utilities may also determine interconnection costs for qualifying facilities with a design capacity of more than 100 kW on either a class average or individual basis.

Numerous comments raised the point that the proposed rule did not address the manner in which electric utilities would be reimbursed. Potential owners and developers of qualifying facilities recommended that the costs be amortized on a reasonable basis, because paying a large lump sum payment would be a considerable obstacle to the program. Electric utilities generally preferred payment up front, although several commenters indicated that amortization might be acceptable for credit-worthy facilities. The Commission believes that the manner of reimbursements (which may include amortization over a reasonable period of time) is best left to the State regulatory authorities and nonregulated utilities. In the determination of any standard rates for purchases established pursuant to § 292.304(c)(i), if the State approves some manner of amortization, it might consider assignment of uncollected interconnection costs to the class for which the rate is established.

§ 292.307 System emergencies.

Paragraph (a) provides that, except as provided under section 202(c) of the Federal Power Act, no qualifying facility shall be compelled to provide energy or capacity to the electric utility during an emergency beyond the extent provided by agreement between the qualifying facility and the utility.

The Commission finds that a qualifying facility should not be required to make available all of its generation to the utility during a system emergency. Such a requirement might interrupt industrial processes with resulting damage to equipment and manufactured goods. Many industries install their own generating equipment in order to ensure that even during a system emergency, their supply of power is not interrupted. To put in jeopardy the availability of power to a qualifying facility during a system emergency because of the facility's ability to provide power to the system during non-emergency periods would result in the discouragement of interconnected operation and a resultant discouragement of cogeneration and small power production. The Commission therefore provides that the qualifying facility's obligation to provide energy and capacity in emergencies be established through contract.

In order to receive full credit for capacity, a qualifying facility must offer energy and capacity during system emergencies to the same extent that it has agreed to provide energy and capacity during non-emergency situations. For example, a 30 megawatt cogenerator may require 20 megawatts for its own industrial purposes, and thus may contract to provide 10 megawatts of capacity to the purchasing utility. During an emergency, the cogenerator must provide the 10 megawatts contracted for to the utility; it need not disrupt its industrial processes by supplying its full capability of 30 megawatts. Of course, if it should so desire, a cogenerator could contractually agree to supply the full 30 megawatts during system emergencies. The availability of such additional backup capacity should increase utility system reliability, and should be accounted for in the utility's rates for purchases from the cogenerator.

Paragraph (b) provides that an electric utility may discontinue purchases from a qualifying facility during a system emergency if such purchases would contribute to the emergency. In addition, during system emergencies, a qualifying facility must be treated on a nondiscriminatory basis in any load shedding program—*i.e.*, on the same basis that other customers of a similar class with similar load characteristics are treated with regard to interruption of service.

Credit for capacity (as noted in § 292.304(e)(2)(v)) will also take into account the ability of the qualifying facility to separate its load and generation during system emergencies. However, the qualifying facility may well be eligible for some capacity credit even if it cannot separate its load and generation.

§ 292.308 Standards for operating reliability.

Section 210(a) of PURPA states that the rules requiring electric utilities to buy from and sell to qualifying facilities shall include provisions respecting minimum reliability of qualifying facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric utilities during emergencies. The Commission believes that the reliability of qualifying facilities can be accounted for through price; namely, the less reliable a qualifying facility might be, the less it should be entitled to receive for purchases from it by the utility.

As a result, the Commission has not included specific standards relating to the reliability in the sense of the ability of qualifying facilities to provide energy or capacity.

The Commission has determined that safety equipment exists which can ensure that qualifying facilities do not energize utility lines during utility outages. This section accordingly provides that each State regulatory authority or nonregulated electric utility may establish standards for interconnected operation between electric utilities and qualifying facilities. These standards may be recommended by any utility, any qualifying facility, or any other person. These standards must be accompanied by a statement showing the need for the standard on the basis of system safety and operating requirements.

Subpart D—Implementation

Summary of this Subpart

Rules in this subpart are intended to carry out the responsibility of the Commission to encourage cogeneration and small power production by clarifying the nature of the obligation to implement the Commission's rules under section 210.

These rules afford the State regulatory authorities and nonregulated electric utilities great latitude in determining the manner of implementation of the

Commission's rules, provided that the manner chosen is reasonably designed to implement the requirements of Subpart C. The Commission recognizes that many States and individual nonregulated electric utilities have ongoing programs to encourage small power production and cogeneration. The Commission also recognizes that economic and regulatory circumstances vary from State to State and utility to utility. It is within this context—in recognition of the work already begun and of the variety of local conditions—that the Commission promulgates its regulations requiring implementation of rules issued under section 210.

Because of the Commission's desire not to create unnecessary burdens at the State level, these rules provide a procedure whereby a State regulatory authority or nonregulated electric utility may apply to the Commission for a waiver if it can demonstrate that compliance with certain requirements of Subpart C is not necessary to encourage cogeneration or small power production and is not otherwise required under section 210.

Several commenters expressed their concern that State regulatory authorities would not be able adequately to implement the Commission's rules, and therefore, recommended that the Commission issue specific rules which the State regulatory authorities would adopt without change. The Commission does not find this proposal to be appropriate at this time, and believes that providing an opportunity for experimentation by the States is more conducive to development of these difficult rate principles.

Implementation

Section 210(f) of PURPA requires that within one year after the date that this Commission prescribes its rules under subsection (a), and within one year of the date any of these rules is revised, each State regulatory authority and each nonregulated electric utility, after notice and opportunity for hearing, must implement the rules or revisions thereof, as the case may be.

The obligation to implement section 210 rules is a continuing obligation which begins within one year after promulgation of such rules. The requirement to implement may be fulfilled either (1) through the enactment of laws or regulations at the State level, (2) by application on a case-by-case basis by the State regulatory authority, or nonregulated utility, of the rules adopted by the Commission, or (3) by any other action reasonably designed to implement the Commission's rules.

Review and Enforcement

Section 210(g) of PURPA provides one of the means of obtaining judicial review of a proceeding conducted by a State regulatory authority or nonregulated utility for purposes of implementing the Commission's rules under section 210. Under subsection (g), review may be obtained pursuant to procedures set forth in section 123 of PURPA. Section 123(c)(1) contains provisions concerning judicial review and enforcement of determinations made by State regulatory authorities and nonregulated utilities under Subtitle A, B, or C of Title I in the appropriate State court. These provisions also apply to review of any action taken to implement the rules under section 210. This means that persons can bring an action in State court to require the State regulatory authorities or nonregulated utilities to implement these regulations.

Section 123(c)(2) of PURPA provides that persons seeking review of any determination made by a Federal agency may bring an action in the appropriate Federal court. This distinction between Federal agencies and non-Federal agencies also applies to review of enforcement of the implementation of the rules under section 210.

Finally, the Commission believes that review and enforcement of implementation under section 210 of PURPA can consist not only of review and enforcement as to whether the State regulatory authority or nonregulated electric utility has conducted the initial implementation properly—namely, put into effect regulations implementing section 210 rules or procedures for that implementation, after notice and an opportunity for a hearing. It can also consist of review and enforcement of the application by a State regulatory authority or nonregulated electric utility, on a case-by-case basis, of its regulations or of any other provision it may have adopted to implement the Commission's rules under section 210.

Section 210(h)(2)(A) of PURPA states that the Commission may enforce the implementation of regulations under section 210(f). The Congress has provided not only for private causes of action in State courts to obtain judicial review and enforcement of the implementation of the Commission's rules under section 210, but also provided that the Commission may serve as a forum for review and enforcement of the implementation of this program.

§ 292.401 Implementation by state regulatory authorities and nonregulated electric utilities

Paragraph (a) of § 292.401 sets forth the obligation of each State regulatory authority to commence implementation of Subpart C within one year of the date these rules take effect. In complying with this paragraph the State regulatory authorities are required to provide for notice of and opportunity for public hearing. As described in the summary of this subpart, such implementation may consist of the adoption of the Commission's rules, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart C, or any other action reasonably designed to implement Subpart C.

This section does not cover one provision of Subpart C which is not required to be implemented by the State regulatory authority or nonregulated electric utility. This provision is § 292.302 (Availability of electric utility system cost data), the implementation of which is subject to § 292.402, discussed below.

Subsection (b) sets forth the obligaton of each nonregulated electric utility to commence, after notice and opportunity for public hearing, implementation of Subpart C. The nonregulated electric utilities, being both the regulator and the utility subject to the regulation, may satisfy the obligation to commence implementation of Subpart C through issuance of regulations, an undertaking to comply with Subpart C, or any other action reasonably designed to implement that subpart.

Paragraph (c) sets forth a reporting requirement under which each State regulatory authority and nonregulated electric utility is to file with the Commission, not later than one year after these rules take effect, a report describing the manner in which it is proceeding to implement Subpart C.

Comments received regarding this section indicated a concern that the obligation of a State regulatory authority or nonregulated utility "to commence implementation * * * within one year * * *" did not provide any guidance as to when the process must be completed. The Commission notes that the intention of this section is that the State regulatory authorities and nonregulated utilities have one year in which to establish procedures and that at the end of that year each State must be prepared to entertain applications. The phrase "commence implementation" is intended by the Commission to connote that implementation of these rules is a continuing process and that oversight will be ongoing.

§ *292.402 Implementation of reporting objectives.*

The obligation to comply with § 292.302 is imposed directly on electric utilities. This is different from the rest of Subpart C where the obligation to act is imposed on the State regulatory authority or the nonregulated electric utility in its role as regulator. The Commission is exercising its authority under section 133 of PURPA and other laws within the Commission's authority to require this reporting.

Any electric utility which fails to comply with the requirements of § 292.302(b) is subject to the same penalties as it might receive as a result of a failure to comply with the requirements of the Commission's regulations issued under section 133 of PURPA. As stated earlier in this preamble, the data required by § 292.302 will form the basis from which the rates for purchases will be derived: § 292.302 is thus a critical element in this program. The Commission believes that, with regard to utilities subject to section 133 of PURPA, the Commission may exercise its authority under section 133 to require the data required by § 292.302(b) on the basis that the Commission finds such information necessary to allow determination of the costs associated with providing electric services. With regard to utilities not subject to section 133, if they fail to provide the data called for in § 292.302(c), the Commission may compel its production under the Federal Power Act and other statutes which provide the Commission with authority to require reporting of such data.

§ *292.403 Waivers.*

Paragraph (a) provides for a procedure by which any State regulatory authority or nonregulated electric utility may apply for a waiver from the application of any of the requirements of Subpart C other than § 292.302. (Section 292.302(d) has been revised to permit a State regulatory authority or nonregulated utility to adopt a substitute method for the provision of system cost data without prior Commission approval.)

Paragraph (b) provides that the Commission will grant such a waiver only if the applicant can show that compliance with any of the requirements is not necessary to encourage cogeneration or small power production and is not otherwise required under section 210 of PURPA.

This section is included in recognition of the need for the Commission to afford flexibility to the States and nonregulated utilities to implement the Commission's rules under section 210.

Several comments suggested that the Commission set forth procedures for considering applications for waivers which would allow formal participation by qualifying facilities in a public hearing. The Commission notes that interested parties would be given an opportunity to be heard in any proceeding it conducts to determine whether or not a waiver should be granted.

Subpart F—Exemption of Qualifying Small Power Production and Cogeneration Facilities From Certain Federal and State Laws and Regulations

§ *292.601 Exemption of qualifying facilities from the Federal Power Act.*

Section 210(e) of PURPA states that the Commission shall prescribe rules under which qualifying facilities are exempt, in part, from the Federal Power Act, from the Public Utility Holding Company Act of 1935, from the State laws and regulations respecting the rates, or respecting the financial or organization regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production. As noted in the Staff Discussion Paper, the Congress intended the Commission to make liberal use of its exemption authority in order to remove the disincentive of utility-type regulation. The Commission believes that broad exemption is appropriate.

Section 210(e)(2) of PURPA provides that the Commission is not authorized to exempt small power production facilities of 30 to 80 megawatt capacity from these laws. An exception is made for small power production facilities using biomass as a primary energy source. Such facilities between 30 and 80 megawatts may be exempted from the Public Utility Holding Company Act of 1935 and from State laws and regulations but may not be exempted from the Federal Power Act. The Commission will establish procedures for the determination of rates for these facilities in a separate proceeding.

Paragraph (a) sets forth those facilities which are eligible for exemption. Paragraph (b) provides that facilities described in paragraph (a) shall be exempted from all but certain specified sections of the Federal Power Act.

Section 210(e)(3)(C) of PURPA provides that no qualifying facility may be exempted from any license or permit requirement under Part I of the Federal Power Act. Accordingly, no qualifying facilities will be exempt from Part I of the Federal Power Act. The Commission recently issued simplified procedures for obtaining water power licenses for hydroelectric projects of 1.5 megawatts or less, and has issued proposed regulations to expedite licensing of existing facilities.[31]

The Commission believes cogeneration and small power production facilities could be the subject of an order under section 202(c) of the Federal Power Act requiring them to provide energy if the Economic Regulatory Administration determines that an emergency situation exists. Because application of this section is limited to emergency situations and is not affected by the fact that a facility attains qualifying status or engages in interchanges with an electric utility, the Commission notes that qualifying facilities will not be exempted from section 202(c) of the Act.

Furthermore, in response to comment, the Commission has revised this paragraph to provide that qualifying facilities are not exempt from sections 210, 211, and 212 of the Federal Power Act, as required by section 210(e)(3)(B) of PURPA.

Sections 203, 204, 205, 206, 208, 301, 302, and 304 of the Federal Power Act reflect traditional rate regulation or regulation of securities of public utilities. The Commission has determined that qualifying facilities shall be exempted from these sections of the Federal Power Act.

Section 305(c) of the Act imposes certain reporting requirements on interlocking directorates. The Commission believes that any person who otherwise is required to file a report regarding interlocking positions should not be exempted from such requirement because he or she is also a director or officer of a qualifying facility.

Finally, the enforcement provisions of Part III of the Federal Power Act will continue to apply with respect to the sections of the Federal Power Act from which qualifying facilities are not exempt.

§ *292.602 Exemption of qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.*

Under section 210(e) of PURPA the Commission can exempt qualifying facilities from regulation under the

[31] See Order No. 11, Simplified Procedures for Certain Water Power Licenses, Docket No. RM79-4 issued September 5, 1978, and Application for License for Major Projects—Existing Dam, Docket No. RM79-36, 44 FR 24095 (April 23, 1979).

Public Utility Holding Company Act of 1935 and State laws and regulations concerning rates or financial organization. Only cogeneration facilities and small power production facilities of 30 megawatts or less may be exempted from both of these laws, with the exception that any qualifying small power production facility (*i.e.*, up to 80 megawatts) using biomass as a primary energy source can be exempted from these laws.

The Commission has determined that where a qualifying facility is subjected to more stringent regulation than other companies solely by reason of the fact that it is engaged in the production of electric energy, these more stringent requirements should be eased through exemption of qualifying facilities. By excluding any qualifying facility from the definition of an "electric utility company" under section 2(a)(3) of the Public Utility Holding Company Act of 1935, such facilities would be removed from Public Utility Holding Company Act regulation which is applied exclusively to electric utility companies. Moreover, by excluding qualifying facilities from this definition, parent companies of qualifying facilities would not be subject to additional regulation as a result of electric production by their subsidiaries. The Commission therefore believes that in order to encourage cogeneration and small power production it is necessary to exempt cogenerators and small power producers from all of the provisions of the Public Utility Holding Company Act of 1935 related to electric utilities.

Accordingly, paragraph (b) states that no qualifying facility shall be considered to be an "electric utility company", as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. § 79b(a)(3).

Section 210(e) of PURPA states that qualifying facilities which may be exempted from the Public Utility Holding Company Act may also be exempted from State laws and regulations respecting the rates or financial organization of electric utilities.

The Commission has decided to provide a broad exemption from State laws and regulations which would conflict with the State's implementation of the Commission's rules under section 210.

The Commission believes that such broad exemption is necessary to encourage cogeneration or small power production. Accordingly, subparagraph (c)(1) provides that any qualifying facility shall be exempt from State laws and regulations respecting rates of electric utilities, and from financial and organizational regulation of electric utilities. Several commenters noted that this section might be interpreted as exempting qualifying facilities from state laws or regulations implementing the Commission's rules, under section 210(f) of PURPA. In order to clarify that qualifying facilities are not to be exempt from these rules, the Commission has added subparagraph (c)(2) prohibiting any exemptions from State laws and regulations promulgated pursuant to Subpart C of these rules.

Some commenters indicated that § 292.301(b)(1) might be interpreted as prohibiting a State from reviewing contracts for purchases. These commenters stated that, as a part of a State's regulation of electric utilities, a State regulatory authority needs to be able to review contracts entered into by electric utilities it regulates.

These rules, and the exemptions being provided by these rules, are not intended to divest a State regulatory agency of its authority under State law to review contracts for purchases as part of its regulation of electric utilities. Such authority may continue to be exercised if consistent with the terms, policies and practices under sections 210 and 201 of PURPA and this Commission's implementing regulations. If the authority or its exercise is in conflict with these sections of PURPA or the Commission's regulations thereunder, the State must yield to the Federal requirements. The Commission does not believe it possible or advisable to attempt to establish more precise guidelines than these. Accordingly, States which have questions in this regard should seek an interpretive ruling from the Commission's General Counsel.

Subparagraph (c)(3) provides that, upon request of a State regulatory authority or nonregulated electric utility, the Commission may limit the applicability of the broad exemption from the State laws. This provision is intended to add flexibility to the exemption.

The Commission perceives that there may be instances in which a qualifying facility would wish to have an interpretation of whether or not it is subject to a particular State law in order to remove any uncertainty. Under subparagraph (c)(4), the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

(Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. § 791 *et seq.*, Federal Power Act, as amended, 16 U.S.C. § 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*, E.O. 12009, 42 Fed. Reg. 46267)

IV. Effective Date

The regulations promulgated in this order are effective March 20, 1980.

In consideration of the foregoing, the Commission amends Part 292 of Chapter I, Title 18, Code of Federal Regulations, as set forth below, effective March 20, 1980. By the Commission.

Kenneth F. Plumb,

Secretary.

(1) Subchapter K is amended in the table of contents and in the text of the regulation by deleting the title for Part 292 and substituting the following in lieu thereof:

Part 292—Regulations Under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 With Regard to Small Power Production and Cogeneration.

(2) Subchapter K is further amended in the table of contents to Part 292 and in the text of the regulations by reserving Subpart B and by adding new Subparts A, C, D, and F to read as follows:

PART 292—REGULATIONS UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WITH REGARD TO SMALL POWER PRODUCTION AND COGENERATION

Act and Certain State Law and Regulation

Authority: This part issued under the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601 *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. § 791 *et seq.*, Federal Power Act, 16 U.S.C. § 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.*, E.O. 12009, 42 FR 46267.

Subpart A—General Provisions

§ 292.101 Definitions.

(a) *General rule.* Terms defined in the Public Utility Regulatory Policies Act of 1978 (PURPA) shall have the same meaning for purposes of this part as they have under PURPA, unless further defined in this part.

(b) *Definitions.* The following definitions apply for purposes of this part.

(1) "Qualifying facility" means a cogeneration facility or a small power production facility which is a qualifying facility under Subpart B of this part of the Commission's regulations.

(2) "Purchase" means the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

(3) "Sale" means the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

(4) "System emergency" means a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(5) "Rate" means any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

(6) "Avoided costs" means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

(7) "Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

(8) "Supplementary power" means electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

(9) "Back-up power" means electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

(10) "Interruptible power" means electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

(11) "Maintenance power" means electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

Subpart B—[Reserved]

Subpart C—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978

§ 292.301 Scope.

(a) *Applicability.* This subpart applies to the regulation of sales and purchases between qualifying facilities and electric utilities.

(b) *Negotiated rates or terms.* Nothing in this subpart:

(1) Limits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this subpart; or

(2) Affects the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.

§ 292.302 Availability of electric utility system cost data.

(a) *Applicability.* (1) Except as provided in paragraph (a)(2) of this section, paragraph (b) applies to each electric utility, in any calendar year, if the total sales of electric energy by such utility for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

(2) Each utility having total sales of electric energy for purposes other than resale of less than one billion kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding year, shall not be subject to the provisions of this section until May 31, 1982.

(b) *General rule.* To make available data from which avoided costs may be derived, not later than November 1, 1980, May 31, 1982, and not less often than every two years thereafter, each regulated electric utility described in paragraph (a) of this section shall provide to its State regulatory authority, and shall maintain for public inspection, and each nonregulated electric utility described in paragraph (a) of this section shall maintain for public inspection, the following data:

(1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;

(2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and

(3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

(c) *Special rule for small electric utilities.*

(1) Each electric utility (other than any electric utility to which paragraph (b) of this section applies) shall, upon request:

(i) Provide comparable data to that required under paragraph (b) of this section to enable qualifying facilities to estimate the electric utility's avoided costs for periods described in paragraph (b) of this section; or

(ii) With regard to an electric utility which is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide the data of its supplying utility and the rates at which it currently purchases such energy and capacity.

(2) If any such electric utility fails to provide such information on request, the qualifying facility may apply to the State regulatory authority (which has ratemaking authority over the electric utility) or the Commission for an order requiring that the information be provided.

(d) *Substitution of alternative method.* (1) After public notice in the area served by the electric utility, and after opportunity for public comment, any State regulatory authority may require (with respect to any electric utility over which it has ratemaking authority), or any non-regulated electric utility may provide, data different than those which are otherwise required by this section if it determines that avoided costs can be derived from such data.

(2) Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated utility which requires such different data shall notify the Commission within 30 days of making such determination.

(e) *State Review.* (1) Any data submitted by an electric utility under this section shall be subject to review by the State regulatory authority which has ratemaking authority over such electric utility.

(2) In any such review, the electric utility has the burden of coming forward with justification for its data.

§ 292.303 Electric utility obligations under this subpart.

(a) *Obligation to purchase from qualifying facilities.* Each electric utility shall purchase, in accordance with § 292.304, any energy and capacity which is made available from a qualifying facility:

(1) Directly to the electric utility; or

(2) Indirectly to the electric utility in accordance with paragraph (d) of this section.

(b) *Obligation to sell to qualifying facilities.* Each electric utility shall sell to any qualifying facility, in accordance with § 292.305, any energy and capacity requested by the qualifying facility.

(c) *Obligation to interconnect.* (1) Subject to paragraph (c)(2) of this section, any electric utility shall make such interconnections with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart. The obligation to pay for any interconnection costs shall be determined in accordance with § 292.306.

(2) No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act.

(d) *Transmission to other electric utilities.* If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to § 292.304(e)(4) and shall not include any charges for transmission.

(e) *Parallel operation.* Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any applicable standards established in accordance with § 292.308.

§ 292.304 Rates for purchases.

(a) *Rates for purchases.* (1) Rates for purchases shall:

(i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and

(ii) Not discriminate against qualifying cogeneration and small power production facilities.

(2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

(b) *Relationship to avoided costs.* (1) For purposes of this paragraph, "new capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

(2) Subject to paragraph (b)(3) of this section, a rate for purchases satisfies the requirements of paragraph (a) of this section if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section.

(3) A rate for purchases (other than from new capacity) may be less than the avoided cost if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the nonregulated electric utility determines that a lower rate is consistent with paragraph (a) of this section, and is sufficient to encourage cogeneration and small power production.

(4) Rates for purchases from new capacity shall be in accordance with paragraph (b)(2) of this section, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(5) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.

(c) *Standard rates for purchases.* (1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) The standard rates for purchases under this paragraph:

(i) Shall be consistent with paragraphs (a) and (e) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(d) *Purchases "as available" or pursuant to a legally enforceable obligation.* Each qualifying facility shall have the option either:

(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

(e) *Factors affecting rates for purchases.* In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

(f) *Periods during which purchases not required.*

(1) Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

(2) Any electric utility seeking to invoke paragraph (f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.

(3) Any electric utility which fails to comply with the provisions of paragraph (f)(2) of this section will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph (f)(1) of this section not occurred.

(4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State regulatory authority determines necessary or appropriate, either before or after the occurrence.

§ 292.305 Rates for sales.

(a) *General rules.* (1) Rates for sales:

(i) Shall be just and reasonable and in the public interest; and

(ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.

(2) Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.

(b) *Additional Services to be Provided to Qualifying Facilities.* (1) Upon request of a qualifying facility, each electric utility shall provide:

(i) Supplementary power;

(ii) Back-up power;

(iii) Maintenance power; and

(iv) Interruptible power.

(2) The State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and the Commission (with respect to any nonregulated electric utility) may waive any requirement of paragraph (b)(1) of this section if, after notice in the area served by the electric utility and after opportunity for public comment, the electric utility demonstrates and the State regulatory authority or the Commission, as the case may be, finds that compliance with such requirement will:

(i) Impair the electric utility's ability to render adequate service to its customers; or

(ii) Place an undue burden on the electric utility.

(c) *Rates for sales of back-up and maintenance power.* The rate for sales of back-up power or maintenance power:

(1) shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(2) shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

§ 292.306 Interconnection costs.

(a) *Obligation to pay.* Each qualifying facility shall be obligated to pay any interconnection costs which the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.

(b) *Reimbursement of interconnection costs.* Each State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and nonregulated utility shall determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time.

§ 292.307 System emergencies.

(a) *Qualifying facility obligation to provide power during system emergencies.* A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:

(1) Provided by agreement between such qualifying facility and electric utility; or

(2) Ordered under section 202(c) of the Federal Power Act.

(b) *Discontinuance of purchases and sales during system emergencies.* During any system emergency, an electric utility may discontinue:

(1) Purchases from a qualifying facility if such purchases would contribute to such emergency; and

(2) Sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

§ 292.308 Standards for operating reliability.

Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may establish reasonable standards to ensure system safety and reliability of interconnected operations. Such standards may be recommended by any electric utility, any qualifying facility, or any other person. If any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility establishes such standards, it shall specify the need for such standards on the basis of system safety and reliability.

Subpart D—Implementation

§ 292.401 Implementation by State regulatory authorities and nonregulated electric utilities.

(a) *State regulatory authorities.* Not later than one year after these rules take effect, each State regulatory authority shall, after notice and an opportunity for public hearing, commence

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implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

(b) *Nonregulated electric utilities.* Not later than one year after these rules take effect, each nonregulated electric utility shall, after notice and an opportunity for public hearing, commence implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to comply with Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

(c) *Reporting requirement.* Not later than one year after these rules take effect, each State regulatory authority and nonreguated electric utility shall file with the Commission a report describing the manner in which it will implement Subpart C (other than § 292.302 thereof).

§ 292.402 Implementation of certain reporting requirements.

Any electric utility which fails to comply with the requirements of § 292.302(b) shall be subject to the same penalties to which it may be subjected for failure to comply with the requirements of the Commission's regulations issued under section 133 of PURPA.

§ 292.403 Waivers.

(a) *State regulatory authority and nonregulated electric utility waivers.* Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may, after public notice in the area served by the electric utility, apply for a waiver from the application of any of the requirements of Subpart C (other than § 292.302 thereof).

(b) *Commission action.* The Commission will grant such a wavier only if an applicant under paragraph (a) of this section demonstrates that compliance with any of the requirements of Subpart C is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA.

Subpart F—Exemption of Qualifying Small Power Production Facilities and Cogeneration Facilities from Certain Federal and State Laws and Regulations

§ 292.601 Exemption to qualifying facilities from the Federal Power Act.

(a) *Applicability.* This section applies to:

(1) qualifying cogeneration facilities; and

(2) qualifying small power production facilities which have a power production capacity which does not exceed 30 megawatts.

(b) *General rule.* Any qualifying facility described in paragraph (a) shall be exempt from all sections of the Federal Power Act, except:

(1) Sections 1–30;

(2) Sections 202(c), 210, 211, and 212;

(3) Sections 305(c); and

(4) Any necessary enforcement provision of Part III with regard to the sections listed in paragraphs (b) (1), (2) and (3) of this section.

§ 292.602 Exemption to qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.

(a) *Applicability.* This section applies to any qualifying facility described in § 292.601(a), and to any qualifying small power production facility with a power production capacity over 30 megawatts if such facility produces electric energy solely by the use of biomass as a primary energy source.

(b) *Exemption from the Public Utility Holding Company Act of 1935.* A qualifying facility described in paragraph (a) shall not be considered to be an "electric utility company" as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3).

(c) *Exemption from certain State law and regulation.*

(1) Any qualifying facility shall be exempted (except as provided in paragraph (c)(2)) of this section from State law or regulation respecting:

(i) The rates of electric utilities; and

(ii) The financial and organizational regulation of electric utilities.

(2) A qualifying facility may not be exempted from State law and regulation implementing Subpart C.

(3) Upon request of a State regulatory authority or nonregulated electric utility, the Commission may consider a limitation on the exemptions specified in subparagraph (1).

(4) Upon request of any person, the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

[FR Doc. 80-5730 Filed 2-22-80; 8:45 am]

BILLING CODE 6450-85-M

DEPARTMENT OF JUSTICE

Parole Commission

28 CFR Part 2

Parole, Release, Supervision and Recommitment of Prisoners, Youth Offenders, and Juvenile Delinquents

AGENCY: U.S. Parole Commission.

ACTION: Final rule.

SUMMARY: The Parole Commission has adopted a rule that contains both procedural and substantive changes in the handling of parolees who are serving sentences of imprisonment for new criminal offenses committed while on parole. Procedurally, parole violators incarcerated in state or local facilities will be afforded revocation hearings after completion of 18 months of confinement on the new sentence, or on the docket following their arrival at a federal institution, whichever comes first. For parole violators serving new sentences in federal facilities, the revocation hearing will be held within 120 days after the Commission has been notified of the new incarceration, or as soon thereafter as practicable. The rule also establishes a substantive change from past Commission policy by providing for a customary policy of partially concurrent service of the parole violator term and the new sentence starting either upon release from confinement on the new sentence, or after 18 months of confinement on the new sentence, whichever comes first. A departure from this customary policy would require the concurring votes of two Commissioners. The purpose of this rule is to reduce the period of uncertainty for incarcerated parolees as to the Federal disposition of his/her case.

EFFECTIVE DATE: July 1, 1980, following the procedure described below.

FOR FURTHER INFORMATION CONTACT: Barbara Meierhoefer, Research Unit, U.S. Parole Commission, 320 First Street, NW., Washington, D.C. 20537; telephone (202) 724-3153.

The Proposal and Its Purpose

On June 5, 1979, the U.S. Parole Commission published in the Federal Register (44 FR 32253) a proposed rule which dealt with the time of revocation hearings for parole violators serving new sentences.

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23 F.E.R.C. 61304 printed in FULL format.

Policy Statement Regarding the Commission's Enforcement Role Under Section 210 of the Public Utility Regulatory Policies Act of 1978

Docket No. PL83-4-000

FEDERAL ENERGY REGULATORY COMMISSION - Commission

23 F.E.R.C. P61,304; 1983 FERC LEXIS 2583

Statement of Policy

May 31, 1983

PANEL:
[*1]

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

OPINION:

In this document, the Commission is defining the role it intends to assume in enforcing the provisions of section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and defining the relationship of its enforcement authority to State judicial enforcement authority. The purpose of this document is to clarify our view of our appropriate place in an apparently ambiguous statutory enforcement scheme and to inform affected persons of the forums available if the PURPA requirements are not fulfilled. This document does not constitute a change in policy or a determination on the merits of any case.

Background

Under section 210 of PURPA, the Commission is required to promulgate rules which encourage the development of cogeneration and small power production. Among other things, the Commission's rules are to require electric utilities to purchase power from, and sell power to, facilities which qualify as cogeneration or small power production facilities under section 201 of PURPA. The Commission is also authorized to exempt certain qualifying cogeneration and [*2] small power production facilities from the provisions of the Federal Power Act, the Public Utility Holding Company Act of 1935, and certain State laws. The Commission's regulations promulgated under sections 201 and 210 of PURPA are codified at 18 C.F.R. Part 292.

Under section 210(f) of PURPA, State regulatory authorities and nonregulated electric utilities are required to implement the Commission's rules described above. The Commission has indicated that the obligation to implement section 210 rules is a continuing obligation. This requirement may be fulfilled either: 1) through the enactment of laws or regulations at the State level; 2) by application on a case-by-case basis by the State regulatory authority, or nonregulated utility, of the rules adopted by the Commission; or, 3) by any other action reasonably designed to implement the Commission's rules.

Sections 210(g) and (h) of PURPA provide judicial review and enforcement procedures and Commission enforcement procedures respectively. Generally, these review and enforcement mechanisms are available to ensure that State regulatory authorities and non-regulated electric utilities undertake implementation of the Commission regulations. [*3]

Section 210(g)(1) of PURPA provides for judicial review, generally to be pursued in a State court forum, n1 respecting any proceeding conducted by a State regulatory authority or nonregulated electric utility for the purpose of implementing the requirements of section 210(a) of PURPA. Section 210(g)(2) authorizes any person to bring an action against any electric utility, qualifying small power producer, or qualifying cogenerator, to enforce any requirement established by a State regulatory authority or nonregulated electric utility pursuant to section 210(f).

n1 Section 210(g) of PURPA states that judicial review and enforcement is obtained under the same requirements and in the same manner that an action would be brought under section 123 of PURPA.

Section 123(c)(1) of PURPA provides that judicial review and enforcement of determinations made by State regulatory authorities and nonregulated electric utilities may be obtained in the appropriate State court. Under section 123(c)(2) of PURPA, review of determinations made by a Federal agency may be obtained in the appropriate Federal court.

Section 210(h)(1) of PURPA grants the Commission certain enforcement authority with regard [*4] to those rules promulgated under section 210(a) which constitute "operations" under Part II of the Federal Power Act. As will be discussed more fully below, this authority applies only in limited circumstances. Section 210(h)(2) of PURPA authorizes the Commission to undertake an enforcement action to require a State regulatory authority or nonregulated electric utility to implement the Commission's regulations. As an important adjunct to this enforcement authority, section 210(h)(2) also authorizes certain private enforcement actions for the purpose of compelling implementation.

The Commission has previously addressed these review and enforcement provisions in the preamble to Order 69. n2 This policy statement is intended as a supplement to that discussion. It will identify some of the major causes of action which may arise under section 210 of PURPA and discuss the Commission's view of the forums in which the variety of actions should be pursued. This list is not intended to be exhaustive, and the Commission will entertain further inquiries on a case-by-case basis.

n2 Docket No. RM79-55, "Small Power Production and Cogeneration Facilities; Regulation Inplementing Section 210 of the Public Utility Regulatory Policies Act of 1978," [FERC Statutes and Regulations P30,128], 45 Fed. Reg. 12214 (Feb. 25, 1980). (Hereinafter, Order 69.) The Commission stated that:

Section 210(g) of PURPA provides one of the means of obtaining judicial review of a proceeding conducted by a State regulatory authority or nonregulated utility for purposes of implementing the Commission's rules under section 210 . . . This means that persons can bring an action in State court to require the State regulatory authorities or nonregulated utilities to implement these regulations.

* * *

The Commission believes that review and enforcement of implementation under section 210 of PURPA can consist not only of review and enforcement as to whether the State regulatory authority or nonregulated electric utility has conducted the initial implementation properly, namely, put into effect regulations implementing section 210 rules or procedures for that implementation, after notice and an opportunity for a hearing. It can also consist of review and enforcement of the application by a State regulatory authority or nonregulated electric utility, on a case-by-case basis, of its regulations or of any other provision it may have adopted to implement the Commission's rules under section 210.

Section 210(h)(2)(A) of PURPA states that the Commission may enforce the implementation of regulations under section 210(f). The Congress has provided not only for private causes of action in State courts to obtain judicial review and enforcement of the implementation of the Commission's rules under section 210, but also provided that the Commission may serve as a forum for review and enforcement of the implementation of this program.

Id. at 12231. [*5]

The Commission does not intend for this statement to have any effect other than to further inform the public of our views and the course we intend to follow in future proceedings. This statement has no legal effect, is not a rule or a binding norm, and imposes no rights or obligations. Therefore, as these issues arise in future proceedings the validity and application of the policies enunciated herein may be subject to further consideration.

Obligation to commence implementation

Under section 210(f) of PURPA, State regulatory authorities and nonregulated electric utilities are required to implement regulations promulgated by this Commission under section 210(a) of PURPA. Under section 210(h)(2)(A) the Commission has the authority to require the commencement of implementation under subsection (f) by any State regulatory authority or nonregulated electric utility. Moreover, the Commission's authority under this subsection extends to situations where State regulatory authorities or nonregulated electric utilities are alleged to have completed the implementation process, but have promulgated regulations which are inconsistent with or contrary to the Commission's regulations. Thus, [*6] for example, an allegation that a State regulatory authority has promulgated regulations which include a purchase rate standard contrary to existing Commission regulations would properly lie either before this Commission or before a judicial forum of proper jurisdiction. n3

n3 See note 2, supra.

As we have already noted, n4 the Commission believes that its jurisdiction to review and enforce the section 210(f) implementation requirement (i.e., the requirement that State regulatory authorities and nonregulated electric utilities promulgate rules consistent with the requirements established by this Commission under section 210(a) of PURPA) is not exclusive. In fact, we would anticipate that generally proceedings would be initiated at the State level.

n4 Id.

The Commission may undertake an enforcement action either on its own motion or upon petition by an electric utility, qualifying cogenerator, or qualifying small power producer. If the Commission chooses to undertake an action to require the commencement of implementation, both State regulatory authorities and nonregulated electric utilities are to be treated as persons under the Federal Power Act. The Commission's [*7] regulations establishing the implementation requirement of section 210(f) of PURPA n5 will be treated as rules under the Federal Power Act.

n5 18 C.F.R. § 292.401.

The Commission is not required to undertake an enforcement action described above. If the Commission does not initiate an enforcement action by notice within 60 days after receipt of a petition from an electric utility, qualifying cogenerator, or qualifying small power producer, the petitioner may bring an action in the appropriate United States district court. We anticipate that such an enforcement action would be an investigation to determine whether there are grounds for the Commission to seek court enforcement. The Commission is entitled to intervene as a matter of right in any private enforcement action under this section.

Implementation procedures

The implementation provisions of section 210(f) of PURPA contain certain statutory procedural requirements--viz., notice and an opportunity for public hearing. The Commission has the authority under section 210(h)(2)(A) of PURPA to enforce these statutory procedural requirements. Thus, a person alleging that a State regulatory authority or nonregulated electric [*8] utility has not issued notice or offered an opportunity for public hearing prior to promulgating regulations under section 210(f) of PURPA may petition the Commission to seek enforcement of these requirements. For purposes of any such enforcement action, the Commission's regulations implementing these procedural requirements will be treated as rules under the Federal Power Act.

The Commission notes that its enforcement jurisdiction in this regard is not exclusive. Section 210(g)(1) provides that any person may seek judicial review of any proceeding conducted by a State regulatory authority or nonregulated electric utility without petitioning this Commission. This provision appears to include procedural as well as substantive judicial review. Moreover, procedural challenges may be raised independently under applicable provisions of State law. Indeed, the Commission's authority to enforce PURPA procedural requirements is limited to those circumstances where an allegation is made that a State regulatory authority or nonregulated electric utility has failed to provide notice or an opportunity for public hearing as required by section 210(f). All other procedural challenges should be directly [*9] addressed to the proper judicial forum, rather than to this Commission.

Application of State regulatory authority or nonregulated electric utility established rules

The Commission perceives that its primary role in the statutory scheme of review and enforcement is to ensure that the State regulatory authorities and nonregulated electric utilities implement regulations under section 210(f) which are consistent with the regulations established by the Commission under section 210(a) of PURPA. However, once the State regulatory authorities and nonregulated electric utilities have appropriately implemented the Commission's regulations, the Commission's role is limited regarding questions of the proper application of these rules on a case-by-case basis. n6

n6 In fact, the only area in which the Commission may get involved in questions regarding the application of rules is with regard to 30 to 80 megawatt small power production facilities. See discussion, infra.

Section 210(g)(2) states that "any person (including the Secretary [of Energy]) may bring an action against any electric utility, qualifying small power producer, or qualifying cogenerator to enforce any requirement [*10] established by a State regulatory authority or nonregulated electric utility pursuant to subsection (f)." This subsection provides the primary enforcement authority by which an aggrieved person may challenge the application of a rule or rules promulgated by a State regulatory authority or nonregulated electric utility.

The following are examples of causes of action which may arise under section 210(g)(2) of PURPA. Assume that a State regulatory authority has promulgated regulations under section 210(f) of PURPA which require electric utilities and qualifying facilities to negotiate a rate for purchase. The underlying State-established regulation is not at issue but, rather, a qualifying facility alleges that a particular electric utility, subject to the State regulatory authority's jurisdiction, refuses to negotiate. This allegation involves the application of a State-established rule and would properly lie before a State judicial forum of competent jurisdiction.

Similarly, where a nonregulated electric utility has promulgated rules appropriately implementing this Commission's regulations, and a qualifying facility alleges that a contract offered to it by the nonregulated utility [*11] contains unreasonable interconnection requirements, for example, this allegation is one which is properly raised under section 210(g)(2) before a State judicial forum, and not before this Commission. n7

n7 The Commission recognizes that nonregulated electric utilities are required to both implement the Commission's regulations and then comply with these self-established regulations. While this situation may seem anomalous, the Commission believes it appropriate to treat the nonregulated electric utility's regulatory function separately from its obligations as an electric utility. Thus, a challenge regarding the regulatory function of such an entity (e.g., that the nonregulated electric utility has not commenced implementation) would properly lie before this Commission under section 210(h) whereas a challenge regarding the application of regulations would not lie before this Commission.

Exception for 30 to 80 megawatt small power production facilities.

The review and enforcement scheme described above contains an exception with regard to certain qualifying small power production facilities. Section 210(h)(1) of PURPA gives the Commission exclusive enforcement authority [*12] with regard to any rules prescribed by the Commission under section 210(a) of

PURPA "with respect to any operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility which are subject to the jurisdiction of the Commission under part II of the Federal Power Act." Pursuant to section 210(e) of PURPA, the Commission has granted liberal exemptions for all eligible qualifying facilities from part II of the Federal Power Act. n8 However, section 210(e)(2) of PURPA prohibits the Commission from exempting small power production facilities between 30 and 80 megawatts capacity, other than geothermal facilities, from the provisions of the Federal Power Act. The sales of power in interstate commerce by such facilities would, therefore, be an "operation" which is subject to this Commission's jurisdiction under Part II of the Federal Power Act.

n8 18 C.F.R. §§ 292.601, 292.602 (1982).

Under Part II of the Federal Power Act, the Commission regulates, inter alia, sales of electric power in interstate commerce. The Commission therefore has the authority under the Federal Power Act to establish the rate for sale by such a facility. n9 [*13] Thus, the Commission may require that the rate for purchase by an electric utility from such a qualifying facility be consistent with the Commission-established rate.

n9 The Commission notes that sales by electric utilities to qualifying facilities are retail sales which are not "operations" under the Federal Power Act and are not, therefore, subject to Commission enforcement jurisdiction. Similarly, the interconnection requirement established in 18 C.F.R. § 292.303(c) is not an "operation" under the Federal Power Act. See American Electric Power Service Corp. v. F.E.R.C., 675 F.2d 1226 (D.C. Cir. 1982) reversed and remanded -- U.S. -- (1983).

The Commission has determined that State-established rates which are consistent with the Commission's regulations will generally be accepted as the "just and reasonable" rate for purchases by electric utilities from Federal Power Act jurisdictional qualifying facilities under section 205 of the Federal Power Act. n10

n10 See Resources Recovery (Dade County), Inc., Docket No. ER82-225-000, et seq., orders issued March 12 [18 FERC P61,243], May 24 [19 FERC P61,188], and August 3, 1982 [20 FERC P61,138]; Wheelabrator Frye, Inc., Docket No. EL82-7-000, order issued December 23, 1982; and Energy Conversions of America, Inc., Docket No. ER82-576-000, order issued December 23, 1982 [21 FERC P61,329]. [*14]

Conclusion

The above discussion represents the Commission's considered, but informal, position regarding its role under the review and enforcement mechanisms of section 210 of PURPA. The Commission is required to promulgate rules to encourage the development of cogeneration and small power production which the State regulatory authorities and nonregulated electric utilities are required to implement these rules. The State regulatory authorities and nonregulated electric utilities are required to implement the Commission's regulations. The Commission's regulations allow the States and nonregulated utilities a wide degree of latitude in establishing an implementation plan. Such latitude is necessary in order for implementation to accommodate local conditions and concerns, so long as the final plan is consistent with statutory requirements.

With regard to review and enforcement, the Commission's role is generally limited to ensuring that the State regulatory authority-or nonregulated electric utility-established implementation plan is consistent with section 210 of PURPA and with the Commission's regulations. Once this is ensured, the State judicial forums are available to ensure [*15] that electric utilities and qualifying facilities are dealing in good faith and in a manner consistent with locally-established regulation.

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CAE-31

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

DRAFT

Before Commissioners:

North Little Rock Cogeneration, L.P. and Power Systems, Ltd.	)	
v.	)	Docket No. EL94-72-000
Entergy Services, Inc. and Arkansas Power & Light Company	)	
Entergy Services, Inc.	)	Docket No. ER94-1128-001

ORDER DISMISSING COMPLAINT AND DENYING REHEARING

Introduction

North Little Rock Cogeneration, L.P. (North Little Rock Cogeneration) and Power Systems, Ltd. (Power Systems) (together, Petitioners) challenge an existing power sale agreement between Arkansas Power & Light Company (Arkansas Power), an operating utility subsidiary of Entergy Corporation and an associate of Entergy Services, Inc. (Entergy Services), and the City of North Little Rock, Arkansas (City). Petitioners contend that the rates in the challenged power sale agreement are unreasonable and unduly discriminatory. Petitioners also contend that the agreement was negotiated in violation of the City's alleged obligation under the Public Utility Regulatory Policies Act of 1978 (PURPA), see 16 U.S.C. § 824a-3 (1994), to purchase capacity and energy from qualifying facilities (QFs) -- such as the facility to be built and operated by Petitioners.

Petitioners have raised the same allegations in separate pleadings filed on approximately the same date (June 27 or 28, 1994) in three related proceedings: (1) a petition for a PURPA enforcement action filed, pursuant to section 210(h) of PURPA, in Docket No. EL94-71-000; (2) a request for rehearing of the Commission order in Docket No. ER94-1128-000 accepting the Arkansas Power/City power sale agreement for filing; and (3) a complaint filed against Entergy Services and Arkansas Power in

Docket No. EL94-72-000. 1/ We already have declined to initiate an enforcement action under PURPA to pursue these issues. We now find no substance in the merits of Petitioners' arguments and, accordingly, dismiss their complaint and deny their request for rehearing.

Background

North Little Rock Cogeneration is a limited partnership formed to build, own and operate a qualifying cogeneration facility to be located in North Little Rock, Arkansas. (North Little Rock Cogeneration filed a notice of self-certification of its facility as a QF on April 19, 1993 in Docket No. QF93-75-000.) Power Systems has an option to acquire an equity interest in North Little Rock Cogeneration and represented North Little Rock Cogeneration in its unsuccessful negotiations with the local electric utility, the City, for the sale of capacity and energy. The City operates its own hydroelectric generating unit, but must purchase the remainder of its requirements.

Arkansas Power/City Power Sale Agreement

Arkansas Power and the City executed a ten-year power sale agreement to replace the then-existing agreement for partial requirements service that was scheduled to expire on June 1, 1994. Entergy Services filed the Arkansas Power/City power sale agreement, on behalf of Arkansas Power, with the Commission in Docket No. ER94-1128-000. Petitioners protested the filing, explaining that they competed to sell power and capacity to the City from their planned QF, but were not selected. Petitioners argued that the rates in the filed agreement are not cost-based or justified on a market basis, and that certain provisions in the agreement and certain procedures utilized by the City in considering possible supply alternatives deprived it of the right to develop a QF to serve the City at its true avoided cost, in violation of the City's obligations under PURPA.

By letter order dated May 26, 1994, the Commission accepted the Arkansas Power/City power sale agreement for filing. See Arkansas Power & Light Company, 67 FERC ¶ 61,250 (1994). In that order, the Commission rejected as unsupported Petitioners' arguments in opposition to the proposed agreement. Specifically,

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1/ Entergy Services is a service company which is neither a public utility under the Federal Power Act (FPA) nor an electric utility under PURPA. As such, the complaint lies against Entergy Services only in its capacity as a representative of Arkansas Power which is both a public utility under the FPA and an electric utility under PURPA.

the Commission stated that its review indicated that the proposed rates would not produce excess revenues. The Commission also explained that Petitioners' "dissatisfaction with North Little Rock's procedures for QF developers are beyond the scope of this docket which involves [Arkansas Power's] rates to North Little Rock." Id. at 61,825.

On June 27, 1994, Petitioners filed a request for rehearing of the Commission's May 26, 1994 order. Petitioners assert that the proposed rate "adversely affects their ability to sell electric capacity and energy to the City of North Little Rock." Rehearing at 1. In support of their request for rejection of the power sale agreement or, at a minimum, a trial-type evidentiary hearing on this matter, Petitioners reiterate many of their earlier arguments and refer to similar arguments presented contemporaneously in their complaint in Docket No. EL94-72-000 (discussed below).

PURPA Enforcement Action

Also on June 27, 1994, Petitioners filed a petition in Docket No. ER94-71-000 pursuant to section 210(h) of PURPA, 16 U.S.C. § 824a-3(h). Petitioners asked the Commission to enforce its regulations implementing PURPA and to issue an order finding that the City's determination of the avoided cost rate for purchases from QFs and the procedures used by the City in dealing with Petitioners violated the Commission's regulations. The issues raised in the enforcement petition, to a large degree, are related to the issues raised in Petitioners' complaint and rehearing request.

On August 26, 1994, the Commission issued a notice of intent not to act on the enforcement petition. See North Little Rock Cogeneration, L.P. and Power Systems, Ltd., 68 FERC ¶ 61,391 (1994). In declining to initiate an enforcement action under PURPA, the Commission explained that "[t]his action is without prejudice to any action the Commission might decide to take on related arguments raised in North Little Rock Cogeneration's complaint filed in Docket No. EL94-72-000 or its request for rehearing of the Commission letter order issued in Docket No. ER94-1128-000." Id. at 62,566.

Petitioners' Complaint

On June 28, 1994, Petitioners filed a complaint against Entergy Services and Arkansas Power, asking the Commission to set aside the power sale agreement executed by Arkansas Power and the City and to direct the City to engage in power supply negotiations with Petitioners. The complaint contains the same arguments as those contained in the pleadings filed by Petitioners on the preceding day in the related proceedings.

Petitioners challenge the rates, terms, and conditions in the power sale agreement as unjust and unreasonable, unduly discriminatory and anticompetitive, and contrary to the public interest. Petitioners complain that the rates contained in the power sale agreement are discounted below Arkansas Power's full cost level and contend that, under the Commission's standards, such discounts are appropriate only if Arkansas Power has excess capacity on its system or if the possible loss of the load is significant, situations not present here. Petitioners also complain that, under the power sale agreement, if the City purchases QF power, Arkansas Power will bill the City at the full contract rate, reduced by the amount that Arkansas Power's variable costs are reduced as a result of North Little Rock's transaction with the QF.

The overall effect of these rate provisions, Petitioners assert, is to establish the City's avoided cost at the level of Arkansas Power's avoided costs. 2/ Petitioners state that, while the Commission's regulations contemplate that QF purchasers served under full requirements contracts will adopt the avoided cost of the full requirements supplier as their own avoided cost, the City is not a full requirements customer of Arkansas Power and, therefore, the billing credit violates the Commission's requirements.

In addition, Petitioners complain that, by entering into the power sale agreement with Arkansas Power, the City would have no need for the QF capacity that Petitioners want to develop. Petitioners complain that the process by which Arkansas Power was chosen to supply power to the City was tainted by anticompetitive and discriminatory conduct. In this regard, Petitioners assert that the actions of City officials and certain Arkansas Power representatives during the solicitation and negotiation process severely disadvantaged Petitioners in their attempt to pursue a competitive QF project. For this reason, Petitioners contend that the resulting power sale agreement is not in the public interest and should be invalidated in favor of renewed QF negotiations.

2/ Petitioners state that, although the power sale agreement does not expressly define the avoided cost rate to be paid by the City to QF suppliers, the City would not offer a QF a rate higher than the credit it receives from Arkansas Power because the credit reflects the purchased power cost that the City can avoid by making a QF purchase.

Notice of Petitioners' complaint was published in the Federal Register, 59 Fed. Reg. 25,921 (1994), with comments, protests or motions to intervene due on or before July 28, 1994.

On July 28, 1994, Entergy Services filed, on behalf of itself and Arkansas Power, an answer to Petitioners' complaint. In its response, Entergy Services requests that the complaint be dismissed, arguing that it is duplicative to Petitioners' requests for relief in related proceedings (involving their requests for enforcement and rehearing). Entergy argues that the Commission never has required a showing that a utility is or will continue to be in an excess capacity situation before approving rates discounted below the full cost level. It argues that, in any event, the data relied upon by Petitioners show that Arkansas Power will have excess capacity on its system until at least 1999, at which time the power sale agreement rates can be revised and the City, at its option, can terminate the agreement. Entergy Services continues that the data used by Petitioners were compiled prior to Entergy Corporation's acquisition of additional capacity (through its recent acquisition of Gulf States Utilities Company), and that more recent data show that additional capacity is not projected to be needed until 2001. Entergy Services argues that the loss of the City's load to a competitor will reduce the load on the Entergy System by one percent, a significant figure.

Entergy Services adds that the City's processes for considering QF proposals are irrelevant to the instant proceeding because the City is not a public utility (see infra note 3) and because the appropriate forum for alleged PURPA violations is in state courts.

On July 28, 1995, the City moved to intervene in the complaint proceeding. The City states that it supports the answer filed by Entergy Services concerning the validity of the power sale agreement. 3/

3/ The City explains that it is an Arkansas municipal corporation that is not regulated by the Arkansas Public Service Commission. The City further explains that the Arkansas General Assembly has delegated responsibility for utility operations, including the setting of rates and the acquisition of power supplies, to the North Little Rock City Council. The City thus satisfies the statutory definition of a "nonregulated electric utility," which is defined in section 3(9) of PURPA, 16 U.S.C. § 2602(9) (1994), as "any electric utility other than a State regulated electric utility."

On August 12, 1994, Petitioners filed a motion for leave to file an answer to Entergy Services' July 28, 1994 answer to Petitioners' complaint. On August 29, 1994, Entergy Services filed an answer in opposition to Petitioners' August 12, 1994 motion. In these pleadings, the parties exchange allegations of purported misstatements and mischaracterizations.

Discussion

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (1995), the timely, unopposed motion to intervene of the City serves to make it a party to the complaint proceeding in Docket No. EL94-72-000. We do not find good cause to accept Petitioners' August 12, 1994 responsive pleading: accordingly, pursuant to Rule 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (1995), which generally prohibits the filing of answers to answers, we will deny Petitioners' August 12, 1994 motion and reject Entergy Services' August 29, 1994 answer as moot.

The allegations raised by Petitioners, arising out of their unsuccessful bid to serve the City, ultimately reduce to two principal concerns: (1) whether Arkansas Power can offer the City a discounted rate to retain its load, when the discount results in a rate which a competing QF cannot match; and (2) whether the Commission should redress Petitioners' allegations concerning improper collusion (between Arkansas Power and the City) in the City's selection of a power supplier. We explain below, as to the first question, that the discount rate is reasonable and entirely consistent with our regulations and precedent. As to the second question, we explain below that the perceived unfairness of the City's competitive power supply solicitation is a matter that should be resolved in other fora.

Reasonableness of the Rate Charged the City

We reject Petitioners' claim that the rates charged the City under its power sale agreement with Arkansas Power are not just and reasonable. Petitioners complain that the billing credit provided to the City, if it purchases power from a QF, is too low to support Petitioners' planned QF project. Petitioners suggest that the City's avoided cost should be established based on the alternatives the City would have pursued if it had not purchased from Arkansas Power and the billing credit in the power sale agreement should be set equal to that avoided cost figure. Petitioners also complain that the billing credit provision is inconsistent with the Commission's PURPA regulations because the City is not a full requirements customer of Arkansas Power.

We disagree with these rate-related objections. Contrary to Petitioners' arguments, we do not perceive any inconsistency with our regulations. The cited regulations address only a situation involving full requirements customers 4/ and do not establish or prohibit any particular rate treatment for partial requirements sales. Thus, Petitioners' assertion, even if correct, that Arkansas Power is a partial requirements supplier to the City -- a matter vigorously disputed by Entergy Services -- does not advance their case.

The challenged billing credit, like all other aspects of the power sale agreement, reflects the bargain struck by the parties, not any Commission requirements. Petitioners' suggestion that the power sale agreement must adopt a billing credit equal to the City's avoided cost, as if it had not entered into the power sale agreement, turns the notion of avoided cost on its head. Avoided costs are determined, in the first instance, by all alternatives available to the purchasing utility. Those alternatives, as we have explained in a number of recent orders, 5/ include all supply alternatives. Here, the City's supply alternatives included the power sale agreement offered by Arkansas Power. If the QF proposed by Petitioners could not match the rate offered

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4/ In support of their argument, Petitioners refer to language in Order No. 69, Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, 1977-81 FERC Stats. & Regs., Regulations Preambles ¶ 30,128 at 30,871 (1980). However, the Commission clarified Order No. 69, in relevant part, in City of Longmont, Colorado, et al., 39 FERC ¶ 61,301 at 61,974 (1987), in which it stated that:

> the appropriate measure of avoided cost of an all-requirements utility should be adjusted to reflect the avoided cost of the supplying utility.

In Carolina Power & Light Company, 48 FERC ¶ 61,101 at 61,389-90 (1989), the Commission reaffirmed that it was the:

> intent of Order No. 69 to measure the avoided cost of a full requirements customer as the avoided cost of the full requirements supplier since it is the supplier that avoids generation when the full requirements customer purchases from a QF.

5/ See Southern California Edison Company and San Diego Gas & Electric Company (Southern California Edison), 70 FERC ¶ 61,215 at 61,676-77, order on reconsideration, 71 FERC ¶ 61,269 (1995).

by a competing supplier of power to the City, regardless of whether the competitor was or was not a QF, then the QF demonstrably was not offering a rate at the City's avoided cost 6/ -- and the City had no obligation under PURPA to purchase power offered at a higher price than the lowest bid. 7/

The balance of Petitioners' rate concerns is devoted to the claim that Arkansas Power's offer of rates discounted below full cost is not just and reasonable because, contrary to their reading of Commission requirements, Arkansas Power has not demonstrated that it has excess capacity on its system. Petitioners cite Public Service Company of Oklahoma (PSO), 54 FERC ¶ 61,021 (1991), and Oklahoma Gas and Electric Company (OG&E), 54 FERC ¶ 61,212, reh'g denied, 55 FERC ¶ 61,142 (1991), to support their position in this regard. However, those cases do not stand for the proposition cited by Petitioners. In PSO and OG&E, the Commission merely noted that "a utility [facing competition] with surplus capacity will take whatever price it

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6/ See PURPA section 210(d), 16 U.S.C. § 824a-3(d) (defining "incremental cost of alternative electric energy" as "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source") (emphasis added).

7/ The parties dispute whether any rate offered by Petitioners should reflect just energy payments or also capacity payments. The City apparently believes that if Petitioners proceed to build, any power available will be less than firm and, therefore, should reflect only energy, and not capacity, payments. The Petitioners, on the other hand, want to supply the City with both capacity and energy, for which payments would be substantially higher, and are unwilling to proceed if they will be paid only an avoided energy cost payment.

We have no need to resolve this issue, however. As we have explained in a number of recent orders, it is the obligation of the states in the first instance to determine the precise level of an electric utility's avoided cost obligation (as long as all alternatives are taken into account). See Southern California Edison, 70 FERC at 61,677; Connecticut Light & Power Company, 70 FERC ¶ 61,012 at 61,029, order denying reconsideration, 71 FERC ¶ 61,035 (1995); West Penn Power Company, 71 FERC ¶ 61,153 at 61,495 (1995). Because the City is a "nonregulated electric utility" (see supra note 3), this matter properly is entrusted in the first instance to the North Little Rock City Council.

can get. . ;" it did not compel the existence of surplus capacity as a condition precedent to approval of a discount rate. 8/ More to the point, in those cases the Commission accepted for filing discounted rates, at or exceeding the seller's variable costs, offered to specific customers for the purpose of responding to competitive market pressures. See also, e.g., Tampa Electric Company, 71 FERC ¶ 61,245 (1995) (explaining that it is not unduly discriminatory to offer a particular customer a rate discount if necessary to retain or attract load).

Moreover, even if the Commission had such a surplus capacity requirement, Arkansas Power would meet it. Even the stale data upon which Petitioners rely show that Arkansas Power will have surplus capacity through 1999, and at that time the City is permitted to terminate the power sale agreement.

City's Selection of a Power Supplier

As to the second principal issue raised (the fairness of the City's power supply procurement), we have no basis for acting further. We recognize that the City is a nonregulated electric utility, and that Petitioners do not have a State regulatory authority to which to articulate their arguments concerning the integrity of the competitive bidding program undertaken by the City. Nevertheless, as explained above, we are fully satisfied with the rates emerging from that process. Further, the parties agree that the City, as a nonregulated electric utility, properly may implement the Commission's PURPA regulations, as here, on a case-by-case basis. See Policy Statement Regarding the Commission's Enforcement Role Under Section 210 of the Public Utility Regulatory Policies Act of 1978, 23 FERC ¶ 61,304 at 61,644 (1983). Any remaining concern for the fairness of the City's competitive procurement can be resolved by a state court applying relevant law.

8/ We see no justification for requiring a utility first to lose load and thereby obtain excess capacity before it can compete to retain the load by offering competitive prices. Very simply, the reason a utility, in meeting competitors' proposals, offers a rate below its full costs is that its ratepayers are better off if the utility receives any value above its variable costs. If the utility loses the existing load, its remaining customers must pay all of the fixed costs associated with the excess capacity (assuming such costs are prudently incurred). Thus, these customers are better off if the utility obtains a price that provides any contribution (to fixed costs) above variable costs.

As we have explained on other occasions, the Commission is wary of becoming entangled unnecessarily in the specifics of administering or reviewing state or local competitive power procurements (absent any facial or patent defect). 9/ We see no such defect here and, accordingly, decline to investigate further the fairness of the City's power supply procurement.

The Commission orders:

(A) Petitioners' request for rehearing in Docket No. ER94-1128-001 is hereby denied.

(B) Petitioners' complaint in Docket No. EL94-72-000 is hereby dismissed.

By the Commission.

Secretary

9/ As the Commission explained in American REF-FUEL of Hempstead, 47 FERC ¶ 61,161 at 61,533 (1989):

> [W]ith regard to review and enforcement of avoided cost determinations under [PURPA] implementation plans, we have said that our role is generally limited to ensuring that the plans are consistent with section 210 of PURPA and the regulations, and once we are satisfied that this requirement is met, state judicial forums are available to ensure that QFs and electric utilities are dealing in good faith and in a way consistent with locally established regulation.

See also LG&E-Westmoreland Hopewell, 62 FERC ¶ 61,098 at 61,712 (1993).

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Southern California Edison Company San Diego Gas & Electric Company

Docket No. EL95-16-001, Docket No. EL95-19-001

FEDERAL ENERGY REGULATORY COMMISSION - COMMISSION

71 F.E.R.C. P61,269; 1995 FERC LEXIS 1061

ORDER ON REQUESTS FOR RECONSIDERATION

June 2, 1995

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

OPINION:

Introduction

On February 23, 1995, the Commission issued an order responding to separate petitions for enforcement under section 210(h) of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. § 824a-3(h), filed by Southern California Edison Company (Edison) and by San Diego Gas & Electric Company (San Diego). See Southern California Edison Company and San Diego Gas & Electric Company, 70 FERC P61,215 (1995). Both utilities challenged orders of the California Public Utilities Commission (California Commission) which they alleged required the utilities to purchase significant amounts of unneeded qualifying facility (QF) capacity at prices far in excess of their avoided costs. The Commission found that the California Commission's process of determining avoided costs did not comply with PURPA. The Commission concluded that because the California Commission procedure was unlawful under PURPA, Edison and San Diego could not lawfully be compelled to enter into purchase contracts resulting from that procedure.

As explained below, we [*2] will deny reconsideration of our view, articulated in the February 23 order in this proceeding, that the California Commission, by failing to consider all sources of generation capacity in determining the avoided cost of the purchasing utilities, violated the directives of section 210 of PURPA and this Commission's implementing regulations. In response to requests for additional guidance from the parties, we also clarify briefly our views on the scope of state authority, both within and outside the confines of PURPA, to make resource planning decisions and to encourage *renewable or alternative sources* of generation.

Background

The California Program

As we explained in our February 23 order, the California Commission's Biennial Resource Plan Update (BRPU) was intended to implement this Commission's rules governing the purchase by electric utilities of electricity from QFs. The BRPU was conducted in three stages. First, following the latest projections of energy and capacity needs of California utilities (Edison, San Diego, and Pacific Gas and Electric Company (PG&E)) made by the California Energy Commission (CEC), the utilities filed a resource plan identifying potential [*3] resource additions. The California Commission examined these plans and determined what new resources the utilities would add. Second, after the utilities supplied certain data, the California Commission determined the utilities' assumed costs, known as "benchmark prices," for these resource additions, and determined which of the additions could be avoided. Third, QFs were then allowed to bid against the utilities' benchmark prices for each of the avoided resources. The winning bidders were paid the price bid by the second lowest bidder with respect to each avoided resource. (This procedure is referred to as a second-price auction.) Certain winning bidders received additional payments to reflect the assumed value to society of reduced air emissions.

Based on the CEC's 1990 electricity report, the California Commission concluded in 1992 that Edison would construct 624 MW of new generation from 1997 to 1999 as follows: two new geothermal plants, one wind farm, and the repowering of an existing steam plant. Invoking the same procedure, the California Commission adopted a resource plan specifying four resources for San Diego: 100 MW of geothermal to come on line in 1997, 100 MW of geothermal [*4] to come on line in 1998, and 273 MW from the repowering of a two-unit plant. The California Commission also estimated Edison's and San Diego's costs for construction of each of the identified projects, which were given the name "Identified Deferrable Resources" (IDRs). n1

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In this regard, Edison and San Diego argued that even though the estimated costs were many times larger than the capital costs of constructing new gas-fired turbines, the California Commission concluded that the IDRs were economic by imputing massive environmental compliance costs to the alternative, gas-fired resources.

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The California utilities subsequently solicited bids for the designated new capacity, broken down into separate IDRs. Only QFs were allowed to bid, despite the utilities' request that non-QFs be permitted to participate. The California Commission, in implementing a California statute, required that half of the capacity for certain of the IDRs be reserved solely for renewable bidders. The solicitation produced bids lower [*5] than the IDR benchmarks. According to Edison and San Diego, because of the set-aside requirement for renewable resources, and the fragmentation of capacity into separate blocks, they could not simply take the least-costly bids sufficient to meet their needs.

The February 23 Order

As explained in the February 23 order, Edison and San Diego challenged the California BRPU program as, allegedly, requiring them to sign long-term, fixed-priced contracts with QFs to purchase significant amounts of unneeded QF capacity at prices far in excess of their avoided costs. They argued that this directive was in violation of PURPA and this Commission's implementing regulations. The California Commission responded that the two utilities challenged only a small part of a complex and comprehensive resource plan that was entirely within its purview under PURPA.

In the February 23 order, the Commission found that the California program violated PURPA and the Commission's implementing regulations. The Commission reasoned that sections 210(b) and 210(d) of PURPA n2 require that any determination of avoided cost must take into account all potential sources of capacity, and that the California program [*6] improperly limited itself to only certain sellers (QFs). Without deciding the matter, the Commission also expressed serious concern as to the need of the California utilities for additional capacity and the staleness of the data upon which the California Commission relied in finding a need for capacity.

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Section 210(b) of PURPA explicitly provides that no Commission rule on QF rates "shall provide for a rate which exceeds the incremental cost to the electric utility of alternative energy." 16 U.S.C. § 824a-3(b) (1988). The "incremental cost of alternative electric energy" is defined in section 210(d) of PURPA as "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." 16 U.S.C. § 824a-3(d) (1988).

The Commission's regulations, tracking the statutory language, in turn expressly provide that QF rates must "be just and reasonable to the electric consumers of the electric utility" and that "nothing in [the Commission's regulations] requires any electric utility to pay more than the avoided cost for purchases." 18 C.F.R. § 292.304(a)(1)-(2) (1994). The Commission's regulations define "avoided costs" as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6) (1994).

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The Commission nevertheless acknowledged (70 FERC at 61,676) California's ability to favor particular generation technologies. The Commission noted that resource planning and resource decisions remain the prerogative of state commissions and that states may wish to diversify their generation mix to meet environmental goals in a variety of ways. It stated that its decision does not, for example, preclude the possibility that, in setting an avoided cost rate, a state may account for environmental costs of all fuel sources included in an all-source determination of avoided cost. The Commission emphasized that its decision "simply makes clear that states can pursue policy choices concerning particular generation technologies consistent with the requirements of PURPA and the Commission's regulations, so long as such action does not result in rates above avoided cost." Id.

Requests for Reconsideration

On March 23, 1995, Oxbow Power Corporation filed a request for rehearing of the Commission's February 23 order. On March 24, 1995, Niagara Mohawk Power Corporation, the Electric Generation Association, and American Wind Energy Association and Zond Systems, Inc. filed requests for [*8] "rehearing" of the Commission's February 23, 1995 order. On March 24, 1995, AES Pacific, Inc. filed a motion to intervene out-of-time in this proceeding and a motion for clarification or, in the alternative, for "rehearing" of the Commission's February 23 order. On March 27, 1995, as revised on April 3, 1995, the California Commission filed a request for "rehearing" of the Commission's February 23 order. On March 27, 1995, the National Association of Regulatory Utility Commissioners, the National Independent Energy Producers, and Pacific Gas and Electric Company filed requests for "rehearing" of the Commission's February 23 order. On March 27, 1995, Air Products and Chemicals, Inc., the Independent Energy Producers Association (IEP), Magma Power Company (Magma), and U.S. Generating Company and Fellows Generating Company, L.P. filed requests for "rehearing" or reconsideration of the Commission's February 23 order. On March 27, 1995, Seawest Energy Corporation filed a request for clarification or "rehearing" of the Commission's February 23 order. On March 27, 1995, San Diego filed a request for clarification of the Commission's February 23 order, and Edison filed a notice in support [*9] of Edison's filing. On March 27, 1995, the Pennsylvania Public Utility Commission and, separately, the Innes Avenue Coalition and the Morgan Heights Homeowners Association (which state that they are neighborhood associations located in San Francisco, California) filed motions for late intervention in this proceeding.

On April 10, 1995, Congressman Edward J. Markey filed a letter commenting on the Commission's February 23 order and raising issues regarding the future of federal-state relations concerning state resource planning decisions.

On April 11, 1995, Edison, San Diego, and Magma filed responses to the pleadings earlier filed in this proceeding in response to the Commission's February 23 order.

On April 12, 1995, the Commission, having concluded that formal rehearing does not lie, either on a mandatory or a discretionary basis, in cases that involve solely PURPA section 210 issues, issued a notice in this proceeding. The notice stated that while many of the parties in the instant proceeding have styled their pleadings as requests for rehearing, the Commission will treat them as requests for reconsideration and will address the issues raised by the various parties' pleadings, [*10] including the requests for clarification and motions to intervene out-of-time, at a later time. See Southern California Edison Company and San Diego Gas & Electric Company, 71 FERC P61,090 (1995).

Discussion

As an initial matter, we find good cause to grant all of the motions to intervene out-of-time in the proceedings in Docket Nos. EL95-16-000 and EL95-19-000, and we will consider all pleadings filed in light of the interests the parties raise and in order to complete all of the arguments of the parties.

The arguments raised on reconsideration fall into three general categories: first, that the Commission lacks jurisdiction to issue a substantive order on a petition for enforcement; second, that the Commission was in error when it concluded that the California process improperly determined avoided costs; and third, that the Commission's decision improperly intrudes into what are properly state decisions regarding utility resource planning. We address each of these general concerns below.

1. Jurisdiction

A number of parties argue, with varying degrees of complexity and support, that the Commission entirely lacked jurisdiction to review the California QF program. [*11] IEP, in particular, argues strongly that there were no PURPA implementation issues to be resolved because the California Commission did include all sources of generation capacity in its determination of the utilities' avoided costs, that its implementation of this Commission's rules was consistent with PURPA, and that the principal issue raised by the utilities is whether the California Commission's methodology for reviewing all sources was the most effective way to consider all sources.

As explained in the February 23 order and as explained further below, the ultimate method of determining price for California QF power was in the auction process following administrative determination of the IDR benchmarks. The auction process did not include all sources of power and, as Edison and San Diego continue to explain in their answers to the requests for reconsideration, did not allow for the selection of the lowest cost bidders. We conclude that the utilities did in fact raise an implementation issue that this Commission has authority to address.

The California Commission, IEP, EGA, and others also argue that the February 23 order is of no legal or binding effect because section 210(h)(2) [*12] of PURPA provides no authority for the Commission to make a final determination as to whether the California Commission violated PURPA. They argue that PURPA only gives the Commission the authority to bring an action in federal district court against state agencies for violation of PURPA section 210(f) (state implementation) and the prosecutorial discretion to choose whether to do so on the complaint of a person aggrieved by the actions of a state regulatory authority.

We have no need to opine further at this time as to the scope of the February 23 order's effect, other than to reiterate our belief that the California procedure violates PURPA and our implementing regulations because of its failure to account for all sources of capacity. As we explained in the February 23 order, the legal status and ultimate fate of the California program rests in the first instance with the California Commission and the parties themselves. Significantly, the Commission decided not to institute a judicial action to enforce the appropriate implementation of PURPA's avoided cost limitation; instead, we encouraged (70 FERC at 61,677-78) the California Commission to stay the effectiveness of its program [*13] before the date of contract execution by Edison and San Diego, and encouraged the utilities and QFs to reach a settlement that would be consistent with PURPA.

Further, we do not share the views of IEP and others that we are without authority to do anything other than to decide without elaboration whether to institute or not to institute an enforcement action under the procedures of section 210(h) of PURPA. These procedures (see 16 U.S.C. § 824a-3(h)(2)(A)-(B)) create an enforcement scheme by which either the Commission or a private party may act to compel a state regulatory authority to comply with PURPA. The Commission can initiate an enforcement action in federal district court either upon its own motion or upon the petition of private party. If the Commission does not initiate an enforcement action within 60 days of such a petition, as here, then the petitioning party may do so.

However, these statutory procedures nowhere state (or imply) that the Commission is without authority to explain its decision whether or not to initiate an enforcement action. We disagree strenuously with the argument that, generally, we have no ability to explain our decision and, specifically, to [*14] respond to arguments that implicate the complementary responsibilities of the Commission and state authorities in implementing section 210 of PURPA. Any uncertainty in this regard was resolved by a recent decision of the D.C. Circuit issued after issuance of the February 23 order. See Industrial Cogenerators v. FERC, No. 93-1372 (D.C. Cir. March 7, 1995). In Industrial Cogenerators, the court, after reviewing the particular judicial review and enforcement provisions of PURPA section 210(h), characterized a Commission order explaining its reason not to initiate an enforcement action, and providing additional explication of the Commission's position, as having the effect of a declaratory order which does not fix the rights of the parties, but merely advises the parties of the Commission's position. The court did not determine that the Commission's articulation of its "pre-enforcement position" was inappropriate, but only that it could not be reviewed in the first instance without prior recourse to a federal district court.

2. The California Process

The California Commission, as well as others, suggest that this Commission did not understand the California process when [*15] it found that the California method of determining avoided costs did not comply with PURPA because it excluded potential sources of capacity from which the utilities could purchase. The California Commission explains that its determination of the benchmark price, against which the QFs bid, was its determination of avoided costs. The California Commission states that it took all sources of capacity into account in determining the benchmark price. The California Commission further explains that the subsequent bidding process was used not to set avoided cost, but to allocate the contracts where available capacity exceeds the amount of capacity deemed deferrable by the utility. In order to obtain a contract, the QFs had to meet or beat the benchmark price. The California Commission explains (Rehearing at 7) that "in order to minimize 'gaming' of bids and to assure that the ultimate prices paid closely reflect the actual cost of the capacity included in the approved resource plan, the [California Commission] determined it appropriate to require that winning QFs be paid the price bid by the lowest losing bidder."

Contrary to the California Commission's argument, the benchmark, by itself, [*16] was not a determination of avoided cost as defined by PURPA. The benchmark considered only the purchasing utility's cost of generating energy but did not take into account fully what it would cost to purchase such energy from another source, as required by PURPA's definition of avoided (incremental) cost. While the benchmark process may have taken all technological sources into account, it did not consider all types of sellers (QFs, IPPs, IOUs, etc.).

We recognize that the California Commission orders purport to consider all sources, both all technological sources and all types of sellers. However, the California Commission required that any purchased power resource claimed in a utility resource plan be shown to be available for the relevant period and at a price attributed to it by the purchasing utility. n3 The California utilities have claimed, with considerable validity, that in order to demonstrate that a non-QF purchase option was indeed available, it would be necessary to negotiate with potential non-QF sellers as to price and terms, and that non-QF suppliers would not, in reality, negotiate seriously if the resulting "sale" would simply result in a benchmark price to be used [*17] as a target for QF bidders. n4 Indeed, under the California Commission process, the California Commission assumed that non-QFs would not be willing to compete vigorously for the California market. n5 Thus, the California Commission, in setting the benchmark price, may have provided for consideration of purchases from all available sources in theory, but in fact did not provide for consideration of all types of sellers.

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See, e.g., D.90-03-060, slip op. at 104.

n4

See San Diego Petition for Enforcement at 7-8.

n5

See D.86-07-004, slip op. at 86.

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Moreover, based on the California Commission's own description of the BRPU process, it is clear that the auction was used not only to allocate contracts, but also was used to set the price for the power. However, this process, too, failed to take into account all potential sellers as required by PURPA.

On these facts, it was the combination of the benchmark determination and the auction that set the purchasing utilities' avoided [*18] cost rate, and we cannot conclude that they took into account, either alone or in combination, all sources, i.e., all technologies and all potential types of sellers (QFs and non-QFs). Whether a benchmark process alone, a bidding process alone, or a combination benchmark-bidding process is used to establish the actual price paid for QF power, it must take into account all sources, i.e., all technologies and all types of sellers.

All but one of the California Commission's remaining arguments have been thoroughly addressed in other portions of this order or in the February 23 order. Thus, we have no reason to respond further to the California Commission's arguments on reconsideration that: if bidding is used to establish avoided cost, PURPA does not require all source bidding; the California process is in full compliance with the Commission's PURPA regulations; the February 23 order amounts to a new policy which should not have been established on a case-by-case basis and should have been given prospective effect only; and the February 23 order unlawfully prevents consideration of renewable resources.

We continue only with respect to the California Commission's argument that [*19] the enforcement petitions were filed too late for Commission consideration and are thus barred by the equitable doctrine of laches. We recognize that the Edison and San Diego petitions were filed many years into the California BRPU process, and that the California Commission has, to date, expended considerable time and effort over the years in conducting this ongoing process. But we reject any suggestion that we are, on our own initiative, belatedly and unnecessarily upsetting this process, or are somehow foreclosed from considering the petitions for enforcement simply by virtue of the date of their filing.

The California Commission made modifications to the original California implementation plan, as reflected in the BRPU process, that implicate the incremental/avoided cost cap on utility PURPA rates in sections 210(b) and 210(d) of PURPA. The California utilities filed their enforcement petitions with this Commission (in January, 1995) only after the BRPU orders they challenge became final, when the California Commission issued its order on rehearing in the BRPU proceeding in December, 1994. Thus, the California utilities sought redress before this Commission only after exhausting [*20] their administrative remedies in California. It would be totally inappropriate for us to intercede in an ongoing state proceeding on the speculation that the state might violate PURPA. In these circumstances, the Commission appropriately exercised its statutory responsibility to respond to Edison's and San Diego's enforcement petitions and to evaluate whether the state implementation process violates the PURPA requirement that purchase rates do not exceed the incremental/avoided cost of the purchasing utilities.

While the California Commission chastises Edison and San Diego for the lateness of their filings, the utilities filed with this Commission before the date they otherwise would have been compelled to execute purchase contracts with the winning bidders in the BRPU process. As the Commission has explained in recent orders, issued after the date of the February 23 order, it does not intend to entertain belated challenges to executed PURPA purchase contracts and is extremely reluctant to upset the settled expectations of parties to, and to invalidate any of their obligations and responsibilities under, executed PURPA purchase contracts. n6 Here, however, the expectations [*21] of the parties had not yet been settled in signed contracts codifying Edison's and San Diego's purchase obligations, and the challenge to the California Commission's orders was timely.

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See New York State Electric & Gas Corporation, 71 FERC P61,027 (1995); West Penn Power Company, 71 FERC P ____ (1995).

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3. Guidance

A significant concern expressed by a number of parties on reconsideration is that while the Commission acknowledged states' general authority concerning resource planning and resource decisions (70 FERC at 61,676), the Commission did not provide adequate guidance as to how states can implement resource planning decisions in light of the February 23 order. They argue that the California BRPU was a comprehensive program intended both to implement PURPA and to implement state policies concerning resource planning and allocation. A number of issues have been raised concerning how states can encourage renewable and other alternative resources, as California is obligated to do under state law [*22] (see sections 701.1, 701.3, and 701.4 of the California code) through set-asides for renewable generation.

In the February 23 order, we noted that the issues raised in this proceeding arise against a background of a utility industry that has changed greatly since enactment of PURPA in 1978, in part as a result of the implementation of PURPA. PURPA was enacted in an era of rapidly rising fossil fuel prices; because natural gas and oil were thought to be in short supply, a principal goal of PURPA was to reduce reliance on fossil fuel sources. In fact, the Fuel Use Act, which was passed concurrently with PURPA, but which subsequently was repealed, prohibited the construction of new gas-fired generating plants.

With PURPA, Congress was seeking to diversify the Nation's generation fuel mix and promote more efficient use of fossil fuels when they were used for generation by encouraging renewable technologies and cogeneration, in order to cushion against further price shock and reduce dependence on fossil fuels. In promoting greater fuel diversity, however, Congress was not asking utilities and utility ratepayers to pay more than they otherwise would have paid for power. As we explained [*23] in the February 23 order, PURPA requires an electric utility to purchase power from a QF, but only if the QF sells at a price no higher than the cost the utility would have incurred for the power if it had not purchased the QF's energy and/or capacity, i.e. would have generated itself or purchased from another source. The intention was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives.

In the February 23 order, we found that PURPA literally means that in calculating avoided cost rates for QF power, state authorities must determine the cost the utility avoids by considering the cost of all alternative sources of power available to the utility, not just the cost of a select group of resources. Many have commented in this proceeding that this determination will make it impossible for states to achieve resource diversity, environmental goals or resource planning objectives because they no longer will be able to use PURPA to encourage renewable generation.

The Commission believes that states have numerous ways outside of PURPA to encourage renewable resources. As a general matter, states have broad powers [*24] under state law to direct the planning and resource decisions of utilities under their jurisdiction. States may, for example, order utilities to build renewable generators themselves, or deny certification of other types of facilities if state law so permits. They also, assuming state law permits, may order utilities to purchase renewable generation.

In this regard, we note that renewable generators do not have to be QFs. Also they can apply for exempt wholesale generator (EWG) status under the Energy Policy Act of 1992 -- in fact, many QFs have done so already. See, e.g., Richmond Power Enterprise, L.P., 62 FERC P61,157 (1993). Their rates for wholesale sales in interstate commerce will be considered by the Commission on a cost-of-service or market basis.

States also may seek to encourage renewable or other types of resources through their tax structure, or by giving direct subsidies. Use of the tax structure may allow states to affect the price of renewables or other alternatives. By imposing a tax on fossil generators or by giving a tax incentive to alternative generation, states may allow the alternative generation to be more competitive in a cost comparison with fossil-fueled [*25] generation.

In our recent decision on an Illinois statute, we found that a rate for QF power under PURPA that would have been above avoided cost, but for the tax incentive provided by the state to the purchasing electric utility, was consistent with PURPA. CGE Fulton, L.L.C., (Fulton) 70 FERC P61,290, reconsideration denied, 71 FERC P , (1995). The tax credit in Illinois is a "dollar-for-dollar tax credit, calculated and credited to the utility on a month-by-month basis, that equals the amount by which rates . . . exceed the utility's avoided cost." Id. at 61,843.

Further, in our February 23 decision, we stated that "our decision today does not, for example, preclude the possibility that, in setting an avoided cost rate, a state may account for environmental costs of all fuel sources included in an all source determination of avoided cost." 70 FERC at 61,676. This means that environmental costs, if they are real costs that would be incurred by utilities, may be accounted for in a determination of avoided cost rates. Under section 210(b) of PURPA, "no rule . . . . shall provide for a rate which exceeds the incremental cost to the electric utility of alternative [*26] electric energy." (emphasis added). Thus, in setting avoided cost rates, a state may only account for costs which actually would be incurred by utilities. A state may, through state action, influence what costs are incurred by the utility. Thus, accounting for environmental costs may be part of a state's approach to encouraging renewable generation. For example, a state may impose a tax or other charge on all generation produced by a particular fuel, and thus increase the costs which would be incurred by utilities in building and operating plants that use that fuel. Conversely, a state may also subsidize certain types of generation, for instance wind, or other renewables, through, e.g., tax credits.

A state, however, may not set avoided cost rates or otherwise adjust the bids of potential suppliers by imposing environmental adders or subtractors that are not based on real costs that would be incurred by utilities. Such practices would result in rates which exceed the incremental cost to the electric utility and are prohibited by PURPA.

These are some ways in which states may encourage renewable resources and achieve planning goals. Others are possible. We do not here intend [*27] to give a definitive prescription for ways in which states may pursue these goals, but merely to reaffirm our conviction that such pursuit is not only possible but a reality. Fulton, supra.

In conclusion, we find that the arguments on reconsideration warrant no change to our February 23 order. While the California Commission must include all sources in determining avoided cost rates, either administratively, through an auction, or a process that combines both, there are means, both through PURPA and under more general state authority, to attain state goals of encouraging renewable and alternative technologies in generation.

The Commission orders:

(A) All motions to intervene out-of-time in this proceeding are hereby granted.

(B) Reconsideration of the February 23 order is hereby granted to the extent and denied to the extent discussed in the body of this order.

By the Commission. Commissioner Massey concurred in part and dissented in part with a separate statement attached.

CONCURBY: MASSEY

CONCUR:

MASSEY, Commissioner, concurring in part and dissenting in part:

I agree with the conclusion of today's order that the California BRPU process violated PURPA's avoided cost cap. The bidding phase [*28] of the California proceeding excluded non-QFs; the benchmark phase, while nominally open to purchases of non-QF power, in effect discouraged reliance on non-QF power. Thus, the avoided cost determination did not fairly consider non-QF sources of power.

I also agree with the order's guidance to states on how to promote renewable resources and implement other state policies outside of PURPA. n7 As I said in my concurrence to the initial order in this proceeding:

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Order, slip op. at 11-12.

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Our order in no way affects the authority of states to adopt and implement power supply policies outside of PURPA. Our order today construes only the requirements of PURPA, and does not (indeed, could not) purport to limit the authority of states beyond the context of PURPA. Our order says only that states cannot act under PURPA to require utilities to pay more than their avoided costs. [n8]

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n8 Southern California Edison Company and San Diego Gas & Electric Company, 70 FERC 61,215 at 61,679 (1995).

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[*29]

But, I am not yet confident that today's order is right with respect to the guidance it offers to states on considering environmental factors, and by implication other non-price factors, under PURPA. The order states that environmental costs may be considered in an avoided cost determination only if they are real costs actually incurred by a utility, instead of so-called environmental adders or subtractors. n3 I agree that states should not have unlimited discretion to take into account environmental issues under PURPA. But I believe the majority's order on this issue, if strictly construed, may wrongly prevent consideration in the avoided cost determination of a range of non-price factors, factors that are important but very difficult to assign a dollar value to.

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Order, slip op. at 12.

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For example, if the only costs cognizable under PURPA are quantifiable costs actually incurred by the utility, how would the PURPA process reflect the value of fuel diversity? If a utility today owns only gas-fired generation [*30] and places a high value on diversifying its fuel mix by making its next capacity addition something other than gas-fired, does today's order require the avoided cost determination nonetheless to include gas-fired generation? If so, would PURPA prohibit even cost adders to the gas bids to reflect the lower relative value to the utility of gas-fired generation? Did Congress really intend in 1978 to limit the determination of avoided costs to a strict price comparison regardless of whether certain power sources meet the utility's needs or how far they deviate from the utility's needs? The majority's order moves perilously close to a rule that PURPA requires selection of the cheapest power regardless of the value of fuel diversity. I hope the order would not be construed this way, but it is unclear.

As another example, I fear that today's order also may eliminate from recognition under PURPA the dispatchability of capacity additions. If a utility wants its next capacity addition to be highly dispatchable, how would the avoided cost determination reflect this value? What about minimum load, ramp rate, startup costs, forced outage rate, plant location, or the developer's experience and [*31] track record? Each of these factors is relevant to the utility planning process but may be hard to quantify into actual, comparable costs. In other words, these factors are valuable in the context of a rational planning process, but very difficult to reduce to a specific dollar value.

Perhaps today's order would allow exclusion from the avoided cost determination of potential sources of power that do not meet pre-established criteria on these factors. For example, perhaps the avoided cost process could exclude all units with projected forced outage rates exceeding ten percent. This interpretation assumes, however, that each of these non-price factors can be reduced to a specific threshold of acceptability and that the cheapest power meeting each of these thresholds is the utility's appropriate "alternative energy" under section 210(b) of PURPA. n4 That may not be a rational process. For example, if the cheapest power barely meeting the pre-established criteria is three cents/kWh and the next cheapest power costs a mill more but is far and away better on the non-price factors, would a utility really choose the three cent power? And did Congress really intend the avoided cost determination [*32] to be driven by the cheapest, minimally acceptable piece of generation on the market, instead of the balancing process inherent in rational planning? I do not think so.

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16 U.S.C. § 824a-3(b) (1988).

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As I indicated in my prior concurrence in this proceeding, this Commission itself has acknowledged the need to consider non-price factors under PURPA. The Commission has said that the terms and conditions for electricity production and delivery cannot be described by a single facet of the sale such as price; that Congress was aware that many attributes must be considered in determining the value of purchases from QFs; and that there are severe drawbacks to focusing solely on price in making an avoided cost determination because of the multiple attributes of electricity. n5

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Regulations Governing Bidding Programs, IV FERC Stats. and Regs. para. 32,455 at p. 32,034, 32,040 (1988), terminated, 64 FERC para. 61,364 (1993).

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[*33]

Obviously, the wholesale competition FERC is encouraging is changing the way we look at PURPA. Nevertheless, these issues warrant much fuller consideration and discussion than the approach the majority takes today. Until a few months ago, FERC's approach to state processes under PURPA was hands off. Now, it is hands on. But the state and utility planning processes are complex, and I am convinced that our orders do not show that we appreciate this complexity. Congress in 1978 chose to promote more efficient fuel use and greater reliance on alternative energy. Before we adopt the view that may be implied in today's order, that price is the only relevant factor and that the cost of all considerations must be quantifiable, we should initiate a generic rulemaking and elicit input from all of the affected interests.

In the past week, the Commission has received two petitions for rulemakings on PURPA-related issues, one from the Edison Electric Institute and the other from the PURPA Reform Group. n6 I take no position today on whether those petitions adequately define the appropriate scope of any rulemaking we may conduct on PURPA, or on the merits of the positions advocated in those petitions. [*34] But, I do concur in their fundamental premise that the time has come for a broad-based rulemaking reevaluating PURPA in light of the increased competition in the industry since PURPA was initially enacted, and providing guidance to the states and utilities on how to implement PURPA's requirements. PURPA is the law of the land. Unless and until Congress repeals PURPA, this Commission will have to make these decisions, through either a forward-looking rulemaking or after-the-fact reviews of state decisions already made. I would strongly prefer the former instead of the latter.

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n6

Docket Nos. RM95-14-000 and RM95-15-000.

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William L. Massey

Commissioner

7

1ST CASE of Level 1 printed in FULL format.

In Re: Petition for determination that implementation of contractual pricing mechanism for energy payments to qualifying facilities complies with Rule 25-17.0832, F.A.C., by Florida Power Corporation

DOCKET NO. 940771-EQ; ORDER NO. **PSC-95-0210**-FOF-EQ

Florida Public Service Commission

95 FPSC 2:263

February 15, 1995

PANEL:
[*1]

The following Commissioners participated in the disposition of this matter: SUSAN F. CLARK, Chairman; J. TERRY DEASON; JOE GARCIA; JULIA L. JOHNSON; DIANE K. KIESLING

OPINION:
ORDER GRANTING MOTIONS TO DISMISS

BACKGROUND

In 1991 and 1992, Florida Power Corporation (FPC) entered into eleven negotiated cogeneration contracts with various cogenerators. Those contracts provide approximately 735 megawatts (MW) out of approximately 1,045 MWs of cogenerated capacity that FPC will have on its system by the end of 1995. The negotiated contracts in question are between FPC and the following cogenerators: Seminole Fertilizer, Lake Cogen Limited, Pasco Cogen Limited, Auburndale Power Partners, Orlando Cogen Limited, Ridge Generating Station, Dade County, Polk Power Partners-Mulberry, Polk Power Partners-Royster, EcoPeat Avon Park, and CFR Biogen.

The contracts all contain the following provision, section 9.1.2:

Except as otherwise provided in Section 9.1.1 hereof, for each billing month beginning with the Contract In-Service Date, the QF will receive electric energy payments based on the Firm Energy Cost calculated on an hour-by-hour basis as follows: (i) the product of the average [*2] monthly *inventory chargeout* price of fuel burned at the Avoided Unit Fuel Reference Plant, the Fuel Multiplier, and the Avoided Unit Heat Rate, plus the Avoided Unit Variable O&M, if applicable, for each hour that the Company would have had a unit with these characteristics operating; and (ii) during all other hours, the energy cost shall be equal to the As-Available Energy Cost.

This provision establishes the method to determine when cogenerators are entitled to receive firm energy payments or as-available energy payments under the contract. The Commission reviewed the 11 negotiated contracts and found them to be cost-effective for FPC's ratepayers under the criteria established in Rules 25-17.082 and 25-17.0832(2), Florida Administrative Code. n1 The information the Commission received at that time was based on simplified assumptions to arrive at the estimated energy payments.

n1 See Order No. 24099, issued February 12, 1991 in Docket No. 900917-EQ; Order No. 24734, issued July 1, 1991 in Docket No. 910401-EQ; Order No. 24923, issued August 19, 1991 in Docket No. 910549-EQ; and Order No. PSC-92-0129-FOF-EQ, issued March 31, 1992 in Docket No. 900383-EQ.

Recently, [*3] FPC states, it reviewed the operational status of the avoided unit described in section 9.1.2 of the contracts during minimum load conditions. FPC determined that the avoided unit would be scheduled off during certain minimum load hours of the day. On July 18, 1994, FPC notified the parties to the contracts that it would begin implementing section 9.1.2, effective August 1, 1994. Prior to that time FPC had paid cogenerators firm energy prices at all hours.

Three days later, on July 21, 1994, FPC filed a petition seeking our declaratory statement that section 9.1.2 of its negotiated cogeneration contracts is consistent with Rule 25-17.0832(4)(b), Florida Administrative Code. Rules 25-17.0832(4)(a) and (b) provide:

(4) Avoided energy payments.

(a) For the purpose of this rule, avoided energy costs associated with firm energy sold to a utility by a qualifying facility pursuant to a utility's standard offer contract shall commence with the in-service date of the avoided unit specified in the contract. Prior to the in-service date of the avoided unit, the qualifying facility may sell as-available energy to the utility pursuant to Rule 25-17.0825(2)(a).

(b) To the extent that the [*4] avoided unit would have been operated, had that unit been installed, avoided energy costs associated with firm energy shall be the energy cost of this unit. To the extent that the avoided unit would not have been operated, firm energy purchased from qualifying facilities shall be treated as as-available energy for the purposes of determining the megawatt block size in Rule 25-17.0825 (2)(a).

Several cogenerators petitioned for leave to intervene and questioned whether the declaratory statement was the appropriate procedure to resolve the issue. In addition, in September 1994, OCL, Pasco, Lake, Metro-Dade County, and Auburndale filed motions to dismiss on the grounds that we do not have jurisdiction to consider FPC's petition. Also, subsequent to the filing of FPC's petition, Pasco Cogen and Lake Cogen initiated lawsuits in the state courts for breach of contract and declaratory judgment.

On November 1, 1994, FPC amended its petition and asked the Commission to determine whether its implementation of section 9.1.2 is lawful under Section 366.051, Florida Statutes, and consistent with Rule 25-17.0832(4)(b), Florida Administrative Code. FPC also requested a formal evidentiary [*5] proceeding. Thereafter the cogenerators filed additional motions to dismiss the amended petition.

On January 5, 1995, we heard oral argument on the motions to dismiss filed in this docket and the motions to dismiss filed in two other dockets involving cogeneration contracts. We have fully considered the merits of the motions to dismiss, and we find that they should be granted. Our reasons for this decision are set out below.

DECISION

In 1978, Congress enacted the Public Utility Regulatory Policies Act (PURPA), to develop ways to lessen the country's dependence on foreign oil and natural gas. PURPA encourages the development of alternative power sources in the form of cogeneration and small power production facilities. In developing PURPA, Congress identified three major obstacles that hindered the development of a strong cogeneration market. First, monopoly electric utilities resisted purchasing power from other generation suppliers instead of building their own generating units. Second, monopoly electric utilities could refuse to sell needed backup power to cogenerators. Third, cogenerators and small power producers could be subject to extensive, expensive federal [*6] and state regulation as electric utilities.

PURPA contains several provisions designed to overcome these obstacles. Section 210(a) directs the Federal Energy Regulatory Commission (FERC) to promulgate rules to encourage the development of alternative sources of power, including rules that require utilities to offer to buy power from and sell power to qualifying cogeneration and small power production facilities (QFs). Section 210(b) directs FERC to set rates for the purchase of power from QFs that are just and reasonable to the utility's ratepayers and in the public interest, not discriminatory against QF's, and not in excess of the incremental cost to the utility of alternative electric energy. Section 210(e) directs FERC to adopt rules exempting QFs from most state and federal utility regulation, and section 210(f) directs state regulatory authorities to implement FERC's rules.

FERC's regulations implementing PURPA require utilities to purchase QF power at a price equal to the utility's full avoided cost, "the incremental costs to the electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such [*7] utility would generate itself or purchase from another source." 18 C.F.R. s. 292.101(b)(6). FERC's rules also contain a provision that permits utilities and QFs to negotiate different provisions of purchased power agreements, including price, as long as they are at or below a utilities' avoided cost. 18 C.F.R. s. 292.301.

In compliance with PURPA, Section 366.051, Florida Statutes, provides that Florida's electric utilities must purchase electricity offered for sale by QFs, "in accordance with applicable law". The statute directs the Commission to establish guidelines relating to the purchase of power or energy from QFs, and it permits the Commission to set rates at which a public utility must purchase that power or energy. The statute does not explicitly grant the Commission the authority to resolve contract disputes between utilities and QFs.

The Commission's implementation of Section 366.051 is codified in Rules 25-17.080-25-17.091, Florida Administrative Code, "Utilities Obligations with Regard to Cogenerators and Small Power Producers". The rules generally reflect FERC's guidelines in their purpose and scope. They provide two ways for a utility to purchase QF [*8] energy and capacity; by means of a standard offer contract, or an individually negotiated power purchase contract. See Rules 25-17.082(1) and 25-17.0832. The two types of contracts are treated very differently in our rules. The rules require utilities to publish a standard offer contract in their tariffs which we must approve and which must conform to extensive guidelines regarding, for example, determination of avoided units, pricing, cost-effectiveness for cost recovery, avoided energy payments, interconnection, and insurance. Utilities must purchase firm energy and capacity and as-available energy under standard offer contracts if a QF signs the contract. A utility may not refuse to accept a standard offer contract unless it petitions the Commission and provides justification for the refusal. See Rule 25-17.0832(3)(d), Florida Administrative Code.

In contrast, our rules are more limited in their treatment of negotiated contracts. Rule 25-17.082(2), Florida Administrative Code, simply encourages utilities and QFs to negotiate contracts, and provides the criteria the Commission will consider when it determines whether the contract is prudent for cost recovery purposes. Rule [*9] 25-17.0834, "Settlement of Disputes in Contract Negotiations", imposes an obligation to negotiate cogeneration contracts in good faith, and provides that either party to negotiations may apply to the Commission for relief if the parties cannot agree on the rates, terms and other conditions of the contract. The rule makes no provision for resolution of a dispute once the contract has been executed and approved for cost recovery.

We use certain standard offer contract rules as guidelines in determining the cost-effectiveness of negotiated contracts for cost recovery purposes, but we have not required any standard provisions to be included in negotiated contracts. In Docket No. 910603-EQ, we specifically addressed the issue of standard provisions for negotiated contracts. In that docket the cogenerators urged us to prescribe certain standard provisions in negotiated contracts and prohibit other provisions, like regulatory out clauses. In Order No. 25668, issued February 3, 1992, we said:

We will not prescribe standard provisions in negotiated contracts, because negotiated contracts are just that -- negotiated contracts. Standardized provisions are not necessary in negotiated [*10] contracts, and they can impair the negotiating process.

Rule 25-17.0834, Florida Administrative Code, provides a remedy to QFs when a utility does not negotiate in good faith. If a utility insists on an unreasonable requirement, QFs are free to petition the Commission for relief. . . .

Standardized terms in negotiated contracts could impair negotiating flexibility to the detriment of the utility and the QF.

As Witness Dolan stated, "[e]ven if guidelines and standards at a given time did reflect the parties' perceptions, guidelines and standards cannot be modified easily or quickly in response to changes in conditions that bear on the risks and benefits of the transaction". Standard terms that suit the needs of some parties will not suit the needs of other QFs wishing to negotiate contracts. Even in this docket, the QFs do not agree as to which terms should be standardized. . . . It is clear from the differing opinions that negotiated contracts should not contain standard provisions.

Order No. 25668, p. 7

This rather lengthy discussion of the statutes and regulations demonstrates that PURPA and FERC's regulations carve out a limited role for the states in the [*11] regulation of the relationship between utilities and qualifying facilities. States and their utility commissions are directed to encourage cogeneration, provide a means by which cogenerators can sell power to utilities under a state-controlled contract if they are unable to negotiate a power purchase agreement, encourage the negotiation process, and review and approve the terms of negotiated contracts for cost recovery from the utilities' ratepayers. That limited role does not encompass continuing control over the fruits of the negotiation process once it has been successful and the contracts have been approved. As Auburndale's attorney pointed out in oral argument, PURPA and FERC's regulations are not designed to open the door to state regulation of what would otherwise be a wholesale power transaction.

While the Commission controls the provisions of standard offer contracts, we do not exercise similar control over the provisions of negotiated contracts. We have interpreted the provisions of standard offer contracts on several occasions, n2 but we have not interpreted the provisions of negotiated contracts. See Docket No. 840438-EI, In Re: Petition of Tampa Electric Company [*12] for Declaratory Statement Regarding Conserv Cogeneration Agreement, Order No. 14207, issued March 31, 1985, where we refused to construe a paragraph of the agreement that concerned renegotiation of contract terms. There we said that while we could interpret our cogeneration rules and decide that the new rules did not apply to preexisting contracts, matters of contractual interpretation were properly left to the civil courts. Our Conserv decision, while not controlling here, does lend support to the proposition that we have limited our involvement in negotiated contracts to the contract formation process and cost recovery review.

n2 In re: CFR Bio-Gen's Petition For Declaratory Statement Regarding the Methodology to be used in its Standard Offer Cogeneration Contracts with Florida Power Corporation, Order No. 24338, issued April 9, 1991, Docket No. 900877-EI; In re: Complaint by CFR Bio-Gen against Florida Power Corporation for alleged violation of standard offer contract, and request for determination of substantial interest, Order No. 24729, issued July 1, 1991, Docket No. 900383-EQ; In re: Petition of Timber Energy Resources, Inc. for a declaratory statement regarding upward modification of committed capacity amount by cogenerators, Order No. 21585, issued July 19, 1989, Docket No. 8890453-EQ; In re: Petition for Declaratory Statement by Wheelabrator North Broward, Inc., Order No. 23110, issued June 25, 1990, Docket No. 900277-EQ. [*13]

The weight of authority from other states that have addressed similar issues supports this position. See, eg. Afton Energy, Inc v. Idaho Power Co., 729 P.2d 400 (Id. 1986); Bates Fabrics, Inc. v. PUC, 447 A.2d 1211 (ME. 1992); Barasch v. Pennsylvania Public Utility Commission, 546 A.2d 1296, reargument denied, 550 A.2d 257 (1988); Erie Associates - Petition for a Declaratory Ruling that Its Power Purchase Contract with New York State Electric & Gas Corporation Remains in Effect, Case 92-E-0032, N.Y. PUC LEXIS 52 (March 4, 1992); Freehold Cogeneration Associates v. Board of Regulatory Commissioners of the State of New Jersey, 1995 WL 4897 (3rd Cir. (N.J. 1995); Fulton Cogeneration Associates v. Niagara Mohawk Power Corporation, Case No. 92-CV-14112 (N.D.N.Y. 1993).

The facts vary in these cases, but the general consensus appears to be that under federal and state regulation of the relationship between utilities and cogenerators, state commissions should not generally resolve contractual disputes over the interpretation of negotiated power purchase agreements once they have been established and approved for cost recovery.

In Afton, supra., Idaho Power [*14] Company (Idaho Power) and Afton Energy, Inc. (Afton) had negotiated a power purchase agreement that included two payment options for the purchase of firm energy and capacity. The options were conditioned on the Idaho Supreme Court's determination whether the Idaho commission had authority to order Idaho Power to negotiate an agreement with Afton or dictate terms and conditions of the agreement. When the Supreme Court made its decision, Idaho Power petitioned the Commission to declare that the lesser payment option would be in effect. The Commission dismissed the petition, holding that the petition was a request for an interpretation of the contract and that the district court was the proper forum to interpret contracts. The Idaho Supreme Court upheld the Commission's decision.

In Erie Associates, supra., the New York Public Service Commission was asked by the cogenerator to declare that its negotiated purchased power agreement was still in effect even though the utility had cancelled the contract because the cogenerator had failed to post a deposit on time. The Commission stated, at page 127:

Erie's petition will not be granted. Jurisdiction under the Public Utility Regulatory [*15] Policies Act of 1978 (PURPA) is generally limited to supervision of the contract formation process. Once a binding contract is finalized, however, that jurisdiction is usually at an end.

We will not generally arbitrate disputes between utilities and developers over the meaning of contract terms, because such questions do not involve our authority, under PURPA and PSL at 66-c, to order utilities to enter into contracts. Requests to arbitrate disputes are simply beyond our jurisdiction, in most cases.

. . . Erie has not justified a departure from the policy of declining to decide breach of contract questions, or identified a source for the authority to exercise jurisdiction over such issues.

FPC has asked us to determine if its implementation of the pricing provision is lawful and consistent with Commission Rule 25-17.0832(4), Florida Administrative Code. We believe that FPC's request is really a request to interpret the meaning of the contract term. FPC is not asking us to interpret the rule. It is asking us to decide that its interpretation of the contract's pricing provision is correct. We believe that endeavor would be inconsistent with the intent of PURPA to [*16] limit our involvement in negotiated contracts once they have been established. Furthermore, we agree with the cogenerators that the pricing methodology outlined in Rule 25-17.0832(4), Florida Administrative Code, is intended to apply to standard offer contracts, not negotiated contracts. We have clearly said that we would not require any standard provisions, pricing or otherwise, for negotiated contracts. Therefore, whether FPC's implementation of the pricing provision is consistent with the rule is really irrelevant to the parties' dispute over the meaning of the negotiated provision. In this case, we will defer to the courts to resolve that dispute. We note however, that courts have the discretion to refer matters to us for consideration to maintain uniformity and to bring the Commission's specialized expertise to bear upon the issues at hand.

We disagree with FPC's proposition that when the Commission issues an order approving negotiated cogeneration contracts for cost recovery, the contracts themselves become an order of the Commission that we have continuing jurisdiction to interpret. It is true that the Supreme Court has determined that territorial agreements merge into [*17] Commission orders approving them, but territorial agreements are not valid commercial purchased power contracts. They are otherwise unlawful, anticompetitive agreements that have no validity under the law until we approve them. Furthermore, territorial agreements involve the provision of retail electric service over which we have exclusive and preemptive authority. As explained above, we do not enjoy such authority over QFs or their negotiated power purchase contracts.

Under certain circumstances we will exercise continuing regulatory supervision over power purchases made pursuant to negotiated contracts. We have made it clear that we will not revisit our cost recovery determinations absent a showing of fraud, misrepresentation or mistake; n3 but if it is determined that any of those facts existed when we approved a contract for cost recovery, we will review our initial decision. That power has been clearly recognized by the parties through the "regulatory out" provisions of those contracts. We do not think, however, that the regulatory out provisions of negotiated contracts somehow confer continuing responsibility or authority to resolve contract interpretation disputes. [*18] Our authority derives from the statutes. United Telephone Company v. Public Service Commission, 496 So.2d 116 (Fla. 1986). It cannot be conferred or inferred from the provisions of a contract.

n3 See Docket No. 910603-EQ, In Re: Implementation of Rules 25-17.080 through 25-17.091, Florida Administrative Code, Order No. 25668, issued February 3, 1992.

For these reasons we find that the motions to dismiss should be granted. FPC's petition fails to set forth any claim that the Commission should resolve. We defer to the courts to answer the question of contract interpretation raised in this case. Thus, FPC's petition is dismissed.

It is therefore

ORDERED by the Florida Public Service Commission that the Motions to Dismiss filed by Lake Cogen Limited, Pasco Cogen Limited, Auburndale Power Partners, Orlando Cogen Limited, and Metro Dade County/Montenay are granted. Florida Power Corporation's Petition is dismissed. It is further

ORDERED that this docket is hereby closed.

By ORDER of the Florida Public Service Commission, this 15th day of February, 1995.

8

4TH CASE of Level 1 printed in FULL format.

In Re: Petition for resolution of a cogeneration contract dispute with Orlando Cogen Limited, L.P., by Florida Power Corporation

DOCKET NO. 940357-EQ; ORDER NO. **PSC-95-0209**-FOF-EQ

Florida Public Service Commission

95 FPSC 2:257

February 15, 1995

PANEL:
[*1]

The following Commissioners participated in the disposition of this matter: SUSAN F. CLARK, Chairman; J. TERRY DEASON; JOE GARCIA; JULIA L. JOHNSON; DIANE K. KIESLING

OPINION:
ORDER GRANTING MOTION TO DISMISSBACKGROUND

On April 7, 1994, Florida Power Corporation filed its petition seeking resolution of a cogeneration contract dispute with Orlando Cogen Limited, L.P. (OCL). The dispute involves the Negotiated Contract for the Purchase of Firm Capacity and Energy from a Qualifying Facility (contract) executed by FPC and OCL on March 31, 1991. We approved the contract for cost recovery in Order No. 24734, issued July 1, 1991.

Under Section 3.3 of the contract, the ability of OCL, the cogenerator, to deliver its committed capacity to FPC "shall not be encumbered by interruptions in its fuel supply." FPC alleges that section 3.3 requires OCL to maintain a back-up fuel supply and OCL has not complied with that requirement. OCL denies that back-up fuel is required, and has filed a lawsuit against FPC in District Court for the Middle District of Florida for breach of contract and antitrust violations. OCL's complaint was filed in federal court prior to the filing of the petition [*2] by FPC in this docket.

OCL also filed a Motion to Dismiss FPL's petition on the grounds that the Commission does not have jurisdiction to resolve contract disputes between utilities and cogenerators. On January 5, 1995, we held oral argument on OCL's motion to dismiss and on the motions to dismiss filed in two other dockets involving cogeneration contracts. We have fully considered the merits of OCL's motion, and we find that it should be granted. Our reasons for this decision are set out below.

DECISION

In 1978, Congress enacted the Public Utility Regulatory Policies Act (PURPA), to develop ways to lessen the country's dependence on foreign oil and natural gas. PURPA encourages the development of alternative power sources in the form of cogeneration and small power production facilities. In developing PURPA, Congress identified three major obstacles that hindered the development of a strong cogeneration market. First, monopoly electric utilities resisted purchasing power from other generation suppliers instead of building their own generating units. Second, monopoly electric utilities could refuse to sell needed backup power to cogenerators. Third, cogenerators [*3] and small power producers could be subject to extensive, expensive federal and state regulation as electric utilities.

PURPA contains several provisions designed to overcome these obstacles. Section 210(a) directs the Federal Energy Regulatory Commission (FERC) to promulgate rules to encourage the development of alternative sources of power, including rules that require utilities to offer to buy power from and sell power to qualifying cogeneration and small power production facilities (QFs). Section 210(b) directs FERC to set rates for the purchase of power from QFs that are just and reasonable to the utility's ratepayers and in the public interest, not discriminatory against QFs, and not in excess of the incremental cost to the utility of alternative electric energy. Section 210(e) directs FERC to adopt rules exempting QFs from most state and federal utility regulation, and section 210(f) directs state regulatory authorities to implement FERC's rules.

FERC's regulations implementing PURPA require utilities to purchase QF power at a price equal to the utility's full avoided cost, "the incremental costs to the electric utility of electric energy or capacity or both which, but [*4] for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R.s. 292.101(b)(6). FERC's rules also contain a provision that permits utilities and QFs to negotiate different provisions of purchased power agreements, including price, as long as they are at or below a utilities' avoided cost. 18 C.F.R.s. 292.301.

In compliance with PURPA, Section 366.051, Florida Statutes, provides that Florida's electric utilities must purchase electricity offered for sale by QFs, "in accordance with applicable law". The statute directs the Commission to establish guidelines relating to the purchase of power or energy from QFs, and it permits the Commission to set rates at which a public utility must purchase that power or energy. The statute does not explicitly grant the Commission the authority to resolve contract disputes between utilities and QFs.

The Commission's implementation of Section 366.051 is codified in Rules 25-17.080-25-17.091, Florida Administrative Code, "Utilities Obligations with Regard to Cogenerators and Small Power Producers". The rules generally reflect FERC's guidelines in their purpose [*5] and scope. They provide two ways for a utility to purchase QF energy and capacity; by means of a standard offer contract, or an individually negotiated power purchase contract. See Rules 25-17.082(1) and 25-17.0832. The two types of contracts are treated very differently in our rules. The rules require utilities to publish a standard offer contract in their tariffs which we must approve and which must conform to extensive guidelines regarding, for example, determination of avoided units, pricing, cost-effectiveness for cost recovery, avoided energy payments, interconnection, and insurance. Utilities must purchase firm energy and capacity and as-available energy under standard offer contracts if a QF signs the contract. A utility may not refuse to accept a standard offer contract unless it petitions the Commission and provides justification for the refusal. See Rule 25-17.0832(3)(d), Florida Administrative Code.

In contrast, our rules are more limited in their treatment of negotiated contracts. Rule 25-17.082(2), Florida Administrative Code, simply encourages utilities and QFs to negotiate contracts, and provides the criteria the Commission will consider when it [*6] determines whether the contract is prudent for cost recovery purposes. Rule 25-17.0834, "Settlement of Disputes in Contract Negotiations", imposes an obligation to negotiate cogeneration contracts in good faith, and provides that either party to negotiations may apply to the Commission for relief if the parties cannot agree on the rates, terms and other conditions of the contract. The rule makes no provision for resolution of a dispute once the contract has been executed and approved for cost recovery.

We use certain standard offer contract rules as guidelines in determining the cost-effectiveness of negotiated contracts for cost recovery purposes, but we have not required any standard provisions to be included in negotiated contracts. In Docket No. 910603-EQ, we specifically addressed the issue of standard provisions for negotiated contracts. In that docket the cogenerators urged us to prescribe certain standard provisions in negotiated contracts and prohibit other provisions, like regulatory out clauses. In Order No.25668, issued February 3, 1992, we said:

We will not prescribe standard provisions in negotiated contracts, because negotiated contracts are just that -- negotiated [*7] contracts. Standardized provisions are not necessary in negotiated contracts, and they can impair the negotiating process.

Rule 25-17.0834, Florida Administrative Code, provides a remedy to QFs when a utility does not negotiate in good faith. If a utility insists on an unreasonable requirement, QFs are free to petition the Commission for relief. . . .

Standardized terms in negotiated contracts could impair negotiating flexibility to the detriment of the utility and the QF. As Witness Dolan stated, "[e]ven if guidelines and standards at a given time did reflect the parties' perceptions, guidelines and standards cannot be modified easily or quickly in response to changes in conditions that bear on the risks and benefits of the transaction". Standard terms that suit the needs of some parties will not suit the needs of other QFs wishing to negotiate contracts. Even in this docket, the QFs do not agree as to which terms should be standardized. . . . It is clear from the differing opinions that negotiated contracts should not contain standard provisions.

Order No. 25668, p. 7

This rather lengthy discussion of the statutes and regulations demonstrates that PURPA and FERC's [*8] regulations carve out a limited role for the states in the regulation of the relationship between utilities and qualifying facilities. States and their utility commissions are directed to encourage cogeneration, provide a means by which cogenerators can sell power to utilities under a state-controlled contract if they are unable to negotiate a power purchase agreement, encourage the negotiation process, and review and approve the terms of negotiated contracts for cost recovery from the utilities' ratepayers. That limited role does not encompass continuing control over the fruits of the negotiation process once it has been successful and the contracts have been approved. As one attorney pointed out in oral argument, PURPA and FERC's regulations are not designed to open the door to state regulation of what would otherwise be a wholesale power transaction.

While the Commission controls the provisions of standard offer contracts, we do not exercise similar control over the provisions of negotiated contracts. We have interpreted the provisions of standard offer contracts on several occasions, n1 but we have not interpreted the provisions of negotiated contracts. See Docket [*9] No. 840438-EI, In Re: Petition of Tampa Electric Company for Declaratory Statement Regarding Conserv Cogeneration Agreement, Order No. 14207, issued March 31, 1985, where we refused to construe a paragraph of the agreement that concerned renegotiation of contract terms. There we said that while we could interpret our cogeneration rules and decide that the new rules did not apply to preexisting contracts, matters of contractual interpretation were properly left to the civil courts. Our Conserv decision, while not controlling here, does lend support to the proposition that we have limited our involvement in negotiated contracts to the contract formation process and cost recovery review.

n1 In re: CFR Bio-Gen's Petition For Declaratory Statement Regarding the Methodology to be used in its Standard Offer Cogeneration Contracts with Florida Power Corporation, Order No. 24338, issued April 9, 1991, Docket No. 900877-EI; In re: Complaint by CFR Bio-Gen against Florida Power Corporation for alleged violation of standard offer contract, and request for determination of substantial interest, Order No. 24729, issued July 1, 1991, Docket No. 900383-EQ; In re: Petition of Timber Energy Resources, Inc. for a declaratory statement regarding upward modification of committed capacity amount by cogenerators, Order No. 21585, issued July 19, 1989, Docket No. 8890453-EQ; In re: Petition for Declaratory Statement by Wheelabrator North Broward, Inc., Order No. 23110, issued June 25, 1990, Docket No. 900277-EQ. [*10]

The weight of authority from other states that have addressed similar issues supports this position. See, eg. Afton Energy, Inc v. Idaho Power Co., 729 P.2d 400 (Id. 1986); Bates Fabrics, Inc. v. PUC, 447 A.2d 1211 (ME. 1992); Barasch v. Pennsylvania Public Utility Commission, 546 A.2d 1296, reargument denied, 550 A.2d 257 (1988); Erie Associates - Petition for a Declaratory Ruling that Its Power Purchase Contract with New York State Electric & Gas Corporation Remains in Effect, Case 92-E-0032, N.Y. PUC LEXIS 52 (March 4, 1992); Freehold Cogeneration Associates v. Board of Regulatory Commissioners of the State of New Jersey, 1995 WL 4897 (3rd Cir. (N.J. 1995); Fulton Cogeneration Associates v. Niagara Mohawk Power Corporation, Case No. 92-CV-14112 (N.D.N.Y. 1993).

The facts vary in these cases, but the general consensus appears to be that under federal and state regulation of the relationship between utilities and cogenerators, state commissions should not generally resolve contractual disputes over the interpretation of negotiated power purchase agreements once they have been established and approved for cost recovery.

In Afton, supra., [*11] Idaho Power Company (Idaho Power) and Afton Energy, Inc. (Afton) had negotiated a power purchase agreement that included two payment options for the purchase of firm energy and capacity. The options were conditioned on the Idaho Supreme Court's determination whether the Idaho commission had authority to order Idaho Power to negotiate an agreement with Afton or dictate terms and conditions of the agreement. When the Supreme Court made its decision, Idaho Power petitioned the Commission to declare that the lesser payment option would be in effect. The Commission dismissed the petition, holding that the petition was a request for an interpretation of the contract and that the district court was the proper forum to interpret contracts. The Idaho Supreme Court upheld the Commission's decision.

In Erie Associates, supra., the New York Public Service Commission was asked by the cogenerator to declare that its negotiated purchased power agreement was still in effect even though the utility had cancelled the contract because the cogenerator had failed to post a deposit on time. The Commission stated, at page 127:

Erie's petition will not be granted. Jurisdiction under the Public [*12] Utility Regulatory Policies Act of 1978 (PURPA) is generally limited to supervision of the contract formation process. Once a binding contract is finalized, however, that jurisdiction is usually at an end.

We will not generally arbitrate disputes between utilities and developers over the meaning of contract terms, because such questions do not involve our authority, under PURPA and PSL at 66-c, to order utilities to enter into contracts. Requests to arbitrate disputes are simply beyond our jurisdiction, in most cases.

. . . Erie has not justified a departure from the policy of declining to decide breach of contract questions, or identified a source for the authority to exercise jurisdiction over such issues.

We disagree with FPC's proposition that when we issue an order approving negotiated cogeneration contracts for cost recovery, the contracts themselves become an order of the Commission that we have continuing jurisdiction to interpret. It is true that the Supreme Court has determined that territorial agreements merge into Commission orders approving them, but territorial agreements are not valid commercial purchased power contracts. They are otherwise unlawful, anticompetitive [*13] agreements that have no validity under the law until we approve them. Furthermore, territorial agreements involve the provision of retail electric service over which we have exclusive and preemptive authority. As explained above, we do not enjoy such authority over QFs or their negotiated power purchase contracts.

Under certain circumstances we will exercise continuing regulatory supervision over power purchases made pursuant to negotiated contracts. We have made it clear that we will not revisit our cost recovery determinations absent a showing of fraud, misrepresentation or mistake; n2 but if it is determined that any of those facts existed when we approved a contract for cost recovery, we will review our initial decision. That power has been clearly recognized by the parties through the "regulatory out" provisions of those contracts. We do not think, however, that the regulatory out provisions of negotiated contracts somehow confer continuing responsibility or authority to resolve contract interpretation disputes. Our authority derives from the statutes. United Telephone Company v. Public Service Commission, 496 So.2d 116 (Fla. 1986). It cannot be conferred [*14] or inferred from the provisions of a contract.

n2 See Docket No. 910603-EQ, In Re: Implementation of Rules 25-17.080 through 25-17.091, Florida Administrative Code, Order No. 25668, issued February 3, 1992.

Nor does our responsibility to ensure the reliability of Florida's electric grid impose a responsibility to interpret the backup fuel provision of this contract. Even if we determined that Orlando Cogen had not complied with the provisions of the contract, we would not have the authority to order the cogenerator to perform. When we approved this contract for cost recovery purposes, we determined that FPC's ratepayers would be protected in the event the cogenerator defaulted. Any further remedy for breach of the contract itself lies with the court. We note, however, that courts have the discretion to refer matters to us for consideration to maintain uniformity and to bring the Commission's special expertise to bear upon the issues at hand.

For these reasons we find that the motion to dismiss should be granted. FPC's petition fails to set forth any claim that the Commission should resolve. We defer to the courts to resolve this contract dispute. Thus, FPC's petition [*15] is dismissed.

It is therefore

ORDERED by the Florida Public Service Commission that the Motion to Dismiss filed by Orlando Cogen Limited is granted. Florida Power Corporation's Petition is dismissed. It is further

ORDERED that this docket is hereby closed.

By ORDER of the Florida Public Service Commission, this 15th day of February, 1995.

9

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Declaratory Statement regarding application of Rule 25-17.0832, F.A.C., to certain negotiated contracts for purchase of firm capacity and energy by Florida Power Corporation.	DOCKET NO. 940771-EQ FILED: November 28, 1994

ORLANDO COGEN LIMITED'S MOTION
TO DISMISS FPC'S AMENDED PETITION

Orlando Cogen Limited, L.P. ("OCL"),[1] through its undersigned counsel, moves to dismiss the Amended Petition filed on October 31, 1994, by Florida Power Corporation ("FPC") in this docket on the following grounds:

1. In its amended petition, FPC requests the Florida Public Service Commission ("Commission") to interpret paragraph 9.1.2 of the negotiated contract between OCL and FPC. The applicable federal and state statutory schemes give the Commission only the limited authority delegated to the states by PURPA, which does not extend to issues and disputes over contract interpretation and related allegations of contractual breach. Those matters are within the exclusive jurisdiction of a court of law.

2. FPC has failed to demonstrate that it is entitled to pursue this action pursuant to section 120.57, Florida Statutes, and rule 25-22.036(7), Florida Administrative Code. FPC's amended

[1] OCL's petition to intervene was granted in Order No. PSC-94-1407-PCO-EQ.

petition fails to either allege or demonstrate the substantial interests of FPC that would be affected in this proceeding. This is a threshold requirement for standing under section 120.57 which FPC has failed to meet.

3. Though FPC alleges in its amended petition that it seeks to "convert" its declaratory statement petition to an adjudicatory proceeding under 120.57, FPC makes the same allegations and seeks the same relief as it did in its original declaratory statement petition. Thus, notwithstanding its changed label, FPC's amended petition remains an inappropriate request for declaratory statement. Pursuant to section 120.565, Florida Statutes, the authority of the Commission to issue a declaratory statement is limited to specific matters: the applicability of a statute, rule or order. FPC's amended petition instead still involves the construction of the terms of a contract. As FPC has conceded, the declaration FPC seeks does not apply to the petitioner in its particular circumstances only, as required by statute and rule; it would impermissibly affect 11 cogenerators who signed contracts having the same contractual provision that is the subject of FPC's petition.

4. FPC's declaratory statement disguised as an amended petition is impermissible because existing litigation in a judicial forum will resolve the issue presented in the amended petition.

The bases for OCL's motion to dismiss are developed in the following supporting memorandum.

Background

In March 1991, FPC and OCL negotiated and executed a power purchase contract. The prices for capacity and energy were based on the capital and operating costs that FPC could avoid by contracting to purchase power from OCL (and other QFs) instead of building and operating a 450 MW pulverized coal unit that FPC would have otherwise needed to meet its system requirements. The Commission found that the negotiated contract met its criteria governing cost recovery in Order No. 24734, Docket No. 910401-EQ, dated July 1, 1991.

OCL financed and constructed a cogeneration unit at a cost of $86 million. OCL began delivering firm capacity and energy to FPC under the contract in September 1993. By letter dated October 11, 1993, FPC claimed that the contract required OCL to install a backup fuel system, and declared OCL to be in default. On March 11, 1994, OCL filed suit against FPC in the United States District Court for the Middle District of Florida.[2] In that suit, which is presently pending, OCL alleges that FPC has breached the contract and has violated antitrust statutes.[3] FPC filed a counterclaim against OCL and others. Commencing in April 1994, FPC began withholding more than $300,000 per month from OCL's capacity payments.

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[2] Orlando CoGen (1), Inc., et al v. Florida Power Corporation, Case No. 94-303-CIV-ORL-18.

[3] OCL has amended its complaint to allege, inter alia, additional damages associated with FPC's recent breach of 9.1.2 of the contract.

On July 18, 1994, FPC informed OCL that FPC intended to begin paying OCL less for energy during certain hours. FPC based its intent on FPC's unilateral application of a pricing methodology that differed markedly from the one that had been employed by the parties at the time FPC submitted the contract for approval by the Commission and thereafter to price energy that OCL delivers to FPC under the contract. On August 1, 1994, OCL notified FPC that it would regard FPC's announced pricing departure as a breach of FPC's obligations to OCL under the negotiated contract and would hold FPC accountable for all related damages.

On July 21, 1994, FPC filed a petition for declaratory statement in which it sought

> a declaration that its reliance on the pricing mechanism specified in Section 9.1.2 of the negotiated contracts for the purchase of firm capacity and energy from certain qualifying facilities (the Negotiated Contracts) to determine the periods when as-available energy payments are to be substituted for firm energy payments, complies with Rule 25-17.0832(4)(b), F.A.C., and the orders of this Commission approving the negotiated contracts.

FPC Petition for Declaratory Statement at 1.

On September 2, 1994, OCL filed a motion to dismiss FPC's petition[4] on the grounds that interpretation of a contractual provision was a matter for the courts, not the Commission, and that FPC had not met the requirements necessary for issuance of a declaratory statement.

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[4] Pasco Cogen, Lake Cogen, and Dade County also filed motions to dismiss.

On October 6, 1994 Staff submitted its recommendation to the Commission. Staff recommended that the Commission decline to issue the requested declaratory statement because it did not comply with the prerequisites for issuance of such relief. Staff's recommendation was to be voted upon by the Commission on October 18. The item was deferred at FPC's request.

On October 31, FPC filed an "Amended Petition" that is the subject of this motion.[5] In the motion, FPC seeks the same relief it sought in its initial petition for declaratory statement.

Basis for Dismissal

I. FPC's amended petition asks the Commission to resolve a contractual dispute over which it has no jurisdiction.

A. The amended petition requests the Commission to interpret a disputed provision of a negotiated contract between OCL and FPC.

FPC's amended petition involves a contract dispute in a second poor disguise. The negotiated contract between OCL and FPC established two energy prices, each of which governs payments under certain conditions. With respect to those hours during which FPC would have operated the avoided coal unit upon which the contract is based, the contract specifies that FPC must pay OCL an energy rate which mirrors -- but does not exceed -- the costs that FPC would have incurred when operating the avoided unit. With respect to energy delivered during those hours in which the avoided unit

[5] As will be demonstrated, despite some fanciful footwork, FPC's new pleading does not overcome the problems which led Staff to recommend dismissal of the first petition.

would not have been operated, the contract calls for the application of FPC's as-available energy tariff.

To identify the hours during which FPC would have operated the avoided unit, it is necessary to know how the avoided unit would have interacted with the units on FPC's system to meet the demand during the period in question. Such determinations can be verified (after the fact) with the aid of a computer model designed to simulate how FPC would "dispatch" (vary the output of) the units on its system to satisfy the load conditions during a certain period of time had the avoided unit been built. These "dispatch decisions" are based on information about the units (including, for purposes of the pricing exercise, the avoided unit) that is fed into the computer. The computer utilizes this data to identify the appropriate combination and operating level of resources which would have been employed to meet the given load conditions for the time period being analyzed. As in any computerized analysis, the results are driven by the assumptions employed and by the values assigned to a number of variables which are inputs to the computer's calculations of production costs.

In the real world of day-to-day operations, FPC instructs its dispatch computer to schedule operation of the generating units economically on the basis of relative unit fuel costs, heat rates, and certain unit-specific physical operating characteristics and constraints. The latter information enables the computer to take into account differences in the units' abilities to decrease or increase their output in response to changes in load, minimum levels of generation needed by some units for stable operations, time required for start-up and shutdown, and the like.

Paragraph 9.1.2 of the negotiated contract states:

> Except as otherwise provided in section 9.1.1 hereof, for each billing month beginning with the Contract In-Service Date, the QF will receive electric energy payments based upon the Firm Energy Cost calculated on an hour-by-hour basis as follows: (i) the product of the average monthly inventory chargeout price of fuel burned at the Avoided Unit Fuel Reference Plant, the Fuel Multiplier, and the Avoided Unit Heat Rate, plus the Avoided Unit Variable O & M, if applicable, for each hour that the Company would have had a unit with these characteristics operating; and (ii) during all other hours, the energy cost shall be equal to the As-Available Energy Cost.

On July 18, 1994 FPC notified OCL (and other QFs having contracts based on the same avoided unit) that FPC intended to begin identifying the hours during which the avoided unit would have run by incorporating as "dispatch criteria" the elements of the <u>pricing</u> equation (and <u>only</u> those elements) identified in paragraph 9.1.2 of the negotiated contract. While in actual practice FPC does not dispatch its own units on the basis of variable O&M costs, it proposed to also utilize variable O&M as one of the criteria for determining dispatch when it simulates the hypothetical system that includes the avoided unit for purposes of contract energy pricing.

In real practice FPC takes unit-specific constraints and operating characteristics into account when identifying the most economical mix of generation resources that is technically and practically feasible for actual operations. However, for pricing purposes, FPC proposed to perform simulations related to the avoided coal unit that ignore the fact that the avoided unit would be physically unable to perform such feats as daily cycling, much less instantaneous start-ups and shutdowns. FPC justifies the discrepancy on the basis that such physical operating parameters are not explicitly mentioned in paragraph 9.1.2. FPC notified OCL and other QFs that, based on the results of simulating this artificially nimble, "contractually defined" pulverized coal unit -- made capable on paper of instantaneous starts and stops by its hypothetical release from the shackles of real world considerations -- FPC had determined that the avoided unit would be completely removed from service a majority of the time.[5]

FPC's new methodology contradicts its previous representations and conduct. In submitting OCL's contract to the Commission for cost recovery purposes, FPC projected energy payments under 9.1.2 that assumed the avoided unit would run 24 hours a day. See FPC Petition for Approval of Contracts, Attachment H, Docket No. 910401-EQ, attached hereto as Exhibit A.

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[5] Based on FPC's new projections, use of the new pricing methodology indicates that FPC would determine the avoided unit to be "turned off" as many as 24 hours on some days, including hours during FPC's on-peak periods. Yet, as the result of a separate attempt to "reinterpret" the contract, FPC proposes to penalize OCL (for purposes of calculating capacity payments) in the event OCL does not operate its unit during on-peak hours even if OCL would receive only the as-available energy price for doing so under FPC's attempted new theory.

Given FPC's assumption that the avoided unit would operate all hours, the Commission applied rule 25-17.0832 and determined that energy payments under the contract would not exceed FPC's avoided cost. Thereafter, from inception of energy payments in September 1993 until August 1994, FPC assumed that the avoided unit would have operated 100% of the time, when calculating payments for energy to OCL under paragraph 9.1.2.

The purpose of FPC's amended petition is identical to the purpose of its original petition for declaratory statement. It asks the Commission to rule that FPC's fantasy coal unit, and not the real world unit avoided by the contract, forms the negotiated basis for determining the hours during which FPC would have operated the 450 MW pulverized coal unit which OCL's contract (and others) displaced. FPC wants the Commission to agree with FPC that in paragraph 9.1.2 the parties negotiated the sole criteria for identifying the operational status of the avoided unit: criteria that differ from those associated with its actual dispatch methodology and that differ from the characteristics of the unit that FPC would have added to its system but for the availability of QF power. By its petition, FPC clearly is asking the Commission to construe and interpret paragraph 9.1.2 of the negotiated contract -- the subject of a vigorous dispute between FPC and OCL (and other QFs).

The fact that the amended (and the original) petition involve a dispute over the interpretation of paragraph 9.1.2 between OCL and FPC is not altered by FPC's amended presentation nor its addition of self-serving extensive quotations from the cogeneration rule proceeding. Throughout its petition, FPC refers to its new pricing methodology as though it has already been validly established as the indisputable contractual pricing mechanism. The claim in FPC's amended petition begs spectacularly the question of interpretation that is raised. FPC's amended petition implies that there is no doubt that FPC's new methodology constitutes the mechanism to which the parties agreed when they negotiated the contract. Yet, if there were no dispute over that issue -- if, in other words, that was the only possible interpretation -- there would be no reason to attempt to seek a mid-course "confirmation."[7]

The fact of competing interpretations is also seen in the differences between the methodology that has been employed by the parties <u>including FPC</u> to date, on the one hand, and the methodology that FPC wants to implement unilaterally on a prospective basis, on the other.

A vigorous dispute exists between OCL and FPC concerning the proper interpretation of paragraph 9.1.2 of the negotiated contract. OCL submits that the parties agreed to identify the same coal unit that FPC would have built but for the purchase of QF power as the avoided unit that should be used for purposes of identifying the hours during which the energy rate associated with

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[7] If, on the other hand, FPC's proposed pricing methodology is <u>not</u> the one to which OCL and FPC agreed when they negotiated the contract, then FPC is attempting to prevail on the Commission to unilaterally change a critical term of a negotiated contract -- something the Commission cannot do. <u>Bates Fabrics, Inc. v. PUC</u>, 447 A.2d 1211 (Me. 1992).

the operation of the avoided unit should be applicable. OCL asserts that the negotiated contract requires FPC to model that unit's interaction with FPC's system utilizing the pertinent physical operating characteristics and idiosyncracies of an actual coal unit and FPC's actual dispatching criteria, just as it would have done had it constructed and operated the pulverized coal unit. OCL further asserts that in paragraph 9.1.2 the parties simply defined the components of the equation (payment = fuel price of reference plant x fuel multiplier specified in contract x heat rate + O&M) that is to be used in calculating the payment for firm energy delivered during the hours identified by the application of that methodology. The paragraph has nothing to do with the identification of the hours when the avoided unit would have been operated.

On the other hand, FPC's newly advanced interpretation is that it used the "actual" coal unit to derive capacity and energy prices, but then negotiated with 11 QFs the use of the elements of the price equation mentioned in paragraph 9.1.2 as dispatch criteria in a specialized, truncated dispatch methodology. FPC says this "negotiation" was accomplished by FPC for the specific purpose of exacting price concessions from QFs and positioning itself to pay low off-peak, as-available energy rates for QF energy being supplied in substitution for the base loaded resource that FPC would have built.

Through its "amended petition" FPC is asking the Commission to sanction FPC's new interpretation of the negotiated contract. If the Commission entertains the petition, it will place itself in the position of trying to resolve an intense dispute between the parties over the meaning of a provision of a negotiated contract, something which is an issue solely for the courts, not the Commission.

B. The interpretation of the disputed provision is a matter for a court of law. Federal and state statutory regimes provide the Commission only limited authority over the relationship between QFs and regulated utilities. It does not extend to resolving contract disputes.

In other contexts, parties demonstrate the existence of a dispute in order to show the need for an evidentiary hearing. Here, because of the limited nature of the Commission's authority in the area of contractual relationships between QFs and utilities, the existence of a dispute over the interpretation of the negotiated contract signifies that the Commission has no jurisdiction over FPC's petition.

Federal law. Fundamentally, the sale of power by a QF to a purchasing utility is a wholesale transaction that, absent some different, intervening statutory mechanism, would be wholly preempted from state regulation by the Federal Power Act. 16 USC § 824; Federal Power Commission v. Southern California Edison, 376 U.S. 205 (1964). That the state has any role to play at all in the relationship between utilities and QFs is due to the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA delegated to the states certain limited authority needed to implement the intent of

PURPA. The Commission's involvement in the relationship between a utility and a QF must be based on the specific limited authority delegated to the state by PURPA.

The intent of PURPA was to encourage the development of cogeneration through the creation of a mandatory wholesale market characterized by prices that would not exceed the utility's avoided cost. 16 USC § 824a-3; Regulations Preamble, ¶ 30,128, p. 30,863 (March 20, 1980). PURPA delegated to the states the authority to implement these purposes through regulations that must conform to the requirements of rules promulgated by the Federal Energy Regulatory Commission. 16 USC § 824a-3(f).

The specific authority granted by Congress to the states through PURPA relates to implementing and enforcing the utilities' obligation to purchase and the setting of rates based on avoided costs. The authority to interpret negotiated contracts or resolve contractual disputes was not specifically delegated to the states by PURPA. Accordingly, it cannot reside in the Commission.

State Law. There is no tension between federal and Florida law concerning the extent of the Commission's jurisdiction over QFs. Unlike other aspects of the statute which is the source of the Commission's powers, the amendments to Chapter 366, Florida Statutes that address the subject of cogeneration have been limited in their scope. State law on the subject is appropriately consistent with the limited scope of the federal delegation of authority under PURPA.

The jurisdiction of the Commission to interpret a negotiated contract or resolve a dispute between a QF and a regulated utility cannot be established by a superficial reference to the Commission's "Grid Bill powers." The provisions of Chapter 366 that have come to be called the "Grid Bill" were enacted in 1974, four years before Congress created the Qualifying Facility entity and the obligation of the utility to purchase cogenerated power by enacting PURPA. In Chapter 74-196, Laws of Florida, the Florida Legislature codified the following functions of the Commission:

> To require electric power conservation and reliability within a coordinated grid for operational as well as emergency purposes. (Section 366.04(2)(c), Florida Statutes)
>
> The commission shall further have jurisdiction over the planning, development and maintenance of a coordinated electric power grid throughout Florida, to assure an adequate and reliable source of energy for operational and emergency purposes in Florida and the avoidance of further uneconomic duplication of generation, transmission, and distribution facilities. (Section 366.04(3), Florida Statutes)

However, the scope of the Commission's jurisdiction to carry out these responsibilities is embodied in the following specific powers to regulate utilities that were conferred on the Commission in the same "Grid Bill":

> The commission shall have the power to require reports from all electric utilities to assure the development of adequate and reliable energy grids. (Section 366.05(7), Florida Statutes; emphasis added)
>
> . . .

> If the commission determines that there is probable cause to believe that inadequacies exist with respect to the energy grids developed by the electric utility industry, it shall have the power, after holding hearings as provided by law, and after a finding that mutual benefits will accrue to the public utilities involved, to require installation or repair of necessary facilities, including generating plants and transmission facilities with the costs to be distributed in proportion to the benefits received, and to take all necessary steps to insure compliance. The electric utilities involved in any action taken or orders issued pursuant to this subsection shall have full power and authority notwithstanding any general or special laws to the contrary, to jointly plan, finance, build, operate or lease generating and transmission facilities and shall be further authorized to exercise the powers granted to corporations in chapter 361, Florida Statutes. Provided that this subsection shall not supersede or control any provision of the electric power plant siting act, sections 403.501 thru 403.516, Florida Statutes, 1973. (Section 366.05(8), Florida Statutes; emphasis added)

. . .

> Energy reserves of all utilities in the Florida energy grid shall be available at all times to insure that grid reliability and integrity are maintained. The commission is hereby authorized to take such action as necessary to assure compliance; provided, however, prior commitments as to energy use in interstate commerce as approved by the Federal Power Commission; commitments between one electric utility and another which have been approved by the Federal Power Commission; or commitments between an electric utility which is a part of the energy grid created herein and another energy grid shall not be abridged or altered except during an energy emergency as declared by the governor and cabinet. (Section 366.055(1), Florida Statutes; emphasis added)

. . .

When the energy produced by one electric utility is transferred to another or others through the energy grid and under the powers granted by this section, the commission shall direct the appropriate recipient utility or utilities to reimburse the producing utility in accordance with the latest wholesale electric rates approved for the producing utility by the Federal Power Commission for such purposes.

Any utility which provides a portion of those transmission facilities involved in the transfer of energy from a producing utility to a recipient utility or utilities at a rate lower than the rate at which the power is purchased from a producing utility. (Section 366.055(2), Florida Statutes; emphasis added)

. . .

To assure efficient and reliable operation of a state energy grid, the commission shall have the power to require any electric utility to transmit electric energy over its transmission lines from one utility to another or as a part of the total energy supply of the entire grid, subject to the provisions hereof. (Section 366.05(3), Florida Statutes; emphasis added)

Each power conferred on the Commission to enable it to carry out its Grid Bill functions is to be applied to utilities. Clearly, the powers conferred by the Legislature on the Commission in the 1974 "Grid Bill" are examples of the Commission's comprehensive authority to regulate the rates and the adequacy and quality of service delivered by electric utilities.

The specific amendments to Chapter 366 dealing with cogeneration show a marked contrast. The purpose of the first such amendment was simply to provide a basis in state law for the promulgation of the rules designed to carry out the limited federal delegation of authority from PURPA. Chapter 81-131, Laws of

Florida. Since that time, Chapter 366 has also been amended to reflect the legislative policy finding that increased development of cogeneration should be encouraged, and the requirement that the Commission identify the increased development of cogeneration as one of the regulated utilities' conservation goals. Chapter 89-229, Laws of Florida.

Chapter 89-229, Laws of Florida, created section 366.051, Florida Statutes, which reads in part:

> Cogeneration; small power production; commission jurisdiction.--Electricity produced by cogeneration and small power production is of benefit to the public when included as part of the total energy supply of the entire electric grid of the state or consumed by a cogenerator or small power producer. . . .

However, the appearance here of the word "grid" does not mean that this reference to cogeneration is associated in any way with the "Grid Bill powers" that the Commission exercises over electric utilities. A finding by the Legislature that cogeneration is a beneficial part of the state's total power supply, made in the context of directing the Commission to encourage cogeneration, does not confer jurisdiction to interpret QFs' negotiated contracts or resolve disputes between QFs and utilities.

The scope and definition of the jurisdiction conferred on the Commission that follows immediately after the finding in section 366.051 delineates the powers available to the Commission to achieve this "benefit." Section 366.051, Florida Statutes, articulates the parameters of the utility's obligation to purchase, requires wheeling to facilitate transactions, defines avoided costs, and directs the Commission to establish guidelines relating to the purchases. While more detailed than its predecessor language in Chapter 366, the scope of the jurisdiction conferred by section 366.051 is perfectly consistent with the objectives and the limited delegation of authority in PURPA. PURPA establishes the utility's obligation to purchase at avoided cost rates and directs the state to implement that obligation.

The Commission has adopted the "guidelines" to which section 366.051 refers. They consist of its cogeneration rules. Rules 25-17.080-.091, Florida Administrative Code. The rules do not establish the Commission as an arbiter of contractual disputes. Instead, they focus on implementing the utility's PURPA obligation to purchase (and the related obligation to negotiate) and set criteria which the Commission will use to determine whether a contract qualifies for cost recovery by the utility.

The guidelines applicable to negotiated contracts for the purchase of firm capacity and energy are found in rule 25-17.0832(2), Florida Administrative Code. This rule encourages the negotiation of power purchase agreements and sets forth several general and four specific requirements for cost recovery of the energy and capacity payments associated with negotiated contracts. The criteria are designed to ensure that the utility needs the QF power for which the utility wants customers to pay; that the price for QF power does not exceed that which customers would pay anyway; and that customers are protected by adequate security in the event the QF does not perform.

All of the criteria of the rule relate to approval of a contract for cost recovery by the utility. The rule does not purport to give the Commission the ability to resolve contract disputes or to interpret the terms and conditions of a negotiated power purchase agreement. This is as it should be, for in its contract approval process the Commission has performed its role of safeguarding ratepayers. When a dispute arises, the negotiated contract -- like any other contract -- is to be construed and interpreted by the courts.

As developed above, the Commission's <u>limited</u> jurisdiction to supervise the relationship between QFs and utilities at the point of contract formation differs fundamentally from the broader powers it exerts over <u>utilities</u> for other purposes. For that reason, certain court decisions reached in the context of the Commission's exercise of other, more plenary powers simply have no application here. For example, in <u>City Gas Co. v. Peoples Gas System, Inc.</u>, 182 So.2d 436 (Fla. 1965) and <u>PSC v. Fuller</u>, 551 So.2d 1210 (Fla. 1989), the Court articulated the doctrine that the contract that the Commission approved in those cases merged with and became part of the Commission's orders. However, in each of these so-called "order jurisdiction" cases, the Commission possessed the inherent or statutory powers to fully regulate the subject matter of the contracts. Those cases do not alter the fundamental truism that a contract cannot imbue the Commission with jurisdiction it does not already possess. Whereas the Commission has broad authority over territorial agreements and territorial disputes due to explicit statutory provisions, Congress has delegated only limited authority to the Commission to implement the objectives of PURPA, and in fact has preempted important aspects of QFs' businesses from state regulation. See, 16 U.S.C. 824a-3(e).

The special limited nature of the regulator's involvement in the relationship between the QF and the purchasing utility -- and the agency's lack of jurisdiction to resolve contract disputes that arise after the contract has been implemented -- has been recognized in other jurisdictions. In In re: Erie Energy Associates - Petition for a Declaratory Ruling that its Purchase Contract with New York State Electric and Gas Corporation Remains in Effect, Case 92-E-0032, March 4, 1992, a QF asked the New York Public Service Commission (in a proceeding analogous to a petition for declaratory statement) to interpret and apply certain milestone provisions of a contract between Erie and New York State Electric and Gas Corporation, and rule that Erie was not in violation of the provision. The New York Public Service Commission refused to construe the contested provisions of the contract. It noted that its role was limited to supervising contract formation, and that later disputes between QFs and utilities over the meaning or requirements of contractual provisions were generally matters for courts to resolve. Id. at 5.

In keeping with the limited scope of its statutory authority, the Commission has never ruled on the validity and legal enforceability of a negotiated power purchase agreement.[8] Neither has the Commission attempted to interpret the terms and conditions of a negotiated power purchase agreement where such an interpretation was objected to by either party to the agreement.[9]

In fact, in its Conserv decision, Order No. 14207, issued on March 21, 1985 in Docket No. 840438-EI, the Commission viewed its role relative to that of the judiciary in much the same way as did the New York agency in the Erie System case, supra. In Conserv, Tampa Electric Company (TECO) sought a declaratory statement from the Commission concerning, among other things, the interpretation of a particular provision of the TECO/Conserv contract. Conserv objected to TECO's petition on several grounds, including that the

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[8] The issue of contract validity was raised but not decided in Docket No. 930977-EQ, In re: Petition for approval of contract for the purchase of firm capacity and energy between General Peat Resources, L.P., and Florida Power and Light Company (GPR). However, the docket was closed by the filing of a voluntary dismissal taken by GPR prior to a decision on this issue by the Commission.

[9] See, In re: CFR Bio-Gen's Petition for declaratory statement regarding the methodology to be used in its Standard Offer Cogeneration Contracts with Florida Power Corporation, Order No. 24338, issued on April 9, 1991, in Docket No. 900877-EI; In re: Complaint by CFR Bio-Gen against Florida Power Corporation for alleged violation of standard offer contract, and request for determination of substantial interests, Order No. 24729, issued on July 1, 1991, in Docket No. 900383-EQ; In re: Petition of Timber Energy Resources, Inc. for a declaratory statement regarding upward modification of committed capacity amount by cogenerators, Order No. 21585, issued on July 19, 1989, in Docket No. 890453-EQ; In re: Petition for declaratory statement by Wheelabrator North Broward, Inc., Order No. 23110, issued on June 25, 1990, in Docket No. 900277-EQ. All these cases requested that the Commission interpret standard offer contract terms and conditions. As the Commission is aware, standard offer contracts are embodied in utility tariffs over which the Commission is given specific jurisdiction in § 366.051, Florida Statutes.

Commission lacked jurisdiction to interpret the agreement because the civil courts possessed the exclusive jurisdiction to resolve the contractual dispute. The Commission said:

> [W]e agree that the civil courts have exclusive jurisdiction to construe the Agreement and award damages if they are merited. Thus we grant in part Conserv's request that we decline to entertain TECO's request on jurisdictional grounds.[10]

Order No. 14207 at 4.

Similarly, the Commission's <u>own</u> <u>assessment</u> of its role in implementing PURPA shows that it appreciates the limitations on the authority which Congress delegated to it. In Order No. 9970, issued on April 22, 1981 in Docket No. 80235-EU, the Commission stated:

> In addition to mandating that utilities engage in purchases, sales, interconnection, wheeling, and operating in parallel with qualifying facilities, Subpart C of the FERC rules leaves to the States the implementation of those rules <u>in the areas of determining a utility's avoided cost, setting prices for the purchases and sales of power, and overseeing the safety and cost provisions of interconnection</u>. (Emphasis added).

In sum, neither Congress, nor the FERC, nor the Florida Statutes, nor any of the Commission's rules gives the Commission jurisdiction to resolve a dispute between a QF and a utility over the terms of a negotiated contract.

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[10] While the Commission has added to the cogeneration rules that were in place at the time of the <u>Conserv</u> case, the rules have continued to focus on the aspects of the QF/utility relationship that are the subject of Congress' limited delegation of authority. The scope of that authority has not changed since the <u>Conserv</u> case.

II. FPC has failed to demonstrate that it has met either the procedural or substantive requirements of section 120.57.

In an effort to withstand numerous motions to dismiss, FPC has attempted to "convert" its defective petition for declaratory statement to a §120.57 proceeding. In attempting to do so, FPC has ignored the Commission's procedural pleading requirements and clearly cannot make the substantive showing which entitles a party to a §120.57 hearing.

A. FPC's "amended petition" fails to comply with rule 25-22.036(7), Florida Administrative Code.

Rule 25-22.036, Florida Administrative Code, governs §120.57 proceedings. Subsection (7) is very specific as to the form and content of initial pleadings. Among other things subsection (7) requires "an explanation of how [the petitioner's] substantial interests will be or are affected by the Commission determinations." As discussed below, a showing that one's substantial interests are affected by a proceeding is a prerequisite to a §120.57 proceeding. This is, no doubt, the reason that an explicit explanation of substantial interests is required by Commission rule. No explanation, no reference, no mention of its substantial interests appears in FPC's "amended petition." This glaring failure to comply with a fundamental aspect of the Commission's rules is, in and of itself, grounds for dismissal.

B. FPC has failed to demonstrate how its substantial interests will be affected by this proceeding.

Section 120.57 states:

> The provisions of this section shall apply in all proceedings in which the substantial interests of a party are determined by an agency . . . .

Substantial interests have been defined through case law. In the seminal case of Agrico Chemical Co. v. Department of Environmental Regulation, 406 So.2d 478, 1982 (Fla. 2d DCA 1981), the court found that in order for a party to meet the substantial interest test, a party must show that (1) it will suffer injury in fact that is of sufficient immediacy to entitle the party to a section 120.57 hearing and (2) that the party's substantial injury is of a type or nature which the proceeding is designed to protect. See also, Local 1267 v. Benevolent Association of Coachmen, Inc., 576 So.2d 379 (Fla. 4th DCA 1991). As discussed above, FPC has not even alleged that its substantial interests will be affected by this proceeding. Indeed it can make no such showing.

Injury in Fact. The first prong of the Agrico test requires a demonstration of injury. FPC can make no such showing because it has no such injury.[11] FPC has already implemented its interpretation of section 9.1.2 of the contract and as a result is paying OCL less than it previously paid. How can FPC claim any injury?

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[11] Instead, FPC has been unjustly enriched by paying OCL less for energy than the contract between OCL and FPC requires.

Further, as the October 6 Staff recommendation notes, FPC conveys no doubt as to the propriety of its actions:

> FPC's actions involving its implementation of the pricing mechanism in Section 9.1.2 of the negotiated contracts do not indicate FPC has any questions or doubts concerning its compliance with Rule 25-17.0832(4)(b). FPC notified the parties to the contracts of its intentions to implement the pricing mechanism before it filed its declaratory statement petition. FPC did not acknowledge it had any doubts or questions about whether it could substitute as-available energy payments for firm energy payments when it notified the QFs of its intentions.
>
> . . .
>
> In fact, FPC's actions before it filed its petition for a declaratory statement show that it had no doubt concerning its use of the pricing mechanism in the negotiated contracts. The petition filed by FPC does not show that an actual controversy exists concerning its use of the pricing mechanism in Section 9.1.2 of the negotiated contracts.

Staff recommendation at 6 - 7.

Finally, Staff correctly notes that FPC has already implemented its new interpretation. FPC has not argued that "without a Commission declaration the pricing mechanism could not be implemented." Staff recommendation at 6. It simply remains for a court of law to determine whether FPC is within its <u>contractual</u> rights, or whether OCL (and others) have sustained damages due to FPC's breach. In other words, FPC can show no injury; instead, it hopes to preempt OCL's opportunity to prove injury in a court of law.

Zone of Interest. The second prong of the Agrico test requires that the party's substantial interests be of the type the proceeding is designed to protect. As discussed in detail above, it is clear that neither Chapter 366 generally nor section 366.051 specifically was intended to apply to disputes over contractual provisions between QFs and utilities. Therefore, FPC has not met this portion of the Agrico test either.

FPC has totally failed to make any demonstration as to how its substantial interests will be affected in this docket. Therefore, it has no standing to seek a §120.57 hearing.

III. FPC's "amended" petition remains a defective petition for declaratory statement. As such, FPC has not properly or successfully invoked the jurisdiction of the Commission pursuant to section 120.565, Florida Statutes. The petition does not validly call for a statement of the applicability of a statute, rule, or order, as that provision of law requires, nor does it request a statement that would pertain solely to FPC in its particular circumstances only, as section 120.565, Florida Statutes, and rule 25-22.020, Florida Administrative Code, require.

Due to Staff's unfavorable recommendation on FPC's petition for declaratory statement, FPC has attempted to "convert" that petition into a §120.57 petition via the filing of an "amended petition." FPC has failed in its attempt. Not only has it failed to meet the requirements of §120.57 discussed above, it is still seeking the very same inappropriate relief - the Commission's blessing of its interpretation of section 9.1.2 - that it sought in its petition for declaratory statement.[12] FPC's acquiescence to the involvement of other parties to the contracts in this docket does not change the type of relief FPC seeks, which is a declaration as to the propriety of the interpretation of a contract provision. As such, FPC's "amended petition" remains an inappropriate petition for declaratory statement which must be dismissed because the prerequisites for a declaratory statement have not been met.

As discussed earlier, FPC's "amended petition" seeks to have the Commission resolve a dispute by interpreting a provision of a negotiated contract. In the above discussion, OCL demonstrated that the Commission's authority over the contractual relationship between OCL and FPC is limited to applying its criteria for contract approval for cost recovery purposes. This means the authority of the Commission would not extend to resolving a dispute between the parties by interpreting a provision of the negotiated contract <u>even if</u> section 120.565, Florida Statutes, permitted such a dispute to be resolved through the vehicle of a declaratory statement. The declaratory statement procedure is simply unavailable to FPC, regardless of how it styles its petition.

Section 120.565, Florida Statutes, provides in pertinent part:

> A declaratory statement shall set out the agency's opinion as to the applicability of a specified statutory provision or of any rule or order of the agency as it applies to the

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[12] One need only compare the prayers for relief in each petition to determine that what FPC seeks from the Commission has not changed at all.

petitioner in his particular set of circumstances only.

Under section 120.565, Florida Statutes, the Commission has only the authority to issue a declaratory statement concerning the applicability of a statute, rule, or order, and is further limited to statements that apply only to the petitioner in its particular circumstances. To invoke the jurisdiction of the Commission -- to present a question that is within the authority of the Commission to answer through a statement issued pursuant to section 120.565, Florida Statutes -- the petition must meet those requirements. FPC's petition does not.

A. FPC's petition seeks to have the Commission interpret a contract, not a statute, rule, or order.

FPC's attempt to legitimize its amended petition by linking it to rule 25-17.0832(4)(b), Florida Administrative Code, fails. First, when the rule is read in context it is clear that, without more, rule 25-17.0832(4), Florida Administrative Code, applies only to standard offer contracts. There is a reference to the subsection in rule 25-17.0832(2), Florida Administrative Code, the provision in the Commission's cogeneration rules that is specific to negotiated contracts. Rule 25-17.0832(2), Florida Administrative Code, sets forth the criteria the Commission will review in gauging whether a negotiated contract should be approved for purposes of cost recovery. Subsection 25-17.0832(2)(b)(1) states:

> (2) . . . In reviewing negotiated firm capacity and energy contracts <u>for the purpose of cost recovery</u>, the Commission shall consider factors relating to the contract that would impact the utility's general body of retail and wholesale customers including:
>
> . . .
>
> (b) whether the cumulative present worth of firm capacity and energy payments made to the qualifying facility over the term of the contract are projected to be no greater than:
>
> 1. the cumulative present worth of the value of a year-by-year deferral of the construction and operation of generation or parts thereof by the purchasing utility over the term of the contract; <u>calculated in accordance with subsection (4) and paragraph (5)(a) of this rule</u>, providing that the contract is designed to contribute towards the deferral or avoidance of such capacity . . . . (Emphasis supplied).

The relevancy of the rule to which FPC refers to a <u>negotiated contract</u> is to identify the benchmark avoided cost against which the payments under a negotiated contract are to be compared. For negotiated contracts, the mechanism of the rule cited by FPC is not a prescription for an energy pricing mechanism. Instead, the rule governing negotiated contracts borrows the avoided cost paradigm of the standard offer rule and uses it -- not as a payment formula -- but as a ceiling against which to measure the payments negotiated by the parties to the contract.

<u>Even if it is assumed</u>, for the sake of argument, that the reference in rule 25-17.0832(2)(b)(1), Florida Administrative Code, is intended to identify a pricing approach to be included in a negotiated contract, the fact remains that the relevancy of rule

25-17.0832(4)(b), Florida Administrative Code, to the contract between OCL and FPC would be limited to its role as one of the criteria of rule 25-17.0832(2), Florida Administrative Code, that govern the Commission's review of a negotiated contract for purposes of cost recovery. This function was completed, in the case of OCL's contract, in 1991. In fact, to raise rule 25-17.0832(4)(b), Florida Administrative Code, at this point, as FPC suggests, would be to fly in the face of the fundamental maxim that, once a contract has been approved for cost recovery by the Commission, that decision will not be revisited absent extraordinary circumstances, such as where the utility obtained the Commission's approval by perjury, fraud, or intentional withholding of key information.[13] FPC has not suggested that it defrauded the Commission when it requested approval of the recovery of costs associated with the contract. In fact, FPC does not suggest that the subject of cost recovery -- the sole context in which rule 25-17.0832(4)(b), Florida Administrative Code, has any possible application to the contract -- is involved in its petition in any way.[14]

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[13] See, In re: Planning Hearings on Load Forecasts Generation Expansion Plans and Cogeneration Prices, Order No. 24989 at 71, issued on August 29, 1991, in Docket No. 910004-EU; In re: Implementation of Rules 25-17.080 through 17.091, F.A.C., regarding cogeneration and small power production, Order No. 25668, issued on February 3, 1992, in Docket No. 910603-EQ; affirmed, Florida Power and Light Company v. Beard, 626 So.2d 660 (Fla. 1993).

[14] In Order No. 24989 the Commission determined, over arguments by utilities, to eliminate the "regulatory out" clause from standard offer contracts. In doing so, the Commission demonstrated that it understood the role which confidence in the

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Moreover, FPC has undercut its own argument concerning the applicability of rule 25-17.0832(4)(b), Florida Administrative Code. In its response to the petition to intervene filed in this docket by Pasco Cogen, FPC says the rule sets out only a "concept" to be "fleshed out" by the parties in their negotiations. FPC's Answer at 2. In other words, even FPC admits that the rule on which it relies has no prescriptive effect on negotiated contracts. In short, there is no "linkage" between the rule cited by FPC and the contractual dispute between the parties.

FPC's attempt to link its petition to the order on contract approval must similarly fail. The Commission approved the negotiated contract for purposes of cost recovery in Order No. 24734, issued in Docket No. 910401-EQ on July 1, 1991. The contract was approved based on the four criteria of rule 25-17.0832, Florida Administrative Code. There is nothing in the order that pertains to the energy pricing mechanism of the contract. Nor is there any language in the order purporting to give the Commission continuing jurisdiction over the contractual relationship between FPC and OCL. FPC wants the Commission to interpret the <u>contract</u>, not the order approving it.

FPC has failed to meet the requirements of section 120.565, Florida Statutes. That failure is jurisdictional.

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finality of Commission decisions plays in the willingness of the lender and developer industries to participate in Florida's energy market. That confidence would be jeopardized by any indication that the Commission is reviewing a previously approved negotiated contract for <u>any</u> purpose under the guise of the very rule under which the contract was approved for cost recovery.

IV. <u>FPC's amended petition must be dismissed because the issue can be resolved through pending litigation.</u>

As mentioned earlier, in March 1994 OCL filed suit against FPC in the United States District Court for the Middle District of Florida. In its complaint, OCL alleges that FPC has breached its contract with OCL (one of the contracts that are the subject of FPC's petition for declaratory statement) and that FPC has violated antitrust laws through its course of conduct towards OCL. OCL has amended its federal complaint to allege an additional breach of paragraph 9.1.2 of the same contract and to include a claim for any and all damages associated with FPC's unilateral departure from the contractual energy pricing mechanism. The amendment to the complaint was filed on October 21, 1994, prior to the time FPC sought to "amend" its inappropriate petition for declaratory statement. In that pending litigation, the issue raised by FPC's ("amended") petition for declaratory statement will be resolved by the federal court.

In <u>Couch v. State</u>, 377 So.2d 32 (Fla. 1st DCA 1987), the appellant had filed a petition for declaratory statement before the Department of Health and Rehabilitative Services asking the agency to issue a statement concerning a matter that was the subject of litigation pending in circuit court. The court drew from analogous principles established in declaratory judgment actions to resolve the issue of which forum properly had jurisdiction. The court affirmed the agency's refusal to issue the requested declaratory statement based on its determination that the adequacy of the litigation pending in circuit court to resolve the issue precluded the request for a declaratory statement.

In Lawyers Professional Liability Insurance Company v. Shand, 394 So.2d 238 (Fla. 1st DCA 1981), the court extended the reasoning of Couch to a situation in which litigation had been filed in federal court prior to the request for declaratory statement. As in Couch, the court turned to established judicial principles for guidance. Because the litigation pending at the time the petition was filed would afford "fully adequate and complete relief," the court ruled that the petition for declaratory statement would not be permitted to proceed, pending the outcome of the federal court action. Lawyers, supra, at 240.

In Suntide Condominium Association, Inc. v. Division of Florida Land Sales, 504 So.2d 1343 (Fla. 1st DCA 1987), an association of condominium owners filed an action in circuit court seeking reformation of the declaration of condominium. A group of dissenting owners opposed the reformation action, and filed a petition for declaratory statement before the agency. The petition asked the agency to declare whether the association was a proper plaintiff and whether it could expend association funds for attorneys' fees in the court case. The court adopted the reasoning in Couch and Lawyers, supra, and ruled that the agency had erred in proceeding with the request for declaratory statement. The court said:

> We do view it as an abuse of authority for an agency to either permit the use of the declaratory statement process by one party to

> a controversy as a vehicle for obstructing an opposing party's pursuit of a judicial remedy, or as a means of obtaining, or attempting to obtain, administrative preemption over legal issues then pending in a court proceeding involving the same parties. This is especially so when, as here, there is not the slightest hint that the relief sought by the opposing party in the court proceeding is available in any forum other than the circuit court.

Suntide at 1345.

These cases are applicable to FPC's amended petition, which remains a request for declaratory relief after the attempt to amend. OCL's suit in federal court, while precipitated by a separate breach, involves a contract that is among those which are the subject matter of FPC's petition. The federal court had jurisdiction over FPC, OCL and the negotiated contract when FPC filed its petition with the Commission. OCL has amended its claim for damages to include the injuries it has sustained as a result of FPC's wrongful change in pricing methodology. Because OCL seeks damages in its suit against FPC, only the federal court can provide an adequate remedy. Suntide, supra.

OCL submits that FPC's amended petition remains an attempt to abuse the declaratory statement mechanism. FPC continues to seek an "administrative preemption" of a matter for which OCL's only adequate remedy is in a court of law. OCL is entitled (as is each of the other QFs) to hold FPC accountable in a court of law for any and all damages that will be sustained by OCL as a result of FPC's breach of contract. For these reasons, in addition to the points raised in the earlier sections of this motion, FPC's amended petition must be dismissed.

CONCLUSION

Through its amended petition, FPC seeks to have the Commission rule on a matter of contract interpretation in a contractual dispute that is beyond its jurisdiction. The amended petition also fails to demonstrate that FPC's substantial interests are affected and fails to properly invoke the limited jurisdiction and authority of the Commission to issue declaratory statements under section 120.565, Florida Statutes. FPC's petition is an improper attempt to preempt the right of OCL (and 10 other QFs) to pursue adequate recourse against FPC through the proper judicial remedy. FPC's amended petition must be dismissed.

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of Orlando CoGen Limited's Motion to Dismiss has been furnished by hand delivery* or by U.S. Mail to the following parties of record, this 28th day of November, 1994.

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Attachment II

COMPARISON OF CONTRACT COSTS AND AVOIDED COSTS

Orlando CoGen Limited, L.P.
Contract Capacity 74.0 MW

Year	Capacity Credits $/KW/Mo.	[illegible] of [illegible] % of Capacity Credits $/KW/Mo.	Contract Capacity Credits $/Year	Avoided Fuel & Var O&M $/MWH	Contract Energy * Payment $/Year	Total Contract Payment $/Year	Avoided Capacity Cost $/KW/Mo.	[illegible] of Avoided Capacity Cost $/KW/Mo.	Avoided Capacity Cost $/Year	Avoided Energy * Cost $/MWH	Avoided Energy Cost $/Year	Total Avoided Cost $/Year
1994	12.66	14.14	12,706,641	[illegible]	18,817,[illegible]	31,[illegible]	12.[illegible]	14.21	12,7[illegible]	19.[illegible]	18,817,849	31,[illegible]
1995	13.32	14.86	13,347,[illegible]	[illegible]	19,[illegible]	[illegible]	12.[illegible]	14.[illegible]	13,414,[illegible]	[illegible]	19,[illegible]	[illegible]
1996	14.00	15.61	14,0[illegible]	[illegible]	20,404,700	34,[illegible]	14.00	[illegible]	14,[illegible]	[illegible]	20,404,700	34,[illegible]
1997	14.72	16.41	14,790,331	[illegible]	21,[illegible],700	[illegible]	14.72	[illegible]	14,[illegible]	34.[illegible]	21,[illegible],700	[illegible],110
1998	[illegible]	17.24	[illegible],401,700	[illegible]	22,[illegible]	[illegible]	[illegible]	17.[illegible]	[illegible]	[illegible]	22,[illegible]	[illegible],101
1999	[illegible]	18.12	[illegible]	37.[illegible]	[illegible],747,[illegible]	40,[illegible],740	[illegible]	[illegible]	[illegible]	[illegible]	[illegible],767,[illegible]	40,[illegible]
2000	17.[illegible]	19.04	17,116,977	[illegible]	24,[illegible]	[illegible]	17.[illegible]	[illegible].14	17,[illegible]	[illegible]	24,[illegible]	[illegible],101,[illegible]
2001	17.[illegible]	20.01	17,[illegible]	41.04	[illegible],710	44,[illegible]	17.[illegible]	[illegible].11	18,077,[illegible]	40.[illegible]	[illegible],710	44,[illegible]
2002	18.07	21.04	18,[illegible],794	43.[illegible]	27,572,[illegible]	48,401,[illegible]	[illegible].07	21.16	[illegible],772	43.[illegible]	27,[illegible]	[illegible]
2003	19.[illegible]	22.11	[illegible],070,726	[illegible]	[illegible],077	48,047,[illegible]	19.[illegible]	22.22	[illegible]	[illegible]	[illegible],077	[illegible]
2004	20.05	23.25	20,[illegible]	48.[illegible]	[illegible],400,[illegible]	51,[illegible]	20.[illegible]	[illegible]	[illegible]	48.[illegible]	[illegible]	51,464,[illegible]
2005	21.01	24.40	21,064,[illegible]	[illegible]	[illegible],011,706	[illegible],700	21.01	24.[illegible]	[illegible]	[illegible]	[illegible],011,706	54,977,110
2006	22.02	25.[illegible]	22,047,[illegible]	[illegible].27	[illegible],107	[illegible],711,[illegible]	22.[illegible]	26.70	[illegible],105,[illegible]	[illegible].27	[illegible],107	[illegible]
2007	24.20	[illegible]	24,[illegible],700	[illegible]	[illegible]	[illegible],700	24.20	27.12	[illegible],271,[illegible]	[illegible]	[illegible]	[illegible],727,[illegible]
2008	[illegible].43	[illegible]	[illegible],220	[illegible]	57,100,[illegible]	[illegible],841,[illegible]	[illegible]	[illegible]	[illegible],277	[illegible]	57,100,[illegible]	[illegible],367
2009	[illegible].74	[illegible]	[illegible],704,[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible],010
2010	[illegible]	31.22	[illegible],147,[illegible]	[illegible]	41,[illegible],012	[illegible],701	[illegible]	31.47	[illegible],131	[illegible]	41,[illegible],012	[illegible],140
2011	[illegible]	[illegible]	[illegible]	[illegible]	43,130,[illegible]	72,[illegible]	[illegible]	[illegible]	[illegible],213	[illegible]	43,130,[illegible]	72,077,749
2012	[illegible]	34.01	31,[illegible],767	71.70	45,[illegible]	[illegible],700	31.04	[illegible]	31,[illegible],047	71.70	45,[illegible]	[illegible]
2013	[illegible]	[illegible]	[illegible]	75.45	47,[illegible]	[illegible]	[illegible]	[illegible]	[illegible],177	75.45	47,[illegible]	[illegible],172
Net Present Value (1/1/94)			$[illegible],712,047		$[illegible],573,[illegible]	$[illegible]			$[illegible],730,700		$[illegible],573,[illegible]	$[illegible]

Contract vs. Avoided Costs [illegible]%
NPV of the Discount (1/1/94) $[illegible]

* [illegible] Capacity Factor and [illegible]% Voltage Adjustment

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for approval, to the extent required, of certain actions relating to approved cogeneration contracts by Florida Power Corporation	DOCKET NO. 940797-EQ ORDER NO. PSC-95-0540-FOF-EQ ISSUED: May 2, 1995

The following Commissioners participated in the disposition of this matter:

SUSAN F. CLARK, Chairman
J. TERRY DEASON
JOE GARCIA
JULIA L. JOHNSON
DIANE K. KIESLING

NOTICE OF PROPOSED AGENCY ACTION ORDER REGARDING CERTAIN ACTIONS RELATING TO APPROVED COGENERATION CONTRACTS

CASE BACKGROUND

On July 29, 1994, Florida Power Corporation (FPC) filed a petition asking us to approve certain actions, modifications, and agreements relating to cogeneration contracts that were taken after the contracts were approved for cost-recovery. During the last decade, we have approved 23 cogeneration contracts between FPC and various cogenerators. FPC states that its petition was prompted by uncertainty over the question of whether certain actions undertaken after our approval of the contracts might require further approval. FPC filed this petition to determine what actions, modifications, and agreements would require further review by us to ensure that it could continue to obtain cost recovery of payments made to cogenerators under the contracts. We considered FPC's petition at our April 18, 1995 Agenda Conference. Our decision on the issues presented is set out below.

DECISION

A negotiated cogeneration contract is a long-term, comprehensive agreement that attempts to address all circumstances that may arise during the life of the contract. It is nevertheless reasonable to expect that situations will arise that require the parties to interpret or adjust the agreement to fit changing circumstances. We believe that a utility should have flexibility to work with qualifying facility (QF) developers when contract questions arise. We also believe, however, that we have the responsibility to ensure that the adjustments made are reasonable and prudent, because the utility's ratepayers are paying the bills for these contracts. As we will explain below, we have decided that routine changes to cogeneration contracts, or changes explicitly contemplated in the original contract, do not require our further review. So that our staff will have current information on the status of all cogeneration contracts, we will require FPC to notify the staff when these actions occur, but we will not require further formal review and approval by the Commission. When the changes are material, however, when they may affect the continuing cost-effectiveness to the ratepayers, the viability of the project, the primary fuel source of the QF facility, the utility's capacity import capability into the state due to a change in location of the facility, or the reliability of the electric grid, we will require further formal review and approval.

Contract Actions That Do Not Require Further Commission Approval

Changes to the following cogeneration contracts do not require further Commission approval: Seminole Fertilizer Corp., NRG Recovery Group, Orlando Cogen Limited, Panda-Kathleen, Pasco Cogen Limited, and U.S. Agri-Chemicals Corporation. The actions, agreements, or modifications to these contracts are either expressly permitted in the contract, or routine in the administration of the contract, with no material effect on FPC's ratepayers. No further approval is necessary.

Seminole Fertilizer Corp.

Assignment: Contract expressly authorizes QF to assign contract obligations, benefits and duties, with FPC's consent. Contract assigned to Cargill Fertilizer with FPC's consent.

Curtailment: Informal verbal agreement to reduce output as much as possible during off-peak hours.

Routine Contract Administration and Performance: Change of address for payments to Cargill Fertilizer.

NRG Recovery Group

Assignment: Contract expressly authorizes QF to assign contract obligations, benefits and duties, with FPC's consent. Contract assigned to Ogden Martin System, National Westminister Bank PLC, and Southeast Bank with FPC's consent.

One-Time Change In Committed Capacity: Contract expressly authorizes an unlimited one-time change in committed capacity. Committed capacity increased from 10.25 to 12.75 MW.

Orlando Cogen Limited

Assignment: Contract expressly authorizes QF to assign contract obligations, benefits and duties, with FPC's consent. Contract assigned to the Sumitomo Bank, Ltd., with FPC's consent.

Regulatory Delay: FPC authorized 37 day extension of the construction commencement date, and the commercial in-service date pursuant to the cogeneration contract clause providing for regulatory delays.

Clarification: Agreement with Orlando Cogen Limited and Reedy Creek regarding dispatch rights.

Panda-Kathleen

Waiver of Early In-Service Date: FPC agreed to the QF's request to waive the contractual "early in-service date" option from 1995 to 1997. This corresponds with the original 1997 in-service date of FPC's planned capacity addition identified as the avoided unit. Panda will receive normal payments rather than early in-service payments.

Pasco Cogen Limited

Assignments: Contract expressly authorizes QF to assign contract obligations, benefits and duties, with FPC's consent. Contract assigned to Prudential and Bankers Trust, with FPC's consent.

Regulatory Delay: FPC authorized 37 day extension of the construction commencement date, and the commercial in-service date pursuant to the cogeneration contract clause providing for regulatory delays.

One-Time Change in Committed Capacity: Contract expressly authorizes a one-time 10% change in committed capacity. Committed capacity increased from 102 MW to 109 MW.

Curtailment: Informal verbal agreement where Pasco Cogen will reduce output as much as possible during off peak hours.

Routine Contract Administration and Performance: Change of address for NCP Dade Power.

U.S. Agri-Chemicals Corporation (USAG)
Clarification: Contract amended to clarify USAG's Contract In-Service Date to January 1, 1997. This corresponds with the original 1997 in-service date of FPC's planned capacity addition identified as the avoided unit. USAG notified FPC that it is ready to conduct the performance test establishing the Commercial In-Service Status of the facility. Contract amended to clarify that the Written Consent and Security Guarantee sections of the Contract shall not be applicable.

Committed Capacity: USAG and FPC mutually agree that the USAG may exercise its contract option to increase or decrease the committed capacity by up to 10% at any time during calendar year 1997.

Also, the following four cogeneration contracts do not require any further approval: Bay Resource Recovery, Timber Energy Resources I, Sun Bank of Tampa Bay (LFC Jefferson), and Sun Bank of Tampa Bay (LFC Madison). These contracts either do not contain any contract actions, modifications, or agreements; or the changes to the contracts have already been reviewed and approved.

Contracts that do Require Further Commission Approval

FPC's petition states that some post-contract actions identified in its petition may not have been contemplated by our original order approving the contracts, or may be more material than a routine administrative change. These are the changes we want to review, because a contract that has been materially changed or modified is not the same contract we originally approved, and it is our responsibility to ensure that the contract costs remain prudent and appropriate for cost recovery from the utility's ratepayers. The threshold question is whether the subsequent actions, modifications, and agreements are material in nature and constitute a contract modification or change that may affect:

1) the continuing cost-effectiveness to the ratepayers; 2) the viability of the project; 3) the primary fuel source of the QF facility; 4) the utility's capacity import capability into the state due to a change in location of a QF facility; or, 5) the reliability of the electric grid.

We have identified the following contracts that have been changed in a material way not expressly addressed in the original contract that may affect one or more of the areas just mentioned. These contract changes require our further review and approval.

Royster Phosphate

Facility Relocation: FPC agreed to the QF's request to relocate the facility to the Polk Power Partners site, which also provides power for the Mulberry facility.

Curtailment: FPC entered into a formal Letter Agreement with the facility to accept a reduced output during off-peak hours.

Mulberry Energy Company

Curtailment: FPC entered into a formal Letter Agreement with the facility to accept a reduced output during off-peak hours.

Change in Primary Fuel: Mulberry changed from orimulsion, its original fuel, to natural gas.

CFR BIO-GEN (Orange)

Curtailment: FPC entered into a formal Letter Agreement with the facility to accept a reduced output during off-peak hours.

Back-Up Fuel Installation: Facility agreed to install back-up fuel prior to November 1998. If acquisition and installation costs exceed $1.3 million, FPC has the option to pay the difference, or relieve CFR of the obligation to install back-up fuel.

Dade County

Curtailment: FPC reached a Settlement Agreement with the facility regarding fluctuations in output that included a formal agreement to reduce output during off-peak hours.

General Peat Resources L.P.

Curtailment: FPC entered into a formal Letter Agreement with the facility to accept a reduced output during off-peak hours.

Change in Primary Fuel: General Peat changed from peat, its original fuel, to natural gas.

Ecopeat Company

Facility Relocation: FPC agreed to allow the facility to serve the capacity requirement for the three General Peat contracts, the Timber Energy Resources contract, and the Ecopeat Avon Park contract from the 218 MW Tiger Bay Facility.

Curtailment: FPC entered into a formal Letter Agreement with the facility to accept a reduced output during off-peak hours concurrent with negotiations for the facility relocation.

Change in Primary Fuel: Ecopeat changed from peat, or other hydrocarbon fuel to natural gas.

Back-Up Fuel Installation: Tiger Bay agrees to install back-up fuel, while FPC agreed to adjust the lease payments at Avon Park to assist Tiger Bay with their cash flow. If the cost of acquisition and installation exceeds $2.6 million, FPC has the option of either paying the difference or having Tiger Bay pay FPC $2.2 million in lieu of requiring the installation.

Timber Energy Resources II

Facility Relocation: Timber Energy signed two standard offer contracts. The July 1989 standard offer contract for 6 MW was assigned to Tiger Bay. FPC agrees that Tiger Bay will provide power from its 218 MW gas fired facility, in leu of Timber Energy's wood waste facility. Timber Energy continues to provide 12.7 MW of capacity pursuant to the December 1984 standard offer contract.

Curtailment: FPC entered into a formal Letter Agreement with the facility to accept a reduced output during off-peak hours concurrent with negotiations for the facility relocation of the second standard offer contract.

Change in Primary Fuel: Timber Energy II changed from wood waste for the July 1989 standard offer contract, to natural gas.

El Dorado Energy (Auburndale)
Curtailment: FPC entered into a formal Letter Agreement with the facility to reduce output during off-peak hours.

Lake Cogen Limited
Curtailment: FPC entered into a formal written agreement whereby Lake Cogen will reduce its output during all off-peak hours.

Pasco County
Curtailment: FPC entered into a Letter of Understanding with the facility to reduce output during their Spring and Fall scheduled maintenance outages.

Pinellas County (Central Facility)
Curtailment: FPC entered into a Letter of Understanding with the facility to reduce output during periods of low electric energy load.

Pinellas County (North Facility)
Extension of In-Service Date: Original contract agreement specified a January 1, 1995 in-service date which was not achieved by facility. The contract was amended on October 2, 1990 granting a one year extension of time to January 1, 1996, with capacity payments based on FPC's current avoided costs commensurate with the facility's in-service date. This contract will come before us for review and approval of the cost-effectiveness if and when entered into by the parties.

Ridge Generating Station
Curtailment: FPC entered into a Letter of Understanding with the facility to reduce output during off-peak hours.

Further Approval Of Contract Actions, Modifications, And Agreements

FPC provided a present worth revenue requirement (PWRR) analysis for each modified or changed contract that compared the current capacity and energy payments to the original contract costs. We approve the material changes made to all of the contracts mentioned above. The changes convey benefits to FPC's ratepayers in the form of lower costs or improved system reliability and import capability.

The majority of the reduced costs comes from the formal curtailment agreements that FPC negotiated with the QFs. Reduced energy deliveries during minimum load periods can lower FPC's costs for purchased power. The formal curtailment agreements provide FPC flexibility in meeting minimum load conditions, usually occurring between 12:00 a.m. to 6:00 a.m., and they provide for increased system reliability that is beneficial to the ratepayers.

Six contracts have changed their primary fuel source from the original proposal. The Mulberry Energy, General Peat, and Ecopeat contracts have been built to burn natural gas instead of orimulsion and peat. The Timber Energy II contract and both Sun Bank of Tampa Bay contracts changed their primary fuel source from wood waste to natural gas when the contracts were assigned to other facilities. Changes in primary fuel sources would not usually affect the cost-effectiveness of a contract, but they could affect the viability of a cogeneration facility. We are also mindful of our responsibility under the Florida Energy Efficiency Conservation Act (FEECA) to encourage the use of renewable fuels. For these reasons, we need to review changes in fuel sources. In this case we find that the changes do not adversely affect the viability of the six contracts.

We note that the utilities' current avoided costs are lower than the avoided costs contained in these cogeneration contracts. When modifications to the contracts are sought, we believe it is a prudent course of action for a utility to negotiate price and other concessions that will benefit its ratepayers through lower costs or improved system reliability and import capability. Our review of the modifications to the cogeneration contracts we have described above demonstrates that those modifications do convey a benefit to FPC's ratepayers in the form of lower payments or improved system reliability and import capability. We, therefore, approve the changes for cost recovery purposes.

Based on the foregoing, it is

ORDERED that Florida Power Corporation need not seek further formal approval for changes to the following cogeneration contracts: Seminole Fertilizer Corp., NRG Recovery Group, Orlando Cogen Limited, Panda-Kathleen, Pasco Cogen Limited, U.S. Agri-chemicals Corporation, Bay Resource Recovery, Timber Energy Resources I, Sun Bank of Tampa Bay (LFC Jefferson), and Sun Bank of Tampa Bay (LFC Madison). The changes are either expressly contemplated by the terms of the original contracts or they are routine administrative changes. It is further

ORDERED that Florida Power Corporation shall notify the Commission staff of all contract changes that do not require further formal Commission approval. It is further

ORDERED that changes to the following cogeneration contracts do require further Commission review and approval: Royster Phosphate, Mulberry Energy Company, CFR BIOGEN, Dade County, General Peat Resources L.P., Ecopeat Company, Timber Energy Resources II, El Dorado Energy, Lake Cogen Limited, Pasco County, Pinellas County, Pinellas County North Facility, and Ridge Generating Station. It is further

ORDERED that we approve the changes to the following cogeneration contracts: Royster Phosphate, Mulberry Energy Company, CFR BIO-GEN, Dade County, General Peat Resources L.P., Ecopeat Company, Timber Energy Resources II, El Dorado Energy, Lade Cogen Limited, Pasco County, Pinellas County, Pinellas County North Facility, and Ridge Generating Station. It is further

ORDERED that the issues presented in this case and the particular modifications to individual contracts are separable. A protest of one proposed action will not delay the other actions from becoming final. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective unless an appropriate petition, in the form provided by Rule 25-22.036, Florida Administrative Code, is received by the Director, Division of Records and Reporting, 101 East Gaines Street, Tallahassee, Florida 32399-0870, by the close of business on the date set forth in the "Notice of Further Proceedings or Judicial Review" attached hereto. It is further

ORDERED that in the event this Order becomes final, this Docket should be closed.

By ORDER of the Florida Public Service Commission, this 2nd day of May, 1995.

BLANCA S. BAYÓ, Director
Division of Records and Reporting

by: /s/ Kay Flynn
Chief, Bureau of Records

This is a facsimile copy. A signed copy of the order may be obtained by calling 1-904-488-8371.

(S E A L)
MCB/LW

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.59(4), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

The action proposed herein is preliminary in nature and will not become effective or final, except as provided by Rule 25-22.029, Florida Administrative Code. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, as provided by Rule 25-22.029(4), Florida Administrative Code, in the form provided by Rule 25-22.036(7)(a) and (f), Florida Administrative Code. This petition must be received by the Director, Division of Records and Reporting, 101 East Gaines Street, Tallahassee, Florida 32399-0870, by the close of business on May 23, 1995.

In the absence of such a petition, this order shall become effective on the day subsequent to the above date as provided by Rule 25-22.029(6), Florida Administrative Code.

Any objection or protest filed in this docket before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

If this order becomes final and effective on the date described above, any party substantially affected may request judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or by the First District Court of Appeal in the case of a water or wastewater utility by filing a notice of appeal with the Director, Division of Records and Reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days of the effective date of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

11

PANDA-KATHLEEN L.P.
A Panda Company

July 27, 1994

Mr. David Gammon, P.E.
Senior Cogeneration Engineer
Florida Power Corporation
3201 34th Street South
St. Petersburg, FL 33711

Re: Standard Offer Contract For The Purchase Of Firm Capacity And Energy From A Qualifying Facility Less Than 75 MW Or A Solid Waste Facility Between Panda-Kathleen, L.P. and Florida Power Corporation

Dear David:

As we discussed in our meeting on June 22, 1994, Panda-Kathleen, L.P. is permitting two equipment configurations, a GE Frame 7EA and an ABB 11 N for the Lakeland cogeneration facility. These two gas turbines are the most environmentally attractive and technically feasible for supplying FPC 74.9 MW of capacity at all times, under all operating and site conditions, as we are obligated to do. The net output of the selected configuration may reach 115 MW under certain operating and site conditions. FPC will not be obligated to pay capacity payments above the committed capacity of 74.9 MW.

The referenced contract provides for payment of as-available energy prices at times when the avoided unit would not have otherwise run. When the avoided unit would have run, FPC agrees that Panda-Kathleen L.P. will be paid the "avoided unit rate" under the contract for all energy delivered to FPC above 74.9 MW during times when the "avoided unit" would have been dispatched.

Please confirm that the foregoing accurately reflects your understanding of the above referenced contract by signing in the space provided below and returning a signed counterpart. In order that Panda-Kathleen, L.P. maintain its project development schedule, I would very much appreciate your prompt response. Panda-Kathleen, L.P. has no objection to submitting this letter to the PSC if it is deemed necessary by FPC.

4100 Spring Valley, Suite 1001 · Dallas, Texas · 75244 · 214/980-7159 · Fax 980-6815

Sincerely,

Ted Hollon

Ted Hollon
Vice President
Project Management and Construction

cc: Jim Fama

Accepted and Agreed to as of ________, 1994

FLORIDA POWER CORPORATION

By:______________________________

Title:______________________________

12

1ST CASE of Level 1 printed in FULL format.

In re: Petition of Tampa Electric Company for Declaratory Statement Regarding Conserv Cogeneration Agreement

DOCKET NO. 840438-EI; ORDER NO. **14207**

Florida Public Service Commission

1985 Fla. PUC LEXIS 825; 85 FPSC 228

March 21, 1985

PANEL:
[*1]

The following Commissioners participated in the disposition of this matter: CHAIRMAN JOHN R. MARKS, III, COMMISSIONER GERALD L. GUNTER, COMMISSIONER JOSEPH P. CRESSE

OPINION:
ORDER GRANTING IN PART AND DENYING IN PART REQUEST FOR A DECLARATORY STATEMENT

BY THE COMMISSION:

In July 1981 Tampa Electric Company (hereinafter TECO) and Conserv, Inc. (a qualifying facility or QF) signed a Cogeneration Agreement that was subsequently approved by this Commission (Docket No. 820165, Order No. 11404). At the time the contract was made and at the time the Commission approved it, the Commission's cogeneration rules simply provided that any QF with a 70% equivalent availability factor was entitled to negotiate a capacity payment with a regulated utility. The Commission's present rules on cogeneration did not become effective until September 1983.

The main features of the TECO - Conserv contract (hereinafter referred to as the Agreement) are as follows:

1. Conserv must provide 13 MW of power to TECO at a 70% capacity factor each month. For energy payments Conserv receives TECO's avoided marginal fuel costs less 3%. For capacity payments Conserv receives TECO's Schedule B (embedded [*2] fossil steam production cost) rate. In 1982 this was about $3 per KW per month; in 1985 it is projected to be $4.17 per KW per month.

2. If Conserv fails to produce any power for 6 months or doesn't achieve a 70% annual capacity factor, it is not eligible for capacity payments for the succeeding 12 months. However there is no requirement that capacity payments be repaid in the event the contract is not fulfilled.

3. The contract has an initial term through 1992. Thereafter it is automatically renewed for 5 year periods unless either party gives 5 years notice of termination. The initial contract term cannot be terminated by notice.

4. Conserv is billed on a simultaneous purchase and sale basis.

The payment methodologies in this contract are similar to those contained in our present cogeneration rules. Marginal fuel costs are calculated in the same way and Sch. B capacity payments are one option that may be selected by a Qualifying Facility. However the present rules would have required Conserv to agree to provide capacity for at least 10 years after 1992. Capacity payments would not have been available before 1985 and Conserv would have been required to provide security [*3] for the early capacity payments (before 1992) it did receve. Thus, Conserv has some benefits under the Agreement not available under the Standard Offer prescribed in our Rules.

Throughout the rulemaking proceeding Conserv indicated that it did not want the revised rules to affect its contract in any way. However in November 1984 Conserv requested renegotiation from TECO of the Agreement based on its belief that the Commission's adoption of the present rules triggered Conserv's right to renegotiate under the Agreement. The renegotiation clause in the Agreement is as follows:

24. Should the legislative standards or requirements governing the proper level of energy or capacity credit payments by electric utilities to qualifying facilities, or the rules or order of any regulatory body implementing or interpreting such standards or requirements, be modified or deleted, or judicially declared invalid, then either party to this Agreement thereafter may require renegotiation of any term or provision of this Agreement affecting the level of such payment to the extent the same is affected by such modification, deletion or judicial declaration. In addition, should any term or [*4] provision of this Agreement be found unjust or unreasonable by any regulatory body having jurisdiction over TECO or the substance of the Agreement, the parties agree to immediately renegotiate such term or provision of the Agreement. This provision will apply only to decisions of legislative, regulatory or judicial bodies having jurisdiction over either of the two (2) parties of this Agreement.

From the pleadings filed in this docket it is clear that, while Conserv has several points it wishes to renegotiate, its' chief objective is to switch from a simultaneous purchase and sale billing method to a net bill method. Under the Agreement it apparently has no right to switch; under the present rule a QF can switch once a year unless the change would contravene "any other previously agreed upon contractual provision between the QF and the utility." (Rule 25-17.82(3)(f), Florida Administrative Code). Thus the whole controversy boils down to whether this "modification" of the rule " affects the level of . . . payment" to Conserv so as to confer on Conserv the right to renegotiate.

Following an exchange of letters wherein Conserv requested and TECO declined to renegotiate, TECO filed [*5] a Petition for Declaratory Statement in December 1984. As originally filed TECO asked the Commission to answer the following questions:

1. Did the Commission intend for its adoption of revised Rules 25-17.80 through 25-17.89 relating to cogeneration or the subsequent implementation of those revised rules in Docket No. 830377-EU to affect or require any modification or renegotiation of the Conserv-Tampa Electric Cogeneration Agreement which was entered into prior to the effective date of such rule revisions and implementation?

2. Does the Commission construe paragraph 24 of the July 15, 1981 Cogeneration Agreement between Conserv and Tampa Electric (heretofore approved by the Commission in Docket No. 820165-EU) to require renegotiation of those aspects of the Cogeneration Agreement in light of the Commission's subsequent revision and implementation of its cogeneration rules?

TECO subsequently "supplemented" its Petition by revising the questions it wished the Commission to answer as follows:

(a) Do revised Rules 25-17.80 - 25-17.89 relating to cogeneration adopted in Docket No. 820406-EU, or the subsequent implementation of those revised rules in Docket No. 830377-EU, [*6] require the level of energy or capacity payments required under the Cogeneration Agreement between Tampa Electric and Conserv to be modified?

(b) In revising said rules, did the Commission modify, delete or declare invalid any provision of its administrative rules governing the proper level of energy or capacity credit payment required under the Cogeneration Agreement between Tampa Electric and Conserv?

(c) In revising said rules, did the Commission find any term or provision of the Conserv/Tampa Electric Agreement to be unjust or unreasonable?

(d) Do revised Rules 25-17.80 - 25-17.89 relating to cogeneration adopted in Docket No. 820406-EU, or the subsequent implementing of the revised rules in Docket No. 830377-EU, apply to cogeneration agreements entered into prior to the effective date of said rules?

(e) Do revised Rules 25-17.80 - 25-17.89 relating to cogeneration adopted in Docket No. 820406-EU, or the subsequent implementation of the revised rules in Docket No. 830377-EU, require a modification to the level of energy or capacity credit payments paid by a utility under cogeneration agreements entered into prior to the effective date of such rules?

Conserv filed a response [*7] to TECO's original petition wherein it alleged that the Commission lacked jurisdiction to entertain TECO's petition on three grounds. First Conserv claimed that TECO was requesting the Commission to interpret the Agreement, a task that was within the exclusive jurisdiction of the civil courts. Second, Conserv alleged that declaratory relief was improper since TECO had not sought gjidance as to how a rule or statute applied to it in its set of circumstances only. Third, Conserv alleged that it was not subject to the Commission's jurisdiction because it was not a public utility and to be forced to submit to the Commission's jurisdiction to protect its contractual rights would violate Conserv's constitutional right to due process of law. Conserv noted that its response was a Special Appearance and requested Oral Argument on the jurisdictional issues.

Oral Argument was scheduled for January 28, 1985.

Meanwhile Conserv filed suit in Polk County Circuit Court against TECO. In its lawsuit Conserv is seeking the following relief:

1. An injunction prohibiting TECO from going forward with its Petition for

Declaratory Statement at the Commission;

2. A declaratory judgment [*8] establishing Conserv's right to renegotiate, to change billing methods and damages for TECO's failure to renegotiate;

3. Recision of the contract for breach thereof, the breach consisting of TECO's failure to renegotiate, and damages for the same;

4. Recision of the contract for fraud in the inducement, the fraud consisting of TECO's knowingly providing false estimates of its future marginal fuel costs, and falsely advising Conserv that it would be to the latter's advantage to be billed on a Simultaneous Purchase and Sale (SPS) basis, and to grant damages for the loss suffered by Conserv as a result of being billed on a SPS basis.

On January 14, 1985 the Polk County Circuit Court granted Conserv's request for injunctive relief and temporarily enjoined TECO from proceeding with its Petition pending before the Commission. TECO has appealed the circuit court's decision to grant the injunction. Thus, as the case now stands, the Commission has before it a Petition for Declaratory Statement but the moving party has been enjoined from further participation and the responding party has from the outset denied that the Commission has any jurisdiction over the matter. The Oral Argument [*9] scheduled for January 28, 1985 was cancelled.

In response to Conserv's jurisdictional arguments, we agree that the civil courts have exclusive jurisdiction to construe the Agreement and award damages if any are merited. Thus we grant in part Conserv's request that we decline to entertain TECO's request on jurisdictional grounds. Specifically, we will not answer this question propounded by TECO:

Does the Commission construe paragraph 24 of the July 15, 1981 Cogeneration Agreement between Conserv and Tampa Electric (heretofore approved by the Commission in Docket No. 820165-EU) to require renegotiation of those aspects of the Cogeneration Agreement in light of the Commission's subsequent revision and implementation of its cogeneration rules?

However, the Commission certainly has jurisdiction to construe its own Rules at the request of a regulated utility to which the rules apply. Conserv's argument that TECO's request is improper as it does not seek guidance as to how the rule applies to it in its set of circumstances only is patently without merit. By its petition, TECO has asked the Commission how its rules relate to or affect a particular contract. A more unique set of circumstances [*10] is difficult to imagine.

Conserv's final argument that it is not subject to the Commission's jurisdiction because it is not a public utility and to force it to submit to the Commission's jurisdiction to protect its contractual rights would violate its constitutional rights is also without merit. First of all, the Commission, by the action taken in this docket, will not adjudicate Conserv's contractual rights. The Commission will interpret its rules. Insofar as the Commission's rules affect Conserv's rights, it is by force of contract, not by force of the rule itself, that they do so. Secondly, Conserv would have the Commission decline jurisdiction because Conserv is not a regulated utility subject to the Commission's jurisdiction. This ignores the fact that TECO, the party seeking relief, has requested the Commission to take action admittedly within the Commission's jurisdiction. Would Conserv have the Commission decline to exercise jurisdiction over a request by TECO to increase its rates simply because the Commission's actions may affect nonregulated entities? Finally we note in passing that when TECO originally brought this contract to the Commission for approval [*11] in 1982, Conserv intervened and through the testimony of its witness urged the Commission to approve the contract.

Thus we finally arrive at the heart of the matter: Did the adoption of Rule 25-17.82(3)(f), Florida Administrative Code, by itself, in any way affect the level of payments specified in any cogeneration contract in existence at the time the rule was adopted? The answer to this question is plainly no. The Rule expressly states that it will not apply where it would contravene prior contractual obligations. This language was clearly intended to preserve contractual commitments existing at the time the rule was adopted, not to serve as a basis for altering them. To hold otherwise would defeat our goal of encouraging cogeneration and would contravene the entire philosophy underpining our rules. The rules recognize that both QFs and utilities need contractual certainty. QFs need contractual certainty to secure financing, and utilities must be able to rely on contractually committed capacity in their generation expansion planning. Thus once a contract is approved by the Commission for cost recovery purposes the Commission will not thereafter, by subsequent rule changes, [*12] deprive either party of the benefit of their bargain.

In short we agree with Conserv that matters of contractual interpretation are properly left to the civil courts but we also believe that TECO has properly requested an interpretation of the Commission's rule on one aspect of our complex and comprehensive program designed to encourage cogeneration and small power production that is cost effective to the electric ratepayers of the State of Florida.

Therefore, in consideration of the above, it is

ORDERED by the Florida Public Service Commission that the petition of Tampa Electric Company for a Declaratory Statement is granted in part and denied in part as set forth herein. It is further

ORDERED that this docket be and the same is hereby closed. It is further

ORDERED that any party adversely affected by the Commission's final action in this matter is entitled to request: 1) reconsideration of the decision by filing a motion for reconsideration with the Commission Clerk within 15 days of the issuance of this order in the form prescribed by Rule 25-22.60, Florida Administrative Code, or 2) judicial review by the Florida Supreme Court by the filing of a notice of appeal with the [*13] Commission Clerk and the filing of a copy of the notice and the filing fee with the Supreme Court. This filing must be completed within 30 days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

By ORDER of the Florida Public Service Commission, this 21st day of MARCH, 1985.

13

1ST CASE of Level 1 printed in FULL format.

In Re: Petition of Polk Power Partners for a Declaratory Statement Regarding Eligibility for Standard Offer Contracts

DOCKET NO. 920556-EQ; ORDER NO. PSC-92-0683-DS-EQ

Florida Public Service Commission

1992 Fla. PUC LEXIS 1076; 92 FPSC 7:388

July 21, 1992

PANEL:
[*1]

The following Commissioners participated in the disposition of this matter: THOMAS M. BEARD, Chairman; BETTY EASLEY; J. TERRY DEASON; SUSAN F. CLARK; LUIS J. LAUREDO

OPINION:
ORDER GRANTING DECLARATORY STATEMENT IN THE NEGATIVE

BY THE COMMISSION:

BACKGROUND

By petition filed May 28, 1992, Polk Power Partners, L.P. ("Polk") has asked for a declaratory statement that Polk Power Partners may sell additional capacity from a qualifying cogeneration facility via a standard offer contract, where the project's total net generating capacity exceeds 75 megawatts (MW) and where the contemplated standard offer contract provides for committed capacity of less than 75 MW.

Though acknowledging that Rule 25-17.0832(3)(a), F.A.C. provides for standard offer contracts involving "small qualifying facilities less than 75 megawatts. ", Polk theorizes an ambiguity as to whether the 75 megawatt cap speaks to the total net generating capacity n1 of the QF, as defined at 18 C.F.R. 292.202 (g) (1990) of the FERC rules implementing PURPA, or the committed capacity which the qualifying facility has contractually committed to deliver on a firm basis to the purchasing utility. It is the latter definition [*2] alone which would be consistent with the declaratory statement petitioned for by Polk.

n1 Total net generating capacity, or "Useful power output" of a cogeneration facility means the electric or mechanical energy made available for use exclusive of any such energy used in the power production process.

DISCUSSION

We grant Polk Power Partners' Petition for Declaratory Statement, albeit in the negative.

The mere allegation at p. 8 of the Petition that

A QF with a total net generating capacity of 95 MW that sells only 70 MW to a purchasing utility is frequently referred to as a 70 MW QF

is hardly sufficient to create authentic ambiguity in this matter in view of the context in which the operable standard offer rule appears. Not only Rule 25-7.0832(3)(a), previously cited, but also Rule 25-17.0832(2) states that

Negotiated contracts shall not be evaluated against an avoided unit in a standard offer contract, thus preserving the standard offer for small qualifying facilities as described in subsection (3) [e.s.]

All of the language in both rule sections relating the 75 MW cap to the goal of preserving the standard offer for small qualifying facilities would [*3] be rendered nugatory by the declaratory statement petitioned for by Polk.

If "committed" capacity, rather than total net generating capacity were the measure by which to calculate the 75 MW cap, QF's of any size could participate in standard offer contracts, contrary to the clear intent of the rules to preserve such participation for small QF's. It is a fundamental principle of statutory construction that statutes are not to be construed in such a manner as to render them meaningless, and that principle should govern the interpretation of rules as well.

Accordingly, we decline Polk's Petition to issue the statement requested. We state instead that the 75 MW cap referenced in Rule 25-17.0832(3)(a) refers to the total net generating capacity of the QF.

In view of the above, it is

ORDERED by the Florida Public Service Commission that Polk Power Partner's Petition for Declaratory Statement is granted in the negative. It is further

ORDERED that this docket is closed.

By Order of the Florida Public Service Commission this 21st day of July, 1992.

14

As described below, we deny West Penn's petition for declaratory order. The Pennsylvania Commission, and the courts, have determined that a valid, legally binding contract exists in this case. We will not disturb that contract. However, we would encourage the parties to the contract to consider settling their differences at this stage particularly if, as may be the case, the facility has not been constructed.

I. Background
[*3]
A. Statutory and Regulatory Background

We have had occasion in several recent cases to summarize the basic components of section 210 of PURPA and our implementing regulations. n3 There are several provisions, discussed below, that are pertinent to the issues raised in this proceeding.

- - - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - - -

n3

See, e.g., New York State Electric & Gas Corp., 71 FERC P61,027 (1995) (NYSEG), slip op. at 1-3; Southern California Edison Co., 70 FERC P61,215 at 61,676-77 (1995) (Southern California Edison); Connecticut Light & Power Co., 70 FERC P61,012 at 61,023-24, reconsideration denied, 71 FERC P61,012 (1995), appeal docketed sub nom. Niagara Mohawk Power Corp. v. FERC, No. 95-1222 (D.C. Cir. Apr. 24, 1995) (Connecticut Power).

- - - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

Under PURPA and our implementing regulations, the rates at which an electric utility is required to purchase a QF's capacity and energy may not exceed the utility's avoided costs. n4 Our regulations expressly provide, however, that if the QF is providing energy or capacity [*4] "pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term," the rates may be based (at the QF's election) on the purchasing utility's "avoided costs calculated at the time the obligation is incurred." n5 Moreover, the regulations further stipulate that rates calculated as of such time will meet the statutory and regulatory standards even if they "differ from avoided costs at the time of delivery." n6 Finally, for most QFs, section 210(e) of PURPA and the Commission's regulations provide for exemptions from regulation under the Federal Power Act (FPA), the Public Utility Holding Company Act and state law--including exemptions from utility-type rate regulation under the FPA and under state law. n7

- - - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - - -

n4

See 16 U.S.C. § 824a-3(b) (1988); 18 C.F.R. § 292.304(a)(2) (1994).

n5

18 C.F.R. § 292.304(d)(2) (1994).

n6

18 C.F.R. § 292.304(b)(5) (1994).

n7

16 U.S.C.A. § 824a-3(e) (West 1985 & Supp. 1995); 18 C.F.R. §§ 292.601(c), 292.602(c)(i) (1994).

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

[*5]

B. Factual Background n8

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - - -

n8

Our description of the factual background is derived primarily from the West Penn Petition, the Protest and Request for Dismissal of Washington Power, filed April 3, 1995 (Washington Power Protest), and the Protest and Motion to Dismiss of the Pennsylvania Commission, also filed April 3, 1995 (Pennsylvania Commission Protest). The relevant facts, particularly as to the extensive litigation that has preceded the filing of the West Penn Petition, are lengthy and convoluted but for the most part are not in dispute. We set forth the factual background prior to summarizing the pleadings, because we believe that acquaintance with the long-running prologue to the instant proceeding is essential to understanding the parties' positions here.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

Washington Power is building a cogeneration and small power production QF located near Burgettstown, Pennsylvania (Facility). n9 On October 15, 1987, after more than one year of negotiations, West Penn and Washington Power entered into an [*6] Electric Energy Purchase Agreement (Purchase Agreement) for sale of the capacity and energy of the Facility to West Penn. n10 The Purchase Agreement is for a 33-year term and originally contemplated that sales of capacity and energy from the Facility to West Penn would commence on October 1, 1991 (but also included provisions addressing the parties' rights and obligations in the event of later commencement dates). The rates are comprised of various components, including a capacity cost originally set at $ 0.036 per kilowatt (kW) hour, which was below West Penn's avoided costs calculated as of October 1986. n11

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - - -

n9

In North Branch Energy Partners, L.P., 42 FERC P62,240 (1988) (Cogeneration

Certification), the Commission certified the Facility as a qualifying cogeneration facility. In Washington Power Co., L.P., 69 FERC 62,119 (1994) (Small Power Production Certification), the Commission also certified the facility as a small power production facility. The Commission recently recertified the Facility as a qualifying cogeneration facility. See Washington Power Co., L.P., 70 FERC P62,168 (1995) (Cogeneration Recertification). In each case, the Commission certifications were issued pursuant to delegated authority. 18 C.F.R. § 375.308(b)(4) (1994).

Whether construction of the Facility actually has begun appears to be in dispute. Washington Power asserts in this proceeding that it has commenced construction. Washington Power Protest at 33 & n.11. Additionally, in its application for certification of the Facility as a small power production QF, Washington Power represented that construction began in July 1994. See 69 FERC at 64,296. West Penn, however, asserts that the Facility is "unbuilt" and argues that the Commission's failure to grant the relief sought by West Penn "may result in construction" of the Facility. West Penn Petition at 11. Several intervenors expressly allege that Washington Power has not yet commenced construction of the Facility. We need not and do not make any determination as to the accuracy of the competing allegations on this point.
[*7]

n10

The Purchase Agreement, which is Exhibit D to the West Penn Petition, was executed by North Branch Energy Partners, L.P., which was Washington Power's name at that time. For convenience, we will refer to the developer of the Facility as Washington Power throughout this order.

n11

While West Penn avers that only the capacity rate is at issue in this proceeding, West Penn Petition at 4, it nonetheless elsewhere appears to request from the Commission a determination that no purchase obligation of any type exists between West Penn and the Facility. See id. at 38.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

The Purchase Agreement further provides for certain "milestone" dates by which certain events in the development of the Facility were to be completed, failure to comply with which would effect a termination of the Purchase Agreement. Among the milestones is completion of construction financing for the Facility, the date for which was originally set at October 1, 1989. The conditions precedent for completion of financing include obtaining the requisite regulatory approvals, among which are the Pennsylvania Commission's [*8] acceptance of the Purchase Agreement and its approval for West Penn's passing through to its customers the rates payable to Washington Power. n12

- - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - - -

n12

See Purchase Agreement §§ 5.3(f)-(i).

- - - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

On January 5, 1988, West Penn submitted the signed Purchase Agreement to the Pennsylvania Commission for approval. The Pennsylvania Commission initially approved the Purchase Agreement as executed in an order dated July 8, 1988. The Pennsylvania Commission's first approval did not entail any modification of the Purchase Agreement, including the capacity charge and milestone dates to which West Penn and Washington Power originally agreed. Thereafter, a lengthy course of litigation ensued before the Pennsylvania Commission and the Pennsylvania courts, culminating in an unsuccessful petition for certiorari filed by West Penn with the United States Supreme Court. We will not here describe all of the subsequent decisions of the Pennsylvania Commission and the Pennsylvania courts. Instead, our description is limited to those [*9] aspects of the various orders that are pertinent to the issues raised in the West Penn Petition. n13

- -Footnotes- - - - - - - - - - - - - - - - - - -

n13

While the parties disagree as to the effect and proper interpretation of the earlier decisions, the actual orders of the Pennsylvania Commission and the Pennsylvania courts are, of course, matters of record, with most of the court decisions having been published in official reporters. In any case, copies of nearly all of the orders involving the Facility also are contained in Exhibit F to the West Penn Petition. Exhibit F is the Appendix to West Penn's petition for certiorari to the United States Supreme Court, filed in Docket No. 94-7 on July 1, 1994. The most recent order of the Pennsylvania Commission, dated December 16, 1994, is Attachment A to the Washington Power Protest.

- - - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

C. West Penn Petition

In its petition, West Penn requests that the Commission address several issues concerning an electric utility's obligations to purchase QF power, particularly regarding the appropriate point or points [*10] at which to calculate the utility's avoided costs. Specifically, West Penn asks this Commission to declare that under federal law:

(1) An electric utility may not be required to purchase capacity from a QF when, as West Penn alleges is the case here, (a) the rates exceed the utility's current avoided costs, (b) the rates are based upon stale avoided-cost data, (c) the utility no longer needs the capacity and (d) the QF is unbuilt;

(2) (a) A State regulatory authority may not modify material terms of a privatelynegotiated power purchase agreement between a utility and a QF; or (b) if the contract is so modified, the utility must be allowed to

demonstrate that the contract's purchase price exceeds the utility's avoided costs as of the time of the modification;

(3) Avoided costs must be redetermined when a QF materially changes its project or seeks certification of a new project design; and

(4) West Penn has no current purchase obligation from Washington Power's QF facility. n14

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n14 See West Penn Petition at 1-2, 37-38.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -
[*11]

West Penn argues, first, that PURPA's setting as the maximum rate for QF power "the incremental cost to the electric utility of alternative electric energy" n15 --i.e., avoided costs--means that the purchase price never can exceed the utility's current avoided costs at any time during the term of the purchase agreement. West Penn initially suggests that the Commission's regulations under PURPA, by permitting rates to be based on avoided costs to be calculated as of the time the utility incurs a legally enforceable obligation to purchase a QF's power and by explicitly recognizing that such rates are permissible even if they differ from the utility's avoided costs at the time of actual delivery of the QF's power and capacity, create an ambiguity concerning whether a QF can "lock in" long-term rates for the entire life of a contract even if such rates turn out later to exceed the utility's actual avoided costs. West Penn asserts that if such provisions of the Commission's PURPA regulations in fact permit purchase rates that exceed avoided costs on a long-term basis, those regulations "are, and always have been, in clear violation of the express terms of PURPA

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n15

16 U.S.C. § 824a-3(b) (1988).

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -
[*12]
§ 210." n16

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n16

West Penn Petition at 22.

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West Penn then suggests, however, that the Commission never intended that its regulations be so interpreted. In support, West Penn asserts that while the regulations provide that avoided costs may be calculated "prior to the beginning of [a] specified term," n17 the Commission never has suggested that the "specified term" of a purchase agreement between an electric utility and a QF might be several decades. West Penn infers that "presumably, the Commission realized that avoided costs could vary *significantly* over time, and that long-term purchase rates premised on avoided costs should be subject to correction if circumstances changed materially." n18

- -Footnotes- - - - - - - - - - - - - - - - - - - -

n17

18 C.F.R. § 292.304(d)(2) (1994).

n18

West Penn Petition at 23.

- - - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

West Penn construes our recent orders in Southern California [*13] Edison and Connecticut Power as providing additional support for its argument that the Commission should abrogate West Penn's 1987 Purchase Agreement with Washington Power because the rates *allegedly* exceed West Penn's current avoided costs. West Penn quotes, for example, our statement in Southern California Edison that "we believe it is inconsistent with our obligation under PURPA to ensure just and reasonable rates, and our goals to encourage development of competitive bulk power markets, to permit the use of PURPA to create new contracts that do not reflect market conditions for new bulk power supplies." n19 West Penn further notes the Commission's concerns, expressed in dicta in Southern California Edison, about the need for the capacity and the staleness of the data at issue in that case. West Penn adds that the Commission held in Connecticut Power that, contrary to suggestions in the preamble to our § 210 regulations, states have *no* authority under PURPA to authorize rates that exceed avoided costs. "Both opinions," West Penn concludes, "strongly suggest that the avoided cost cap must be strictly enforced." n20

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n19

Id. at 24 (quoting 70 FERC at 61,676).
[*14]

n20

West Penn Petition at 25.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

West Penn's second argument is that the Pennsylvania Commission had no authority to modify the Purchase Agreement, because it was a privately negotiated agreement between an electric utility and a QF and thus protected by our PURPA regulations from any modifications by the Pennsylvania Commission. n21 In support, West Penn quotes section 292.301(b) of this Commission's PURPA regulations:

- - - - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - - - -

n21

See id. at 26-29.

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Nothing in this subpart:

(1) Limits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this subpart; or

(2) Affects the validity of any contract entered into between a qualifying facility and an electric utility for any purchase. [n22]

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n22 18 C.F.R. § 292.301(b) (1994). The "subpart" to which the above-quoted language refers is Subpart C of the Commission's PURPA regulations. Subpart C governs arrangements between electric utilities and QFs under section 210 of PURPA, including arrangements for utilities' purchases from QFs.

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[*15]

West Penn construes section 292.301(b) of our PURPA regulations as not only authorizing utilities and QFs to make their own contractual arrangements independent of our PURPA regulations but also as precluding State regulatory authorities from ordering modifications to utilities' contracts with QFs. West Penn argues in particular that the Pennsylvania Commission violated section 292.301(b) by changing certain milestone provisions, which West Penn claims it negotiated for its protection, while enforcing a purchase price based on allegedly stale data.

Alternatively, West Penn argues, if PURPA permits a State regulatory authority to modify a privately-negotiated utility/QF contract, the purchase price must be based upon the utility's avoided costs as of the time of the modification. n23 In support, West Penn opines that until the date of the modification, the QF has no legally enforceable obligation to deliver power.

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n23

See West Penn Petition at 29-31.

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Finally, West Penn claims that, because Washington Power [*16] obtained dual certification of the Facility as a qualifying small power production facility *after* its initial certification as a qualifying cogeneration facility, the Purchase Agreement is void and West Penn has no obligation to purchase capacity from the Facility. n24 West Penn argues that Washington Power's proposed small power production facility is substantially different from the proposed cogeneration facility that the parties contemplated when they signed the Purchase Agreement in 1987 and that it neither has agreed, nor has been ordered by the Pennsylvania Commission, to purchase capacity from Washington Power's proposed, allegedly redesigned, small power production facility. West Penn urges that if and when it is required to purchase capacity from Washington Power's small power production facility, the rates must be calculated as of the date that Washington Power incurs a legally enforceable obligation to deliver the capacity. In West Penn's view, that date as of which the purchase rate must be calculated could only be some future date upon which the Pennsylvania Commission orders West Penn to purchase power from the small power production facility certified by this Commission. [*17]

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n24

See id. at 32-37. See also supra note 9 (citing Commission's QF certification orders for Facility).

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Notice of the West Penn Petition was published in the Federal Register, n25 with protests and motions to intervene originally due on or before April 3, 1995. By notice of the Commission issued on March 3, 1995, the due date for protests and interventions was extended to April 5, 1995.

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n25

60 Fed. Reg. 14,741 (1995).

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D. Response of Washington Power

Washington Power filed a motion to intervene on March 30, 1995, and followed, on April 3, 1995, with the Washington Power Protest, which contains its substantive arguments against the West Penn Petition. After summarizing what it regards as the salient aspects of the Purchase Agreement and the prior legal proceedings, Washington Power argues, first, that the West Penn Petition [*18] must be dismissed on the grounds of res judicata. Washington Power asserts that this case satisfies all of the requirements for application of the res judicata doctrine as adopted by the Commission in Greensboro Lumber Co. v. Rayle Electric Membership Corp., 40 FERC P61,283 (1987) *(Greensboro)*. Specifically, Washington Power urges, the West Penn Petition involves the same cause of action, the same parties and the same issues that were raised or that could have been raised in the prior proceedings before the Pennsylvania Commission, the Pennsylvania courts and the United States Supreme Court. Washington Power contends that West Penn, having had its arguments consistently rejected in all of the prior litigation, should not be permitted to resurrect its arguments before the Commission, thereby "being offered yet another bite at the apple." n26

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n26

Washington Power Protest at 16.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

Washington Power's second argument is that, even if res judicata did not bar the West Penn Petition, West Penn's claim that changed [*19] circumstances entitle it to avoid its obligations under *the Purchase Agreement* still provide no basis for the Commission to grant the requested relief. Washington Power's argument on this point is two-fold. First, Washington Power asserts that the Commission has no jurisdiction to invalidate the Power Agreement and its rates because under our regulations issued pursuant to section 210(e) of PURPA, QFs are exempt from utility-type regulation, including such regulation under both state law and the FPA. Thus, Washington Power concludes, once the State regulatory authority has determined that the contract rates are consistent with the avoided cost cap, neither the State authority nor this Commission has authority to revisit those rates on the basis of allegedly changed circumstances. n27

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n27

In support, Washington Power cites, among other cases, Freehold Cogeneration Association, L.P. v. Board of Regulatory Commissioners, 44 F.3d 1178 (3d Cir. 1995) (Freehold).

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Washington Power further argues that the Commission [*20] already has addressed and rejected the claim that changed circumstances justify revising agreed-upon avoided cost rates. Washington Power, quoting extensively from the preamble to the Commission's regulations implementing section 210 of PURPA, urges that in enacting those regulations, the Commission expressly recognized that basing rates in long-term contracts on avoided cost estimates made at the time of contracting will result in some contracts that will have overestimated avoided costs and some that will have underestimated. Moreover, Washington Power asserts, the discussion in the preamble also demonstrates that the Commission considered and expressly rejected the changed circumstances argument now made by West Penn and concluded instead that QFs, having obtained the certainty of long-term rates, should not be deprived of the benefits of that certainty as a result of changed circumstances.

Washington Power next argues that to the extent that the West Penn Petition claims that sections 292.304(b)(5) and 292.304(d)(2)(ii) of the Commission's PURPA regulations violate section 210 of PURPA by permitting rates in excess of current avoided costs, such challenge to the regulations is [*21] untimely and jurisdictionally defective. Washington Power asserts that the regulations became final and nonappealable in 1980 and that West Penn cannot evade that bar by attempting to characterize its challenge as addressing the implementation of the regulations rather than the regulations themselves.

Fourth, Washington Power disputes that either Connecticut Power or Southern California Edison provides any support for West Penn's claims. Washington Power distinguishes Connecticut Power as involving a challenge under PURPA, not resolved by the courts in prior litigation, to a state law that required rates acknowledged to be above avoided costs. Here, Washington Power argues, the challenged rates were found by the Pennsylvania Commission to be below avoided cost at the time of a legally enforceable obligation, and that determination, as well as the revised milestone dates, was addressed and upheld by the courts.

Washington Power also argues that this case differs from Southern California Edison, because West Penn's claim, raised only after the Power Agreement was signed, that current avoided costs are lower because it no longer needs the Facility's capacity, has been [*22] fully litigated through the courts and is no longer pending. Washington Power adds that the Commission's dicta in Southern California Edison expressing concern with the staleness of the data used in that case to determine avoided costs does not support West Penn's position, because the data used to calculate the Purchase Agreement capacity rate were not stale as of the time the contract was signed.

Finally, Washington Power argues that the Facility's dual QF certification as both a qualifying small power production and a qualifying cogeneration facility is irrelevant to the issue of the avoided cost rates under the Purchase Agreement. Washington Power explains that it obtained additional certification as a qualifying small power production facility because the Facility intends to use a waste fuel as its primary energy source.

E. Response of Pennsylvania Commission

Having filed a notice of intervention and reservation of the right to protest on March 29, 1995, the Pennsylvania Commission filed its protest and motion to dismiss on April 3, 1995. In its protest and motion to dismiss, the Pennsylvania Commission details the prior litigation over the Purchase Agreement and [*23] asserts that the issues raised by the West Penn Petition have been fully adjudicated before the Pennsylvania Commission, whose resolution of those issues has been left undisturbed by both the Supreme Court of Pennsylvania and the United States Supreme Court. The Pennsylvania Commission contends, therefore, that the doctrine of res judicata (claim preclusion) bars West Penn from relitigating the issues before this Commission.

Characterizing the West Penn Petition as in essence asserting that an alleged change in capacity needs since the time that a legally enforceable obligation was incurred requires revisiting the Purchase Agreement, the Pennsylvania Commission observes that this argument has been raised by West Penn in prior proceedings and has been repeatedly rejected. The Pennsylvania Commission asserts that West Penn now seeks this Commission's assistance in the rescission of prior-adjudicated Pennsylvania Commission orders that have been upheld by all appellate courts. The Pennsylvania Commission further points out that West Penn at the same time also not only now has asked the Pennsylvania Commission to rescind its own orders, notwithstanding the refusal of the United States [*24] Supreme Court to overturn them, but continues to challenge before the Pennsylvania courts the state commission's refusal to permit West Penn to relitigate its previously-rejected claims.

The Pennsylvania Commission also argues that under PURPA and our regulations, the issues raised by West Penn are appropriately determined not by this Commission but at the state level. The Pennsylvania Commission states that in the amici brief filed in September 1994 in response to West Penn's certiorari petition to the United States Supreme Court in a companion case to that involving the Facility, this Commission agreed that the Pennsylvania Commission's actions with respect to the Power Agreement were not inconsistent with PURPA and, in particular, that it was reasonable for the Pennsylvania Commission to calculate the capacity rate as of the date of contract execution. The Pennsylvania Commission asserts that those determinations, now being challenged by West Penn yet again in this proceeding, remain reasonable and within the authority that PURPA delegates to the States. The Pennsylvania Commission urges this Commission to reject West Penn's attempt to have the Commission micromanage [*25] the details of PURPA contract administration, requiring the Commission to delve into fact-based issues as to such matters as avoided costs and capacity needs for specific facilities, when our own regulations expressly delegate such matters to the States.

F. Other Responses

On March 29, 1995, Armco Advanced Materials Company, a Business Unit of Armco, Inc. (Armco), a retail customer of West Penn, filed a motion to intervene in support of the West Penn Petition. Armco argues that if West Penn is required to purchase capacity from the Facility--on which, according to Armco, no construction has begun n28 --rates to retail customers would increase substantially and result in substantial economic harm to Armco, which currently consumes approximately five percent of all energy sold by West Penn at retail in Pennsylvania. Armco agrees with West Penn that the Purchase Agreement rates were based on a now outdated capacity expansion forecast from 1986/1987 and that West Penn now does not need the Facility's capacity. Armco further argues that the Purchase Agreement will be a stranded cost that will deter any state or federal effort to open up to competition the West Penn system and thus [*26] is not in the public interest.

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n28

But see supra note 9 (describing parties' disagreement as to whether construction has begun).

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On March 31, 1995, the West Penn Power Industrial Intervenors (Industrials) filed a motion to intervene in support of the West Penn Petition. Industrials identifies itself as an ad hoc association of energy-intensive industrial customers of West Penn. n29 Industrials agrees with West Penn's claims that the Purchase Agreement's capacity charge of 5.71 cents /kWh exceeds West Penn's current avoided costs and will cause West Penn's ratepayers to incur excess costs of $ 962 million over the life of the contract. Industrials further agrees with West Penn that such rate increases would damage the competitive positions of West Penn and its industrial customers.

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n29

Industrials states that its membership for purposes of this proceeding currently consists of Anchor Glass Container Corporation, Corning Incorporated, Ervin Industries, Latrobe Steel Company, Lukens Steel Company, MG Industries, National Roll Company, Owens-Illinois, Inc. and Washington Steel Corporation.

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[*27]

On April 3, 1995, Allegheny Ludlum Corporation (Allegheny Ludlum) filed a motion to intervene in support of the West Penn Petition. Allegheny Ludlum states that it is a manufacturer of stainless steel and other specialty steel products and is one of West Penn's two largest retail customers. Like Armco and Industrials, Allegheny Ludlum agrees with West Penn that the rates under the Purchase Agreement exceed current avoided costs and that West Penn currently has no need for additional capacity. Allegheny Ludlum contends that the Facility has neither been built nor financed and that it is unfair to West Penn's ratepayers to force them to bear the costs of an unneeded power plant so that Washington Power and its investors can reap what Allegheny Ludlum characterizes as windfall profits. Allegheny Ludlum further suggests that forcing the West Penn ratepayers to incur the costs of the Facility will "severely diminish the ability of industrial companies to compete in the marketplace, and . . . effectively threaten the jobs of thousands of residents in southwestern Pennsylvania." n30

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n30

Allegheny Ludlum Intervention at 7.

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[*28]

On April 3, 1995, the Cogeneration Association of California (Cogeneration Association) filed a motion to intervene and protest in opposition to the West Penn Petition. Cogeneration Association states that it is an ad hoc association representing the interests of its member companies in several cogeneration companies. n31 It explains that such cogeneration companies are primarily engaged in electrical generation and the sale of steam for enhanced oil recovery operations in California and that they sell electricity pursuant to long-term contracts. Cogeneration Association argues that granting the relief sought by West Penn would undermine both the sanctity of contracts, relied upon by QFs to obtain financing, and years of Commission precedent, upon which QFs also have relied, concerning the validity and enforceability of QF contracts that have been approved by State regulatory authorities. Cogeneration Association argues that neither PURPA nor the Commission's regulations permit the undoing of valid and binding contracts because of changing market conditions.

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n31

Cogeneration Association states that the constituent cogeneration companies include Sycamore, Kern River, Midway-Sunset, Mid-Set, Coalinga, Sargent Canyon and Salinas River Cogeneration Companies.

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[*29]

Also on April 3, 1995, National Independent Energy Producers (NIEP) filed a motion to intervene, protest and answer in opposition to the West Penn Petition. NIEP states that it is an association of a variety of publicly-traded and privately-held corporations that develop and operate cogeneration and other wholesale generation facilities that use a broad spectrum of fossil-fueled and renewable technologies, as well as power marketers. NIEP argues that the West Penn Petition presents the Commission with one primary question that is similar to the main issue in NYSEG: can and should the Commission terminate or modify the Purchase Agreement, after it has been voluntarily executed by West Penn and approved by the Pennsylvania Commission, simply because the contract differs from West Penn's current estimates of avoided costs and its current forecasts of demand on its system? NIEP urges the Commission to reject West Penn's proposal, because accepting it would be inconsistent with PURPA and the Commission's regulations, would destroy the certainty of income stream upon which QF financing is based and would chill development of new generation projects and thereby destroy competition in [*30] the wholesale generation market.

NIEP argues, first, that the Purchase Agreement is consistent with PURPA and the Commission's implementing regulations and that PURPA prevents modifications of the Purchase Agreement after it has received approval by the Pennsylvania Commission. In enacting PURPA, NIEP asserts, Congress recognized the difficulty that QFs would have obtaining financing and gave the Commission the authority and responsibility to implement regulations that would further the development of QFs. The Commission, in turn, recognized that it would be virtually impossible to finance QFs without assurances of a steady stream of revenue to cover their fixed costs and accordingly provided in its regulations that QFs could choose to sell power to an electric utility at a pre-determined fixed rate that represents an estimation of the utility's avoided cost. Moreover, the Commission expressly acknowledged that the rates under the permissible fixed-rate QF contracts may exceed current market prices. NIEP argues that West Penn's interpretation of PURPA and the Commission's regulations essentially would eliminate the fixed-rate option now provided to QFs in the regulations.

NIEP's [*31] argument that PURPA precludes attempts to modify power purchase contracts after the State regulatory authority has approved them is essentially the same as Washington Power's argument on this point. n32 NIEP also cites in support a recent temporary restraining order issued by the United States District Court for the Western District of New York in Kamine/Besicorp v. Rochester Gas & Electric, No. 6:95-cv-06045 (March 20, 1995) (Kamine), in which the court prevented the utility from suspending payment under a power purchase contract with a QF where the utility claimed that the rates exceeded the utility's avoided cost. NIEP states that the Kamine court followed Freehold in determining that a utility was precluded from seeking to modify the rates in its power purchase agreement. NIEP additionally argues that West Penn's request to have the Commission evaluate the rates under the Purchase Agreement (as well as West Penn's present need for the Facility's output) is precisely the kind of regulatory review that is precluded by QFs' exemption from regulation under the FPA that section 210(e) of PURPA provides. NIEP concludes that the only jurisdiction that the Commission has [*32] over QF contracts is to ensure that states abide by the Commission's regulations implementing PURPA.

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n32

See supra text accompanying note 27.

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

NIEP's second argument is that granting West Penn's requested relief would be bad public policy and would harm competition in the generation market. NIEP contends that adopting West Penn's position not only would vitiate QFs' ability to obtain financing through the use of fixed-rate contracts and thus inhibit the construction of new generating facilities but also would undermine the pervasive use of long-term contracts throughout the industry. The result, NIEP argues, would be to reduce competition in the generation markets and increase the cost of generation to consumers.

Fulton Cogeneration Associates (Fulton) filed a motion to intervene on April 3, 1995. Fulton states that it is a New York limited partnership formed for the purpose of constructing a cogeneration facility in Fulton, New York. Fulton explains that it is a QF and that any determination in this proceeding [*33] with respect to the validity of QF contracts could affect it. Fulton takes no position on the West Penn Petition and raises no issues.

ANR Pipeline Company (ANR) filed a motion to intervene on April 3, 1995. It states that it is a natural gas transmission company that, pursuant to long-term firm contracts, transports natural gas to a substantial number of cogeneration QFs in New York and New Jersey. ANR asserts that a determination in this proceeding concerning purchase obligations under QFs' contracts with utilities could affect its long-term firm natural gas transportation contracts. ANR takes no position on the West Penn Petition and raises no issues.

On April 4, 1995, the Pennsylvania Office of Consumer Advocate (Consumer Advocate) filed a motion to intervene in support of the West Penn Petition. Consumer Advocate explains that it is a state agency empowered by statute to represent the interests of consumers of utility services in the Commonwealth of Pennsylvania before the Pennsylvania Commission, similar federal regulatory agencies and state and federal courts. Consumer Advocate suggests that the West Penn Petition raises an unresolved issue regarding the implementation of PURPA's [*34] requirements, particularly in view of the Energy Policy Act of 1992 and other developments that have increased competition in the electric utility industry. Specifically, Consumer Advocate argues, the West Penn Petition presents the issue whether PURPA requires a utility to pay a rate for QF power that exceeds current avoided cost when the purchase rates are based on stale data, the utility no longer needs the capacity and the QF remains unbuilt. Consumer Advocate contends that from the perspective of Pennsylvania's consumers, requiring West Penn to purchase the Facility's capacity and energy at rates in excess of avoided cost, now and in the foreseeable future, cannot result in rates that are just and reasonable.

Consumer Advocate argues that while PURPA intended to encourage the development of QFs, it made clear that a utility's ratepayers should not subsidize the utility's mandated purchase of QF power. In this case, Consumer Advocate avers, requiring West Penn to proceed with the Purchase Agreement would violate that balance. Consumer Advocate argues that because the Facility is not built, West Penn's requested relief is not precluded by Southern California Edison or Freehold [*35] . Consumer Advocate asserts that those decisions left unresolved the issue presented in this case, which it characterizes as whether PURPA requires West Penn to go forward with a contract that is now known to be for unneeded capacity at rates in excess of current avoided costs. Consumer Advocate acknowledges that it can be argued that West Penn must be required to honor the Purchase Agreement because the delays in the Washington Power project result from West Penn's own actions but nonetheless contends that that would be unfair to West Penn's ratepayers, who will be asked to pay the costs of the contract. Finally, Consumer Advocate argues that the project, if completed, potentially would be stranded investment and thus would hinder, not foster, the development of competitive generation markets.

On April 5, 1995, PECO Energy Company (PECO) filed a motion to intervene. PECO states that it is an operating utility that provides electric service in southeastern Pennsylvania and northern Maryland. It represents that as an electric utility subject to both PURPA and the Pennsylvania Commission's implementing regulations, which are at issue here, it may be directly affected by the outcome of [*36] this proceeding. PECO takes no position on the West Penn Petition and raises no issues.

The Mid-Atlantic Independent Power Producers (Mid-Atlantic Independents) also filed a motion to intervene on April 5, 1995. Mid-Atlantic Independents states that it is a trade association that represents companies and individuals who have interests in the competitive power market in Maryland, Pennsylvania, New Jersey, Delaware, Virginia and the District of Columbia, including members involved in the development of QFs. Because its members are consumers of West Penn's utility services, are competitors of West Penn in the wholesale energy market and are parties to and beneficiaries of the types of QF contracts under PURPA that the West Penn Petition challenges, Mid-Atlantic Independents states that its interest and its members' interests are likely to be directly affected by the outcome of this proceeding. Mid-Atlantic Independents takes no position on the West Penn Petition and raises no issues.

Finally, in addition to the intervening West Penn industrial retail customers already identified, a substantial number of West Penn retail customers, primarily individual ratepayers, have written to the [*37] Commission expressing their opposition to Washington Power's project. Most of the letters reached the Commission after the April 5 deadline for filing protests and motions to intervene. We note, however, that none of the letters constitutes a formal motion to intervene or (as they all support West Penn's position) a protest. The letters are for the most part substantively identical. One letter, filed April 18, 1995, attaches a sheet that sets forth, in abbreviated and highly partisan terms, the "facts" regarding the excess cost of and lack of need for the Facility (as well as the Milesburg and Shannopin QFs). That same version of the facts is reflected both in West Penn's pleadings in this case and in most of the letters from West Penn's retail customers. Thus most of the letters object to requiring West Penn to purchase the Facility's power on the grounds that it is unneeded and overly expensive and that forcing West Penn to buy the power is likely to lead to substantial rate increases for West Penn customers and the risk of job losses in the region because of increased industrial and commercial electric rates.

G. West Penn Answer

On April 17, 1995, West Penn filed an answer [*38] (West Penn Answer) to the motions to dismiss of Washington Power and the Pennsylvania Commission. n33 The West Penn Answer also supplements the West Penn Petition by arguing that NYSEG, which was issued after the filing of West Penn's original petition, does not bar the relief requested by West Penn.

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n33

West Penn correctly notes that while our regulations do not permit answers to protests, they do permit answers to motions to dismiss. See 18 C.F.R. §§ 385.213(a)(2)-(3) (1994).

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In its answer to the motions to dismiss, West Penn argues that, for five specified reasons, its petition is not barred by the doctrine of res judicata. First, West Penn asserts that the doctrine is not applicable in utility rate proceedings, because such proceedings are inherently subject to changes in circumstances. West Penn claims that the proceedings in this case "ultimately are indistinguishable from a rate proceeding." n34 Second, West Penn claims that the Commission has not applied res judicata where the prior adjudication [*39] is based on stale data. For this proposition, West Penn relies on an administrative law judge's opinion addressing decommissioning expenses for a nuclear plant, which West Penn claims are similar to QF rates. n35 Third, West Penn claims that under the Commission's interpretation of the doctrine of primary jurisdiction, res judicata does not bar West Penn's request for relief from a state court judgment that erroneously interpreted the Commission's regulations. Fourth, West Penn alleges that it has not had a full and fair opportunity to litigate before the Pennsylvania Commission and courts the same cause of action raised by its petition to this Commission. West Penn asserts that its first requested declaration--that a utility cannot be required to purchase power from a QF when the rates exceed the utility's current avoided costs and are based upon eight-year-old data--obviously was never resolved by the Pennsylvania courts because it depends on facts currently available. West Penn adds that whether a QF's recertification and alleged substantial redesign triggers a new avoided cost determination also was not decided by the Pennsylvania courts. Finally, as to res judicata, West Penn [*40] argues that the doctrine, even if otherwise applicable to this case, cannot bar the Commission from issuing adjudicative rules--i.e., an interpretation of its PURPA regulations--in its legislative capacity. West Penn also responds to Washington Power's argument that the Commission lacks jurisdiction to modify the Purchase Agreement. West Penn asserts that neither Freehold nor the Commission's regulations preclude it from interpreting its regulations and finding that the Pennsylvania Commission's modifications of the Purchase Agreement violated federal law. West Penn asserts that it is not asking this Commission to "'second-guess state regulatory authorities' actual determinations of avoided costs.'" n36 Rather, West Penn insists, its challenge to the Pennsylvania Commission's actions is consistent with the Commission's statement in Southern California Edison that its role is limited to ensuring that the process used by the state commission to calculate the per unit charge accords with PURPA and this Commission's regulations.

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n34

West Penn Answer at 9.

n35

West Penn cites the administrative law judge's initial decision in Boston Edison Co., 59 FERC P63,028 at 65,239 (1992).
[*41]

n36

West Penn Answer at 25 (quoting Southern California Edison, 70 FERC at 61,677). We made clear in that case, of course, that we will not engage in such second guessing.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

Third, West Penn argues that the preamble to our PURPA regulations did not in fact consider and reject the claim of changed circumstances now asserted by West Penn. West Penn urges that even if Washington Power has correctly interpreted the preamble discussion, this Commission is not bound by the preamble. West Penn adds that, because avoided costs allegedly have declined since the regulations were enacted, the Commission should reject the preamble discussion to the extent that it suggests that changed circumstances will not require reconsideration of QF rates.

West Penn also offers further arguments as to why our decisions in Connecticut Power and Southern California Edison allegedly support its requested relief and as to why Washington Power's dual certification requires recalculation of the Purchase Agreement rates. Finally, West Penn attempts to explain why our recent decision in NYSEG does not preclude [*42] granting West Penn its requested relief. n37

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n37

West Penn's arguments on these points, to the extent that they are of any substance and relevance, are addressed in our discussion below on the merits of the West Penn Petition, and we will not repeat the arguments here.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

II. Discussion

A. Procedural Matters

Under Rule 214 of the Commission's Rules of Practice and Procedure, n38 the notice of intervention of the Pennsylvania Commission and the timely, unopposed motions to intervene of Washington Power, Armco, Industrials, Allegheny Ludlum, Cogeneration Association, NIEP, Fulton, ANR, Consumer Advocate, PECO and Mid-Atlantic Independents serve to make them parties to this proceeding.

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n38

18 C.F.R. § 385.214 (1994).

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

B. West Penn's Requests for Relief

The gravamen of the West Penn Petition is an allegation that the Pennsylvania [*43] Commission, in violation of PURPA and this Commission's implementing regulations, modified the Purchase Agreement by calculating the rates based on avoided costs estimated as of the date of the contract's execution and by extending certain milestone dates to take account of litigation delays. Additionally, West Penn asks us, in essence, to declare that PURPA and our regulations require that established rates in long-term QF contracts be recalculated if changed circumstances result in avoided cost projections that differ from earlier avoided cost projections upon which the rates originally were based.

We will deny West Penn's petition. West Penn's complaints about the specific actions taken by the Pennsylvania Commission regarding the Purchase Agreement already have been fully litigated in another forum. We will not entertain an attempt to relitigate before this Commission matters that have been settled by the Pennsylvania courts, whose determinations the United States Supreme Court also declined to disturb. The Pennsylvania Commission's modifications to the Purchase Agreement involve fact-based determinations and PURPA enforcement issues that we consistently have regarded as the province [*44] of the States. n39 Moreover, West Penn's attack on our PURPA regulations permitting rates for QF contracts to be calculated as of the time a legal obligation for the sale of power is incurred raises essentially the same issue that we addressed and rejected in NYSEG. n40

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n39

See, e.g., *NYSEG*, slip op. at 22.

n40

West Penn's final argument, regarding the supposed effect of recertification of a QF, is, as we discuss below, essentially a variation on its argument that changed circumstances require recalculation of avoided costs and is, we find, without merit.

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West Penn argues that it really is challenging the "process" by which the Pennsylvania Commission determines avoided costs in general and is not asking us to "second-guess" the Pennsylvania Commission's actual determination of avoided cost for the Facility. n41 By this assertion, West Penn seeks to evade our warnings in Southern California Edison and NYSEG that we would not engage in such second-guessing. n42 West Penn's [*45] effort is unsuccessful. Our regulations expressly permit rates in long-term QF contracts to be based on avoided costs as of the time a legally enforceable obligation is incurred. It is up to the States, not this Commission, to determine the specific parameters of individual QF power purchase agreements, n43 including the date at which a legally enforceable obligation is incurred under State law. Similarly, whether the particular facts applicable to an individual QF necessitate modifications of other terms and conditions of the QF's contract with the purchasing utility is a matter for the States to determine. This Commission does not intend to adjudicate the specific provisions of individual QF contracts. n44

- - - - - - - - - - - - - - - - - -Footnotes- - - - - - - - - - - - - - - - - -

n41

West Penn Answer at 25-26.

n42

See Southern California Edison, 70 FERC at 61,677; NYSEG, slip op. at 22.

n43

See NYSEG, slip op. at 22.

n44

Moreover, as we pointed out in our amici brief in the companion certiorari proceedings to those involving Washington Power, we do not find Pennsylvania's determinations on these issues, the resolution of which are State responsibilities, inconsistent with or in violation of PURPA or our regulations. See Pennsylvania Commission Protest Appendix A at 17-20. None of West Penn's arguments in this proceeding persuades us to reverse our earlier view.

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[*46]

One other of West Penn's arguments that merits comment is its claim that its petition is not precluded by our determination, as explained in Connecticut Power and Southern California Edison and confirmed in NYSEG, that we will not accept challenges to State-approved avoided-cost rates unless the rates were challenged prior to the execution of the contract and the challenge is pending. We agree that in this case, West Penn had no reason to challenge the Purchase Agreement prior to the date of execution. n45 We do not agree, however, that West Penn's challenge to the Purchase Agreement as modified by the Pennsylvania Commission is ongoing or pending in the sense that we contemplated in our prior decisions. The only reason that West Penn now can contend that the matter is pending is that it refused to accept the judgments of the Pennsylvania courts and the Pennsylvania Commission, as left standing by the United States Supreme Court. Instead of accepting the court decisions, West Penn has sought to reopen the issues before this Commission as well as before the Pennsylvania Commission. While West Penn has attempted to fit its petition into certain isolated language in our recent [*47] orders, it ignores the intent of those decisions.

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n45

As all parties agree, the rates as originally set were negotiated by West Penn and Washington Power and were not modified by the Pennsylvania Commission in its initial acceptance of the contract.

- - - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - - -

In addition to challenging specific Pennsylvania Commission actions affecting the Purchase Agreement, a claim that we have rejected, West Penn also asks this Commission to declare that PURPA and our regulations do not require, and indeed preclude, a utility's purchase of power from a QF when the rates exceed the utility's current avoided costs, the rates are based upon stale avoided-cost data, the utility no longer needs the capacity and the QF is not yet built. In essence, West Penn is arguing that changed circumstances mandate recalculation of rates based on avoided costs as of the time of the new circumstances. Thus West Penn directly challenges our long-standing rule, as set forth in section 292.304 of our PURPA regulations, that rates for a long-term QF contract [*48] based on avoided costs calculated as of the time the legal obligation to sell power was incurred continue to comply with statutory and regulatory requirements--including the requirement that QF rates be just and reasonable--even if the rates differ from avoided costs at the time the power is delivered.

West Penn raises essentially the same issue as was before the Commission in NYSEG. As we confirmed in that case, the provisions of section 292.304 allowing long-term fixed rate contracts for QFs--"lock-ins," in West Penn's parlance--mean what they say. As we further explained in NYSEG, in promulgating the regulations, we expressly considered and rejected the argument now made by West Penn that changed circumstances would require resetting of established rates to match the latest avoided cost determinations. In NYSEG we examined in detail the legal and policy reasons why we would not amend or reinterpret our regulations in response to allegations that current avoided costs have fallen. n46 We will not repeat that discussion here except to confirm our continued adherence to the principles enunciated in NYSEG. While we do not believe that our discussion in NYSEG requires [*49] amplification, we will address certain of West Penn's additional arguments in which it attempts to distinguish its petition from issues that we resolved in NYSEG. n47

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n46

See NYSEG, slip op. at 20-26.

n47

We already have considered and rejected West Penn's arguments that NYSEG and our earlier decisions do not preclude its petition because (a) its challenge to the Purchase Agreement is ongoing, and (b) it is challenging only the "process" of the Pennsylvania Commission. See supra text accompanying notes 41-45.

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First, West Penn claims that a critical factual distinction is that the Facility in this case is neither financed nor built. West Penn argues, therefore, that granting it relief from the Purchase Agreement will not undermine QF financing in general, because "the critical issue from a lender's point of view is stability after the financing is actually provided." n48 West Penn's argument on this point strikes us as somewhat disingenuous. Under West Penn's theory, the purchasing [*50] utility would be free to challenge the rates at any time before financing arrangements are completed, so that QF developers could be forced to pursue a "moving target" in attempting to arrange financing. Allowing utility challenges to rates at any point between the time that a legally enforceable obligation is incurred and the completion of financing could involve repeated delays. In any event, our regulations specifically authorize QF rates to be established as of the time a legally enforceable obligation is incurred.

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n48

West Penn Answer at 39.

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Second, West Penn asserts that it is entitled to relief under Connecticut Power, quoting in support our description of that case in NYSEG. We stated in the latter case that in Connecticut Power, "we found that the rates for purchases from the QF in that case, as a legal matter, may have exceeded avoided costs at the time the rates were imposed, a situation we determined would be in violation of Section 210(b) of PURPA." n49 West Penn argues that it is entitled [*51] to relief on the same grounds, because the modified rates under the Purchase Agreement were imposed not in 1987 when the contract was signed but either in 1989 (when the Pennsylvania Commission established the date at which a legally enforceable obligation arose as the date of execution rather than during the negotiation period) or more likely 1992 (when the Pennsylvania Commission modified the rates to reflect avoided costs estimates as of the date of execution). West Penn alleges that the rates exceeded then-current avoided costs estimates in both 1989 and 1992.

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n49

NYSEG, slip op. at 23 (emphasis omitted).

- - - - - - - - - - - - - - - - -End Footnotes- - - - - - - - - - - - - - - - -

West Penn has misunderstood our decision in Connecticut Power. That case involved a challenge to a state statute that required QF rates to be set at rates that exceeded avoided costs regardless of when a legally enforceable obligation was incurred. In this case, the rates were set not by statute but were based on a determination, specific to the Purchase Agreement, as to the date at which the [*52] legally enforceable obligation was incurred. The fact that the determination as to the specific proper date in this case was made after the date itself is immaterial. For purposes of our regulations, the critical date is the date on which a legally enforceable obligation is incurred, and choosing that date for a specific QF is the responsibility of the States, not of this Commission.

West Penn's final argument, relating to the dual certification of the Facility as both a cogeneration and small power production QF, borders on the frivolous. The scope of a QF certification proceeding is quite narrow -- it is limited to a determination whether, on the facts presented in the certification application, the facility at issue will comply with the Commission's ownership and technical requirements for QFs. A QF certification proceeding does not address any issues that are unrelated to the limited definitional criteria for QF status. n50 Thus, the Commission's certifications of the Facility did not purport to address the rates and terms upon which West Penn would satisfy its obligation to purchase the Facility's capacity and energy or the time at which that obligation was incurred.

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n50

Midland Cogeneration Venture Limited Partnership, 56 FERC P61,361 at 62,393 (1991), aff'd mem. sub nom. Michigan Municipal Cooperative Group v. FERC, 990 F.2d 1377 (D.C. Cir. 1993) (per curiam), cert. denied, 114 S. Ct. 546 (1993) (Midland). Accord, e.g., Citizens for Clean Air and Reclaiming our Environment v. Newbay Corp., 56 FERC P61,428 at 62,523-33 (1991) (Newbay).

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[*53]

A QF certification or recertification is an entirely separate matter from when, for purposes of calculating avoided costs in accordance with sections 292.304(b)(5) and 292.304(d)(2)(ii) of our regulations, a "legally enforceable obligation" is incurred. The fact that dual certification is obtained for a single facility means only that the facility satisfies the requirements for both a qualifying cogeneration and a qualifying small power production facility. Moreover, recertification reflects the fact that, because QF certifications are issued based on the facts presented in the application at issue, recertification may be appropriate if any of the facts change. n51 In no sense does a QF certification or recertification ratify or impose modifications on any power sales contract to which the QF is party.

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n51

See, e.g., Newbay, 56 FERC at 62,532-33; Midland, 56 FERC at 62,393.

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West Penn's invocation of the legislative history of the Solar, Wind, Waste, and Geothermal Power Production Incentives [*54] Act of 1990 is equally unavailing. n52 West Penn correctly points out that that legislation, which by increasing the permissible size limits under certain circumstances for small power production facilities under PURPA enabled Washington Power to obtain additional certification as a qualifying small power production facility, expressly did not intend to have the effect of requiring the purchase of additional capacity or energy under existing contracts. No such effect, however, resulted in this case. The obligations of West Penn to purchase capacity and energy from the Facility were established by the Purchase Agreement, which continued to govern those obligations after Washington Power's additional certification. Moreover, we note that West Penn incorrectly alleges that after the passage of that legislation, Washington Power converted from a cogeneration facility to a small power production facility. n53 That simply is not true. As our certification orders indicate, the Facility's certification as a qualifying small power production facility was in addition to, not in replacement of, its certification as a qualifying cogeneration facility. n54

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n52

See id. at 35-36.
[*55]

n53

Id. at 35.

n54

See Cogeneration Recertification, 70 FERC at 64,386 n.1; Small Power Production Certification, 69 FERC 64,296 n.1. We note that West Penn did not intervene in or protest any of Washington Power's QF certification proceedings. See Cogeneration Recertification, 70 FERC at 64,386; Small Power Production Certification, 69 FERC at 64,296; Cogeneration Certification, 42 FERC at 63,443.

We note that West Penn claims that Washington Power's proposed small power production facility is "substantially different" from the proposed cogeneration facility that formed the basis of the Purchase Agreement. West Penn Petition at 33. West Penn similarly alleges that Washington Power made a "substantial redesign of its proposed QF." West Penn Answer at 19. West Penn fails to specify any differences, however, and our QF certification orders reflect no such differences.

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As noted above, the Pennsylvania Commission, and the courts, have determined that a valid, legally binding contract exists. Our decision not to disturb the contract has not turned on [*56] the factual issue of whether the contract rate required by the Pennsylvania Commission will in fact exceed West Penn's avoided cost over the term of the contract. However, if West Penn believes that this is the case, it should make every attempt to buy out (or buy down) the contract. We would encourage the parties to the contract to consider settling their differences particularly if the facility has not been constructed. Moreover, if this is the case, we believe that both the Commission and the Pennsylvania Commission should encourage such an effort.

We do not believe that there is any significant difference between this situation and that faced by utilities when they find that previously negotiated fuel contracts are no longer competitive due to changes in fuel markets. In the latter situation, we have encouraged utilities to buy out (or buy down) higher-priced fuel contracts in order to substitute lower-priced fuel currently available and we have allowed the recovery of prudently-incurred buy-out/buy-down costs. See Kentucky Utilities Company, 45 FERC P61,409 (1988).

The Commission is aware today, as it was in 1980 when it adopted its PURPA regulations, that some QF contracts [*57] may result in rates above avoided cost over the term of the agreement, just as some may result in rates below avoided cost. However, as we explained in Connecticut Power, NYSEG and in this order, we do not believe the remedy is to invalidate such contracts, except in narrow circumstances. n55 Rather, we believe the appropriate action is to buy out or buy down such contracts. To facilitate such action, we clarify that if utilities are prudent in buying out or buying down existing power purchase agreements, whether or not with QFs, this Commission will permit the recovery in wholesale rates of a pro rata share of the buy-out or buy-down costs.

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n55

See Connecticut Power, 70 FERC at 61,029-30; NYSEG, slip op. at 23-24.

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The Commission orders:

The relief requested in the West Penn Petition is hereby denied as discussed in the body of this order.

By the Commission.

71 F.E.R.C. 61153 printed in FULL format.

West Penn Power Company

Docket No. EL95-30-000

FEDERAL ENERGY REGULATORY COMMISSION - COMMISSION

71 F.E.R.C. P61,153; 1995 FERC LEXIS 856

ORDER DENYING PETITION FOR DECLARATORY ORDER

May 8, 1995

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

OPINION:
On March 10, 1995, West Penn Power Company (West Penn) filed a Petition for Issuance of a Declaratory Order (West Penn Petition). West Penn seeks a declaration by the Commission that certain actions by the Pennsylvania Public Utility Commission (Pennsylvania Commission) and Washington Power Company, L.P. (Washington Power) violate section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) n1 and this Commission's implementing regulations. Specifically, West Penn argues that under federal law: (a) an electric utility cannot be required to purchase capacity from a qualifying facility (QF) n2 at rates that exceed the utility's current avoided costs; (b) a State regulatory authority may not modify a power purchase agreement privately negotiated between an electric utility and a QF or, alternatively, avoided costs must be recalculated as of the time of such modification; and (c) avoided costs must be recalculated if a QF seeks certification of a new project design. Finally, West Penn requests a determination that it has no current obligation to [*2] purchase capacity and energy from Washington Power's QF.

- -Footnotes- -

n1

16 U.S.C.A. § 824a-3 (West 1985 & Supp. 1995).

n2

A QF is a cogeneration or small power production facility that meets certain specified criteria, primarily relating to technical aspects and ownership, under PURPA and our implementing regulations. See 16 U.S.C.A. §§ 796(17)-(18) (West 1985 & Supp. 1995); 18 C.F.R. Part 292 (1994). If all of the relevant statutory and regulatory criteria are satisfied, a QF may be both a qualifying cogeneration facility and a qualifying small power production facility. See id.

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15

1989 Cal. PUC LEXIS 813 printed in FULL format.

AMERICAN COGEN TECHNOLOGY, INC. a California corporation, Complainant, vs. PACIFIC GAS AND ELECTRIC COMPANY, a California corporation, Defendant

Decision No. 89-11-062, Case No. 89-05-018 (Filed May 8, 1989)

California Public Utilities Commission

1989 Cal. PUC LEXIS 813

November 22, 1989

PANEL:
[*1]

G. Mitchell Wilk, President; Frederick R. Duda, Stanley W. Hulett, John B. Ohanian, Patricia M. Eckert, Commissioners

OPINION

I. Introduction

The parties to this case request an order approving a settlement and finding the terms of the settlement to be reasonable. The parties further ask for a finding that Pacific Gas and Electric Company (PG&E) is prudent in entering into the settlement. If we approve the settlement as requested, the parties ask for dismissal of this case with prejudice.

The case originated when American Cogen Technology, Inc. (ACT) filed its complaint against PG&E on May 8, 1989. The complaint alleged that PG&E had acted in bad faith in refusing to acknowledge a force majeure and to extend certain contractual deadlines, as required under ACT's two power purchase agreements (PPA) with PG&E. (Force majeure is a legal term referring to uncontrollable and unforeseeable events. Claims of force majeure often arise, as in this case, in contractual disputes. In this context, the force majeure prevents a party from rendering the performance required by a contract.)

The complaint detailed the harm that ACT would suffer because of PG&E's [*2] acts, and requested an order declaring that a force majeure had occurred, that ACT had fulfilled its contractual obligations in response to the force majeure, and that ACT was entitled to an extension of certain contractual deadlines corresponding to the duration of the force majeure.

Before PG&E's answer was due, the parties jointly requested a stay of the proceeding to allow them to work out the final details of a settlement they had negotiated. The stay was granted by an order of the Administrative Law Judge on May 19, and the parties' "Joint Motion to Dismiss Complaint and for Approval of Settlement" was filed on August 1.

The Commission's Division of Ratepayer Advocates (DRA) filed comments on the joint motion on August 31 and submitted additional comments on September 28.

ACT replied to DRA's additional comments on October 6.

II. Background to the Dispute

The motion recites ACT's version of the facts behind this dispute. PG&E does not necessarily agree with the facts as stated, and it reserves the right to contest these facts if we do not approve the settlement. The probable areas of dispute will become clear from the description of the complaint and [*3] proposed settlement.

ACT is the developer of two cogeneration projects in Monterey County. The first is a 49.9 megawatt (MW) project at the site of the Spreckels Sugar Company. The second is an identically sized project at an abandoned industrial site formerly owned by Firestone Tire and Rubber Company. ACT and PG&E entered into contracts based on interim Standard Offer No. 4 (SO 4) for both projects in October 1984. The PPAs contain a standard deadline terminating the contract if ACT does not begin delivering energy within five years of the date of the execution of the contract. Both projects began as 59 MW plants, but the planned size was reduced to 49.9 MW in March 1986. The parties amended the PPAs to reflect the reduction in size in March 1989.

ACT proceeded to take steps to construct the projects, including securing property rights, obtaining engineering and contracting services, purchasing equipment, contracting for permitting studies, obtaining a financing commitment, and getting certification as a qualifying facility (QF) from the Federal Energy Regulatory Commission. (QFs are cogeneration and small power production projects that qualify for certain benefits under [*4] the federal Public Utility Regulatory Policies Act of 1978.)

ACT states that the incidents leading to the force majeure claim began in May 1988 when ACT applied for use permits from Monterey County. ACT expected to be able to obtain the permits without the need for an Environmental Impact Report (EIR) under the California Environmental Quality Act or CEQA (California Public Resources Code Section 21000 et seq.).

According to ACT, the County's previous actions had led ACT to believe that no EIR would be required. At the time of its application, ACT continues, the policy of the Monterey County Board of Supervisors was to treat cogeneration facilities of less than 50 MW as categorically exempt from the EIR requirement. In this respect, the Board followed Section 15329 of the CEQA Guidelines (14 Cal. Code of Regs. 15000 et seq.), which provided that cogeneration projects of less than 50 MW at existing industrial sites are categorically exempt from the EIR requirement if they meet certain air quality standards. With its application for the use permits, ACT had provided the air quality studies that it believed would entitle its projects to the categorical exemption under [*5] the Board's existing policies.

In addition, local officials had not required EIRs from two comparable cogeneration facilities, the O'Brien Energy Facility and the Texaco/Yokum project. Negative declarations had been prepared for these two projects.

In July 1988, ACT received two nearly identical letters from the Monterey County Planning Department. The letters stated that the County Department of Health and the County Flood Control and Water Conservation District had recommended that EIRs be prepared for the projects. ACT believes the recommendations apparently resulted from a study completed in May that raised concerns about seawater intrusion into groundwater basins in the Salinas Valley.

ACT contends that the change in the County's policy on EIRs for cogeneration projects constitutes a force majeure under the PPAs. Each of its PPAs states that a force majeure is an action by a federal, state, or municipal agency that was "unforeseeable" at the time the PPA was executed and was "beyond the reasonable control and without the fault or negligence of the party claiming force majeure."

ACT believes the County's actions meet these criteria for several reasons. As already [*6] mentioned, ACT contends that the County's express existing policy would have exempted ACT's projects from the EIR requirement. In earlier conversations with County Health Department officials, ACT states that it had been assured that neither water availability nor contamination would impede its projects. The projects are located 13 and 16 miles from the coast, and ACt argues that it had no reason to suspect that seawater intrusion would be an issue in the permitting process. Furthermore, the Spreckels project will use less than one-tenth and the Firestone project less than one-third of the water used by the previous occupants of the sites. Finally, County officials have confirmed in writing that the ACT projects were the first projects in the Salinas Valley basin that were subject to the EIR requirement and that the requirement of an EIR was "new" and an "unforeseeable change in policy."

The PPAs require a party claiming force majeure to notify the other party within two weeks of the occurrence of the force majeure. ACT states that it met this requirement by notifying PG&E on July 28 and August 10 of the County's position on EIRs for the projects. ACT asked PG&E for [*7] an extension of the five-year deadline only for the exact number of days from the time ACT learned that County officials were recommending EIRs for the projects until the date the final EIRs are certified as legally adequate under CEQA. PG&E's refusal of this request led to the complaint and eventually to the settlement.

ACT also recites facts to show that it made its best efforts to remedy the inability to perform created by the force majeure. Its actions included retaining experts to perform the necessary hydrologic studies and meeting repeatedly with County officials, first to attempt to obtain a negative declaration or categorical exemption for the projects and later to narrow the scope of the EIR to the seawater intrusion issue.

The projects have been and continue to be viable, according to ACT. ACT has taken various steps to maintain the projects' viability and to comply with the requirements of the Qualifying Facility Milestone Procedure (QFMP) established by the Commission. ACT believes the projects also meet the standards on evaluation of proposed modifications of utilities' contracts with QFs the Commission set up in Decision (D.) 88-10-032. But for the force [*8] majeure, ACT contends, the projects would have been completed within the five-year deadlines established in the PPAs.

III. The Settlement

ACT and PG&E join in supporting their settlement as a reasonable resolution of this dispute.

The settlement has three main points.

First, commencement of firm capacity payments under both PPAs is delayed until May 1, 1991. This date assumes a revised on-line date of May 1, 1990.

Second, the five-year deadline for beginning energy deliveries is extended to no later than May 1, 1991.

Third, PG&E has the right to curtail each facility for up to 2000 hours during off-peak and super off-peak periods each year. During these periods, PG&E may require ACT to reduce its capacity from 47 MW to 37 MW.

The parties negotiated the settlement with the Commission's guidelines on contract modifications (D.88-10-032) in mind, and they believe that the settlement serves ratepayers' interests "demonstrably better" than the original agreements.

Several factors motivated the settlement. First, both parties felt the outcome of litigation on this issue was uncertain. Second, settlements avoid the substantial costs of litigation. Third, the parties were [*9] able to arrive at a settlement that benefited ratepayers sufficiently to approach the Commission for approval.

The net present value of the settlement to ratepayers is estimated to be between $ 14 million and $ 53.5 million. The value to PG&E of being able physically to curtail the facilities' generation is difficult to quantify but substantial. The parties believe these benefits should be weighed against the result if ACT had prevailed in litigation -- no deferral of the capacity payments and no control by PG&E over the facilities' generation.

IV. DRA's Comments

DRA's initial comments reviewed the joint motion and the standards that DRA applied in evaluating the parties' request. DRA concluded that "the dispute between PG&E and ACT presents to the ratepayers a bona fide risk if it were to be resolved through litigation." DRA weighed that risk against the savings for ratepayers that result from the settlement and recommended that the Commission approve the settlement.

In its additional comments, DRA notes that its initial comments were based on a limited evaluation, constrained by time, of the primary issue raised in the joint motion: "whether or not Monterey County's [*10] 'new policy' of requiring EIRs for these projects constituted a force majeure event." New information led DRA to reconsider its evaluation.

The new information consists of correspondence received by the California Energy Commission (CEC) when it reviewed the original version of the Spreckels project. DRA believes this new information "suggests that, contrary to ACT's and Monterey County's suggestions in the record, Monterey County's interest in a thorough EIR on the issue of saltwater intrusion for projects in its jurisdiction was or should have been foreseeable from the time of ACT's initial attempts to get its permits, and well before the spring of 1988." DRA attaches several letters to its comments. The letters indicate that Monterey County agencies had expressed their belief that the project required preparation of an EIR and had raised concerns about seawater intrusion. DRA concludes that "ACT at no time had assurances from either the lead agency or any responsible agency that its projects qualified for categorical exemptions."

In light of this new information, DRA withdraws its previous endorsement of the joint motion and is "guardedly neutral" on the reasonableness [*11] of the settlement. DRA does not request hearings on this matter, but it suggests that the Commission should "admonish the parties and future applicants for settlement approvals of their duty to fully disclose all information."

ACT's response to the additional comments begins by noting that the correspondence attached to DRA's motion pertained to a previous version of the Spreckels project, which included a large food processing center and a larger generator. When the letters are read in this light, ACT believes it is clear that they do not relate to the concerns that led to the force majeure that delayed the smaller projects that are the subject of the joint motion.

ACT also argues that DRA's additional comments misstate the facts reflected in the letters.

Even if DRA's concerns are accepted as stated, however, ACT believes that they are irrelevant to the claim of force majeure. "The ultimate fact upon which ACT's force majeure claim is based is not the recognition of the potentially harmful effects of seawater intrusion, or where or when it had been discussed," ACT contends, "but the change in policy that required EIR review to assess the risks of seawater [*12] intrusion for projects like ACT's, projects that had previously been Categorically Exempt."

ACT believes the benefits of the settlement overwhelm the concerns raised by DRA, and the settlement should therefore be approved.

V. Discussion

The proposed settlement includes several modifications to existing contracts. We recently set forth our expectations about how utilities should evaluate requests for contract modifications in our "Guidelines for Contract Administration of Standard Offers" (D.88-10-032). The settlement was apparently negotiated with these guidelines in mind, and the motion contains statements that seem to be intended to show that the settlement complies with the guidelines.

The guidelines include several provisions concerning claims of force majeure. The guidelines allow an exception to strict enforcement of the five-year deadline for force majeure and limit any extension of the five-year deadline to the duration of the force majeure.

The guidelines are cautious about force majeure claims arising from permitting delays:

"Events giving rise to valid claims of force majeure may include delay in obtaining required governmental permits, depending [*13] on the circumstances of the individual QF. However, not all project delays resulting from delays in obtaining required governmental permits are valid claims of force majeure. Permitting delays and denials are a regular part of project development and should be anticipated by project developers."

Thus, we must examine whether the permitting delays arising from the EIR requirement should be viewed as a regular part of the development of the projects and whether ACT should have anticipated the delays associated with the EIR requirement.

The guidelines also give a general description of how we will evaluate claims of force majeure:

"Decisions about the applicability of the force majeure clause will be made on a case-by-case basis. Factors to be considered will include an examination of the factual basis of the force majeure claim, the specific language of the contractual force majeure clause, and whether the QF has complied with applicable contractual requirements to give notice of the force majeure and to mitigate the delay caused by the force majeure. The effect of the force majeure on the utility's obligations under the contract will also be considered as cases arise." [*14]

The guidelines also require utilities to examine the viability of a project before any contract modifications are considered and to obtain concessions favorable to ratepayers before granting deferrals of the five-year deadline, like the deferral in the amendments connected to the settlement. We have already summarized ACT's description of the factual basis of its claim of force majeure. We will consider the other factors mentioned in the guidelines -- foreseeability of permitting delays, viability, ratepayer benefits, the language of the contracts, notice and mitigation -- in the following sections.

A. Foreseeability

The guidelines state that not all permitting delays result in force majeure and that the project developer should anticipate some delays as a regular part of project development. A threshhold issue, then, is whether the EIR requirement was a delay that ACT should have anticipated.

ACT argues that it could not have foreseen that the County would change its policy to require an EIR for cogeneration projects of less than 50 MW at existing industrial sites.

DRA's additional comments, however, cast some doubt on ACT's assertions. ACT has represented [*15] that a new emphasis on the problem of seawater intrusion into the Salinas basin led the County to cease granting categorical exemptions for such projects. But the attachments to DRA's additional comments show that several county agencies had expressed their concerns about seawater intrusion in connection with the Spreckels project several years before the county changed its policy. Even though the environmental review undertaken by the CEC became moot when the projects were reconfigured, these letters raise the question whether it was really unforeseeable that these agencies would raise this issue again.

ACT has not addressed the legal basis for the change in the County's policy that led to the force majeure. Section 15329 of the CEQA Guidelines has not been amended, and ACT's projects still appear to fall under the exemption created by that section. The only exceptions that are allowed from this categorical exemption arise "when the cumulative impact of successive projects of the same type in the same place, over time is significant" or when "there is a reasonable possibility that the activity will have a significant effect on the environment due to unusual circumstances" [*16] (14 Cal. Code of Regs. Section 15300.2(b), (c)).

Presumably the County relied on one of these exceptions in revising its policy on categorical exemptions for cogeneration projects. Exhibits attached to the joint exhibit, although not contemporary with the change in policy, indicate that concern over groundwater overdrafts and resulting seawater intrusion led to stricter environmental reviews for facilities, like cogeneration projects, with large water requirements. Groundwater overdrafts and seawater intrusion could be viewed as facts justifying either exception to the categorical exemption: The cumulative effects of overdrafts result in the significant impact of seawater intrusion, and the unusual circumstance of seawater intrusion justifies the exception.

Regardless of the legal bases for the County's action, the question here is this: Was it foreseeable that the County's concerns about groundwater overdrafts and seawater intrusion, expressed at least as early as 1985, would lead it to revise its review of cogeneration projects in 1988?

If we relied only on the materials submitted with the motion, we would find that the change was not foreseeable, because the motion leaves the [*17] impression that the issue of seawater intrusion never reached a level of concern that stimulated County officials to require EIRs because of this issue until May 1988. The materials attached to DRA's additional comments, however, cast some doubt on that impression. Solely on the basis of the information before us, we cannot conclude that it was foreseeable that the County would require an EIR for ACT's projects.

This conclusion must be tempered with another observation. Particularly when cases come before us without having been tested in adversary hearings, we must limit our approvals to the scope of the information we have before us. Any finding of reasonableness in cases like this is strictly limited to the facts and materials that are presented by the parties. The implication of this limitation falls primarily on PG&E. For reasons of strategy in potential litigation, PG&E has not concurred in ACT's presentation of the facts behind the settlement. In presenting such a settlement to us, PG&E is presumed to have investigated the underlying facts fully and to have found an adequate basis for concluding that the settlement is a fair resolution of a legitimate dispute. In circumstances [*18] like the ones presented in this case, our finding of reasonableness is conditioned on the accuracy of this presumption.

B. Viability

The joint motion contains a recitation of how ACT's projects are viable and, except for the force majeure, would be able to comply with the requirements of the original PPAs. ACT's descriptions closely follow the items listed in the guidelines for determining the viability of a project.

ACT states that it has expended substantial sums of money to secure site control. It has submitted complete Project Description and Interconnection Study Request forms and paid PG&E the necessary fees for commencement of an interconnection study. ACT further states that it has the ability to pay the remaining $ 5 per kilowatt project fee upon receipt of the Special Facilities Agreement from PG&E. ACT has pursued and obtained all other permits needed for the projects, and PG&E has agreed to supply fuel for the projects under a standard agreement. ACT has engaged construction contractors, has ordered the projects' turbines and generators, and has secured construction financing. ACT has prepared financial data showing that the plants will operate profitably [*19] for 30 years. A similar cogeneration project of ACT's is proceeding to a timely completion.

Although PG&E reserves its right to dispute these facts and has accordingly not joined ACT in this presentation of facts, it appears from the facts contained in sworn declarations attached to the joint motion that ACT meets the standard of viability established in the guidelines. We conclude that ACT's projects are viable but for the intervention of the claimed force majeure.

C. Benefits for Ratepayers

The guidelines support strict enforcement of the five-year on-line requirement, subject to extension because of force majeure, and set the standards for deferral of the five-year on-line date: "On-line data deferrals . . . may be considered only if the ratepayers' interests will be served demonstrably better by such deferral." The joint motion describes the parties' efforts to meet this guideline.

In exchange for consenting to the extension of the five-year deadline, the parties have agreed to several contract modifications that will benefit ratepayers. First, firm capacity payments under the PPAs are delayed until May 1, 1991, even if the projects begin operation at an [*20] earlier date. ACT expects to be on-line by May 1, 1990, and even with the extension due to force majeure, the amended contract requires ACT to begin delivering energy by May 1, 1991.

Second, PG&E acquires the right to curtail the generation from each project for up to 2000 hours annually. The curtailment must occur during off-peak or super off-peak periods, when curtailments are most beneficial to PG&E's system. PG&E may reduce each project's output to no lower than the generation associated with 37 MW, or about 12.5 MW less than each facility's full capacity.

The joint motion contains a declaration setting forth an analysis of these amendments. Although no information is given concerning the expertise or even the employer of the declarant, it appears from the context of the analysis that it was prepared for PG&E to aid in the decision to accept the settlement. The analysis concludes that these amendments benefit PG&E and its ratepayers in terms of both economics and the efficient operation of PG&E's system.

A one-year deferral in the commencement of capacity payments to ACT saves ratepayers between $ 11.9 million and $ 16.6 million, depending on the forecast of the value [*21] of capacity. Using a medium forecast of capacity value, the savings are estimated to be $ 14.2 million. The one-year deferral used in the analysis apparently refers to the delay between the expected operation of ACT's projects and the start of capacity payments. We note that the beginning of capacity payments on May 1, 1991, is about two years later than the deadline for energy deliveries under the original PPAs.

Savings from the curtailment provisions, on a net present value basis, would total between $ 2.1 million and $ 36.8 million, depending on the forecast of the cost and amount of replacement energy. (This analysis assumes a right to reduce output by 11.5 MW for each unit, rather than the 12.5 MW stated in the motion. It appears that use of 12.5 MW would increase the economic benefits. On the other hand, the amendments to the PPA proposed by the stipulation reduce the projects' firm capacity to 47 MW, and this reduction would appear to decrease the economic benefits. The discrepancies in the capacities stated in the motion, the analysis, and the amendments are not explained.)

Thus, on a net present value basis, the analysis concludes that the amendments would save PG&E's [*22] ratepayers between $ 14.0 million and $ 53.5 million.

In addition, the analysis points out that the amendments provide benefits that are substantial but difficult to quantify. These benefits are connected to PG&E's right to curtail energy deliveries for 2000 hours annually.

Without endorsing the specific figures presented in the analysis, we are persuaded that the amendments will produce substantial benefits for PG&E and its ratepayers compared with the original PPAs.

D. The Language of the Contracts

The guidelines suggest that the validity of a claim of force majeure may be affected by "the specific language of the contractual force majeure clause." Even though we have found the contractual modification to be beneficial to ratepayers, examination of the contract's specific provisions is necessary because greater ratepayer benefits might have accrued if PG&E had successfully resisted the force majeure claim and allowed the contracts to terminate. Thus, we must examine the contractual provisions to evaluate the reasonableness of PG&E's decision to settle this dispute on these terms, rather than to continue to resist ACT's assertions.

The dispute underlying the [*23] proposed settlement concerns whether or not the action of Monterey County officials in requiring preparation of an EIR for ACT's project is a force majeure under the terms of the PPAs. The contracts define force majeure as

"unforeseeable causes, other than forced outages, beyond the reasonable control of and without the fault or negligence of the Party claiming force majeure including, but not limited to, acts of God, labor disputes, sudden actions of the elements, actions by federal, state, and municipal agencies, and actions of legislative judicial, or regulatory agencies which conflict with the terms of this Agreement."

The effect of force majeure on the performance required by the contracts is also addressed in the PPAs:

"If either Party because of force majeure is rendered wholly or partly unable to perform its obligations under this Agreement, that Party shall be excused from whatever performance is affected by the force majeure to the extent so affected provided that:

"(1) the non-performing Party, within two weeks after the occurrence of the force majeure, gives the other Party written notice describing the particulars of the occurrence,

"(2) the suspension [*24] of performance is of no greater scope and of no longer duration that is required by the force majeure, [and]

"(3) the non-performing Party uses its best efforts to remedy its inability to perform. . ."

The force majeure provisions of the PPAs, as applied to the facts in this dispute, are somewhat ambiguous. If the acts of state agencies (including the agencies of counties, which are subdivisions of the state (Gov. Code Section 23002)) must conflict with the terms of the agreement to qualify as force majeure, then force majeure as defined under the PPAs has not occurred. There was no allegation that the EIR requirement conflicted with any provision of the PPAs. If, on the other hand, such acts become force majeure merely by rendering a party unable to perform, in whole or in part, its obligations under the contract, then requiring the EIR could be seen as rendering ACT unable to meet the five-year deadline.

The ambiguity exists because it does not make sense to apply the limiting phrase -- "which conflict with the terms of this Agreement" -- to all of the examples listed in the definition of force majeure. Acts of God, labor disputes, and sudden actions of [*25] the elements, for example, are unlikely to conflict directly with the terms of the contracts. The limiting phrase obviously applies to the example it immediately follows -- actions of legislative, judicial, or regulatory agencies -- but it is not clear that a county's actions must be similarly limited to qualify as force majeure.

In addition, judicial interpretation of the notion of the impossibility of performing the obligations required by a contract, which underlies force majeure provisions, is somewhat in transition. The older interpretations, which required a strict impossibility of performance, have been expanded by modern courts to include extreme economic difficulty in rendering the required performance. Thus, it is not clear how courts would view the force majeure provision of the PPAs nor what would be the outcome of litigation between the parties on this issue.

E. Notice and Mitigation

The guidelines recommend a consideration of whether ACT gave notice of the claimed force majeure as required under the PPAs and whether ACT took reasonable steps to mitigate the delay cause by the force majeure.

The motion contains copies of ACT's letters [*26] to PG&E, which notified PG&E that an EIR might be required for each project. The letters were sent 14 and 15 days after ACT received notice of the EIR requirements. The letter for the Spreckels plant appears to have been sent later than the two weeks allowed under the PPA, but PG&E has not raised an issue of timely notice, so far as the joint motion reveals. It is doubtful that a one-day delay in the notice for the second plant would have detrimentally affected PG&E, and we conclude that, for the limited purpose of evaluating the settlement, ACT substantially complied with the contractual provisions on notice of the force majeure.

The motion also recites facts to support ACT's claim that it has acted to mitigate the effect of the delay on its projects. It quickly retained the hydrologic and other experts needed to perform the studies for the EIR, and it met repeatedly and successfully with County officials to limit the scope of the EIR to the question of seawater intrusion, shortening the delay. It also explored, unsuccessfully, various options to forego the EIR requirement.

We conclude that ACT has made reasonable efforts to mitigate the delay connected with the preparation [*27] of EIRs for its projects.

F. The Reasonableness of the Settlement

Uncertainty about how a court would resolve the issues raised by this dispute undoubtedly led the parties to consider a settlement. There may have been additional questions about the facts of the case and how legal doctrines concerning the impossibility of performing a contract's required duties would be applied in these circumstances. The parties have acknowledged that the expense and uncertainty about the outcome of litigation helped incline them to settle their dispute.

For similar reasons, we have consistently encouraged QFs and utilities to attempt to settle disputes that arise in the interpretation or modification of standard offers, and we have agreed to review settlements when there appears to be a legitimate underlying dispute. (See D.87-09-080.)

In this case, we believe that the ambiguous definition of force majeure in the PPAs, when applied to the facts as recited by ACT, presents a legitimate dispute that reasonable parties would attempt to resolve through negotiations.

The settlement provides substantial benefits to ratepayers when compared with the original PPAs, and PG&E's ability to [*28] curtail part of the output of ACT's projects makes it likely that ratepayers will benefit from the energy supplied by the projects. The right to curtail makes it easier for PG&E to integrate the projects into its system and to maximize the value of the projects' production for the benefit of its system and its ratepayers.

The parties have estimated that the net present value of the amendments resulting from the settlement as compared with ACT's existing PPAs is from $ 14.0 million to $ 53.5 million. We accept this range as an illustration, rather than a precise calculation, of the benefits that ratepayers may receive under the settlement.

Finally, the settlement is a final resolution of this dispute, which eliminates substantial litigation costs for both parties and protects PG&E and its ratepayers from any exposure to liability raised by these issues.

However, we have two additional reservations about the settlement as presented in the joint motion.

One minor reservation is that the pages of the settlement attached to the joint motion skip from page 6 to page 12. This appears to be a clerical error, but we obviously cannot approve any portions of the settlement that have not [*29] been presented to us.

Our second and more serious reservation concerns a provision of the settlement that states, "The Commission shall have exclusive jurisdiction and venue over the Parties with respect to any dispute or controversy arising from or in connection with this Agreement. . . ." We have many strong objections to this provision.

First, this provision incorporates a bad policy. From the very inception of the development of the standard offers and related contracts between QFs and utilities, we have viewed the resulting agreements as legally enforceable contracts between two equal parties. We have been very hesitant to engage in reviews of these agreements, because the resolution of contractual disputes is an area that our laws and traditions have delegated to the courts and similar entities for centuries. We have reluctantly become involved in some contractual disputes when the issues were closely related to our proper authority as the agency charged with the regulation of investor-owned electric utilities. (See D.82-01-103, 8 CPUC 2d 20, 81-84; D.87-09-080, mimeo. pp. 7-8.) We have recently discussed our discomfort at being asked to resolve legal matters having nothing [*30] to do with our jurisdiction and expertise that came before us as part of a QF's claim of bad faith negotiation by a utility (D.89-03-012, mimeo. pp. 23-25; D.89-04-081, mimeo. pp. 28-29).

The settlement attempts to put us in a position that is one step further removed from our proper role in the relations between QFs and utilities. The settlement agreement, the subject of this provision, is a purely legal document that was negotiated and arrived at to settle a dispute concerning other contracts, the PPAs. The disputes and controversies that may arise under this settlement agreement, over which the parties attempt to give this Commission "exclusive jurisdiction and venue," will almost certainly be narrow questions of traditional contract law. Such issues should be resolved by the courts and other agencies for dispute resolution that have the expertise, resources, and authority to address them.

Second, the legal validity of this provision appears to us to be highly questionable. We doubt that the mere agreement of two parties can force jurisdiction on a constitutional agency like the Commission, particularly when the State Constitution and the Legislature have granted other entities [*31] jurisdiction to resolve these issues. The provision also raises many other legal issues, which we will not purport to resolve, such as the nature of the Commission's jurisdiction over ACT, a private, unregulated corporation; the approaches the Commission, with its quasi-legislative and quasi-judicial powers, would use to resolve disputes and interpret the agreement; and the Commission's role in granting attorneys' fees to the prevailing party, as called for under the agreement.

Finally, we feel very strongly that the question of what types of cases come before us is a decision for the Commission, the Legislature, and the people of this state, speaking through the Legislature and the State Constitution, and not for private parties who may be seeking a convenient forum for resolving their disputes. We are not a private dispute resolution agency, and our budget and staffing limitations do not permit us to act beyond our properly prescribed functions.

We believe that the jurisdiction provision of the settlement agreement is unwise. We do not approve of that provision of the settlement, and we will not be forced by our desire to encourage settlements to accept disputes on collateral [*32] agreements that parties attempt to bring before us.

G. Conclusion

We are persuaded that, in light of all the circumstances, the settlement, subject to the reservations we have expressed in this decision and based solely on the information submitted to us, and the resulting amended PPAs are reasonable and that PG&E should be allowed to recover in rates all payments properly made under the amended PPAs.

Although we cannot approve the settlement's jurisdiction provision or any missing pages, we approve all other provisions, and we will issue the order requested in the joint motion and dismiss the complaint.

Findings of Fact

1. ACT filed a complaint against PG&E on May 8, 1989. The complaint alleged that PG&E had acted in bad faith in refusing to acknowledge a force majeure and to extend the five-year deadlines in the PPAs of ACT's Firestone and Spreckels projects.

2. On August 1, ACT and PG&E filed a joint motion, setting forth the terms of the settlement of their dispute. The parties request the Commission to find that the settlement is reasonable, to find that PG&E was prudent in entering into the settlement agreement, and to dismiss the complaint upon approval [*33] of the settlement.

3. DRA filed comments on the joint motion on August 31 and additional comments on September 28, and ACT responded to DRA's additional comments on October 6. DRA is neutral on the question of the reasonableness of the settlement, and DRA did not request hearings.

4. ACT claims that the actions of Monterey County officials in requiring an EIR for its projects is a force majeure as defined in the projects' PPAs.

5. The settlement amends the PPAs for ACT's Firestone and Speckels projects. The amendments extend the five-year deadline to no later than May 1, 1991, release PG&E from any obligation to pay for capacity from the projects before May 1, 1991, and grant PG&E the right to curtail generation at each project as low as 37 MW for up to 2000 off-peak and super off-peak hours each year.

6. The parties estimate that the ratepayer benefits resulting from the amendments as compared with ACT's original PPAs for the two projects have a total net present value ranging from $ 14.0 million to $ 53.5 million.

7. The declarations and exhibits attached to the joint motion support the contentions that ACT gave timely notice to PG&E when it became aware of the [*34] force majeure, that ACT has attempted to mitigate the delay caused by the force majeure, and that the projects are viable but for the force majeure.

8. The settlement is the final resolution of the parties' dispute.

Conclusions of Law

1. Under the facts alleged by ACT, ACT has a colorable claim to force majeure under the wording of its contracts with PG&E.

2. The portion of the definition of force majeure contained in the PPAs that relates to this case is ambiguous.

3. In light of the wording of the PPAs, the trend of the law on impossibility of performance, and the facts alleged by ACT, the outcome of litigation of the dispute between PG&E and ACT is uncertain.

4. The settlement between ACT and PG&E is a fair and reasonable compromise of the parties' dispute.

5. Substantial ratepayer savings are likely to result from the amendments to the PPAs required by the settlement.

6. Except for the reservations noted in this decision, the settlement and amended PPAs entered into between ACT and PG&E are reasonable, and PG&E was prudent in entering into the settlement with ACT.

7. This complaint should be dismissed as requested by the parties.

ORDER [*35]

IT IS ORDERED that:

1. Except for subparagraph 9(j) and any material contained on pages 7 through 11, and based on the information presented in the joint motion, the settlement entered into by Pacific Gas and Electric Company and American Cogen Technology, Inc. (ACT) in connection with ACT's Firestone and Spreckels cogeneration projects in Monterey County is a reasonable resolution of the dispute concerning the interpretation and application of the force majeure provision of the power purchase agreements for those projects.

2. Except as limited in Ordering Paragraph 1, the joint motion for an order approving the settlement and dismissing the complaint is granted.

3. ACT's complaint is dismissed with prejudice.

This order is effective today.

Dated November 22, 1989, at San Francisco, California.

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1989 Minn. PUC LEXIS 107 printed in FULL format.

In the Matter of the Petition of Rosemount Cogeneration Joint Venture, Biosyn Chemical Corporation, and Oxbow Power Corporation for an Order Resolving a Dispute with Northern States Power Company

DOCKET NO. E002/CG-88-491

Minnesota Public Utilities Commission

1989 Minn. PUC LEXIS 107

May 11, 1989

PANEL:
[*1]

Barbara Beerhalter, Chair; Cynthia A. Kitlinski, Commissioner; Norma McKanna, Commissioner; Robert J. O'Keefe, Commissioner; Darrel L. Peterson, Commissioner

OPINION:
ORDER GRANTING PETITION, CONSTRUING CONTRACT, AND REQUIRING PAYMENT OF COSTS AND ATTORNEYS' FEES

PROCEDURAL HISTORY

On July 19, 1988, Rosemount Cogeneration Joint Venture (Joint Venture or the Petitioners) and its general partners, Biosyn Chemical Corporation (Biosyn) and Oxbow Power Corporation filed a Petition with the Minnesota Public Utilities Commission (the Commission) under Minn. Stat. Section 216B.164 (1988). The Joint Venture asked the Commission to resolve disputes between Northern States Power Company (NSP) and the Joint Venture relating to NSP's purchase of electricity and capacity to be provided from the Joint Venture's operation of a qualifying cogeneration facility (the Facility) to be located in Rosemount, Minnesota. Specifically, the Joint Venture asked the Commission to compel NSP to honor the terms of a contract which provides for the purchase and sale of electrical energy and capacity made available by the Facility to NSP.

NSP and Biosyn had executed an Agreement on January 3, 1986 providing that [*2] NSP would buy and Biosyn would sell cogenerated electrical energy and capacity from the Facility under the terms and conditions specified therein. The Agreement was amended on April 1, 1986 and was assigned by Biosyn to the Joint Venture on January 29, 1988.

On August 3, 1988, the Commission directed NSP to respond to the Joint Venture's petition.

NSP filed its Answer to Petition on August 10, 1988. In general, NSP alleged that the January 3, 1986 Agreement was for a different facility to be built at a different time from that now proposed by the Joint Venture. NSP requested that the matter be referred to the Office of Administrative Hearings for a contested case hearing.

On September 2, 1988, the Commission issued its Notice and Order for Hearing directing that a contested case hearing be held on the Petition.

On September 21, 1988, a Pre-Hearing Conference was held before John W. Harrigan, Administrative Law Judge. A Pre-Hearing Order was issued on September 26, 1988, establishing the hearing schedule and procedural guidelines governing the conduct of the case, including provisions for discovery, the filing of testimony, procedures for the evidentiary hearing and a briefing [*3] schedule. At the request of the Joint Venture and NSP, a Protective Order regarding the use of confidential and proprietary data was entered on October 10, 1988. The Department of Public Service (DPS or the Department) did not consent to the Order but notified the parties that it would be governed by its "Notice of Amended Internal Procedures for Handling Trade Secret Information".

The hearing was conducted by the ALJ from November 14-18, 1988. Prefiled direct and rebuttal testimony, along with accompanying exhibits, was admitted at the hearing and witnesses for the parties were cross-examined.

John O'Sullivan and Keith Kriebel, Chadbourne & Parke, 1101 Vermont Avenue N.W., Washington, D.C. 20005 and Rodney A. Wilson, Rodney A. Wilson Law Office, 701 Fourth Avenue, Minneapolis, MN 55415 appeared on behalf of the Joint Venture; David Lawrence, Northern States Power Company, 414 Nicollet Mall, Minneapolis, MN 55401 and Samuel L. Hanson and Michael C. Krikava, Briggs and Morgan, P.A., 2400 IDS Center, Minneapolis, MN 55402 appeared on behalf of NSP; Joan C. Peterson and Maria E. Christu, Special Assistant Attorneys General, 1101 Bremer Tower, St. Paul, MN 55101 appeared on behalf [*4] of the Department; Stuart Mitchell, Commission Staff, 780 American Center Building, 160 E. Kellogg Boulevard, St. Paul, MN 55101 appeared on behalf of the Commission.

The record closed on January 3, 1989.

The ALJ issued his Findings of Fact, Conclusions of Law, Recommendation and Memorandum on February 3, 1989.

On February 17, 1989 the DPS filed its Request for Oral Argument and Exceptions to the ALJ Report.

On February 22, 1989, NSP filed its Request for Oral Argument and Exceptions to the ALJ's Report. On the same date, NSP filed Proposed Findings of Fact, Conclusions of Law and Recommendation.

On the following day, the Joint Venture filed its Exceptions to the ALJ's Report.

On March 14, 1989, NSP and the Joint Venture each filed a Reply to Exceptions. The DPS filed its Reply to Exceptions on March 15, 1989.

Oral Argument was held on March 16, 1989.

The Commission considered this matter on March 20, 1989 and continued deliberations on April 12, 1989.

FINDINGS AND CONCLUSIONS

The Commission has jurisdiction over this matter under Minn. Stat. § 216B.164 (1988) which governs Cogeneration and Small Power Production. Specifically, Minn. Stat. § 216B.164, subd. 5 (1986) [*5] provides that:

In the event of disputes between an electric utility and a qualifying facility, either party may request a determination of the issue by the commission.

There is no dispute between the parties that the Joint Venture intends to be a qualifying facility. On January 3, 1986, NSP and Biosyn entered into an agreement that NSP would buy and Biosyn would sell cogenerated electrical energy and capacity from a facility located in Rosemount, Minnesota. This agreement was amended by letter on April 1, 1986 which indicated that the Commission had approved the standard offer form as submitted by NSP. Under the contract, Biosyn was to build a 50-megawatt facility known as the "Rosemount Cogenerator". The facility was intended to be a qualified cogeneration facility under the Public Utility Regulatory Policies Act (PURPA) (16 U.S.C. § 824a-3 (1985 and Supp. 1988)), and the agreement, therefore, subject to the requirements of PURPA and corresponding state law. (Minn. Stat. § 216B.164 (1988) and Minn. Rules, parts 7835.0100-7835.9910.)

A dispute arose between the parties over the interpretation of certain terms of the contract. The Joint Venture claimed that by letter of January [*6] 7, 1987, NSP evidenced its intent to repudiate the agreement. On March 8, 1988, the Joint Venture and NSP met to discuss the project. On July 19, 1988, the Joint Venture filed a petition with the Commission seeking a declaratory judgment ordering NSP to carry out the terms of the contract.

This is a contract dispute. Minn. Stat. § 216B.164, subd. 5 (1988) provides that in any dispute between an electric utility and a qualifying facility the utility has the burden of proof.

Further, Minnesota law provides that any ambiguity in a contract be construed against the drafter of the contract, in this case, NSP. Naftalin v. John Wood Co., 263 Minn. 135, 142-143, 116 N.W.2d 91, 97 (1962) citing Wick v. Murphy, 237 Minn. 447, 54 N.W.2d 805 (1952).

The Commission must determine the terms and enforceability of the agreement entered into by NSP and Rosemount Cogeneration Joint Venture. The Commission will address four issues raised by the parties' dispute. First, did the parties contract for a fluidized bed boiler fueled by petroleum coke? Second, did the contract require the facility to begin operations in 1988 to qualify for the price terms in Appendix 2? Third, if not, [*7] when must the unit achieve commercial operation to qualify for them? Fourth, did NSP act in bad faith following execution of the contract?

The Commission has thoroughly reviewed the ALJ Report in this proceeding. An ALJ report is a recommendation to the Commission; it is not binding upon it. That report is part of the record before this body. It is, however, only one part of the record. The Commission has carefully analyzed the entire record: testimony and exhibits presented by parties during the contested case, the briefs, reply briefs, the ALJ Report and exceptions to it filed by the parties.

In reviewing the voluminous record before it, the Commission is governed by

Minn. Stat. § 14.60, subd. 4 (1988):

Agencies may take notice of judicially cognizable facts and in addition may take notice of general, technical, or scientific facts within their specialized knowledge. . . Agencies may utilize their experience, technical competence, and specialized knowledge in the evaluation of the evidence in the hearing record.

The Commission has drawn on its expertise, particularly in time frames for construction of generation facilities, in reviewing the record and independently deciding [*8] all legal and factual issues.

DID THE CONTRACT REQUIRE A FLUIDIZED-BED BOILER?

NSP argued that during the negotiations prior to the execution of the contract, Biosyn stated that it would build a fluidized-bed boiler, capable of using petroleum coke and other waste fuels. NSP further argued that the price term and the length of the contract was based on the flexibility and reliability of a fluidized bed. The Joint Venture argued that the plain language of the contract does not require a specific type of facility. The Joint Venture argued that the contract requires a 50 MW baseload qualifying cogeneration facility and that it proposes to deliver just that. The DPS and the ALJ agreed with Joint Venture.

The Commission finds that the contract is unambiguous on the type of facility required. The Commission agrees with Joint Venture, the DPS, and the ALJ. While the parties may have discussed only a fluidized-bed boiler capable of using petroleum coke prior to the execution of the contract, the importance of that type of a facility is not evident in the document itself. The contract requires that Biosyn build a 50 MW baseload qualifying cogeneration facility without further [*9] definition. The Commission believes that if NSP relied heavily on the type of facility to be built in determining the price to be paid for the energy generation and the length of the contract, it would have become a written contract term. In the absence of any such proviso, the Commission concludes that the parties did not contract for a fluidized bed boiler fueled by petroleum coke.

MUST THE UNIT ACHIEVE COMMERCIAL OPERATION IN 1988 TO RECEIVE THE CONTRACT PRICE?

The contract itself makes two references to a commercial operation date. The first is the definition of a commercial operation date found in Section 1.04 of the Agreement. It provides:

1.04 Commercial Operation Date. The initial date on which the Rosemount Cogenerator can reasonably be expected to operate reliably as determined by the Coordinating Committee.

The second reference to a commercial operation date is in Appendix 2 to the contract. Appendix 2 is entitled Rate Schedule and provides a rate of $16.68 per kilowatt "for Contract Term Starting on Commercial Operation Date in 1988".

NSP argued that the price set forth in Appendix 2 to the contract is for a unit achieving commercial operation [*10] on a date in 1988. The exact date was to be determined by a Coordinating Committee created by the contract. Further NSP argued that the contract is silent on any price to be paid for a unit coming on line at another time.

The Joint Venture argued that the contract does not require a commercial operation date in 1988 but within a reasonable time of the execution of the contract, that the Coordinating Committee would establish the date, and that Appendix 2 is a schedule to lock in payments as of the date of execution of the contract as is permitted under PURPA. The DPS argued that Appendix 2 locks in a price term only and that because the contract is silent on a commercial operation date, a reasonable time for performance is implied.

The ALJ found that the Agreement did not specify a commercial operation date.

The Commission finds that the 1988 reference in Appendix 2 of the contract does not prevent enforcement of the contract. Either it was not a material term of the contract, a reasonable time for performance being implied, or NSP waived performance in 1988 by its continuing to deal with Biosyn as though the contract was in effect after it was informed there would be no 1988 [*11] performance by Biosyn. The Commission agrees with the ALJ that there is substantial evidence in the record to support either rationale for its conclusion that the contract does not require performance in 1988 for the price terms of Appendix 2 to apply. Furthermore, it is the Commission's experience that development of such facilities may take four to five years. Four to five years from the January, 1986 date of the contract signing would put the unit on line in 1990-1991.

The language defining commercial operation date neither mentions nor requires commercial operation during 1988. There is no dispute here that the Coordinating Committee did not establish any commercial operation date.

NSP relies on Appendix 2 to the contract for its position that commercial operation was required in 1988.

PURPA requires that a utility permit a qualifying facility to elect to receive payments based on the utility's estimated avoided cost at the time the contract is executed. PURPA, 18 C.F.R. 292, 304 (d) (2) (ii) (1988) provides:

Each qualifying facility shall have the option . . (2) to provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or [*12] capacity over a specified term in which case, the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term be based on . . (ii) the avoided costs calculated at the time the obligation is incurred.

Biosyn made this election. The 1988 date of Appendix 2 reflects that election and locks in a price term, not a performance date. Performance is due within a reasonable time.

Even if Appendix 2 required performance in 1988, there is substantial evidence in the record to support the Joint Venture's position that NSP waived a 1988 performance date. The Commission recognizes that under the law parties to a contract have a duty to deal with each other fairly and in good faith. NSP continued to recognize the contract with Biosyn well after it was clear that the facility would not be operating in 1988. NSP did not terminate the contract, continued to ask Biosyn for information on the facility's development, and included Biosyn in its 1987 Advance plan, which lists energy source the utility will rely on for its energy supply in the future. By this behavior NSP effectively waived any performance which could arguably be [*13] due 1988.

The Commission concludes that the contract, including its price term, is enforceable under the theories discussed above.

REASONABLE TIME FOR PERFORMANCE

Having determined that the 1988 date in Appendix Two does not preclude enforcement of the contract, the Commission must determine what is a reasonable time for performance. The Commission recognizes that the development and financing of a cogeneration facility of this size is complex. Many of the steps, e.g. environmental permitting, may be outside the control of the developers. It is not uncommon for the development and financing for this type of facility to take four to five years. The Commission finds that the parties' dispute has delayed the Joint Venture's financing efforts for the facility. Considering the time loss sustained by this proceeding, the Commission finds that *performance* during 1991 is reasonable.

ALLEGATIONS OF BAD FAITH

The Joint Venture argued that if the Commission determined that the contract specified a 1988 commercial operation date for the rates found in Appendix 2, then the Commission must evaluate NSP's behavior following execution of the contract. The Joint Venture argued [*14] that NSP acted in bad faith following the execution of the contract and that that behavior rendered Biosyn unable to *perform* its *obligations*.

After thorough examination of the record, the Commission finds that NSP's conduct after the contract was executed cannot reasonably be interpreted as bad faith. NSP sought information and clarification of Biosyn's plans. NSP's need to plan for both the availability of the power and the construction of interconnection facilities to responsibly manage its electric power system required the information and clarification of plans. NSP's conduct reflects responsible management oversight, and cannot reasonably be interpreted to reach a threshold of bad faith, *but does support a view* that NSP waived *any rights* it might claim for a 1988 performance.

Finally the Commission recognizes that Minn. Stat. § 216B.164, subd. 5 (1988) provides:

The commission in its order resolving each such dispute shall require payments to the prevailing party of the prevailing party's costs, disbursements, and reasonable attorneys' fees. . .

The Commission will order NSP to pay the Joint venture all of its reasonable costs, disbursements and attorneys' fees related [*15] to this proceeding.

ORDER

1. Joint Venture's Petition is hereby granted as discussed above.

2. NSP shall pay the Joint Venture all of its costs, disbursements and reasonable attorneys' fees related to this proceeding.

3. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Mary Ellen Hennen, Executive Secretary

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1995 U.S. Dist. LEXIS 7249 printed in FULL format.

FULTON COGENERATION ASSOCIATES, Plaintiff, vs. NIAGARA MOHAWK POWER CORPORATION, Defendant.

FULTON COGENERATION ASSOCS. v. NIAGARA MOHAWK POWER CORP.

Civil No. 92-CV-1412 (FJS)

UNITED STATES DISTRICT COURT FOR THE NORTHERN DISTRICT OF NEW YORK

1995 U.S. Dist. LEXIS 7249

March 28, 1995, Decided

March 28, 1995, FILED

SUBSEQUENT HISTORY: [*1] Reconsideration Denied May 10, 1995, Reported at: *1995 U.S. Dist. LEXIS 6414.*

COUNSEL: COUCH, WHITE, BRENNER, HOWARD & FEIGENBAUM, Albany, New York, Attorneys for Plaintiff, OF COUNSEL: Leonard H. Singer.

HISCOCK & BARCLAY, Syracuse, New York, Attorneys for Defendant, OF COUNSEL: Robert A. Barrer.

NIAGARA MOHAWK POWER CORP., Syracuse, New York, Attorneys for Defendant, OF COUNSEL: Brian K. Billinson.

JUDGES: FREDERICK J. SCULLIN, JR., U.S. DISTRICT JUDGE

OPINIONBY: FREDERICK J. SCULLIN, JR.

OPINION: MEMORANDUM DECISION AND ORDER

INTRODUCTION

Fulton Cogeneration Associates ("Fulton") commenced this action on October 30, 1992, alleging that Niagara Mohawk Power Corporation ("NiMo") breached its agreement with Fulton under which NiMo was required to purchase electricity from an electric generating facility operated by Fulton in the Town of Fulton, New York. Fulton seeks $ 279,671.19 in damages for breach of contract plus pre-judgment interest of 1.5 % per month. n1

n1 NiMo admits that it owes $ 152,264.47 of the $ 279,671.19 sought and thus the dispute is over the remaining $ 127,426.72.

[*2]

On June 4, 1994, this Court denied defendant's motions to dismiss the complaint under 12(b)(1), which defendant based on principles of abstention and primary jurisdiction. On October 11, 1994, this Court denied both parties' motions for summary judgment and denied Fulton's motion for Rule 11 sanctions. The matter was scheduled for a final pre-trial conference and a bench trial to commence on March 27, 1995. The parties submitted trial briefs and a joint stipulation of undisputed facts. After reviewing the trial submissions, the court sua sponte raised the issue of reconsidering the summary judgment motions, and offered both parties an opportunity to come forward with evidence. See *Celotex Corp. v. Catrett, 477 U.S. 317, 326, 91 L. Ed. 2d 265, 106 S. Ct. 2548 (1986).* The court heard oral argument on the summary judgment motion on March 27, 1995.

BACKGROUND

I. Regulatory Background

Under the federal statutory framework, utilities are required to purchase all the energy that non-utility generators produce. Public Utility Regulatory Policies Act, *16 U.S.C. § 824* et seq. New York State Public Service Law § 66-c established a minimum sale price of 6 [cents] per kilowatthour [*3] ("6 [cents] /Kwh") for energy sold by qualifying non-utility generators pursuant to contracts approved by the State. In 1992, the law was amended eliminating that minimum rate for contracts entered into after June 26, 1992, but retaining it for contracts entered into and filed with the Public Service Commission ("PSC") prior to June 26, 1992 and which provided for the purchase of electricity at a utility tariff rate referencing a statutory minimum sales price.

In addition, the PSC is responsible for approving contracts between qualifying facilities and utilities to ensure they are entered into under such terms and conditions that are just and reasonable to rate payers.

II. Factual Background

On December 10, 1987, Turner Power Group, Inc., plaintiff Fulton's predecessor in interest, entered into an output contract with NiMo. The recital clause to the agreement provides for Fulton to operate a facility with a capacity of "approximately 47.0 megawatts, and with expected annual production of approximately 392,000 Megawatt-hours." n2 Agreement Whereas Clause. The operative clauses provide for Fulton to deliver and NiMo to accept all of the "electricity" produced at the plant, net [*4] of amounts used by the plant or sold elsewhere. The contract further provides for NiMo to pay for the electricity at the rate established in NiMo's tariff, which is 6 [cents] /Kwh. The contract was approved by the PSC on April 20, 1988.

n2 The term "capacity" refers to the amount of electric power that an electric generator can produce, and is measured in kilowatts or megawatts. The term "energy" is the usage of power or capacity over a period of time and is measured in kilowatthours or megawatthours. See Joint Pretrial Stipulation PP 8, 9.

The plant commenced operation in July 1991 and began selling electricity to NiMo. NiMo installed meters to monitor both the capacity and kilowatthours produced at the plant. From July 1991 through April 1992, NiMo bought all the electricity delivered by Fulton and paid based on kilowatthours at a rate of 6 [cents] /Kwh.

On March 13, 1992, NiMo informed Fulton that the plant was producing above a 47 megawatt capacity. Because it believed it was not required to pay [*5] for production above that level, NiMo stated that it would use a formula ("Demonstrated Maximum Net Capacity" or "DMNC") to measure the capacity of the plant. If the capacity was over the 47 megawatts provided in the contract, NiMo would only pay the 6 [cents] /Kwh rate for the proportion of energy attributable to a 47 megawatt capacity. Any excess would be paid at a market rate, which was lower than the 6 [cents] /Kwh contract rate.

Application of NiMo's formula measured a capacity of 50 megawatts. NiMo thereafter paid for 47/50ths of the electricity at the 6 [cents] /Kwh rate and the rest at a market rate. NiMo used this pricing method from May 1992 through October 1992. After October 1992, it began paying the 6 [cents] /Kwh rate again. The use of the formula resulted in Fulton being paid $ 279,691.19 less than it would have received at the contract rate.

Because of the alleged underpayment, Fulton instituted this action for breach of contract.

DISCUSSION

I. The Contract Action

"The primary objective in contract interpretation is to give effect to the intent of the parties 'as revealed by the language they chose to use.'" *Sayers v. Rochester Telephone. Corp. Pension [*6] Plan, 7 F.3d 1091, 1094-95 (2d Cir. 1993).* Where the terms of a contract are clear and unambiguous, the court will not look beyond the four corners of the document to determine what the parties meant. *Mysack v. Honeywell, Inc., 953 F.2d 798, 802 (2d Cir. 1992);* Cibro Petroleum Products, Inc. v. Sohio Alaska Petroleum Corp., 602 F. Supp. 1520 (N.D.N.Y. 1985) (Munson, C.J.), aff'd, 298 F.2d 1421 (2d Cir. 1986). "No ambiguity exists when contract language has 'a definite and precise meaning, unattended by danger of misconception in the purport of the [contract] itself, and concerning which there is no reasonable basis for a difference of opinion.'" *Sayers, 7 F.3d at 1094-95.* Further, the court must read the provisions in the context of the entire agreement, and must safeguard against adopting an interpretation that would render any individual provision superfluous. Id.

The pertinent provisions of the contract are:

WHEREAS, SELLER will own and operate an electric generating plant ... with a capacity of approximately 47.0 megawatts, and with expected annual production of approximately 392,000 Megawatt-hours (individually and together referred to as "ELECTRICITY") [*7] ....

....

FOURTH: SELLER shall deliver to NIAGARA AND NIAGARA shall accept all of the ELECTRICITY produced at the plant net of parasitic loads subject to the terms and conditions of this Agreement.

....

NINTH: ... NIAGARA will pay SELLER monthly for ELECTRICITY received from SELLER at the applicable rates contained in NIAGARA's [SC-6 Tariff], applicable for payments to qualifying on-site generation suppliers, as defined in the Public Service Law ....

The parties agree that Philadelphia Corp. v. Niagara Mohawk Power Corp., No. 71149, slip op. (N.Y. A.D., 3d Dep't Jan. 19, 1995) (construing output contracts which "define the electricity to be sold in terms of approximate annual production") controls the court's analysis of the contract presently at is sue. n3 The Philadelphia court reasoned that because output contracts allow the seller to control the output, and thus the purchaser's obligation to buy, "obligations arising under an output contract are subject to good faith and commercial standards of fair dealing." Philadelphia, slip op. at 2 (citing U.C.C. § 2-306). The court held that the language describing the approximate annual production was [*8] merely an estimate. n4 The court further held that such language unambiguously provides that "defendant is obligated to purchase and plaintiffs are obligated to sell electricity in such quantities which are not unreasonably disproportionate to the stated estimates within the contracts." Id. "While the estimates are not absolute maximum quantities beyond which the contracts do not apply ... neither may plaintiffs modify their outputs beyond the normal range commercially consistent with the capacity estimates used in the contracts." Id. Thus, "plaintiffs may not under the contracts increase their electrical output beyond the reasonable expectations of the parties as quantified by the stated estimates." Id. at 2-3.

n3 It should be noted that despite agreeing that Philadelphia is controlling authority, defendant still maintains that the 47 megawatt capacity is a maximum limit and not an estimate.

n4 Indeed this proposition seems indisputable since the PSC has even recognized that the use of the word "approximately" in the recital clause "is generally understood to refer to an inescapable imprecision with respect to the expected output of a planned facility." NYPSC Case No. 88-E-114, Indeck-Yerkes Energy Services, Inc., at 3 (Sept 14, 1988), ultimately aff'd by *164 A.D.2d 618, 564 N.Y.S.2d 841* (3d Dep't 1991).

[*9]

This court agrees with the Philadelphia court and holds that the contract language unambiguously obligates NiMo to purchase and Fulton to sell electricity in such quantities that are not unreasonably disproportionate to the stated estimates within the contract. See Philadelphia, slip op. at 2-3.; N.Y. U.C.C. § 2-306.

Further this court finds, as a matter of law, that Fulton's production never exceeded commercially reasonable expectations. The parties stipulate that Fulton never produced more than 392,000 megawatthours of energy annually--the estimate contemplated in the contract. Moreover, the parties stipulate that "the term 'energy' is the usage of power or capacity over a period of time and is measured in kilowatthours ... or megawatthours .... and under the Agreement, Fulton provides only energy to [NiMo]." n5 Joint Pretrial Stipulation PP 9, 10. Because the contract only contemplates the sale of energy measured in kilowatthours, and not capacity, see Joint Pretrial Stipulation PP 10, 11, the relevant inquiry is confined to whether Fulton produced an amount of energy unreasonably disproportionate to the stated estimates. Because the production never exceeded [*10] the amount contemplated in the contract, Fulton did not produce an amount of energy unreasonably disproportionate to the stated estimates. Therefore, NiMo breached the contract by not purchasing at the contract rate all of the energy produced by Fulton.

n5 Those stipulations are further buttressed by the contract language which links payment only to kilowatthours. See Contract Paragraph NINTH.

The court also finds that even if it were to look at the capacity levels as measured by NiMo, n6 there is no genuine issue of material fact whether such levels are unreasonably disproportionate to the stated estimates. The two cases upon which NiMo relies lead us to this result. See NYPSC Case No. 90-E-238, American Ref-Fuel Co. (Aug. 22, 1990) and NYPSC Case No. 88-E-114, Indeck-Yerkes Energy Services, Inc. (Sept. 14, 1988), ultimately aff'd by *164 A.D.2d 618, 564 N.Y.S.2d 841* (3d Dep't 1991).

n6 The court notes that plaintiff would value the level of capacity by looking at the average annual capacity. Under plaintiff's valuation, the average annual capacity is the annual production (approximately 380,000 megawatthours) divided by the number of hours in a year (8760 hours), which equals 43.4 megawatts.

[*11]

In American Ref-Fuel, the PSC found that increases in capacity "form the basis for a new contract price if there is a design change and the magnitude of the increase is a material alteration not contemplated under the approval of the original contract." American Ref-Fuel Co. at 9. The PSC then held that the size increase in the case, from 63.5 MW to 65.25 MW, or 2.75%, was insubstantial because it did not result from a design change and because it was relatively small compared to other cases. See American Ref-Fuel Co. at 9 n.2 (citing Indeck (9% increase due to design change); PSC Case No. 28689, United Development Group II, (June 13, 1989) (15.5% increase); PSC Case No. 28689, Niagara Mohawk Power Corp. and Cogen Energy Technology, Inc., (Jan. 11, 1989) (50% increase); PSC Case No. 28689, Niagara Mohawk Power Corp. and Shawmut Engineering (Oct. 14, 1987) (30% increase)). In Indeck-Yerkes, the PSC held that a 9% increase in a plant's capacity was a substantial increase that was not within the contemplation of the parties at the time the contract was executed because it was due to changes in design and construction. See NYPSC Case No. 88-E-114, [*12] Indeck-Yerkes Energy Services, Inc. (Sept. 14, 1988), ultimately aff'd by *164 A.D.2d 618, 564 N.Y.S.2d 841* (3d Dep't 1991).

Here a 3 megawatt or 6% increase in capacity cannot be considered significant or unreasonably disproportionate to the stated estimates. First, there is no evidence in the record that the increase is the result of any bad faith or contrivance. Second, any increase in capacity is the result of expected variations, not a design change. Lastly, the excess capacity, which NiMo calculated based upon a single four hour period, is insubstantial compared to the cases cited by American Ref-Fuel. Defendant has not identified and the court has found no case in which such a small increase was found to be substantial absent a post-contract design change or modification.

Moreover, the court notes that while the reference to capacity in an energy purchase contract is important for NiMo as a public utility to plan for future electric needs--so as to match generation and load--such considerations are not determinative of the issues present in this case. n7 The law as it existed at the time required NiMo to purchase all the energy produced by Fulton. See N.Y. Pub. Serv. Law § [*13] 66-c. Moreover, as the parties stipulated, the contract was for the purchase of energy not capacity. As long as the plant was operating within its expected level of energy production, the focus remains on energy production. It is only when the energy production exceeds expectations that the parties look to capacity. In such cases the court must then look to whether the increased production was related to an increase in capacity not contemplated by the parties. Philadelphia Corp. v. Niagara Mohawk Power Corp., No. 71149, slip op. (N.Y. A.D., 3d Dep't Jan. 19, 1995). In this case, energy production never exceeded the 392,000 megawatts contemplated by the estimates. Furthermore, looking to capacity in the context of this case, the stipulated facts show that NiMo measured capacity during the "highest consecutive four hour output during the Summer [of 1991]." Joint Pretrial Stipulation P 32. During that interval, the capacity of the plant was 50 megawatts. Joint Pretrial Stipulation P 31. Therefore, it cannot reasonably be inferred that this increase in capacity interfered with NiMo's ability to plan for future electric needs nor did it materially exceed the reasonably expected levels [*14] of generation. See Philadelphia, slip op. at 2-3; NYPSC Case No. 88-E-114, Indeck-Yerkes Energy Services, Inc. (Sept. 14, 1988), ultimately aff'd by *164 A.D.2d 618, 564 N.Y.S.2d 841* (3d Dep't 1991); NYPSC Case No. 90-E-238, American Ref-Fuel Co. (Aug. 22, 1990).

n7 See Indeck, at 3 ("Planning for future electric needs thus requires firm estimates of the expected amount and timing of on-site generation that will be sold to utilities.").

For all the foregoing reasons, plaintiff is granted summary judgment as a matter of law.

II. Pre-Judgment Interest

Under New York law "when a contract provides for interest to be paid at a specified rate until the principal is paid, the contract rate of interest, rather than the legal rate set forth in CPLR 5004, governs until payment of the principal or until the contract is merged in a judgment." *Citibank v. Liebowitz, 110 A.D.2d 615, 487 N.Y.S.2d 368* (2d Dep't 1985).

Paragraph NINTH of the contract provides: "Any amount remaining unpaid after the time it is [*15] due shall thereafter be subject to a late payment charge equal to the amount provided for in NIAGARA's then current tariff PSC No. 207, Electricity, or in such subsequent tariffs as may be in effect from time to time. The charge is currently equal to 1 1/2% per month applied to the unpaid balance."

The tariff rate at the time the balance became overdue was 1.5% per month, and that is what plaintiff is entitled to.

Therefore, it is hereby

ORDERED that plaintiff is GRANTED summary judgment, and it is further

ORDERED that the plaintiff be awarded $ 279,671.19 in damages for breach of contract plus pre-judgment interest of 1.5 % per month.

IT IS SO ORDERED.

DATED: MARCH 28, 1995

SYRACUSE, NEW YORK

U.S. DISTRICT JUDGE

FREDERICK J. SCULLIN, JR.

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1992 N.Y. PUC LEXIS 52 printed in FULL format.

Erie Energy Associates - Petition For a Declaratory Ruling That Its Power Purchase Contract With New York State Electric & Gas Corporation Remains in Effect

Case 92-E-0032

New York Public Service Commission

1992 N.Y. PUC LEXIS 52

March 4, 1992

PANEL:
[*1]

COMMISSIONERS PRESENT: Peter Bradford, Chairman; Gail Garfield Schwartz; James T. McFarland; Henry G. Williams

OPINION:
At a Session of the Public Service Commission held in the City of Albany on February 20, 1992

DECLARATORY RULING

(Issued and Effective March 4, 1992)

BY THE COMMISSION:

On January 9, 1992, Erie Energy Associates (Erie) filed a petition asking for a ruling establishing that its power contract with New York State Electric & Gas Corporation (NYSEG) remains in effect. n1 The utility, in a letter dated November 15, 1991, had cancelled the contract on the ground that Erie had breached it by failing to post a deposit payment of $ 180,000 due on November 14, 1991. The relief the developer requests will not be granted.

n1 Contract No. 468 between Erie and NYSEG, approved in a Letter Order issued in Case 28689 on May 14, 1990, provides for power purchases from Erie's proposed 28 MW qualifying facility (QF) fueled with waste tires to be located in Lackawanna, New York.

This is essentially a contractual dispute between a utility and a potential supplier, not different from such disputes when they involve fuel, labor or equipment. These are not subject to our regulation [*2] under normal circumstances, unlike a dispute between a utility and a consumer. NYSEG's decision to cancel the contract, however, is subject to prudence review. Given the potential for that review, any utility should explore the possibility that restructuring of contract price and other terms, rather than contract cancellation, could be beneficial.

POSITIONS OF THE PARTIES n1

n1 Because Erie requested expedited treatment for its petition, it was not possible to evaluate late-filed comments in support of Erie's project from the New York State Department of Environmental Conservation (received February 11, 1992), the New York State Department of Economic Development (received February 19, 1992) and Dennis T. Gorski, Erie County Executive (received February 19, 1992).

Erie's Petition

Erie begins by asserting that its tire-burning facility will alleviate the waste tire disposal problem in New York State and will improve economic conditions in the financially-distressed City of Lackawanna. Erie also claims it has made substantial progress in obtaining all necessary environmental and local permits, and contends its parent, Oxford Energy Company, has built a successful [*3] tire-burning facility in Connecticut.

Erie next describes the deposit milestones included in its contract with NYSEG, in conformance with the milestone policy. n2 Under those milestones, Erie was required to deposit $ 120,000 within six months from the date of approval of the contract, post an additional $ 180,000 within one year after the first deposit was due, and post $ 150,000 more on or before the commencement of construction milestone date, which was set at 28 months after contract approval. A failure to post any of the deposits permitted NYSEG to cancel the agreement.

n2 Case 88-E-087, et al., Opinion and Order Establishing Milestone and Contract Conversion Procedures, Opinion No. 88-28 (Issued November 10, 1988) and Opinion and Order Clarifying Milestone and Contract Conversion Procedures, Opinion No. 88-28(A) (Issued June 2, 1989) (Milestone Opinions).

Although it timely posted the first deposit, Erie admits it did not attempt to post the second deposit, due on November 14, 1990, until December 10, 1991. Erie excuses its late posting on the grounds that City of Lackawanna elections in early November 1991 resulted in the defeat of the mayor and a city council [*4] member who had supported the project. Erie complains it needed the support of the newly-elected officials before it could post the deposit.

Erie reports that, on November 13, 1991, the day before the deposit was due, it wrote NYSEG and asked for a five-month extension to post, in order to seek assurances of support from the new officials. Despite NYSEG's failure to grant the extension, and its cancellation of the contract in writing on November 15, 1991, Erie says it continued its effort to obtain those assurances. Following the success of those efforts, the developer relates, it tendered its deposit on December 10, 1991, but the utility promptly rejected it.

Erie maintains that, under these circumstances, a narrow, fact-specific exception from the milestone policy should be created, and NYSEG should be advised to excuse the delay in the posting of the second deposit. According to Erie, it needed only a short extension of time to evaluate the temporary "municipal election risk" and its project is not otherwise speculative. The developer insists that NYSEG's refusal to grant the short extension was unreasonable.

Erie also references precedent which it alleges supports its position. [*5] Erie finds in the Milestone Opinions support for interpreting the second deposit as intended to measure a developer's ability to obtain its environmental permits. Consequently, Erie asserts, its failure to post that deposit should be excused because the "municipal election risk" it faced differed substantially from the risk of failure to obtain environmental permits contemplated under the second deposit milestone. Erie also argues that a prior request for extension of a milestone was considered on its merits, n1 and that at least one facility has been exempted from compliance with the Milestone Opinions. n2

n1 Case 89-E-162, Island Cogeneration Associates, Declaratory Ruling (Issued December 27, 1989) (Island Cogen Ruling).

n2 Case 28689, Niagara Mohawk Power Corporation and Inter-Power of New York, Inc. - Contract No. 512, Letter Order (Issued May 16, 1988) (Inter-Power Order).

NYSEG's Reply

On January 31, 1992, NYSEG replied to Erie. NYSEG argues that the petition should be denied, because we have previously decided that we will not intervene in breach of contract disputes such as this. Asserting that Erie's arguments in support of its petition are meritless, [*6] NYSEG criticizes the developer's request for a delay of five months in posting the deposit, which it characterizes as unreasonable in length. NYSEG also objects to the timing of the request for delay, presented on the day before the deposit was due.

NYSEG disputes Erie's interpretations of precedent. The utility contends that the milestones were intended to objectively measure a developer's ability to go forward, given the circumstances that exist on the date the milestone falls. The utility maintains that the relief Erie requests -- extension of a milestone because of force majeure or other excuse -- was explicitly rejected in the Milestone Opinions. As the utility sees it, Erie made a decision to breach the contract although fully aware of the potential consequences, and, consequently, there is no reason to create a loophole allowing it to escape its choice. NYSEG concludes that its decision to terminate this contract was justified under the milestone policy and this contract's milestone clause, and was in the best interests of its ratepayers. n1

n1 According to NYSEG, its ratepayers would pay $ 55 million more for Erie's electricity than it is worth during the first 15 years of the contract term.
[*7]

DISCUSSION AND CONCLUSION

Erie's petition will not be granted. Jurisdiction under the Public Utility Regulatory Policies Act of 1978 (PURPA) and PSL § 66-c is generally limited to supervision of the contract formation process. n2 Once a binding contract is finalized, however, that jurisdiction is usually at an end. n1 As we explained it in the Northeast Ruling:

We will not generally arbitrate disputes between utilities and developers over the meaning of contract terms, because such questions do not involve our authority, under PURPA and PSL § 66-c, to order utilities to enter into contracts. Requests to arbitrate disputes over breach of contract issues are simply beyond our jurisdiction, in most cases. n2

n2 Case 90-E-0975, Northeast Cogen, Inc., Declaratory Ruling (Issued April 8,

1991) (Northeast Ruling); see also Case 89-E-207, Long Island Lighting Company and American Ref-Fuel Company of Hempstead, Declaratory Ruling (Issued January 4, 1990) (Ref-Fuel Ruling).

n1 Continuing jurisdiction is exercised only over a few contract clauses, generally where required by statute or regulation. See, e.g., Case 88-E-081, Order Denying Rehearing and Clarifying Prior Order (Issued December 12, 1989).

n2 Northeast Ruling, p. 5. [*8]

Exercising the plenary jurisdiction over contract terms that Erie desires is not possible, n3 because the PURPA regulations provide that contractual arrangements between a QF like Erie and the utility purchasing its power are binding and beyond state interference. n4 Indeed, contracts that included clauses requiring the exercise of continuing jurisdiction over all contract terms were denied approval until modified. n5 Erie has not justified a departure from the policy of declining to decide breach of contract questions, or identified a source for the authority to exercise jurisdiction over such issues. n1

n3 Although Erie couches its petition as a request to revise our milestone policies, the relief it desires would require revision of the contractual milestone terms as well.

n4 18 C.F.R. § 292.304(d); Case 28689, Niagara Mohawk Power Corporation and Dresser-Rand Company, Order Approving Contract Subject to Conditions and Denying Petition (Issued June 19, 1989), pp. 10-11.

n5 See Case 90-E-0285, New York State Electric & Gas Corporation and Empire Energy Niagara L.P. - Contract No. 480, Letter Order (Issued July 23, 1990).

n1 While, as in the Ref-Fuel Ruling, policies that existed at the time a contract was approved may be clarified later, Erie's citations do not demonstrate that clarification of the milestone policies is needed. Both the Milestone Opinions and the Island Cogen Ruling unequivocally reject arguments, like Erie's, in favor of excusing missed milestones. The Inter-Power Order is not relevant, because, unlike Erie and all other QFs now under contract, that developer is subject to PSL Article VIII. [*9]

Moreover, intervention in this sort of dispute would lead to frequent petitions requesting resolution of other contract controversies between utilities and suppliers of all sorts. Nothing about such disputes is unique to utility regulation or to utility consumer production. These are disputes between businesses, better resolved, according to commercial law principles, through negotiation, arbitration, or the courts.

Opinion No. 91-2, n2 however, stated that utility managements are expected to make power supply decisions prudently, and are compensated accordingly. In making such judgments, NYSEG should consider all the facts and circumstances, and should not view contract cancellation as the only alternative. When a potentially beneficial project encounters difficulty, restructuring the contract to realize the benefits and shield ratepayers against the potential for overpayments should be explored. n1 n2 Case 90-E-0675, et al., Opinion and Order Establishing Power Purchase Contract Policies and Procedures (Issued February 25, 1991).

n1 The preexisting contract is a factor which may be considered during such restructuring negotiations. See Case 90-E-0289, *Oxbow Power Corporation,* Order Denying Rehearing (Issued September 10, 1990) and Declaratory Ruling (Issued June 20, 1990). [*10]

Accordingly, we find and declare that we will not grant the petition to resolve the dispute between Erie Energy Associates and New York State Electric & Gas Corporation, although the prudence of the utility's overall approach to this dispute and others like it may be reviewed in an appropriate proceeding.

By the Commission

19

1995 Pa. Commw. LEXIS 344 printed in FULL format.

ARMCO ADVANCED MATERIALS CORPORATION and ALLEGHENY LUDLUM CORPORATION, Petitioners v. PENNSYLVANIA PUBLIC UTILITY COMMISSION, Respondent; WEST PENN POWER COMPANY, Petitioner v. PENNSYLVANIA PUBLIC UTILITY COMMISSION, Respondent

ARMCO ADVANCED MATERIALS CORP. v. PENNSYLVANIA PUC

No. 3280 C.D. 1994, No. 12 C.D. 1995

COMMONWEALTH COURT OF PENNSYLVANIA

1995 Pa. Commw. LEXIS 344

June 8, 1995, Argued

July 20, 1995, Decided

July 20, 1995, Filed

SUBSEQUENT HISTORY: As Amended August 25, 1995.

PRIOR HISTORY: [*1] APPEALED From No. Docket No. P-880286. State Agency: Pennsylvania Public Utility Commission.

COUNSEL: Michael L. Kurtz for petitioners Armco Advanced Materials

Corporation and Allegheny Ludlum Corporation.

ATTORNEYS: Theresa J. Colecchia for petitioner West Penn Power Company.

ATTORNEYS: Lee E. Morrison, Assistant Counsel, for respondnet.

JUDGES: BEFORE: HONORABLE DAN PELLEGRINI, Judge, HONORABLE ROCHELLE S. FRIEDMAN, Judge, HONORABLE SILVESTRI SILVESTRI, Senior Judge.

OPINIONBY: DAN PELLEGRINI

OPINION:
OPINION BY JUDGE PELLEGRINI

FILED: July 20, 1995

West Penn Power Company (West Penn) and Armco Advanced Materials Corporation and Allegheny Ludlum Corporation (Industrials), two large industrial customers of West Penn, petition for review of an order of the Pennsylvania Public Utility Commission (PUC) recalculating the amount West Penn is to pay for power from a qualifying facility n1 (QF) called the Shannopin project to be built by Mon Valley Energy Corporation (Mon Valley). West Penn and the Industrials contend the amount to be paid for this power is excessive because the PUC used improper factors in calculating the amount to be paid for power produced by the Shannopin QF. [*2] The amount to be paid for QF power ordered by the PUC here was based on a recalculation of the avoided cost in response to a remand from this court, in *West Penn Power Company v. Pennsylvania Public Utility Commission, 154 Pa. Commonwealth Ct. 136, 623 A.2d 383,* appeals discontinued, *535 Pa. 662, 634 A.2d 225, 227 (1993)* (Shannopin III). We directed the PUC to make a new calculation of the amount to be paid to a QF, called the capacity cost rate, using inputs and criteria appropriate for October 15, 1987, the date of the "legally enforceable obligation" between West Penn and Mon Valley.

n1 A "qualifying facility" or QF is the common term for cogeneration facilities and small power production facilities as defined in the Public Utility Regulatory Policies Act of 1978 (PURPA), and the implementing regulations promulgated by the Federal Energy Regulatory Commission (FERC).

A "cogeneration facility" is one that produces both electric energy and steam or some other form of useful energy, such as heat. *16 U.S.C. § 796*(18)(A). A "small power production facility" is one that has a production capacity of no more than 80 megawatts (MW) and uses as a primary energy source biomass, waste, geothermal resources or renewable resources such as wind, water or solar energy to produce electric power. *16 U.S.C. § 796*(17)(A).

[*3]

I.

To understand the issues in this case, it is first necessary to give the history of the Shannopin QF. n2 The Shannopin QF project was one of a number of projects agreed to by West Penn so that the purchase of QF power would replace its portion of a 900 MW, coal-fired power station comprised of three units at one facility which was planned by West Penn's parent company, Allegheny Power Systems, Inc. n3 The first unit of the power station was planned to come on-line in 1995, the second and third units in 1997 and 1998. After lengthy negotiations, on October 15, 1987, the parties had entered into an electric energy purchase agreement (EEPA) for the Shannopin project. The agreement stated that Mon Valley would build the Shannopin facility to be an 80 MW output coal-fired cogeneration facility with a steam host. The EEPA had a term of thirty years and originally stated Shannopin would come on line in September of 1992. The EEPA provided that Mon Valley would receive a capacity credit of 4 cents per kilowatt hour for capacity, based on West Penn's calculation of its avoided costs n4 for a portion of the planned 900 MW power station. The avoided costs contained in the EEPA were based [*4] on West Penn's projections at the time of "serious negotiations" with Mon Valley in September of 1986. At the same time, West Penn made agreements with two other QFs so that the three combined would replace its portion of the 900 MW plant. The anticipated power station was expected to meet West Penn's demand for power beginning in 1995. Because of litigation delays, the Shannopin QF has not yet been built.

n2 For a discussion of PURPA and how it relates to the history between West Penn and Shannopin and related QFs, see West Penn Power Company v. Pennsylvania Public Utility Commission, Pa. Commonwealth Ct. , A.2d (*No. 107 C.D. 1995,* filed May 25, 1995).

n3 The 900 MW power station was planned to meet the power needs of several subsidiaries of Allegheny Power Systems, Inc. The other subsidiaries also became involved in QF purchase arrangements to otherwise meet their needs.

n4 Avoided costs are calculated when a QF "offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit ... then the rates for such a purchase will be based on the avoided capacity and energy costs." 18 C.F.R. § 292.101(b)(6).

[*5]

One of the other QF projects that was intended to replace the 900 MW power station was being developed by North Branch Energy Partners (now Washington Power Company) at Burgettstown. The EEPA for that QF project was signed on the same date the EEPA was signed for Shannopin, and the Burgettstown project would also be an 80 MW cogeneration facility. The EEPA with Burgettstown provided for a capacity cost rate of 3.6 cents per kilowatt hour and the term of the EEPA was for 33 years rather than the 30-year term of the EEPA for Shannopin. The capacity cost rate was lower for the Burgettstown project because it was expected to be in service as of October of 1991, whereas Shannopin was not expected to be in service until September of 1992, and, to a lesser extent, because it was for a three-year longer term. It too has not yet been built, and the approval of the Burgettstown project and its avoided cost rate has taken a parallel course with the litigation for the Shannopin project.

The litigation for both projects began almost immediately after the signing of the contracts, albeit initially it was amicable between the QFs and West Penn. In January of 1988, West Penn filed a petition [*6] with the PUC seeking approval of its EEPA with Mon Valley and seeking assurance that it would be able to recover all of the payments to the QF from ratepayers. After giving notice and an opportunity to be heard to West Penn's customers, n5 the PUC approved the EEPA and the pass-through of costs associated with it. On appeal, this court reversed the PUC in an unpublished decision, holding that the calculation of avoided costs under PURPA should not be based on the time of "serious negotiations" but instead should be based on the date of a "legally enforceable obligation". n6 We remanded the case for a recalculation of capacity cost rate as of October 15, 1987, the date of the contract signing. *Armco Advanced Materials Corp. v. Pennsylvania Public Utility Commission, No. 2091 C.D. 1989,* filed July 17, 1990, petition for allowance of appeal denied, *No. 545 W.D. 1990,* filed November 19, 1991

(Shannopin I). See also the related decision in *Armco Advanced Materials Corp. v. Pennsylvania Public Utility Commission, 135 Pa. Commonwealth Ct. 15, 579 A.2d 1337 (1990),* affirmed per curiam, *535 Pa. 108, 634 A.2d 207 (1993),* cert. denied, U.S. , 115 [*7] S. Ct. 311 (1994) (Milesburg II). n7

n5 The participation of West Penn's customers was permitted after this court's decision in *Barasch v. Pennsylvania Public Utility Commission, 119 Pa. Commonwealth Ct. 115, 550 A.2d 257 (1988),* petition for allowance of appeal denied, *523 Pa. 652, 567 A.2d 655 (1989)* (Milesburg I), a decision in regard to one of the related QFs.

n6 The legally enforceable obligation refers to the time the QF makes a binding commitment to deliver energy and capacity and generally is the time a contract is signed between the QF and the utility. The serious negotiations standard refers to an agreement in principle on price, but does not oblige the QF to sell power in the first place.

n7 While Shannopin I was pending, Mon Valley requested that the PUC extend certain milestone deadlines in the EEPA due to litigation and other delays. Milestone deadlines are conditions on the QF in the EEPA such as the date by which a good faith deposit must be made, or the date by which financing for the facility is closed. Apparently, based on subsequent forecasts, West Penn submitted evidence in an attempt to demonstrate that it no longer needed the capacity that was bargained for in the EEPA. The PUC extended the milestones as requested by Mon Valley and refused to consider whether West Penn currently needed the capacity it had agreed to. On appeal from that decision, this court affirmed the PUC in *West Penn Power Co. v. Pennsylvania Public Utility Commission, 150 Pa. Commonwealth Ct. 349, 615 A.2d 951 (1992),* petition for allowance of appeal denied, *536 Pa. 631, 637 A.2d 291 (1993),* cert. denied, U.S. , 115 S. Ct. 311 (1994) (Shannopin II). We held that, because West Penn legally agreed it had a need for capacity when it made the agreement with Mon Valley, it cannot at a later date change the terms of the agreement because it believes that, based on hindsight information, it made an erroneous decision.

[*8]

On remand, the PUC interpreted our decision to require recalculation of only the corporate tax rate component of the capacity cost rate, contending that it was the only component challenged by West Penn and the Industrials. The PUC directed all parties to submit proposed calculations of a capacity cost rate based on corporate tax rates in effect October 15, 1987, and for various potential in-service dates. The PUC issued an order adopting the calculations of Mon Valley and entering an order recalculating the cost rate. West Penn and the Industrials appealed.

Reversing the PUC, we held that by fixing as the "polestar" the date that the parties entered into a "legally enforceable obligation," PURPA requires the PUC to determine as of that date whether the avoided cost agreed to by the utility and the QF was just and reasonable to ratepayers. *Shannopin III, 154 Pa. Commonwealth Ct. at 145, 623 A.2d at 387.* Because that determination is made on time-sensitive data and the avoided cost is set as of that date, we held that the PUC has to make the determination by reexamining all of the elements that determine the avoided cost, rather than just one element. Id. Again, we remanded [*9] for a recalculation of the amount to be paid for power produced by the Shannopin QF. It is the PUC's calculation of the amount paid for QF power on the remand that is before us now.

II.

The amount to be paid for QF power is based on the avoided cost. The "avoided cost" essentially represents the amount of money a utility would otherwise spend if it had to construct a facility to produce needed energy or to purchase it from another source, rather than purchasing it from the QF. See 18 C.F.R. § 292.101(b)(6). Section 210(b) of PURPA, *16 U.S.C. § 824a-3*(b), establishes that rates for QF purchases may not be greater than the full avoided costs of the utility. n8 See also 18 C.F.R. § 292.304(a)(2); *American Paper Institute, Inc. v. American Electric Power Service Corp., 461 U.S. 402, 76 L. Ed. 2d 22, 103 S. Ct. 1921 (1983);* Milesburg II.

n8 Avoided costs may be calculated at the time the legally enforceable obligation is incurred, and rates calculated as of such time will meet the statutory and regulatory requirements even if they differ from avoided costs at the time of delivery. 18 C.F.R. § 292.304(b)(5) and (d)(2). FERC has determined that PURPA permits "lock-ins," that is, fixed-rate long-term QF contracts. *In re West Penn Power Company, 71 F.E.R.C. P61,153* (order denying petition for declaratory order, May 8, 1995).

[*10]

While avoided costs is the basis for the amount to be paid, the rate to a QF supplying electric power from the purchasing utility, as set under the terms of the EEPA, is known as the capacity cost rate or capacity credit. 52 Pa. Code § 57.31. n9 The capacity cost rate is intended to reflect the ability of the QF to allow the utility to avoid the planned generating facility or another power purchase, and to reflect how closely the QF matches the utility's need for capacity. Milesburg II. If the QF comes on-line on the same day as the avoided plant was planned to come on-line and all other factors are the same, the capacity cost rate for the period of the contract would equal the avoided cost (over the period of the contract).

n9 Capacity costs are those costs associated with providing the capability to deliver energy -- primarily the capital costs of facilities. See *45 Fed. Reg. 12216,* the commentary to the original publication of 18 C.F.R. § 292.101, the definition section of the FERC regulations implementing PURPA.

[*11]

While the avoided cost never changes, the capacity cost rate changes when there is a change in the QF's in-service date because some factors in the calculation for the rate are time-sensitive, for example the cost of capital and construction costs, and a discount rate is applied to adjust for those factors. n10 Where the parties bargain for an in-service date that is close to the planned in-service date for the avoided facility, the capacity cost rate is higher to reflect a close match to the actual capacity needs of the utility, and for an earlier in-service date, the capacity cost rate is lower to reflect the amount of time it is in-service prior to the time the utility is projected to need the power. *Milesburg II, 135 Pa. Commonwealth Ct. at 39, 579 A.2d 1350.* Using the Burgettstown QF as an example, if the contract had set an in-service date of October 1, 1995 for the QF, the date of the planned avoided facility, the capacity cost rate would have been set at 5.71 cents per kilowatt hour, but the contract set an in-service date of four years before October of 1995, and the analogous capacity cost rate was set at 3.6 cents per kilowatt hour.

n10 This is reflected in both the PUC's methodology for calculating capacity cost rates in the regulations and in West Penn's methodology by the application of a fixed charge rate. See 52 Pa. Code § 57.34(c)(1) and R.R. 402a. The fixed charge rate represents those costs that change over time, such as the cost of debt or cost of capital.

[*12]

In response to a petition for recalculation filed by Mon Valley after the remand order, the PUC issued a tentative order on February 3, 1994 recalculating the avoided cost rates for the Shannopin project and setting a capacity cost rate. With the tentative order, the PUC issued a set of calculations purportedly based on the West Penn methodology for calculating payments to QFs, as submitted in the original Shannopin III recalculation proceeding. However, while West Penn's calculations were based on the avoided costs of the total power station in-service as of October 1, 1995, the PUC extended the calculations to establish a range of rates based on QF in-service dates from October 1994 through October 1998. The tentative order calculations produced capacity rates varying from 4.9538 cents per kilowatt hour, to a maximum rate of 8.0151 cents per kilowatt hour, for concomitant project on-line dates ranging from October 1, 1994 to October 1, 1998. (R.R. 398a, 402a-418a).

The PUC stated that it was relying on factors used for the capacity cost rate calculation for the Burgettstown project because that calculation was approved by this court in *Armco Advanced Materials Corporation v. [*13] Pennsylvania Public Utility Commission, 157 Pa. Commonwealth Ct. 150, 629 A.2d 221 (1993),* petition for allowance of appeal denied, *Pa.* , *644 A.2d 165,* cert. denied, U.S. , 115 S. Ct. 315 (1994) (Burgettstown II), and was used by both West Penn and Mon Valley. In Burgettstown II, the PUC directed all parties to submit their recalculations of the avoided costs based on factors known at the time of the legally enforceable obligation, i.e., October 15, 1987. The PUC adopted the calculations of North Branch which, considering inputs at the time of the legally enforceable obligation, established a range from 4.91 cents per kilowatt hour based on an in-service date of July 1, 1994, to 5.71 cents per kilowatt hour based on an in-service date of October 1, 1995, or a later in-service date. This court affirmed those calculations in Burgettstown II. n11

n11 West Penn and the Industrials appealed the PUC's decision contending that the recalculations were in error because they provided sufficient evidence that, as of the October 15, 1987, the power was not needed. We held in Burgettstown II that hindsight information could not be relied on by the utility to establish it did not need power at the time it agreed to purchase power from the QF, and that the avoided cost calculation must be determined on factors known as of the date the legally enforceable obligation was incurred. Id., at 159, 629 A.2d at 226.

[*14]

West Penn and the Industrials responded to the PUC's tentative order by filing several motions:

. a motion for summary judgment arguing that Mon Valley is no longer a QF because it's original steam host, Shannopin Mining Company, is bankrupt and it had to find a new one.

. a motion for reconsideration arguing that a hearing must be provided on the recalculation because the adjudication is a rate case and involves a large amount of costs affecting the public.

. exceptions arguing that, if the calculations used in Burgettstown II are applicable, then the maximum capacity rate that can be set for Shannopin is 5.593 cents per kilowatt hour because that was the capacity rate set in Burgettstown II for a QF coming on-line on October 1, 1995, or thereafter.

The PUC denied all of the motions and adopted the rates set forth in the tentative order with the maximum rate at 8.0151 cents per kilowatt hour for an on-line date in 1998. The PUC stated that if a developer loses its QF status, the EEPA is no longer valid; some non-crucial changes in a project does not mean it is no longer a QF. It noted that Mon Valley promptly found a new steam host when [*15] its host went bankrupt and that the steam host was not specified in the EEPA. Also, if West Penn questions the QF status of the Shannopin project, the PUC stated, it could file a petition with FERC, noting that whether Shannopin maintained sufficient site control is beyond the scope of the remand order and outside of its jurisdiction. The PUC also held that this is not a rate case and because the PUC's role is limited, no additional hearings are warranted.

As to whether the maximum rate set in Burgettstown II should apply, the PUC stated:

Mon Valley should not be penalized because the Shannopin Project will come on line in late 1995 or thereafter. The project was originally intended to avoid a combination of the three base load plants scheduled for 1995 through 1998. The original calculations of avoided capacity costs were based on that understanding. The basis for the calculations will not be altered here. Further, that the Shannopin contract is for three years less than the Burgettstown contract is irrelevant here. The capacity payment was based on West Penn's anticipated costs to build three base load coal plants and broken down to a price per kilowatt hour (kWh).

[*16]

(PUC's opinion and order of December 1, 1994, slip op. at 11). West Penn and the Industrials then filed these appeals. n12

n12 Our scope of review of a decision of the PUC is to determine whether constitutional rights have been violated, or an error of law committed, and whether the necessary findings of fact are supported by substantial evidence in the record. Section 704 of the Administrative Agency Law, 2 Pa. C.S. § 704; *GPU Industrial v. Pennsylvania Public Utility Commission, 156 Pa. Commonwealth Ct. 626, 628 A.2d 1187 (1993).*

III.

At issue is the propriety of the PUC's translation of the avoided cost into the capacity cost rate. West Penn and the Industrials contend the PUC erred as a matter of law by ordering a capacity cost rate that exceeds West Penn's avoided cost as determined in Burgettstown II. The Shannopin rate of 8.0151 cents per kilowatt hour is forty percent higher than the maximum rate for Burgettstown, and the maximum rate for Burgettstown is set for an in-service date [*17] of October 1, 1995 or thereafter. Because both projects were contracted on the same date to avoid the blended costs of the 900 MW power station, they assert both projects should have substantially the same rates and those rates cannot exceed West Penn's avoided costs as calculated based on data available at the time of the EEPA.

The difference in rates is largely based on extending the on-line dates beyond October 1, 1995 to October 1, 1998 for Shannopin. West Penn and the Industrials contend that the PUC abused its discretion:

. by extending the on-line dates of the QF beyond the date when the avoided cost for the power station was determined;

. by ignoring the fact that the EEPA was meant to avoid a power station, including the sunk costs associated with the first unit, rather than a single unit of the power station;

. by mistakenly assuming West Penn's methodology could be used for on-line dates after 1995 resulting in the unintended compounding of costs; n13 and,

n13 West Penn and the Industrials argue that West Penn's methodology was set up to give a discount in rates when the QF came on-line before October of 1995. But the inclusion of that discount factor when the in-service date is after October 1995 creates a positive number that compounds the rates.

[*18]

. by failing to properly update all of the inputs in the avoided cost calculation as required by this court's remand order.

Examining the EEPA and the course of conduct between the parties at the time of the contract, the parties understood that:

. The QF projects were agreed to in order for West Penn to avoid building the 900 MW station as a whole, and the avoided costs for the QFs were based on the costs to West Penn for building the power station.

. October 1, 1995 was the planned date that the first unit of the 900 MW power station would come on-line.

. The EEPAs did not state that any QF was intended to avoid a specific unit of the 900 MW power station.

. All parties admit that the rate offered all of the QF developers at the time of the EEPAs and used throughout the proceedings was based on the blended cost of the three units for the 900 MW power station. The blending of costs gives the ratepayers, the PUC stated, the benefit of economy of scale resulting in a reduced rate. (PUC's opinion, slip op. at 24).

. There has never been an objection to the calculation of avoided costs based on the cost of the 900 MW power station [*19] as a whole, including the sunk costs n14 that would be necessary for building the first unit of the station, but would provide structures that must be present for each unit of the station to run.

n14 Sunk costs are the costs associated with the common facilities that would be required no matter how many units were built at the site.

From the foregoing, it is clear that the parties agreed to an avoided cost equal to the blended cost of the entire power station and treated it as if the entire avoided power station was to come on-line on October 1, 1995.

The central question then is whether the PUC can calculate a capacity cost rate based on in-service dates of the second and third units of the power station, coming on-line in 1997 and 1998, rather than based on when the entire station was treated by the parties as coming on-line, October 1, 1995, the date of the avoided cost calculation. Although this court has agreed that the PUC may alter some terms of an EEPA, the PUC may not extend the rate calculation [*20] to dates beyond the planned date for the avoided power station because that results in a rate that is greater than the full avoided cost to the utility.

In Milesburg II, the developer requested relief from certain contract deadlines that it asserted could not be met due solely to litigation delays. We held that where the utility subjects its purchase agreement to the scrutiny of the PUC, it incurs the risk that the PUC may modify provisions of the contract if it concludes those provisions are not in accordance with PURPA and FERC regulations. We stated that the principle applies to terms relating to milestone dates as well as terms relating to price, that is, the PUC must order a rate for a power purchase for equivalent to, but no more than, the full avoided costs, citing 18 C.F.R. § 292.304(b)(2). *Milesburg II, 135 Pa. Commonwealth Ct. at 37, 579 A.2d at 1348-49.* We held, then, that the PUC properly extended the milestone deadlines of the original EEPA in order to ensure that litigation delays did not become the factor to determine whether a project proceeds or fails. *Id. at 38-39, 579 A.2d at 1349.* We also held that the capacity cost rate could be based on an in-service [*21] date later than the one agreed upon in the EEPA (but not beyond the planned in-service date of the avoided facility) because such a change did not affect the avoided cost but only reflected a closer match to the projected capacity needs of the utility. Id. In Shannopin II, we held that the PUC could change the financing closing date in the EEPA due to litigation delays, and that because that date was changed, the other dates in the EEPA which rely on that date were also postponed, including the in-service date of the QF. We reiterated that, despite a change in the in-service date, West Penn's avoided cost remained constant and the capacity cost rate is reasonable so long as the rates are at or below the full avoided cost of utility. *Shannopin II, 150 Pa. Commonwealth Ct. at 370, 615 A.2d at 962.*

While the PUC may alter terms of the contract due to litigation delay or terms that are not in compliance with PURPA, including terms relating to price, that discretion is not without limits. The PUC is without discretion to change terms of the EEPA by ordering a capacity cost rate that is greater than the full avoided cost to the facility. As calculated by the PUC, if Shannopin [*22] comes on-line on October 1, 1995, the date of West Penn's projected need for power, the capacity cost rate is 5.5933 cents per kilowatt hour. (R.R. 406a). This is the capacity cost rate that is equivalent to West Penn's full avoided cost as fixed at the time of the contract. Although the PUC may reform the EEPA to allow Shannopin to come-on line later than October 1, 1995, n15 the PUC cannot change the EEPA under PURPA to allow a capacity cost rate calculation that is higher than the capacity cost rate equal to a breakdown of the avoided cost to West Penn for the power station on October 1, 1995, that is, 5.5933 cents per kilowatt hour. The PUC's calculations for Shannopin raises to a maximum of 8.0151 cents per kilowatt hour based on an in-service date for Shannopin of October 1, 1998. This is well above the capacity cost rate that is equivalent to the full avoided cost of West Penn and is an abuse of discretion and in violation of PURPA. Section 210(b) of PURPA, *16 U.S.C. § 824a-3*(b); 18 C.F.R. § 292.304(a)(2) and (b)(2); American Paper Institute.

n15 We do not address whether the PUC could allow the QF to come on-line after the date of when the last unit of the avoided facility was planned to come on-line, however we note that the PUC determined in this case that it would not extend the calculations beyond October 1, 1998, in order to coincide with the planned on-line date for the third unit of the power station.

[*23]

The error in calculating capacity cost rates beyond the date the parties agreed to in the EEPA, as to when the avoided power station was projected to come on-line, is apparent when comparing the rates established in Burgettstown II and those set by the PUC in this case. The maximum capacity cost rate set for the Burgettstown project is 5.71 cents per kilowatt hour for an in-service date of October 1, 1995 or thereafter. The maximum capacity cost rate for Shannopin was set by the PUC as 8.0151 cents per kilowatt hour, which is forty percent higher than the maximum capacity cost rate for Burgettstown. Because both QF projects were agreed to in order for West Penn to avoid the same 900 MW power station projected to be needed on October 1, 1995, and the contracts were signed on the same day, the parties admit, and the PUC determined (PUC's opinion, slip op. at 24 and 27), that the avoided cost to West Penn is exactly the same for each project. n16 Because the avoided cost is exactly the same for each project, the maximum capacity cost rates should be substantially the same rather than forty percent different. Also, if as here, one or both QFs are coming on-line after the date of the [*24] planned in-service date of the avoided facility as fixed at the time of the contract, the capacity cost rate cannot exceed the full avoided cost which is equivalent to the capacity cost rate calculated for the QF on the date of the projected need for power.

n16 For any given in-service date, only a slight difference should result in the capacity cost rate due to the three-year difference in the term of the EEPAs for the projects.

Mon Valley argues that the fact that the EEPA did not specify which unit of the power station Shannopin was intended to avoid means that the capacity cost rate can be calculated up to the projected dates for those units to come on-line because it could still avoid that power. Initially, we point out that the fact that the unit of the power station that each QF was supplanting was not specified supports the agreement of the parties that all of the QFs were intended to avoid the blended cost of the whole 900 MW power station as those costs were projected for October 1, 1995, the date when [*25] some power would be needed by West Penn, and that all of the QFs were intended to come on-line prior to that date. More importantly, while it is true that the 900 MW power station was to consist of three units, with the second and third coming on-line in 1997 and 1998, because of sunk costs, the parties agreed to a blended avoided cost based on an October 1, 1995 date when power from the first unit would come on-line. While West Penn and Shannopin could have agreed to an EEPA that specified one unit of the 900 MW power station that it was intended to avoid, and in that case the avoided cost of that unit (including a portion of the sunk costs in each unit) at the time its power would be needed may have been higher resulting in a higher maximum capacity cost rate, the parties did not make such a bargain.

The PUC stated that to limit the capacity cost rate to 1995 would penalize Mon Valley presumably because it fixed a date before it could deliver power. However, Mon Valley is not prohibited from coming on-line after October 1, 1995, it is only the capacity cost rate that is maximized. The maximization is mandated by PURPA and the PUC cannot alter that part of a QF contract. Accordingly, [*26] we must reverse the PUC's calculations and that part of the PUC's order determining that the capacity cost rate for Shannopin may be calculated and continues to rise for on-line dates later than October 1, 1995 because the capacity cost rate calculated for an on-line date of October 1, 1995 is the maximum capacity cost rate available to Shannopin because it is equal to the full avoided cost to West Penn.

IV.

West Penn argues that the recalculation proceeding is moot and the Shannopin QF project no longer exists because Mon Valley failed to maintain adequate site control. The PUC found that, because Mon Valley promptly arranged for a new steam host when the planned site went bankrupt, it maintained adequate control. The PUC also found that, if West Penn questions the QF status of the Shannopin project, it could file a petition with FERC. The record establishes that at the time Mon Valley lost its steam host, no action was taken to decertify the QF. West Penn filed neither a petition to decertify the QF or for a declaratory order from FERC. See Independent Energy Producers, Inc. v. California Public Utilities Commission, 36 F.3d 848 (9th Cir. 1994). Because there is substantial [*27] evidence in the record for the PUC findings that Mon Valley promptly corrected the loss of the steam host, and because a specific steam host was not named in the EEPA, there was no basis to conclude that Mon Valley lost its QF status or that the contract was violated. The PUC is affirmed in that part, and West Penn continues to remain obligated under the EEPA.

V.

West Penn summarily argues that the PUC did not properly update all of the inputs in the calculation to the time of the contract signing, relying on the statement of its expert, Albert F. Kave. Kave stated that the AFUDC (Additional Funds Used During Construction) and the inventory costs used in the PUC's Attachment A were overstated. In response to Kave's statement, the PUC held that the AFUDC and inventory costs used were those found to be appropriate in its Burgettstown decision and upheld in Burgettstown II. Although Kave presented testimony contrary to the calculations in the tentative order, this does not mean that the PUC erred in not adopting that testimony. The PUC made findings on this matter in its Burgettstown decision (PUC's opinion and order of November 24, 1992, Docket No. 4-880284), and we agree that, [*28] because those inputs were approved in Burgettstown II, they were appropriate in this case because the calculation is based on the same avoided plant and the EEPA was signed on the same day.

VI.

West Penn also argues that the PUC's order was in error because it relied on stale data. It argues that FERC recently established that QF rates cannot exceed the avoided cost to the utility, and that stale data should not be relied on to support the avoided cost calculation if there is no current need for power, renewing its argument that it does not need the power it contracted for in the EEPA. In In re Southern California Edison Company, F.E.R.C. No. EL95-16-000 and No. EL95-19-000, issued February 23, 1995, the decision relied on by West Penn, FERC stated that it has "grave concerns about the need for this capacity and the staleness of the data relied upon by the California Commission." Id. slip op. at 26. However, FERC expressly declined to address the issue of stale data and decided the case on other grounds. Id. This court recently rejected West Penn's argument on this issue and we see no need to address it further. West Penn Power Company v. Pennsylvania Public [*29] Utility Commission, Pa. Commonwealth Ct. , A.2d (*No. 107 C.D. 1995*, filed May 25, 1995). We affirm that part of the PUC's order.

Accordingly, the order of the PUC is affirmed in part and reversed in part. The case is remanded for a recalculation of capacity cost rates for the Shannopin QF project that does not exceed the full avoided cost to West Penn, as set at the time of agreement, based on the blended costs of the 900 MW power station planned to be in-service on October 1, 1995. On remand, the PUC should use the capacity cost rates established for the Burgettstown project, as upheld in Burgettstown II, as a guide, with the only difference being related to the three-year difference in the term of the contracts. The other differences in the contracts, such as the 11-month difference in original in-service dates, are not applicable where the rate is maximized because that difference is caused by the application of the discount for coming on-line earlier than the planned in-service date of the planned power station. The capacity cost rate should be maximized as calculated for the in-service date of Shannopin on October 1, 1995 and will [*30] not change due to an actual in-service date of the QF after that date. The order is affirmed only in that part determining that the recalculation proceeding is not moot and relying on the data known at the time of the contract between the parties.

DAN PELLEGRINI, Judge

ORDER

AND NOW, this 20th day of July, 1995, the order of the Pennsylvania Public Utility Commission, dated December 1, 1994, No. P-880286 is affirmed in part and reversed in part. The order is affirmed insofar as it determined the recalculation proceeding is not moot and that there was no error in relying on the data known at the time of the contract between the parties. The order is reversed insofar as it calculated and approved capacity cost rates that are greater than the full avoided cost or the equivalent, the rate for an in-service date of October 1, 1995. The case is remanded to the Pennsylvania Public Utility Commission for a recalculation of capacity cost rates that duplicate those rates previously approved for the Burgettstown project, as discussed in our opinion in this matter, with the only adjustment for the three-year difference in term of the contract.

Jurisdiction relinquished.

DAN [*31] PELLEGRINI, Judge