Duke Energy®

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VIA OVERNIGHT MAIL

April 12, 2006

Ms. Elizabeth O'Donnell
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602

RECEIVED
APR 13 2006
PUBLIC SERVICE COMMISSION

Re: In the Matter of the Application of The Union Light, Heat and Power Company for a Certificate of Public Convenience and Necessity to Acquire Certain Generation Resources and Related Property; for Approval of Certain Purchase Power Agreements; for Approval of Certain Accounting Treatment; and for Approval of Deviation from Requirements of KRS 278.2207 and 278.2213(6), Case No. 2003-00252

Dear Ms. O'Donnell:

At the informal conference in this matter on March 30, 2006, we handed out and referenced a document entitled *Utility/Affiliate Power Sales: Has the Death Knell Sounded?* I have enclosed another copy of this document as Attachment A to this letter. We were asked at the informal conference to provide copies of the FERC decisions referenced in the handout. Attachment B to this letter is a copy of a letter I filed in this case on July 22, 2004, which also lists several FERC cases. I have enclosed five binders with this letter. The binder contains copies of the FERC cases referenced in Attachments A and B.

In the July 22, 2004 letter, the Company expressed concern about getting FERC approval for transferring the three generating plants to Duke Energy Kentucky. The Company informed the Commission in the letter that it would delay applying for FERC approval so the Company could monitor pending FERC cases to determine how to best structure this transaction to assure FERC approval. We believed at that time, and we continue to believe today, that this was the best course of action to obtain FERC approval for the asset transfer. As we mentioned during the informal conference, we succeeded in this approach by eventually getting FERC approval for the asset transfer, but FERC changed the conditions for wholesale power transactions between affiliates, such that

FERC would not approve the back-up supply agreement as we had originally proposed it to this Commission in 2003.

We appreciate the opportunity to discuss this matter at the informal conference. As discussed, we will make a proposal in our upcoming rate case for a substitute arrangement for the back-up supply agreement. Thank you for your consideration in this matter.

Sincerely,

John Finnigan

John J. Finnigan, Jr.
Senior Counsel
Duke Energy Shared Services, Inc.

cc: Hon. Richard G. Raff (with enclosures)
Hon. Dennis G. Howard, II (with enclosures)
Hon. Elizabeth E. Blackford (with enclosures)
Hon. David Edward Spenard (with enclosures)
Hon. Michael L. Kurtz (with enclosures)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
APPLICATION OF THE UNION LIGHT,	)	
HEAT AND POWER COMPANY FOR A	)	
CERTIFICATE OF PUBLIC CONVENIENCE	)	
AND NECESSITY TO ACQUIRE CERTAIN	)	
GENERATION RESOURCES AND RELATED	)	
PROPERTY; FOR APPROVAL OF CERTAIN	)	CASE NO. 2003-00252
PURCHASE POWER AGREEMENTS; FOR	)	
APPROVAL OF CERTAIN ACCOUNTING	)	
TREATMENT; AND FOR APPROVAL OF	)	
DEVIATION FROM REQUIREMENTS OF	)	
KRS 278.2207 AND 278.2213(6)	)	

CASES SUBMITTED BY DUKE ENERGY KENTUCKY
WITH APRIL 10, 2006 LETTER

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Senior Counsel

VIA OVERNIGHT MAIL

July 22, 2004

CINERGY.

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JUL 23 2004

PUBLIC SERVICE
COMMISSION

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Executive Director
Public Service Commission
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Frankfort, Kentucky 40602

Re: In the Matter of the Application of the Union Light, Heat and Power Company for a Certificate of Public Convenience and Necessity to Acquire Certain Generation Resources and Related Property; for Approval of Certain Purchase Power Agreements; for Approval of Certain Accounting Treatment; and for Approval of Deviation from Requirements of KRS 278.2207 and 278.2213(6); Case No. 2003-00252

Dear Ms. O'Donnell:

In the above captioned proceeding, in which The Union Light, Heat and Power Company (ULH&P) sought, among other things, Commission approval to acquire certain generating facilities from its parent company, The Cincinnati Gas & Electric Company (CG&E), ULH&P stated that its anticipated date for the closing of this transaction would be July, 2004. For reasons related to the Federal Energy Regulatory Commission's (FERC) close scrutiny of affiliate transactions, ULH&P has not yet sought FERC approval of certain purchase power agreements between ULH&P and CG&E related to this transaction, and thus has not closed this transaction.

ULH&P believes that the most prudent course of action with regard to seeking FERC approval is to postpone seeking FERC approval of this transaction at the present time, and to continue to monitor developments in similar cases currently before FERC, including the Ameren case[1], and Cinergy's case involving the transfer of two generating facilities to PSI Energy, Inc. (which is pending rehearing).[2] FERC also has recently initiated two technical conferences examining the issues pertinent to affiliate purchase power transactions[3] and

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[1] *See Ameren Energy Generating Co., et al.*, 103 FERC P 61,128 (2003), reh'g pending.

[2] *See Cinergy Services, Inc.*, 102 FERC P 61,128 (2003), reh'g pending.

[3] *See In the Matter of Solicitation Processes for Public Utilities*, Docket No. PL04-6-000.

utility purchase of affiliate generating facilities.[4] ULH&P has monitored these technical conferences. ULH&P believes that by waiting for these cases to progress further, it will be better able to shape its filing to any specific requirements arising out of these proceedings and avoid a hearing at FERC. ULH&P believes that if it makes its filing before these proceedings are concluded, the matter may very well be set for hearing, delaying the ultimate closing date by 14 – 16 months.

ULH&P and CG&E maintain every intention of seeing this transaction close, and providing ULH&P's customers a reliable source of reasonably-priced electric generation. Please be encouraged to contact me should you have any questions regarding this matter.

Very truly yours,

John J. Finnigan, Jr.

JJF/mak

cc: A. W. Turner
Anita Mitchell
Elizabeth Blackford

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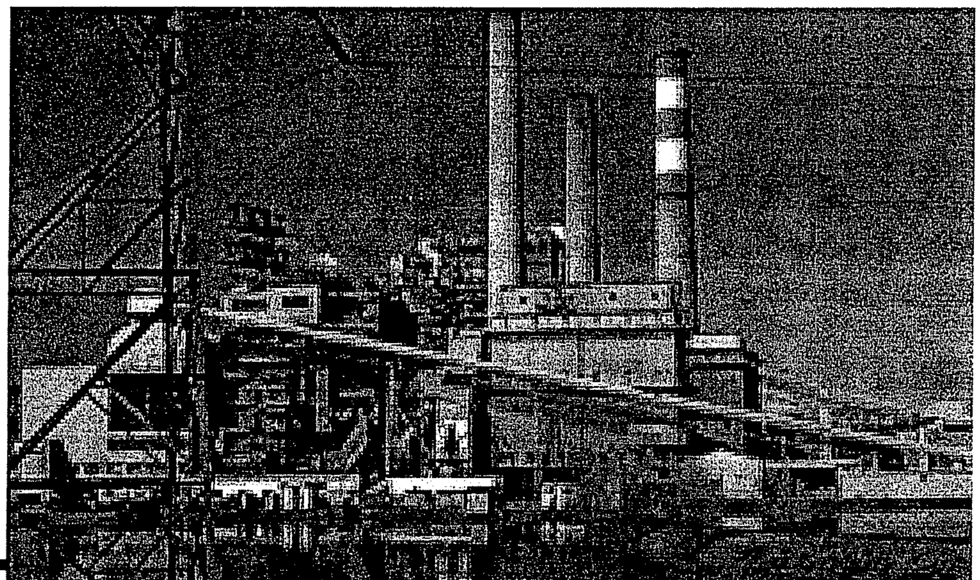
[4] *See In The Matter of Conference on Public Utilities' Acquisition and Disposition of Merchant Generation Assets*, Docket No. PL04-9-000.

UTILITY/AFFILIATE POWER SALES: HAS THE DEATH KNELL SOUNDED?

Energy Bar Association
Southern Chapter
April 25, 2005



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The Edgar Standards

- Boston Edison proposed to purchase energy from Edgar Electric, an affiliate, at rates set based on comparison to the market.
  - 15 contracts negotiated by BECO over 3 years;
  - an RFP resulting in 48 proposals from QFs;
  - 34 QF/IPP contracts signed in Massachusetts;
  - 2 IPPs whose rates were approved by FERC.
- FERC rejected the rates without prejudice, stating that there was not a clear showing of a lack of potential for affiliate abuse. *Boston Edison Company Re: Edgar Electric Energy Company*, 55 FERC ¶ 61,382 (1991).

FERC's "Edgar" Standards for Utility Purchases from Affiliates

- A utility may demonstrate that there is head-to-head competition, where:
  - the solicitation or negotiation was designed and implemented without undue preference;
  - the analysis did not favor the affiliate, in particular regarding non-price terms;
  - the affiliate was selected based on a reasonable combination of price and non-price factors.
- A utility may demonstrate that the price is reasonable based on the prices that non-affiliated buyers were paid for similar services, provided that the other buyers are in the relevant market and were not subject to market power.
- A utility may demonstrate benchmark evidence of prices, terms and conditions of sales by non-affiliated sellers to the utility or others in the relevant market at the same period of time and for similar services.

FERC's Rationale for Rejecting the Edgar Filing

- FERC must be certain that the buyer has chosen the least-cost option, taking into account both price and non-price terms.
- Transactions must be "above suspicion"; not only must there be no affiliate abuse – there must be no **potential** for affiliate abuse.
- FERC was concerned that the utility has an incentive to favor its affiliate even if it is not the least cost supplier, because that would benefit its shareholders.
- Consequently, evidence of a competitive marketplace with sufficient supply options and no barriers to competition through the control of transmission was not sufficient to show that the price is reasonable.

Reasons for Rejection of Edgar's Prices

- The company had inadequate documentation of the cost of the Edgar contract and the alternatives.
- It failed to include non-price factors in the rankings of alternatives or to show how it calculated the scores of potential alternative suppliers.
- Data on benchmark sales were not shown to reflect similar services in the relevant market.
- The company did not demonstrate that all relevant contemporaneous purchases were included in the comparison.

Mountainview – The FERC Broadens the Edgar Decision

- Southern California Edison proposed to purchase power from Mountainview, a to-be-acquired affiliate, at cost-based rates that gave Mountainview incentives to control discretionary costs and maintain high availability and a low heat rate.
- The FERC accepted the agreement, but required Mountainview to modify the rates in several respects to ensure that the charges reflect its actual costs, rather than fixed rates that are based on cost estimates; and to conform in all respects to the requirements placed on utilities selling power at cost-based rates.
- The FERC also held that in the future it would require all affiliate long-term power sales agreements, at cost-based or market-based rates, to be subject to the *Edgar* standards. *Southern California Edison Company,* 106 FERC ¶ 61,184 (2004).

Mountainview –
The FERC Broadens the Edgar Decision continued

- The Commission stated that it was concerned that undue preferences to affiliates could cause long-term harm to the wholesale market by discouraging non-affiliates from adding supply.
- The Commission also held that restricting SCE's resale of the output of Mountainview to spot market sales at the marginal cost of each unit would address concerns that SCE could depress market prices by bidding Mountainview into the market at below cost.

FERC's Objectives in Mountainview

- FERC was faced with a sharp decline in the number of planned generators that were being completed. Construction had been suspended.
- FERC also saw a trend toward the purchase of independent generators by utilities. Mountainview had three owners before SCE proposed to purchase it.
- Post-Enron, FERC also was concerned about the ability of large owners of generation to affect the market through bidding strategies. It concluded that this could be avoided by broadening the number of owners of generation and restricting the bidding practices of the large owners.
- FERC wanted to protect and encourage production markets, having concluded that a robust generation market with numerous participants achieves long-term consumer benefits.

Allegheny Energy Supply – the FERC Establishes New Standards

- AE Supply was selected to supply a portion of Potomac Edison's standard offer service obligations.
- The contract was awarded pursuant to a public RFP that was designed through a proceeding at the Maryland PSC; provided for all bidders to be pre-qualified using publicly available criteria; was monitored by an independent consultant; and the results of which were approved by the Maryland PSC.
- The FERC held that the RFP met the *Edgar* standards. It also provided guidance on the standards it will use to evaluate future RFPs to ensure that affiliates do not receive undue preference.

The Allegheny Energy Supply Standards for RFPs

- **Transparency:** The solicitation must be an open and fair competition in which all parties have equal access to information. The utility should use a public solicitation, not one in which selected parties are invited to bid.
- **Definition:** Products sought must be precisely defined and nondiscriminatory.
- **Evaluation:** Criteria for evaluation must be standardized, publicized and applied equally. The utility should specify the importance of each evaluation criterion. A third party should negotiate with short-listed bidders if an affiliate is involved.
- **Oversight:** An independent third party should design the solicitation, administer bidding and evaluate bids prior to the company's selection.

Conectiv Energy Supply – A “Reductio ad Absurdum”?

- Delmarva Power & Light notified suppliers that it would seek bids for service to its retail load and published the RFP on its web site. It pre-qualified bidders so that they competed only on price terms; non-price terms were non-negotiable. It awarded the contract to CESI, an affiliate, which had the lowest price of the 7 bidders.
- Delmarva did not use an independent third party to design the solicitation, administer bidding or evaluate the bids, but it used the same process that the Commission had approved in the *Allegheny* case.
- FERC held that since an independent third party had not been involved, the RFP did not meet the “oversight” criterion. It cited the inability to determine whether CESI received preferential treatment at any stage of the proceeding, such as the pre-qualification process, and it set the matter for hearing. *Conectiv Energy Supply, Inc.*, 109 FERC ¶ 61,385 (2004).

Conectiv Energy Supply – A "Reductio ad Absurdum"? continued

- Commissioner Kelliher dissented, stating that the Commission should have approved the contract since the Commission had approved the RFP process in *Allegheny* and no protests had been filed. He stated that the *Allegheny* criteria should be guidelines rather than a bright line test.
- It seems unlikely that the Commission will achieve any additional protection of competition as a result of setting the case for hearing. The proceeding is now in settlement negotiations.

Wisconsin Public Service – A Meaningless Exercise?

- WPSC filed a renegotiated power sales agreement with its affiliated utility, Upper Peninsula Power Company. UPPCO is in a transmission-constrained area and had not received any responses to three previous RFPs other than responses from WPSC.
- WPSC proposed to charge UPPCO the average price WPSC charges under its market-based rate authority to non-affiliated wholesale long-term power purchasers in the region, which resulted in a reduction in the rates that otherwise would be charged to UPPCO.
- The Commission held that another RFP was not necessary, given the past history. However, it set the matter for hearing, stating that the rates had not been shown to be just and reasonable. *WPSC*, 109 FERC ¶ 61,319 (2004).

The WPSC Decision – Matters Set For Hearing

- Whether the price was set based on a sufficiently large sample of contracts to ensure a lack of affiliate abuse.
- Whether power purchase agreements between WPSC and other wholesale customers allow comparable variations in annual power nominations.
- Whether a similarly situated customer would be permitted to terminate an unfavorable power supply contract.
- Whether the new agreement is likely to reduce UPPCO's costs after the end of the superseded agreement.
- Whether an automatic renewal clause is appropriate in an affiliate transaction.
- Whether UPPCO's wholesale power customers are likely to be put at a competitive disadvantage given their formula rate pass-through of these costs and the transmission constraints.

Lesson Learned # 1: State Commission Oversight May Not Be Relevant

- The Massachusetts (Edgar), California (Mountainview), Maryland (Allegheny) and Virginia (CESI) commissions approved the RFP processes, were closely involved and/or filed interventions in support.
- The FERC has shown no inclination to defer to state commission involvement or determinations, even where the sale is solely for the purpose of supplying retail customers.
- The FERC has on several occasions rejected restrictions by state commissions on sales of power by marketing affiliates to their utilities, asserting that the matter is subject to its exclusive jurisdiction.
- The FERC evidently has concluded that the need to oversee the wholesale markets overrides any incentive to grant deference to state commissions with respect to the oversight of power purchases by utilities.

Lesson Learned #2:
It's a "Lower of Cost or Market" Environment

- The *Edgar* decision applied market evaluation criteria to a market-based price: head-to-head competition, comparability to similar transactions in the relevant market and benchmark evidence.
- The *Mountainview* decision required cost-based contracts to be subject to the market evaluation standards, and *Allegheny* expanded the evaluation criteria.
- Utilities that make power purchases from affiliates at cost are also subject to market-based evaluations. Consequently, they are subject to "lower of cost or market" limits on prices.
- In WPSC/UPPCO, FERC was evidently concerned about affiliate abuse resulting from <u>lowering</u> the price charged by one regulated utility to another.

Lesson Learned # 3:
FERC Will Set All for Hearing All Affiliate Transactions that Do Not Result from RFPs that Meet the *Allegheny* Criteria

- Commissioner Kelliher correctly pointed out in *CESI* that the FERC was using *Allegheny* as a "bright line" instead of as guideline. Doing so wastes resources; the FERC should have known that it would not achieve a lower price as a result of setting the case for hearing.
- FERC set the WPSC/UPPCO case for hearing even though the price was below cost and there obviously was no competitive market in the UPPCO region. The contract could not have an adverse impact on other suppliers in the market or competition in general – the asserted reasons for expanding the FERC's oversight of such transactions.
- It is almost certain that the Commission will also set for hearing all cases that attempt to justify rates based on the other criteria set out in *Edgar* – comparisons to the prices paid by other purchasers and benchmark data.

Lesson Learned # 4:
FERC's Decisions May Have Additional Implications

- FERC has now applied its criteria to a transaction between two affiliated regulated utilities. Will it apply them to all transactions between holding company affiliates?
  - Sales between holding company affiliates of temporarily unneeded "lumpy" new generation.
  - Sales of jointly planned new generation by a utility service company to its operating companies.
- FERC has not discussed (or evidently considered) the implications for utilities subject to the Public Utility Holding Company Act:
  - Sales at cost.
  - Requirement of integrated operation.

Lesson Learned # 5:
FERC Has a Strong Bias Against Affiliate Transactions

- FERC's decisions could be interpreted as an almost paranoid concern about affiliate abuse; or a fundamental intention to force the industry to give a greater market share to independent generators. Either interpretation leads to the same result.
- FERC's concern with opening up the market can be seen elsewhere:
  - *Oklahoma Gas & Electric*, where FERC held that a purchase of an IPP whose long-term power sales contract was expiring resulted in an adverse effect on competition in the absence of mitigation;
  - *Ameren,* in which FERC expanded the *Edgar* criteria to evaluations of utility acquisitions of their marketing affiliates' generation and encouraged use of the *Allegheny* RFP criteria.
  - *Entergy-Perryville,* where the FERC conceded that it had no jurisdiction over a sale of a generator without a step-up transformer, but held that it would evaluate changes in market share in the utility's market-based rate filing.

Lesson Learned # 5:
FERC Has a Strong Bias Against Affiliate Transactions continued

  - Entergy Services, where the Commission trial staff filed testimony stating that Entergy had unfairly favored its affiliate's bid in response to an RFP.

- FERC has expressed concern with "recent trends" in the markets toward the re-integration of generation into traditional utilities. It intends to revise its affiliate transaction criteria in the pending market-based rate rulemaking, RM04-7-000.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF THE UNION LIGHT, HEAT AND POWER COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO ACQUIRE CERTAIN GENERATION RESOURCES AND RELATED PROPERTY; FOR APPROVAL OF CERTAIN PURCHASE POWER AGREEMENTS; FOR APPROVAL OF CERTAIN ACCOUNTING TREATMENT; AND FOR APPROVAL OF DEVIATION FROM REQUIREMENTS OF KRS 278.2207 AND 278.2213(6)

CASE NO. 2003-00252

INDEX OF REFERENCED FERC CASES

Tab	Case Caption/Cite	Pleading/Date	Document Reference
1	Ameren Energy Generating Company, et al. 103 FERC P ¶ 61,128	Order Setting Disposition of Facilities Application for Hearing May 5, 2003	July 22, 2004 letter at footnote 1
2	Cinergy Services, Inc. On behalf of PSI Energy, Inc.; et al. 102 FERC P ¶ 61, 128	Order Authorizing Disposition of Jurisdictional Facilities February 4, 2003	July 22, 2004 letter at footnote 2
3	In the Matter of Solicitation Processes for Public Utilities Docket No. PL04-6-000	Notice of Technical Conference May 11, 2004	July 22, 2004 letter at footnote 3
4	In the Matter of Conference on Public Utilities' Acquisition and Disposition of Merchant Generation Assets Docket No. PL04-9-000	Notice of Technical Conference May 11, 2004	July 22, 2004 letter at footnote 4

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:)
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APPLICATION OF THE UNION LIGHT,)
HEAT AND POWER COMPANY FOR A)
CERTIFICATE OF PUBLIC CONVENIENCE)
AND NECESSITY TO ACQUIRE CERTAIN)
GENERATION RESOURCES AND RELATED)
PROPERTY; FOR APPROVAL OF CERTAIN) CASE NO. 2003-00252
PURCHASE POWER AGREEMENTS; FOR)
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DEVIATION FROM REQUIREMENTS OF)
KRS 278.2207 AND 278.2213(6))

INDEX OF REFERENCED FERC CASES

Tab	**Case Caption/Cite**	**Pleading/Date**	**Document Reference**
5	Boston Edison Company Re: Edgar Electric Energy Company 55 FERC ¶ 61,382	Order Noting and Granting Interventions, and Rejecting Rates Without Prejudice June 7, 1991	"*Utility/Affiliate Power Sales...*" at slide 2
6	Southern California Edison Company 106 FERC¶ 61,183	Order Conditionally Accepting Proposed Rate Schedule and Revising Affiliate Policy February 25, 2004	*Utility/Affiliate Power Sales...*" at slide 6
7	Allegheny Energy Supply Co. 108 FERC ¶ 61,082	Order Granting Authorization to Make Affiliate Sales	*Utility/Affiliate Power Sales...*" at slide 9
8	Conectiv Energy Supply, Inc. 109 FERC ¶ 61,385	Order Accepting and Suspending Power Purchase Agreement, Subject of Refund, and Establishing Hearing Procedures December 30, 2004	*Utility/Affiliate Power Sales...*" at slide 11
9	WPSC, 109 FERC¶ 61,319	Order Accepting and Suspending Rate Schedules and Establishing Hearing and Settlement Judge Procedures December 21, 2004	*Utility/Affiliate Power Sales...*" at slide 13

103 FERC ¶ 61, 128
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
William L. Massey, and Nora Mead Brownell.

Ameren Energy Generating Company
and Union Electric Company, Docket No. EC03-53-000
d/b/a AmerenUE

ORDER SETTING DISPOSITION OF FACILITIES APPLICATION FOR HEARING

(Issued May 5, 2003)

1. On February 5, 2003, Ameren Energy Generating Company (AEG) and Union Electric Company d/b/a AmerenUE (AmerenUE) (collectively, Applicants) filed an application under Section 203 of the Federal Power Act (FPA)[1] requesting Commission authorization to transfer from AEG to AmerenUE the jurisdictional interconnection facilities associated with certain generating assets that are also to be sold to AmerenUE. The Commission is concerned that the proposed transaction may undermine competition and thus may not be consistent with the public interest. We will, therefore, set the application for hearing, as discussed below.

I. Background

A. Applicants

2. AmerenUE, a subsidiary of the Ameren Corporation (Ameren), provides wholesale and retail electric service and retail gas service to customers in Missouri and Illinois.[2] AmerenUE owns about 8,500 megawatts (MW) of generating capacity and also

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[1] 16 U.S.C. § 824b (2000).

[2] AmerenUE serves wholesale electric load (at market-based rates) only in Missouri and most of its retail electric load is located in Missouri, where retail service
(continued...)

purchases power to meet its peak load, which exceeded 8,600 MW in 2002. Central Illinois Public Service Company d/b/a AmerenCIPS (AmerenCIPS), also a subsidiary of Ameren, provides retail electric and gas service to customers in Illinois. AmerenUE has market-based rate authority. Both AmerenUE and AmerenCIPS provide transmission service under the Ameren OATT, and Ameren has received conditional authorization from the Commission to join the Midwest Independent Transmission Operator, Inc. (Midwest ISO) through GridAmerica, an independent transmission company.

3. AEG, another subsidiary of Ameren, has market-based rate authority.[3] AEG owns generating resources of approximately 4,600 MW and sells wholesale power to its affiliate, Ameren Energy Marketing Company (AEM), and to non-affiliates.[4] Among AEG's current resources are the Pinckneyville, Illinois generation facility (Pinckneyville), consisting of eight combustion turbine generator units (CTG) with a total capacity of 316 MW and placed in service in 2000 and 2001, and the Kinmundy, Illinois generation facility (Kinmundy), consisting of two CTG units with a total capacity of 232 MW and placed in service in 2001.

B. Transaction and Arguments Presented by Applicants

4. Under separate asset transfer agreements, AEG will sell Pinckneyville and Kinmundy, along with certain transmission facilities that interconnect these generating facilities to the Ameren transmission system, to AmerenUE at a net book value of $161.5 million and $96.4 million, respectively. As a result, AmerenUE would own an additional 548 MW of generation capacity.

5. According to Applicants, the purpose of the transaction is to enable AmerenUE to meet its peak load requirements, both short-term and long-term, including planning reserve requirements (15 percent for 2003 and 17 percent for 2006) established in the Mid-America Interconnected Network, Inc. (MAIN) regional reliability council. Based on these requirements, Applicants state that AmerenUE's resource needs are 543 MW in 2003, increasing to 991 MW in 2006.

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[2](...continued)
has not been deregulated. Retail electric service has been deregulated in Illinois.

[3]AEG does not own a transmission system and does not provide retail service.

[4]Most of AEG's resources were transferred to it from AmerenCIPS in 1999. AEM's purchases from AEG are principally resold to AmerenCIPS for the purpose of serving AmerenCIPS' retail customers.

6. Applicants argue that AmerenUE's decision to meet its needs by buying these plants is a reasonable one that does not reflect affiliate preference. Applicants state that the choice of Pinckneyville and Kinmundy resulted from AmerenUE's resource planning process and is consistent with a Stipulation and Agreement (Missouri Stipulation) approved by the Missouri Public Service Commission (Missouri Commission). They also assert that the proposed price of the facilities is reasonable, in comparison with other recent sales of similar types of generating capacity used for peaking purposes. According to Applicants, AmerenUE analyzed several options in addition to the proposed purchase, such as purchasing power on the market, purchasing existing assets from non-affiliates, and building new capacity, before reaching a decision, as discussed below.

7. In support, Applicants offer an affidavit, based principally on analyses contained in Attachment II to the affidavit, filed confidentially pursuant to § 388.112 of the Commission's regulations.[5] Applicants contend that disclosure of the information contained in Attachment II could damage their ability to engage in transactions at reasonable prices.

8. In the fall of 2001, AmerenUE issued a Request for Proposal (RFP) for 500 MW of capacity for the period 2002 through 2011. The bids received were evaluated in conjunction with a 25-year analysis of the cost to build peaking capacity. According to Applicants, an Asset Mix Optimization (AMO) Analysis presented to the Missouri Commission staff in January 2002, indicated that the least cost RFP options, coupled with the construction of combustion turbine generators at the end of the contracting period (2011), was comparable in cost to the purchase of generating facilities from AEG. However, Applicants state that during the period when the RFP bids were being evaluated, the Missouri Commission staff expressed a concern with AmerenUE meeting its needs through power purchases and indicated a preference that AmerenUE own hard assets. Applicants claim that as a result of discussions with the Missouri Commission staff, AmerenUE agreed "to focus on building and/or owning generating assets as the long-term least-cost method of meeting AmerenUE's resource needs."[6] AmerenUE updated the AMO Analysis in 2002, and the analysis showed that the addition of simple

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[5]Applicants state that Attachment II contains highly confidential and sensitive information, including (1) marketing analyses, (2) pricing information, (3) information about the operating characteristics of AEG's facilities and (4) commercially sensitive analysis of the value of certain generating facilities owned by unaffiliated entities.

[6]Appendix A to the Application, Affidavit of Richard A.Voytas at 5-6.

cycle and combined cycle combustion turbines would meet AmerenUE's needs on a least cost planning basis.

9. Applicants state that among the alternatives considered by AmerenUE were the purchase of existing generating assets from non-affiliated entities both inside and outside of the Ameren control area. However, AmerenUE rejected the purchase of generators outside of its control area due to the inability of the generators to obtain firm transmission service to the Ameren border, as documented in its evaluation of the responses to the RFP. Although transmission facility upgrades are planned, the timing of the completion of the upgrades is uncertain, making this option unrealistic, in AmerenUE's view. Similarly, Applicants indicate that AmerenUE rejected the purchase of two non-affiliated generators inside of its control area due to concerns about the creditworthiness of the owners of the assets and about transmission constraints associated with the plants.[7]

10. Apart from the Pinckneyville and Kinmundy plants, AmerenUE also evaluated other AEG plants. Applicants state that municipal property tax issues and implications for holding company requirements eliminated one plant from consideration, transmission constraints eliminated another, and high net book value caused still another to be infeasible. According to Applicants, none of these concerns were present for Pinckneyville and Kinmundy.

11. In addition, AmerenUE evaluated the option of constructing new capacity. According to Applicants, although the cost of new combustion turbines is slightly lower in today's environment of surplus capacity than a few years ago, AmerenUE estimated the site acquisition and development costs for new facilities to be higher than the costs incurred by AEG to develop the Pinckneyville and Kinmundy sites. The higher costs are, in part, due to the fact that the most desirable sites for new generation, where existing gas pipelines intersect with transmission lines, have already been taken. Applicants point out that site and development costs increase as plants are located farther from either a gas pipeline or a transmission system.

12. Further, Applicants claim, the net book value AmerenUE will pay for Pinckneyville and Kinmundy is within the range of prices at which other facilities comparable in terms of operational flexibility and reliability that have recently been sold. A comparison with five other plant sales shows that the price to be paid for Kinmundy is

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[7]According to Applicants, these concerns involve commercially sensitive issues, the disclosure of which could harm the owners of the assets.

lower than for all of the other sales except one. The price to be paid for Pinckneyville, although greater than that of four of the plants, is 20 percent less than the highest priced plant recently sold.

13. Finally, Applicants claim that their decision is consistent with the Missouri Stipulation between Ameren UE and the Missouri Commission staff, which was approved by the Missouri Commission on July 25, 2002. The Missouri Stipulation requires AmerenUE to acquire 700 MW of new "regulated" generating capacity by June 30, 2006,[8] and specifically states that this requirement may be met by the purchase of generation plant from an Ameren affiliate at net book value. The Missouri Stipulation also requires that AmerenUE construct new transmission lines and transmission upgrades that will increase transmission import capability by 1,300 MW.[9]

C. Notice and Responsive Filings

14. Notice of Applicants' filing was published in the Federal Register, 68 Fed. Reg. 7,995 (2003) with motions to intervene and protests due on or before February 26, 2003. Timely motions protesting the application were filed by Midwest Independent Power Suppliers, Inc. (MWIPS), The Electric Power Supply Association (EPSA) and Calpine Corporation (Calpine).[10] Timely motions to intervene without protest were filed by the PSEG Companies,[11] the NRG Companies (NRG) and Exelon Corporation. An untimely motion to intervene without protest was filed by National Energy Marketers Association (NEM). On March 13, 2003, Applicants filed an answer (Applicants' Answer) to the protests.

15. On March 18, 2003, the Missouri Commission submitted a letter to the Commission in response to Applicants' request that the Missouri Commission ask the

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[8]"Regulated" capacity is not defined, but presumably refers to generating capacity that will be subject to cost-based regulation and will be used to meet Missouri retail load.

[9]In addition, the Missouri Stipulation provides that retail rates will remain frozen, except for certain specified rate decreases, through June 30, 2006.

[10]Calpine endorses EPSA's protest without offering separate comments. Calpine requests that it be permitted to supplement its filing to provide more detailed comments, if necessary.

[11]Although not filing a protest, the PSEG Companies state that they generally support the filings by EPSA and Midwest Suppliers.

Commission to expeditiously approve the application. The Missouri Commission requests that the Commission timely consider the application and states that it does not object to approval of the application, but further states that it is not seeking to comment in any manner on the protests that have been filed in the proceeding. As explained in its letter, the Missouri Commission does not pre-approve acquisitions such as this one. Rather, it reviews the prudence of the acquisition when AmerenUE files to pass through the costs of the acquisition to retail customers.

16. On March 28, 2003, NRG, which had not filed a protest, filed a motion for leave to file an answer to AmerenUE's Answer. On April 14, 2003, Applicants filed a response to NRG's Answer. Finally, on April 25, 2003, Calpine filed a motion to lodge recent relevant information regarding a pending Illinois Commerce Commission proceeding involving the facilities at issue in this proceeding.

II. Discussion

A. Procedural Matters

17. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.214 (2002)), the timely motions to intervene make the movants parties to these proceedings. In addition, the Commission will grant NEM's untimely motion to intervene, as it was filed at an early stage of the proceeding and will not unduly delay the proceeding. Answers to protests are prohibited by Rule 213(a)(2) (18 C.F.R § 385.213(a)(2)) unless otherwise ordered by the decisional authority. We will accept Applicants' Answer since it assists the Commission in understanding several issues. However, we will not accept NRG's Answer and Applicants' April 14 response to NRG's Answer because they do not add anything to the Commission's understanding of the issues in this case. We will accept Calpine's motion to lodge because it aids in the Commission's understanding of the issues in this case.

B. Analysis

18. Section 203(a) of the FPA provides that:

> No public utility shall sell, lease, or otherwise dispose of the whole of its facilities subject to the jurisdiction of the Commission, or any part thereof of a value in excess of $50,000, or by any means whatsoever, directly or indirectly, merge or consolidate such facilities or any part thereof with those of any other person, or

purchase, acquire, or take any security of any other public utility, without first having secured an order of the Commission authorizing it to do so.[12]

19. In 1996, the Commission issued the Merger Policy Statement setting forth procedures, criteria and policies applicable to public utility mergers and other dispositions of jurisdictional facilities.[13] The Merger Policy Statement and Order No. 642,[14] which sets forth the Commission's filing requirements for Section 203 applications, provide that the Commission will take account of three factors in its Section 203 analysis: (a) the effect on competition; (b) the effect on rates; and (c) the effect on regulation. For the reasons discussed below, we will set the proposed transaction for hearing on the effect on competition.

1. Effect on Competition

a. Arguments in Application

20. Applicants state that Order No. 642 does not require a competitive screen analysis for intra-company transfers, as is the case here.[15] They point out that such transfers do not change concentration in generation markets and state that the Commission has recognized that such transfers do not present competitive concerns, citing Order No. 642,[16] GenHoldings I, L.L.C.,[17] and PP&L Resources, Inc.[18] Thus, Applicants claim that the proposed transaction will not adversely affect competition.

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[12] 16 U.S.C. § 824b(a) (2000).

[13] See Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, 61 Fed. Reg. 68,595 (1996), FERC Stats. & Regs. ¶ 31,044 at 30,117-18 (1996), order on reconsideration, Order No. 592-A, 62 Fed. Reg. 33,341 (1997), 79 FERC ¶ 61,321 (1997) (Merger Policy Statement).

[14] Revised Filing Requirements Under Part 33 of the Commission's Regulations, FERC Stats. & Regs., Regs. Preambles 1996-2000 ¶ 31,111 (2000) (Order No. 642).

[15] Order No. 642 at 31,902.

[16] Id.

[17] 96 FERC ¶ 61,140 at 61,602 (2001).

[18] 90 FERC ¶ 61,203 at 61,649 (2000).

b. Intervenors' Arguments

21. Protestors distinguish the precedent cited by Applicants in support of the transaction, noting that the cited cases involved intra-company transfers that separate generation activity from other lines of business in order to facilitate competition. To the contrary here, Protestors note, the proposed transfer of merchant generation to a franchised utility's regulated rate base to meet retail needs reverses the process and removes demand from the wholesale market that would otherwise be subject to competitive forces. Protestors contend that, at the least, this transfer should be considered a change in status that the Commission must consider in determining whether to permit AmerenUE and AEG to retain market-based rate authority. If the Commission approves the transfer, they urge that it be conditioned on AmerenUE agreeing to not make any off-system sales at market-based rates, including sales to any Ameren affiliate. According to Protestors, this requirement would be consistent with DTE East China, LLC,[19] where the Commission allowed a merchant affiliate of the operating public utility to sell power in the public utility's region at negotiated rates subject to a cost-based rate cap.

22. Protestors express concerns about the possible effects on the competitive process resulting from the type of affiliate transaction proposed here. They note that the success of facilities constructed as merchant plants, such as Pinckneyville and Kinmundy, depends on market conditions and efficiency of plant operations. They argue that AEG and Ameren (and their investors) were able both to avoid obligations placed on traditional utilities in building the plants and to obtain the benefit of opportunities to sell in the market at market-based rates. Thus, AEG and Ameren should have to accept the risk of possible non-recovery of costs in a depressed market, the same risk accepted by non-affiliated generators. Protestors contend that permitting this risk to be transferred will protect the merchant from losses due to power sales at marginal cost in a soft market and thus destroy a level playing field. Also, with a greater likelihood of cost recovery than is the case for non-affiliated suppliers, affiliated generators that are more costly than non-affiliated generators may capture sales that would be otherwise gained by less costly alternatives. In addition, Protestors suggest that a company not affiliated with a traditional utility in whose shadow it is able to build may be deterred from making generation investments if it perceives that affiliated merchant generators will be allowed to move generation in and out of rate base in response to changing market conditions and that the output of such plants can be sold at less than marginal cost.

[19] 99 FERC ¶ 61,315 (2002).

23. Protestors further regard the type of transaction proposed here to be inconsistent with the concepts underlying RTO initiatives and the Standard Market Design (SMD) NOPR.[20] They state that the Commission has emphasized the importance of long-term bilateral contracts in conjunction with short-term spot markets as necessary to achieve competitive market outcomes. According to Protestors, transactions such as this undermine the opportunity to compete for load through bilateral contracts.

24. Protestors, particularly EPSA, assert that the transfer of merchant generation to an affiliated franchised utility should be permitted only upon a showing that the transfer is superior to a "market" alternative. Because the proposed transaction is equivalent to a life-of-unit power purchase and sale contract between affiliates, the Commission should evaluate the transaction in the same manner as it does affiliate purchase contracts. EPSA would have the Commission use the standards first developed in Boston Edison Company Re: Edgar Electric Company (Edgar)[21] for judging power sales between affiliates. Specifically, EPSA believes that Applicants should be required to either conduct a transparent competitive solicitation or provide benchmark evidence. Only with such evidence can Applicants show that their proposal is more reliable, efficient and economical that other competitive options and that AmerenUE has not unduly favored its affiliate.

25. Based on Edgar, EPSA identifies three forms of evidence for demonstrating lack of affiliate abuse: (1) evidence of direct head-to-head competition between the affiliated seller and unaffiliated suppliers in either a formal solicitation or an informal negotiation process; (2) evidence of the prices that non-affiliated buyers were willing to pay the affiliated sellers for similar services; or (3) benchmark evidence of market value, based on both price and non-price terms and conditions, of contemporaneous sales made by non-affiliated sellers for similar services in the relevant market. EPSA notes that since Edgar, the Commission has approved affiliate contracts based on review of the RFP process used by the purchasing utility (in Aquila Energy Marketing Corp.[22] and Southern

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[20]Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, 67 Fed. Reg. 55,451 (Aug. 29, 2002); IV FERC Stats. & Regs. ¶ 32,563 (July 31, 2002).

[21]55 FERC ¶ 61,382 (1991).

[22]87 FERC ¶ 61,217 (1999)

Power Co.[23]), thus indicating that affiliate contracts that result from a fair, contemporaneous RFP process are acceptable. In addition, EPSA points out, the Commission has approved a contract based solely on "benchmark" testimony (in Ocean State Power II[24], which explained that several factors, such as the relevant market, the contemporaneousness of the benchmark evidence, comparability and non-price terms must be evaluated in the benchmark analysis).

26. EPSA regards Applicants' evidence as inadequate with respect to either the first or third Edgar test.[25] First, according to EPSA, Applicants have not relied on a competitive solicitation, as their sole purpose was to avoid direct competition. Second, Applicants have not provided evidence of valid competitive benchmarks. EPSA argues that the two-year-old RFP can hardly be viewed as yielding bids comparable to the proposed transfer, given that market conditions have changed in the interim. Also, the analysis of the RFP results may be faulty, since it may be based on unreliable market price projections after 2011. Further, intervenors note that they are prevented from evaluating the reasonableness of an analysis that has been filed confidentially.

27. Thus, Protestors argue that before the Commission acts on this application, Applicants should be required to either conduct a new, updated and transparent solicitation or submit some other form of market evidence that the requested transfer is equivalent or superior to any "market" alternative. Absent this showing, Protestors urge that the Commission deny the application, or, in the alternative, set the matter for a trial-type evidentiary hearing, similar to that the Commission has required for its review of other types of affiliate transactions.

c. Applicants' Response

28. Applicants acknowledge that the Commission has announced its intention, in light of "generic concerns" raised by affiliate plant sales, to modify its approach to analyzing

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[23] 97 FERC ¶ 61,279 (2001).

[24] 59 FERC ¶ 61,360 at 62,332 (1992), order denying reh'g and granting clarification, 69 FERC ¶ 61,146 (1994).

[25] EPSA states that to date, no utility has attempted to justify a contract on the basis of evidence required under the second Edgar test.

the competitive effects of such transactions "in the future."[26] However, because the Commission has not yet enunciated new standards or criteria, they contend that the Commission should not apply new standards to this transaction; the transaction meets current standards, and the capacity at issue is needed to meet reserve margin requirements for summer 2003. In addition, Applicants note that the sale is consistent with the Missouri Stipulation, which was entered into in summer 2002, long before Cinergy was issued. Applicants state that no evidence has been submitted to show that the sale of the plants is intended to provide AEG a "safety net" or to shield AEG from competition. Rather, AmerenUE is simply seeking to meet its needs on a least cost basis consistent with the Missouri Stipulation while taking into account the Missouri Commission staff's preference that AmerenUE own hard assets. Applicants disagree that AmerenUE is guaranteed recovery of the costs associated with the transaction, since such a claim assumes that state regulators will not act responsibly to protect retail customers.

29. Applicants argue that Protestors, rather than offering relevant evidence or studies, have made only vague or speculative claims that the purchase of the plants is not prudent or reasonable. They suggest that Protestors are more concerned with protecting their interests as competitors, as opposed to protecting competition. Creating an artificial preference for the purchase of power from non-affiliates is no more conducive to the competitive process than is an unjustified preference for an affiliate.

30. In this instance, Applicants argue, power purchases would be inconsistent with the Missouri Stipulation. The purchase of comparable units from non-affiliated entities was not viable for meeting summer 2003 needs, due to uncertainty and potential delay arising out of transmission availability and creditworthiness. Applicants contend that the Voytas affidavit explains why these alternatives are not viable and also shows that the price to be paid for the plants is less than or comparable to the prices paid in arms-length transactions between non-affiliates for similar facilities. While Applicants recognize that the proposed sale would "remove" demand from the wholesale market, they note that any long-term contract has the same consequence. The fact that some other supplier or other plant owner offering less favorable terms was not chosen does not mean that competition did not occur.

31. Applicants disagree that the standards of Edgar should be applied to the proposed transaction. A heightened standard of review for affiliate transactions under Section 205

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[26]See Cinergy Services, Inc., et al., 102 FERC ¶ 62,128 at 61,345 (Cinergy) (2003).

is unnecessary where, as here, all customers are protected by retail rate freezes, retail customer choice or fixed rate contracts. Even when such protections end, Applicants claim, approval of the transaction by the Commission would not prevent the Missouri Commission from reviewing any AmerenUE filing to recover the costs in cost-based rates. Applicants point out that, in contrast, the Missouri Commission would not have similar review authority over costs arising from a Commission-approved contract involving power purchases in the market.

32. Applicants claim that, in any case, they have adequately demonstrated that no affiliate preference has occurred. First, they refer to the prices paid in similar transactions between non-affiliates and conclude that the prices to be paid for Pinckneyville and Kinmundy are comparable. Second, they note that the Voytas affidavit contains a comparative analysis of non-price factors, such as deliverability and creditworthiness. Third, they reiterate the Missouri Commission staff's preference that AmerenUE own hard assets. Fourth, with respect to the timing of the analyses, Applicants note that AmerenUE relied on data on plant sales that closed as late as December of 2002 and an updated AMO Analysis in 2002. Fifth, Applicants state that EPSA has provided no evidence to show that AmerenUE's long-term energy projections are inaccurate.

33. Applicants also contend that Protestors have not provided any legitimate basis to condition AmerenUE's market-based rate authority, noting that the transaction does not alter the amount of company-owned generating capacity and that no evidence of market power abuse has been submitted. Applicants also argue that Protestors' reference to DTE East China is not on point, since the affiliate in that case had not requested market-based rate authority in the first instance.

34. Finally, Applicants dispute that the proposed transaction is inconsistent with SMD. According to Applicants, SMD emphasizes the need for utilities to avoid overuse of spot-market purchases and, instead, rely on a variety of long-term resources, including self-supply as well as bilateral contracts, to achieve resource adequacy. Applicants state that AmerenUE expects to continue to use a mix of resources, including self-owned generation, long-term purchases and spot market purchases and that members of the groups protesting this application will be able to compete for sales to meet AmerenUE's needs. They also challenge the assertion that the proposed transaction is contrary to the Commission's RTO policies, as no competitor alleges that Ameren has denied access to its transmission system.

d. Commission Determination

35. Applicants have not shown that the proposed transaction will not adversely affect competition. We will order a trial-type hearing to be held to examine possible effects of the proposed transaction on competition before we make any determination as to whether the proposed transaction is consistent with the public interest.

36. Heretofore, as we stated in Order No. 642, the Commission's experience has been "that anticompetitive effects are unlikely to arise with regard to internal corporate reorganizations or transactions."[27] However, this pronouncement was made in the context of the types of intra-corporate transactions that the Commission had been confronted with at that time. Such transactions had been of two general types. Usually, in a transfer of jurisdictional facilities occurring as a consequence of the creation of a holding company or a reorganization of interests or entities holding the facilities, no change would occur in the way the associated generating facilities were operated or the way output from the generation facilities was marketed or sold, regardless of whether the generation facilities were used for cost-based sales or market-based sales. On other occasions, sometimes as the result of state restructuring initiatives, separate generating subsidiaries had been established. In both types of Section 203 transactions, the Commission found that competitive concerns generally do not arise.

37. In contrast, the filing here marks the second occasion within a very short period that a franchised utility has sought our approval to acquire jurisdictional facilities associated with generating facilities initially developed and marketed as merchant generation by a power marketer affiliate. We indicated in Cinergy our concerns about "the possible implications of affiliate transactions of the type proposed here for the competitive process in general and for the region's wholesale competition."[28] We noted that "the ability of a franchised utility to assume its affiliated merchant's generation when market demand declines gives the affiliated merchant a "'safety net"' that merchant generators not affiliated with a franchised utility lack."[29] We expressed concern that "the existence of a safety net may affect the incentive of new merchant generators to invest in new facilities," erecting a barrier to entry that harms the competitive process and raises

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[27]Order No. 642 at 31,902. This statement was made in a discussion of the type of Section 203 applications that could make abbreviated filings.

[28]102 FERC at 61,345.

[29]Id.

prices to customers in the long run "because affiliated merchant generation with a safety net option will not be subject to the price discipline of a competitive market."[30]

38. While the Commission did not withhold approval of the transaction in Cinergy (referring to the Indiana Utility Regulatory Commission's specific review and approval of the generation acquisition and also the need of the franchised utility to acquire secure supplies), we also stated that "in light of the generic concerns raised by this case, the Commission will in the future modify its approach to analyzing competitive effects of intra-corporate transactions of this nature."[31] The case at hand presents these types of competitive concerns; the transaction proposed by Applicants would change the competitive landscape by means that do not reflect the exercise of competitive forces in the market, i.e., the interaction of independent sellers with an independent buyer. Unlike Cinergy, the only state regulatory commission with pre-approval authority here, the Illinois Commerce Commission (Illinois Commission), has not acted and its staff has recommended that the transaction not be approved. As this Commission has previously noted:

> if the Commission is to fulfill its statutory responsibilities, it must determine what is consistent with the public interest in light of conditions in the electric industry in general as well as the specific circumstances presented by a proposed merger. In an era of traditional, cost-of-service based regulation, the Commission defined its public interest responsibilities consistent with that structure. Today, we believe that the public interest requires policies that do not impede the development of vibrant, competitive generation markets.[32]

39. Under Edgar, the reasonableness of a franchised utility's wholesale purchases from an affiliate is evaluated to ensure that affiliate abuse has not occurred. However, we have no similar established standards to evaluate Section 203 transactions between affiliates that effectively accomplish the same end. In the Commission's view, however, the two situations are similar. Just as our Section 205 review of affiliate transactions under Edgar is intended to prevent affiliate abuse and to ensure prices that would be consistent with competitive outcomes, a franchised utility should be required to

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[30]Id.

[31]Id.

[32]Merger Policy Statement at 30,115.

demonstrate that its purchase of an affiliate's plant is on terms similar to any other competitive alternatives available.

40. In defending AmerenUE's decision to acquire two affiliate plants, Applicants rely on the results of the RFP issued in August 2001,[33] an updated assessment of the viability of non-affiliated generators located both outside and inside the Ameren control area and an updated AMO Analysis completed in mid-2002. Applicants also provide a comparability analysis of recent non-affiliated plant sales.

41. We have concerns regarding the adequacy of the evidence offered by Applicants. Initially, we note that AmerenUE did not issue an RFP. The application gives some indication that generating facilities were offered for sale in response to the RFP issued in August 2001. Market conditions may have pushed down the price of generating assets since then.

42. Applicants' evaluation process rejected a number of alternatives due to the claimed lack of necessary transmission availability, alleged specific transmission constraints associated with particular plants, and creditworthiness concerns about the owners of certain plants. A fair and reasonable evaluation of the transmission system is vital to ensuring that all generation resources are given a fair opportunity to compete. As discussed below, a hearing on the application is necessary to determine whether Applicants' evaluation of transmission service factors adequately considered competing

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[33]We note that the Missouri Commission has required AmerenUE to conduct a competitive bidding process before entering into a power purchase contract with AEG or a marketing affiliate of AEG. Motion to Intervene and Comments in Support of Union Electric Company at 5, Docket No. ER02-1451-000, April 11, 2002. Because the potential bidders to supply AmerenUE's needs for power for the period 2002-2011 included its affiliates, AmerenUE issued the 2001 RFP. AmerenUE also employed an independent consultant to help evaluate the responses. The Missouri Commission staff then recommended that the RFP proposal be modified to reflect a one-year term. AmerenUE obtained revised bids and ultimately chose a combination of three, including an AEM bid, to supply its 2002 needs. After the AEM contract was filed with this Commission and set for hearing, the case was settled. Among other terms, the settlement provides that whenever an RFP is issued for capacity and energy in the future and purchases from an affiliate are a possible result, AmerenUE will use an independent consultant and ensure that the consultant has all of the information necessary for it to make a fair and independent analysis of the bids. Article III, Offer of Settlement filed in Docket No. ER02-1451-001, December 6, 2002.

alternatives. In the hearing, the parties are not limited to presenting evidence regarding the concerns raised here, but also may present other evidence bearing on whether Applicants' analysis fairly addressed competing alternatives, such as whether Applicants properly took account of changing market conditions or creditworthiness concerns in investigating alternatives.

43. The Commission is unable to determine from the analysis submitted with the application whether the costs of solutions to the lack of transmission availability, such as incremental transmission investments or redispatch opportunities to relieve constraints, were properly considered and evaluated. We also note that Applicants refer to the transmission evaluation conducted for the 2001 RFP and to uncertainty associated with the timing of planned facility upgrades within the control area. However, it is unclear from the application whether Applicants updated the 2001 assessment of transmission availability before concluding that transmission service necessary to deliver power from plants outside of the Ameren control area was inadequate.

44. In addition, we note as a condition of the Commission's approval of Ameren's acquisition of Central Illinois Light Company, Ameren agreed to make certain transmission upgrades, some of which were to be completed within six months of consummation of the acquisition.[34] It is also anticipated that Ameren will join the MISO. While these potentially beneficial actions would not add transmission capability to facilitate power deliveries to meet summer 2003 needs, they would improve transmission availability in later periods and could expand the range of power supply options. It is unclear whether the option of purchasing power by contract for 2003 in conjunction with buying power plants in 2004 or later years was considered or fairly evaluated.

45. Further, the Commission must note that the use of an independent consultant to analyze the alternatives considered in the application would have provided greater assurance that an affiliate did not receive undue preference in the evaluation process and that the necessary transmission upgrades and potential redispatch were properly considered in the evaluation of each alternative.

46. Based on all of above considerations, the Commission finds it necessary to set this matter for hearing. We need to be certain that the purchase of the Pinckneyville and Kinmundy plants at net book value is consistent with results that would be obtained through a competitive process reflecting the interplay between AmerenUE and independent sellers and has not resulted in undue preference being shown to

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[34] See Ameren Services Co., et al., 101 FERC ¶ 61,202 (2002).

AmerenUE's affiliate, AEG. We are mindful that a hearing process may force AmerenUE to seek other means of satisfying summer 2003 peak requirements.[35] Nonetheless, we believe it vital to fully address before the fact the potential effects of changes in the competitive landscape that could be caused by the transaction, changes that would be long-lasting.

47. We emphasize that our determination to set the merits of the proposed transaction for hearing is not inconsistent with any ruling by the Missouri Commission or any position that may have been taken by the staff of the Missouri Commission regarding the acquisition of generating assets versus power purchase contracts as a solution to either AmerenUE's short-term or long-term needs. The Missouri Commission staff's apparent preference that AmerenUE own hard generation assets, instead of relying on power purchase contracts, was expressed in the context of AmerenUE's evaluation of RFP bids to meet power needs over the period 2002-2011, that is, as a means of meeting long-term power needs. Just as AmerenUE acted to meet its needs for Summer 2003 with power purchase contracts, there is no indication that the Missouri Commission staff sought to preclude AmerenUE from considering short-term power purchases for 2003.[36] The Missouri Stipulation itself does not preclude power purchases in the near term, given that AmerenUE has until 2006 to satisfy its commitment to add 700 MW of regulated generation capacity.

48. Finally, the Illinois Commission, which does have review authority over the proposed asset transfers,[37] has initiated a proceeding to address AmerenUE's proposed acquisitions. In that proceeding, the staff of the Illinois Commission has filed testimony

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[35]Applicants bear some responsibility for these circumstances. The need for additional power supplies for 2003 was long evident and the Missouri Stipulation, which noted the option of buying an affiliate plant at net book value, was approved in July, 2002. In addition, the updated AMO analysis, which considered the possibility of buying the Pinckneyville plant, was presented to the Missouri Commission staff in August 2002. None of the information disclosed in the application suggests any reason why this application could not have been filed earlier than February 5, 2003.

[36]It was also apparent early in 2002, long before AmerenUE submitted its application in this proceeding, that the problem of obtaining sufficient power supplies would be present in 2003 as well as beyond.

[37]The Illinois Commission also has prudence review authority if and when AmerenUE seeks to recover the costs of the acquisition in its Illinois retail rates, which are currently frozen.

urging the Illinois Commission to disallow the proposed asset transfer. In its testimony, the Illinois Commission staff concludes, among other things, that AmerenUE has not shown that the proposed asset transfer is the least-cost means to meet its customers' needs.

2. Effect on Rates

a. Applicants' Position

49. Applicants state that the proposed transaction will not adversely affect rates. They note that all of AmerenUE's wholesale customers are served under contracts that have fixed rates or other pricing provisions that will not be affected by any costs associated with this transfer. The wholesale customers will be able to purchase power from other suppliers when their contracts expire. Applicants contend that the Commission has found that wholesale customers are adequately protected in such circumstances, citing Cinergy Services, Inc.[38] and Potomac Electric Power Co.[39] At the retail level in Missouri, Applicants note that retail rates are frozen through 2006, a protection previously found by the Commission to be sufficient, citing First Energy Corp.[40]

50. Applicants state that none of AmerenCIPS' customers will be affected, noting that AmerenCIPS has no wholesale customers. They also point out that the AEG capacity being sold is not needed to support power sales by AmerenCIPS to its bundled retail load, which also occur at rates frozen at current levels through 2006.

b. Protests

51. Protestors note that the assets to be transferred would become part of regulated utility facilities, with their costs presumably to be rolled into AmerenUE's regulated rate base. While retail rate settlements and rate freezes may protect retail consumers in the near-term from cost- and risk-shifting, Protestors claim that the costs and risks associated with the facilities will remain for decades.

c. Applicants' Response

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[38] 98 FERC ¶ 61,306 at 62,307 (2002).

[39] 96 FERC ¶ 61,323 (2001).

[40] 94 FERC ¶ 61,179 at 61,620 (2001).

52. Applicants dispute Protestors' assertion that the transfer would improperly shift risks from the AEG merchant operations to AmerenUE. They point out that no customer, customer group, or state regulatory commission has opposed the transfer. Applicants also reiterate that AmerenUE's wholesale customers take service under contracts with fixed rate provisions, with most of the contracts extending several years into the future, and that the customers will be able to buy power from other suppliers when the contracts expire. They also point out that if AmerenUE seeks in the future to sell wholesale power at cost-based rates, the Commission will be able to review and judge the reasonableness of any cost-based rate levels. At the retail level, while Applicants acknowledge that Missouri retail customers may not have a choice of supplier when the rate freeze expires in 2006, they stress that AmerenUE will still need to obtain the Missouri Commission's approval before any of the costs associated with the transfer may be recovered from retail ratepayers.

d. Commission Determination

53. The Commission finds that the proposed transfer will not adversely affect rates. All of the municipal wholesale customers are served at fixed rates under AmerenUE's market-based tariff, with most contracts extending to the end of 2008. Although three of the wholesale contracts terminate at the end of 2003, those customers will be able to seek other sources of supply. The ability of wholesale customers to seek other sources of supply is dependent on the competitiveness of the market. We are setting for hearing the effects of this disposition on competition. Moreover, no issue has been raised by any customer as to the need for ratepayer protection.[41]

54. In addition, the Commission notes that the Missouri Commission has approved the Missouri Stipulation, which provides that AmerenUE will institute three periodic retail rate decreases through 2006. The Missouri Stipulation also specifically permits any of the signatories to raise issues concerning the prudence and reasonableness of the infrastructure investment decisions made by AmerenUE regarding generation and transmission projects contemplated by the Missouri Stipulation. Thus, retail customers are protected.

3. Effect on Regulation

a. Applicants' Arguments

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[41] Merger Policy Statement at 30,123-24. In fact, no wholesale customer has sought to intervene in the proceeding.

55. Applicants assert the proposed transfer will not undermine the Commission's regulation. They state that while Ameren is a registered public utility holding company under the Public Utility Holding Company Act of 1935, Ameren has previously committed to abide by the Commission's policies with respect to intra-company and affiliate transactions and will continue to do so.[42] Also, the Commission will continue to have authority over any wholesale power sales from the generating facilities being sold, as well as all wholesale power sales by AmerenUE and AEG.

56. At the state level, Applicants point out that the Illinois Commerce Commission (Illinois Commission) must approve the transaction and that the Missouri Commission, while lacking similar approval authority over the transaction, has the authority to require AmerenUE to comply with its resource planning regulations and has done so here. Applicants further note that both state commissions will continue to have jurisdiction over all retail sales of power and all bundled transactions currently subject to their jurisdiction.

b. Protests

57. MWIPS claims that the Commission will not have jurisdiction to prohibit and regulate affiliate transactions once the facilities become part of AmerenUE's regulated rate base. It points out that after the plant transfers the Commission will not have jurisdiction over sales to the extent that the output of the plants is sold at retail and not at wholesale. MWIPS assets that as a result, the Commission would lose its ability to prevent affiliate abuse associated with cross-subsidization by captive AmerenUE customers. MWIPS believes that the Commission should not give up its ability to regulate such affiliate transactions without first assuring itself that the transfer of the plants is not a new form of abusive affiliate practice.

c. Applicants' Response

58. Applicants disagree with MWIPS' assertions. They point out that to the extent that AmerenUE continues to sell power from the plants at wholesale, the Commission will maintain review authority over cost-based transactions and oversight of market-based sales. They also note that in Cinergy, the Commission found that a reduction in the amount of sales subject to its jurisdiction does not imply that its regulation will be impaired.

d. Commission Determination

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[42]Application at 18.

59. The Commission finds that its regulation will not be adversely affected by the proposed transaction. As we stated in Cinergy, if the generating units that are the subject of the proposed transfer are used to make wholesale sales, whether market-based or cost-based, the Commission will continue to review transactions under its Section 205 authority. Even if the output from the plants will be used principally for retail needs, thus potentially reducing the amount of possible wholesale sales from the plant, a reduction in the amount of sales subject to our regulation does not mean that the effectiveness of our regulation will be impaired. In addition, Applicants have reiterated their commitment to abide by the Commission's policies with respect to intra-company and affiliate transactions.[43]

60. The Commission is mainly concerned with the effect of a Section 203 transaction on state regulation where the affected state regulatory commission lacks approval authority over the transaction. Here, Applicants are required to seek the approval of the Illinois Commission, which is currently conducting a proceeding on the transaction. Approval by the Missouri Commission is not specifically required. However, as stated previously, under the Missouri Stipulation approved by the Missouri Commission, AmerenUE may satisfy its commitment to add 700 MW of regulated capacity by purchase of generation plant from an affiliate at net book value and issues relating to prudence and reasonableness of such an infrastructure investment decision may be brought before the Missouri Commission. We note further that the Missouri Commission has not intervened in this proceeding. Therefore, the Commission finds that the proposed transfer will not adversely affect state regulation.

4. Accounting

61. The asset transfer agreements provide for AmerenUE to acquire AEG's Pinckneyville and Kinmundy generation and associated transmission facilities at the net book value of $161.5 million and $94.6 million, respectively. Section 33.5, Proposed Accounting Entries, of the Commission's Regulations requires that Applicants present proposed accounting entries with sufficient detail showing the effect of the transaction.[44] Applicants have not included the proposed accounting entries and related details in the application and request waiver of Section 33.5 of the Commission's regulations. They state that they will provide this information at a later date if and as required by the Commission.

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[43] Merger Policy Statement at 30,125.

[44] 18 CFR § 33.5 (2002).

62. In the Merger Policy Statement,[45] we indicated that it is important for entities to properly account for transactions under Section 203. The information required in Section 33.5 enables the Commission to evaluate an applicant's accounting for Section 203 transactions and to provide guidance and direction when the accounting is inconsistent with the Commission's Uniform System of Accounts. The recent and widely reported allegations of accounting irregularities by the business community at large and their negative effect on capital markets reinforce our views regarding the importance of proper accounting. Therefore, we will deny Applicants' request for waiver of Section 33.5 of our regulations and will require that Applicants satisfactorily demonstrate that their proposed accounting for the transaction complies with the Commission's Uniform System of Accounts. In addition, Applicants are advised that they must comply with Section 33.5 for any future transaction requiring Commission authorization under Section 203 of the FPA.

The Commission orders:

(A) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by Section 402(a) of the Department of Energy Organization Act and the Federal Power Act, particularly Section 203 thereof, and pursuant to the Commission's Rules of Practice and Procedure and regulations under the Federal Power Act (18 C.F.R. Chapter I), a public hearing shall be held to address the effect of Applicants' proposed disposition of facilities on competition.

(B) Applicants' request for a waiver of the requirement of Section 33.5 of the Commission's regulations is denied. Applicants shall submit their proposed journal entries and related details required by Section 33.5 within 30 days of the date of this Order. The submission must include appropriate narrative explanations of the proposed accounting entries, how the net book value of the assets was calculated and the related income tax consequences.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.

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[45]Merger Policy Statement at 30,126.

LEXSEE 102 F.E.R.C. 61128

Cinergy Services, Inc., On behalf of PSI Energy, Inc.; CinCap Madison, LLC; CinCap VII, LLC

DOCKET NO. EC02-113-000

FEDERAL ENERGY REGULATORY COMMISSION - COMMISSION

102 F.E.R.C. P61,128; 2003 FERC LEXIS 225

ORDER AUTHORIZING DISPOSITION OF JURISDICTIONAL FACILITIES

February 4, 2003

PANEL:
[**1] Before Commissioners: Pat Wood, III, Chairman; William L. Massey, and Nora Mead Brownell

OPINION:
[*61,342]

1. On September 6, 2002, Cinergy Services, Inc. (Cinergy Services), on behalf of PSI Energy, Inc. (PSI), CinCap Madison, LLC (CinCap Madison), and CinCap VII, LLC (CinCap VII) (collectively, Applicants) filed an application under section 203 of the Federal Power Act (FPA) n1 requesting Commission authorization to transfer the jurisdictional interconnection facilities associated with certain generating assets owned by CinCap Madison and CinCap VII to PSI. As discussed below, while the Commission has concerns about the possible implications of affiliate transactions of the type proposed here for competition, the Commission will approve the transaction. This order is consistent with the public interest because it allows PSI to acquire needed generation supply consistent with the determination of the Indiana Utility Regulatory Commission (Indiana Commission).

n1 16 U.S.C. 824b (1994).

Background [2]**

Description of Applicants

2. PSI, a public utility and a wholly-owned subsidiary of Cinergy Corp. (Cinergy), provides wholesale service at cost-based rates and is also authorized to sell wholesale power at market-based rates. In addition, PSI provides retail electric service in Indiana, subject to regulation by the Indiana Commission.

3. CinCap Madison and CinCap VII (jointly referred to as CinCap) are indirect, wholly-owned subsidiaries of Cinergy. They own and operate, respectively, the Madison Generating Station, a 576 megawatt (MW) generation plant in Butler County, Ohio and the Henry County Generating Station, a 136 MW generation plant in Cadiz, Indiana. The generating stations are interconnected with the transmission system of Cinergy's public utility subsidiaries. CinCap Madison and CinCap VII have been authorized to sell power at market-based rates.

Description of the Proposed Transaction

4. Under the proposed transaction (Transfer), PSI would acquire all of CinCap's assets, including the generating stations, the jurisdictional interconnection facilities associated with the generating facilities and plant inventory balances as of the time of transfer. Applicants [**3] have proposed to effectuate the Transfer at net book value as of January 1, 2002, plus carrying costs on this book value from January 1, 2002, through the date of transfer, for an aggregate pur-

chase price not to exceed $ 450 million. On December 19, 2002, the Indiana Commission, with one Commissioner dissenting, issued certificates of public convenience and necessity for PSI to purchase CinCap's generating assets. The current proposed purchase price is a result of a settlement agreement between PSI (and CinCap) and the Indiana Commission staff, which was also approved by the Indiana Commission in its December 19 order.

5. Applicants state that PSI has determined that its demand for electricity requires additional generating capacity as soon as practical. After considering and implementing many resource options, PSI decided that buying CinCap's generating facilities is the most economical and reliable means of providing for PSI's native load and wholesale power requirements. n2

n2 Applicants describe the CinCap acquisition as providing peaking capacity and state that except for a 50 MW unit power sale to another entity, all of the CinCap capacity will be available to serve PSI's Indiana retail customers' and other wholesale customers' demand requirements.

[4]**
6. Applicants request full or partial waiver of several of the information requirements of Part 33 of the Commission's regulations on the grounds that their proposal is a purely internal transfer of assets, without the need for the higher level of scrutiny that might be needed for a merger combining previously unaffiliated assets. Specifically, Applicants request waiver of the requirements of 18 C.F.R § 33.2(h), partial waiver of the requirements of 18 C.F.R. § § 33.2 (c) and (d), and waiver of any other requirements of Part 33, if Applicants inadvertently omitted information required by Order No. 642. n3 For this reason, Applicants also have not submitted a horizontal competitive analysis under 18 C.F.R. § 33.3(a)(1) of the regulations, or any other information under § 33.3.

n3 See Revised Filing Requirements Under Part 33 of the Commission's Regulations, FERC Stats. & Regs., Regs. Preambles 1996-2000 P31,111 (2000) (Order No. 642).

Notice and Responsive Filings

7. Notice of **[**5]** Applicants' filing was published in the Federal Register, 67 Fed. Reg. 58,597 (2002) with motions to intervene and protests due on or **[*61,343]** before October 7, 2002. Timely motions to intervene were filed by Midwest Independent Power Suppliers, Inc NFP (Midwest Suppliers), Reliant Resources, Inc., PG&E Energy Trading - Power, L.P., The Electric Power Supply Association (EPSA), PSEG Companies, and Williams Energy Marketing & Trading Co. (Williams). Midwest Suppliers, EPSA and Williams (collectively, Protestors) also protested Cinergy Services' filing, and Cinergy Services filed an answer to the protests.

Discussion

Procedural Matters

8. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.214 (2002)), the motions to intervene make the movants parties to these proceedings. Answers to protests are prohibited by Rule 213(a)(2) (18 C.F.R § 385.213(a)(2)) unless otherwise ordered by the decisional authority. However, we will accept Cinergy's answer since it assists the Commission in understanding several issues presented by its section 203 filing.

Analysis of the Section 203 Application

9. Section 203(a) of the FPA **[**6]** provides that:

No public utility shall sell, lease, or otherwise dispose of the whole of its facilities subject to the jurisdiction of the Commission, or any part thereof of a value in excess of $ 50,000, or by any means whatsoever, directly or indirectly, merge or consolidate such facilities or any part thereof with those of any other person, or purchase, acquire, or take any security of any other public utility, without first having secured an order of the Commission authorizing it to do so. n4 n4 16 U.S.C. 824b(a) (1994).

10. In 1996, the Commission issued the Merger Policy Statement setting forth procedures, criteria and policies applicable to public utility mergers and other dispositions of jurisdictional facilities. n5 The Merger Policy Statement and Order No. 642 provide that the Commission will take account of three factors in its section 203 analysis: (a) the effect on competition; (b) the effect on rates; and (c) the effect on regulation. For the reasons discussed below, [**7] we will authorize the proposed disposition of jurisdictional facilities.

n5 See Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, 61 Fed. Reg. 68,595 (1996), FERC Stats. & Regs. 31,044 at 30,117-18 (1996), order on reconsideration, Order No. 592-A, 62 Fed. Reg. 33,341 (1997), 79 FERC 61,321 (1997) (Merger Policy Statement).

11. Initially, the Commission observes that the Indiana Commission has an important role in reviewing the retail aspects of the proposed transaction. Complementing that review is the role this Commission has in reviewing the wholesale aspects of the transaction. Of course, both Commissions must consider the overall regulatory and competitive structure of the market that would result if the transaction were approved.

Effect on Competition

Applicants' Position

12. Applicants assert that the proposed transfer will not alter the competitive situation within [**8] the relevant wholesale geographic markets, and that the transfer will not change the fact that the Cinergy public utility subsidiaries' transmission system is operated on an integrated, single-system basis pursuant to the Midwest ISO's OATT. They state that the transfer will be limited to the transfer of generation market share between Cinergy affiliates, and therefore that the relative market share of the Cinergy affiliates or any other market participant will not change. Citing Calpine Power Servs. Co., n6 PP&L Res., Inc., n7 and Allegheny Energy Supply Co, n8 Applicants maintain that the Commission has concluded that similar internal transfers of generating facilities have no adverse effect on competition, and that this approach was affirmed in Order No. 642. In addition, Applicants state that the Commission recently found that the Cinergy companies, including CinCap Madison and CinCap VII, passed the Supply Margin Assessment screen. n9

n6 92 FERC P62,150 (2000).

n7 90 FERC P61,203 (2000).

n8 89 FERC P62,063 (1999).

[**9]

n9 Citing Cinergy Services, Inc., et al., 98 FERC P61,306 (2002).

Protests

13. Midwest Suppliers argue that Cinergy's reliance on the Commission's market share analysis as to the effect on competition is insufficient, and that Cinergy's proposal would enable its merchant affiliates to capture market share for energy and capacity that they would be unlikely to gain in the competitive market place. Midwest Suppliers assert that Cinergy's proposal would prevent market participants that have supplied PSI with capacity and energy during the summers of 2000, 2001, and 2002 from doing so again, to the extent that they are displaced by energy and capacity produced by the transferred plants. EPSA makes a similar argument. In addition, Midwest Suppliers believe that there

should be an investigation as to whether the $ 632/kW book value ceiling price Cinergy proposes to pay for the Madison and Henry County plants exceeds the market value of those plants. In support of Midwest Suppliers' protest is an affidavit of Dr. Craig Roach indicating that the plants have not been **[**10]** profitable, that their cost exceeds the high end of the range of a sample of comparable peaking facilities, and that there is glut of power plants that could compete with the plants proposed to be transferred. Midwest Suppliers **[*61,344]** maintain that the apparent lack of market driven incentives for the proposed transaction suggests that it could be a means of extricating Cinergy's merchant affiliates from unprofitable capital investments by shifting costs now subject to market risk from the affiliates to captive ratepayers.

14. Citing GPU Advanced Resources, Inc. (GPU) n10 and FirstEnergy Trading Services (First Energy), n11 Midwest Suppliers assert that the Commission has prohibited similar attempts to shift cost in other contexts that are indistinguishable from the present case in terms of economic impacts. EPSA makes a similar argument. GPU was a sale of power subject to FPA section 205 in which the Commission recognized that affiliate abuse would stem from the marketing affiliate selling to the franchised utility at a price above the prevailing market price. Similarly, Midwest Suppliers maintain, the Code of Conduct that the Commission requires for the issuance of **[**11]** certificates to sell power at market-based rates (which Cinergy's merchant affiliates have) prohibits the sale of non-power goods and services at rates that exceed market value. Midwest Suppliers assert that the proposed sale of both the plants and the contracts for fuel gas come within the scope of the Code of Conduct requirement concerning " non-power goods".

n10 81 FERC P61,335 (1997).

n11 88 FERC P61,067 (1999).

15. Midwest Suppliers further argue that allowing Cinergy's proposal to go forward could depress investment by creating a competitive advantage for those generating companies that are able to construct facilities in the footprint of an affiliated utility. Williams makes a similar argument. In addition, Midwest Suppliers, EPSA and Williams all maintain that the cases cited by Cinergy for the proposition that intra-corporate transfers are routinely granted by the Commission are not on point, since they typically involve the transfer of generation **[**12]** of a vertically integrated utility to a FERC jurisdictional competitor, which tends to increase rather than decrease competition.

16. Midwest Suppliers request that Cinergy's proposal be rejected or, at a minimum, that Cinergy be required to show that the proposed transfer of the plants is the least cost alternative for the acquisition of energy. They assert that if the Commission is concerned that such a requirement would infringe impermissibly upon state jurisdiction, an alternative approach would be to grant PSI conditional authority to sell retail rate-base capacity in excess of daily system demand via mandatory auctions for 12-month periods with no floor under the bids. Williams proposes a similar alternative. According to Midwest Suppliers, another alternative would be to convene a hearing for the purpose of determining whether the price for transfer of the plants exceeds market value.

17. EPSA argues that argues that Cinergy cannot claim that the proposed transaction is the most expeditious, reliable, efficient and economic method of meeting the anticipated demand for electricity on the PSI system without evidence that it submitted the transaction to a market test or other **[**13]** form of benchmark analysis. EPSA contends that if the Commission decides to approve the transfer, at a minimum, it should condition its approval to prohibit PSI from making any off-system sales at market-based rates, including sales to any PSI affiliate.

18. Williams asserts that competition is harmed when generating assets are removed from the risk of a competitive wholesale market and placed in the shelter of a monopoly affiliate's rate base. It states that while PSI may have a statutory franchise granting it a monopoly for retail sales in its service territory, it may not use that monopoly to interfere with interstate commerce in the regional wholesale power market.

Applicants' Answer

19. Applicants state that many of the protesters are parties to the Indiana Commission proceeding and have had, or will have, the opportunity to present evidence and arguments in that hearing challenging the settlement and raising the issue of whether the proposed transaction (including the provisions concerning the purchase price of the facilities) is an ap-

propriate means by which to procure additional resources to serve PSI's retail load. They believe that the protests are a collateral attack [**14] on the Indiana Commission proceeding, and would require this Commission to interfere with the Indiana Commission's determination as to whether the proposed transaction is in the best interest of PSI's retail customers given the credit, liquidity, and reliability problems of electricity marketers. They assert that there is no federal interest in forcing PSI to purchase power at wholesale, as opposed to purchasing specific generating assets.

20. Applicants state that in the Indiana Commission proceeding, PSI showed through its Integrated Resource Plan (IRP) and other testimony that, after considering the costs of a number of supply-side and demand-side options, the proposed transfer is the most economical and reliable means of providing for PSI's native load and wholesale power requirements. They assert that PSI considered over one hundred supply side resources as potential supply alternatives in its IRP process, including power purchases. While conceding that many of these alternatives were generic resources from the EPRI Technical Assessment Guide, Applicants state that PSI considered "real world" alternatives such as cost and reliability estimates concerning the installation of [**15] specific combustion turbine facilities at actual sites on the PSI system, the repowering of one of its coal-powered generating facilities, the installation [*61,345] of new coal-fired generation at a site in Northern Kentucky, and various demand-side alternatives.

21. Citing Northeast Utilities Serv. Co. n12 and Kansas City Power & Light Co., n13 Applicants assert that in a section 203 proceeding the Commission limits its scope of review to whether a particular transaction will harm competition, ratepayers or regulation, and that it does not evaluate the comparative merits of other hypothetical transactions that could have been consummated instead. With regard to the question of whether a heightened standard of review should apply because an affiliate transaction is at issue, Applicants maintain that in Louisville Gas and Electric Company (Louisville) n14 the Commission approved a transaction that is essentially indistinguishable to the proposed transfer in this case without adopting a heightened standard of review. They assert that any such change in the standard of review should be the product of a notice-and-comment rulemaking.

n12 56 FERC P61,269 (1992).

[**16]

n13 53 FERC P61,097 (1990).

n14 99 FERC P62,168 (2002).

22. Specifically with regard to the effect on competition and protesters' concerns about their ability to compete for some of PSI's load, Applicants cite the Commission's revised merger filing requirements rule n15 and argue that the proposed internal transfer of generation meets the Commissions standards under section 203 because no entity's generation market share would increase. Further, they assert that no load is being removed from the market because if one of the protesters or any market participant offers to provide energy to the Cinergy operating companies at a price below Cinergy's marginal cost of producing the power from the peaking units, Cinergy will purchase power at this lesser cost since it serves load on the basis of economic dispatch. Applicants also assert that they have not violated section 2 of the Sherman Antitrust Act since they do not have monopoly power, as shown by their (Cinergy's) ability to pass the Commission's supply margin assessment. n16 Finally, with [**17] regard to protesters' arguments concerning the Codes of Conduct, Applicants, citing Portland General Elec. Co., n17 maintain that the Commission has expressly rejected the application of such code of conduct provisions where it is reviewing a transaction under section 203.

n15 Order No. 642 at 31,902.

n16 Applicants cite Cinergy Services, Inc., 98 FERC P61,306 (2002), in which the Commission found that Cinergy lacks market power under the supply margin assessment test.

n17 81 FERC P61,374 (1997).

Commission Determination

23. Because the Transfer does not involve facilities of non-affiliated parties (ownership of facilities is changing hands within a single, corporate family), Applicants did not submit a horizontal screen analysis. An intra-corporate transaction by its nature will not result in a change in market concentration levels in any relevant market. Consequently, the Transfer will not affect competition under the standards currently applied **[**18]** by the Commission to determine whether a proposed transaction would have an adverse effect on competition. However the Commission has concerns about the possible implications of affiliate transactions of the type proposed here for the competitive process in general and for the region's wholesale competition. The ability of a franchised utility to assume its affiliated merchant's generation when market demand declines gives the affiliated merchant a "safety net" that merchant generators not affiliated with a franchised utility lack. The existence of such a "safety net" may affect the incentive of new merchant generators to invest in new facilities and, given the likelihood of recovery of capital investment through rate base treatment, gives the franchised utility a competitive advantage in making market-based sales of the plants' generation that is not available to merchant generators unaffiliated with franchised utilities. The safety net could, therefore, be a barrier to entry that harms the competitive process in general and raises prices to customers in the long run because affiliated merchant generation with a safety net option will not be subject to the price discipline of a competitive **[**19]** market.

24. As noted above, the Indiana Commission, has approved the proposed transaction as it affects matters within its jurisdiction. The Indiana Commission found that the lack of an RFP process was not a critical defect in Applicants' proposal. Recognizing PSI's need to acquire secure supplies, the Commission will not withhold approval of this transaction on competitive grounds. However, in light of the generic concerns raised by this case, the Commission will in the future modify its approach to analyzing competitive effects of intra-corporate transactions of this nature.

Effect on Rates

Applicants' Position

25. Applicants state that the proposed transfer will not adversely affect wholesale rates, principally because costs associated with the transfer cannot be passed through to wholesale ratepayers absent further regulatory proceedings before the Commission. Citing Niagara Mohawk Holding, Inc., and National Grid USA (Niagara) n18 and Duquesne Light Co. (Duquesne), n19 Applicants assert that the Commission has previously held that customers are protected from the effect on rates where those effects on rates were subject to Commission **[*61,346]** approval in a **[**20]** subsequent ratemaking proceeding. Applicants also note that certain settlements currently in effect between PSI and its wholesale native load customers prohibit PSI from seeking to revise its wholesale native load customer base rates schedules to be effective prior to June 1, 2003. In addition, Applicants suggest that the transfer will likely have a beneficial effect on the fuel-related charges to wholesale customers, since the CinCap plants will only be dispatched if they are the next lowest-cost source for the next incremental power needed to satisfy demand.

n18 96 FERC P61,144 (2001), denying reh'g of 95 FERC P61,381 (2001).

n19 88 FERC P61,248 (1999).

26. Similarly, Applicants point out, any changes in PSI's retail rates to reflect the costs of the transfer will be the subject of a general retail rate case at the state level. In any event, Applicants maintain that PSI's integrated resource planning analysis indicates that **[**21]** the transfer is the least cost and most reliable method of meeting its native load customers' demand requirements. As at the wholesale level,Applicants argue that the transfer will likely have a beneficial effect on retail consumers through PSI's retail fuel adjustment clause, since much of the cost of operating generating plants is comprised of the cost of fuel and the CinCap plants will only be dispatched if they provide power at the next lowest incremental cost.

Protests

27. Midwest Suppliers and EPSA reject Applicants' assertions that ratemaking review and the wholesale rate freeze through May, 2003, provide meaningful protection against the possibility of higher rates caused by the Transfer. Midwest Suppliers states that it is not claiming that a state commission should be prohibited from ordering policies that may result in higher rates for retail consumers, but that this Commission should not enable such a result through a transaction

subject to its jurisdiction. To establish that there will be no adverse impact on rates, Midwest Suppliers and EPSA argue, Applicants should be required to provide evidence that competitive alternatives to the acquisition of the plants would **[**22]** have an impact on rates comparable to the passthrough of the full purchase price. n20 As ways of making this showing, Midwest Suppliers and EPSA urge the Commission to require PSI to initiate a competitive solicitation for its power needs or to provide a benchmark analysis.

n20 Midwest Suppliers cite Ocean State Power II, 59 FERC P61,360 (1992), reh'g denied, 69 FERC P61,146 (1992).

28. EPSA maintains that ratepayers could be harmed by permitting any utility to acquire new generation via what is essentially a sole source procurement from an affiliate. EPSA also maintains that Cinergy's application fails to meet the public interest standard of section 203 because it contains no analysis that the proposed transfer would benefit ratepayers. EPSA further argues that this case is different from merger cases where increased rates would have to be approved in a subsequent proceeding, because the facilities proposed to be transferred here are not part of a merger expected **[**23]** to eventually lower overall operating costs. Rather, EPSA asserts, the facilities are being sought in conjunction with a resource acquisition decision, the merits of which are unknown to and untested by this Commission.

Applicants' Answer

29. Applicants contend that with respect to Protestors' arguments about the effect of the Transfer on retail rates, those arguments are properly presented before the Indiana Commission for resolution. Citing Kansas Power & Light Co. and Kansas Gas & Elec. Co., (Kansas) n21 Applicants assert that in a section 203 proceeding the Commission does not review the retail rate impacts of a given transaction when the affected state commission has authority to review that transaction. Since the Transfer was entered into in order to support retail service and is subject to the jurisdiction of the Indiana Commission, which is currently conducting a proceeding on the Transfer, Applicants argue that there is no basis for the Commission to interfere with this process.

n21 54 FERC P61,077 (1991).

[24]**
30. According to Applicants, the state review process relating to the Transfer will adequately and appropriately consider whether PSI has made a reasonable decision about how best to meets its future power needs. They note that Protestors have intervened in that proceeding to make many of the same arguments being advanced in the section 203 proceeding. Applicants also note that although utilities are required to consider the purchase of power, no state law or state commission regulation requires that an RFP be issued. Rather, as long as the utility reasonably considers and evaluates options, it is accorded some discretion in making a reasonable judgement in selecting options. In this case, Applicants assert, PSI has provided evidence to the Indiana Commission regarding the reliability of relying on power purchases, as opposed to generation ownership, to meet retail load and the Indiana Commission will then decide on the appropriate resource mix for serving that load.

31. Applicants disagree that a heightened standard of review advocated by Protestors should apply here because an affiliate transaction is at issue. They assert that the Commission has approved many internal reorganizations **[**25]** and affiliated transactions under section 203 without imposing a higher standard of review, including a transaction virtually identical to that proposed here, citing Louisville.

32. With respect to the effect on wholesale rates, Applicants note that Protestors or interested parties can intervene in PSI's next wholesale rate case and make the same arguments that are being addressed in the state proceeding. Applicants further contend that in a section 203 proceeding they **[*61,347]** are required to show only that wholesale ratepayers are not harmed by the Transfer, not that the Transfer is superior to any other possible transaction. In this regard, Applicants reiterate that (1) a wholesale rate settlement currently prevents any increase in wholesale rates prior to June 1, 2003, (2) no wholesale customer opposes the Transfer and (3) PSI cannot place the CinCap units into wholesale rate base without the Commission's approval.

Commission Determination

33. Applicants have not proposed to raise wholesale rates as a part of their application here. We note that the approach of the Merger Policy Statement with respect to the effect of a merger on rates is to assess the extent of ratepayer **[**26]** protection offered by applicants and to encourage applicants and ratepayers to negotiate adequate ratepayer protection. In this instance, although Applicants have not offered any protection beyond that already available from the wholesale rate freeze though May, 2003, wholesale ratepayers have not complained. Therefore we find that there will be no effect on current wholesale rates. Moreover, the consequences for wholesale ratepayers of adding the CinCap plants and associated jurisdictional facilities to rate base will be addressed in the next section 205 wholesale rate case filed by PSI.

Effect on Regulation

Applicants' Position

34. Applicants state that the proposed transfer will not impair the effectiveness of Federal regulation because the Commission will continue to have jurisdiction over the wholesale power sales of electricity from these units, as well as the wholesale power sales and transmission in interstate commerce of PSI. In addition, Cinergy and its affiliates will remain subject to the same degree of regulation under the Public Utility Holding Company Act of 1935, as amended, after the transfer as before. n22 Applicants state that consistent with the Commission's **[**27]** requirements, Cinergy, as a registered public utility holding company, has agreed to, and hereby reconfirms its commitment to, abide by the Commission's policy regarding the treatment of cost and revenues related to intra-company transactions. Further, Applicants assert that the transfer will not impair the effectiveness of state regulation because the Indiana Commission must first approve the transfer before it can be undertaken, and will have the authority to regulate the generating assets once the transfer is completed, since these assets will become part of PSI's regulated utility plant and associated rate base.

n22 In the application Applicants stated that the Securities and Exchange Commission's (SEC's) approval for the transaction was required and that an application for the SEC's approval had been filed. By letter of October 31, 2002, to the Secretary of the Commission, Applicants informed the Commission that based on discussions with the SEC staff, Applicants believe the SEC to be of the view that the transaction is exempt from the SEC's approval. As a result, Applicants state that they have withdrawn their SEC application in its entireity.

[28]**

Protests

35. Midwest Suppliers, supported by Williams, disputes Applicants' claim that the Transfer will not adversely affect federal regulation. Midwest Suppliers argues that federal regulation will be harmed if Cinergy's proposal is approved, because the Commission will lose the jurisdiction to prohibit and regulate affiliate transactions once the CinCap units are included in PSI's rate base. It contends that after the Transfer, the Commission will lose jurisdiction over sales, to the extent that the units' output serves PSI's retail load, rather than wholesale load only, as is the case currently. Midwest Suppliers asserts that as a result, the Commission will lose its current ability to prevent potential affiliate abuse associated with cross-subsidization by captive PSI customers. It urges the Commission to not relinquish the regulatory authority it now exercises over such affiliate transactions without first assuring itself that the Transfer does not itself introduce a new form of affiliate abuse. Midwest Suppliers further regards the rate base protection afforded by the Transfer as counter to the Commission's expressed preference for market-based solutions.

Commission [29] Determination**

36. We find that the Transfer will not adversely affect the Commission's regulation. The fact that the transaction would result in a change in the form of the Commission's regulation of sales from the units and in the magnitude of sales subject to our regulation does not imply that the effectiveness of our regulation will be impaired. To the extent that the units are used by PSI to make market-based wholesale spot sales, the Commission will continue to have an ability to review transactions under the market-based authority granted to PSI. As noted above, to the extent that the units are included in wholesale rate base, sales from the units at cost-based wholesale rates will be subject to the Commission's regulation.

Accounting

37. According to the application, PSI would acquire the CinCap facilities and the associated interconnection facilities at net book value as of January 1, 2002, plus added carrying costs on this book value from January 1, 2002 through the date of transfer. Applicants state that the carrying costs will be computed using PSI's AFUDC rate for an aggregate purchase price not to exceed $ 450 million. Since the final price for the Transfer **[**30]** is not yet known, Applicants propose to file accounting entries within six months of an order approving the Transfer. **[*61,348]**

38. The purchase of the jurisdictional facilities together with the related generating assets by PSI is an acquisition of an operating unit or system, which must be accounted for in accordance with the provisions of Electric Plant Instruction No. 5 and the instructions to Account 102 of the Uniform System of Accounts. Applicants, however, are unclear as to how they intend to apply these requirements, if at all, to this transaction. We note particularly that the application does not explain the basis for the carrying costs from January 1, 2002 forward and what if any implication the inclusion of this item in the purchase price should have on PSI's accounting. In light of our uncertainty as to how PSI intends to account for this transaction, we will require PSI to submit within 30 days of the date of this order, the full particulars of its proposed accounting for the acquisition of the interconnection and related facilities, including an explanation of the basis for any carrying charges.

The Commission orders:

(A) The proposed transaction is authorized upon the **[**31]** terms and condition and for the purposes set forth in the Application.

(B) PSI shall submit its proposed accounting for the acquisition of the interconnection and related generating facilities within 30 days of the date of this order.

(C) Nothing in this order shall be construed to imply acquiescence in any estimate or determination of cost or any valuation of property claimed or asserted.

(D) The Commission retains authority under sections 203(b) of the FPA to issue supplemental orders as appropriate.

(E) Applicants shall notify the Commission within 10 days of the date the disposition of the jurisdictional facilities is consummated.

By the Commission.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Solicitation Processes For Public Utilities   Docket No. PL04-6-000

NOTICE OF TECHNICAL CONFERENCE

(May 11, 2004)

1. Take notice that a technical conference will be held on the solicitation processes for public utilities on June 10, 2004, from 9:30 a.m. to 12:00 p.m. (EST), in the Commission Meeting Room at the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C. Members of the Commission will attend the conference. An agenda will be issued at a later time.

2. The topic of the conference will be issues associated with solicitation processes, including solicitations whereby public utilities sell to their affiliates. The conference will address proposals for best practice competitive solicitation methods or principles that could be used to ensure that transactions filed with the Commission for approval are the result of an open and fair process.

3. The conference will be transcribed. Those interested in acquiring the transcript should contact Ace Reporters at 202-347-3700 or 800-336-6646. Transcripts will be placed in the public record ten days after the Commission receives the transcripts. Additionally, Capitol Connection offers the opportunity for remote listening and viewing of the conference. It is available for a fee, live over the Internet, by phone or via satellite. Persons interested in receiving the broadcast, or who need information on making arrangements, should contact David Reininger or Julia Morelli at Capitol Connection (703-993-3100) as soon as possible or visit the Capitol Connection website at http://www.capitolconnection.org and click on "FERC."

4. For more information about the conference, please contact Mary Beth Tighe at 202-502-6452 or mary.beth.tighe@ferc.gov.

5. A supplemental notice of this conference will be issued later that will provide details of the conference, including the panelists.

Magalie R. Salas,
Secretary

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Acquisition and Disposition of Merchant Generation Assets by Public Utilities

Docket No. PL04-9-000

NOTICE OF TECHNICAL CONFERENCE

(May 11, 2004)

1. Take notice that a technical conference will be held on acquisitions and dispositions by public utilities on June 10, 2004, from 1:00 a.m. to 4:00 p.m. (EST), in the Commission Meeting Room at the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C. Members of the Commission will attend the conference. An agenda will be issued at a later time.

The topic of the conference will be issues associated with public utilities' acquisition and disposition of merchant generation assets, including the implications for the competitive landscape in general and for a region's wholesale competition in particular. The conference will discuss proposals for addressing these issues and concerns.

2. The conference will be transcribed. Those interested in acquiring the transcript should contact Ace Reporters at 202-347-3700 or 800-336-6646. Transcripts will be placed in the public record ten days after the Commission receives the transcripts. Additionally, Capitol Connection offers the opportunity for remote listening and viewing of the conference. It is available for a fee, live over the Internet, by phone or via satellite. Persons interested in receiving the broadcast, or who need information on making arrangements, should contact David Reininger or Julia Morelli at Capitol Connection (703-993-3100) as soon as possible or visit the Capitol Connection website at http://www.capitolconnection.org and click on "FERC."

3. For more information about the conference, please contact Mary Beth Tighe at 202-502-6452 or mary.beth.tighe@ferc.gov.

4. A supplemental notice of this conference will be issued later that will provide details of the conference, including the panelists.

Magalie R. Salas
Secretary

LEXSEE

Boston Edison Company Re: Edgar Electric Energy Company

Docket No. ER91-243-000

FEDERAL ENERGY REGULATORY COMMISSION - Commission

55 F.E.R.C. P61,382; 1991 FERC LEXIS 1322

Order Noting and Granting Interventions, and Rejecting Rates Without Prejudice

June 7, 1991

CORE TERMS: affiliate, seller, facility, filing, benchmark, supplier, filed, buyer, self-dealing, proceeding, process, nonprice, cost-of-service, transmission, preapproval, customer, notice, fuel, regulation, protest, competitive market, motion to intervene, nonaffiliated, negotiated, intervene, ratepayers, find, relevant market, solicitation, competitor

PANEL:
[**1]

Before Commissioners: Martin L. Allday, Chairman; Charles A. Trabandt, Elizabeth Anne Moler, Jerry J. Langdon and Branko Terzic.

OPINION:
[*62,161]

Background

On January 31, 1991, Boston Edison Company (Boston Edison) filed on behalf of its subsidiary, Edgar Electric Energy Company (Edgar), a 20-year contract (contract) for the sale by Edgar to Boston Edison of the capacity and energy n1 from Edgar Energy Park (facility), a 306 MW combined-cycle generating unit. Edgar intends to begin constructing the facility in 1992. Ownership of the facility will revert to Boston Edison after the contract [*62,162] term. Boston Edison requests that the effective date of the contract coincide with the in-service date of the facility. n2 As discussed below, the Commission rejects without prejudice the proposed rates.

n1 The proposed rate has three components: (1) a capacity charge initially set at $17.42/kW/month which declines annually to a level of $9.89/kW/month in the 20th year; (2) an operation and maintenance (O&M) charge which is initially set at $2.77/kW/month, to be revised annually to track an index reflecting industry average O&M expenses; and (3) an administrative and general expense charge of $1.304/kW/month. Fuel charges will track actual fuel and transportation costs incurred.

[**2]

n2 The expected in-service date for the facility is November 1, 1994.

Boston Edison states that the terms of the contract, including the allocation of risk between Edgar and Boston Edison, "are the product of regulatory requirements in Massachusetts and market conditions in New England for new generating sources." n3 According to Boston Edison, the Massachusetts Department of Public Utilities (Massachusetts DPU) has announced a change in policy that shifts state regulatory review from embedded cost/cost-of-service regulation to allowing competitive market forces to determine price. The Massachusetts DPU has devised a "pre-approval contract process." Under traditional cost-of-service regulation, the customers bear most of the risk. By contrast, under the preapproval process, Boston Edison states that the power producer assumes most of the risk, with customers only assuming risks associated with changes in fuel cost and changes in demand. Boston Edison states that a subsidiary arrangement (here, the creation of Edgar) is therefore necessary in order to protect Boston Edison's ratepayers from risks associated with the facility.

n3 Boston Edison Transmittal Letter at 1.

Boston [**3] Edison notes that the Massachusetts DPU preapproval contract process has been described as follows:

This new preapproval system involves examining new utility investment proposals before the money is spent, determining whether the new investment is prudent, and establishing in a "contract" between the regulators and the utility company the specific terms of cost-recovery and allocation of risk before the utility company invests funds. Under this approach a utility, like an independent power producer, has the opportunity to earn and keep market rates of return on this investment. [n4]

n4 Boston Edison Transmittal Letter at 3 (citing Remarks of Susan Tierney, Commissioner, Massachusetts Department of Public Utilities, Edison Electric Institute Financial Conference (October 29, 1990)).

Boston Edison describes three main aspects of the preapproval process. First, the cost recovery system is based upon the competitive market (least cost requirement). Second, the power producer assumes most of the risk (risk allocation requirement). n5 Third, "the utility is required to segregate the entirety of its risk associated with the new plant from the balance of its operations so that [**4] the utility's customers will not bear directly or indirectly any portion of the risk associated with the new plant" (risk segregation requirement). n6

n5 Under the preapproval process, the customer assumes the risk of fuel cost changes and changes in demand; the utility assumes all other risks. Boston Edison Transmittal Letter at 2.

n6 Boston Edison Transmittal Letter at 2-3.

Boston Edison states that proceedings before the Massachusetts DPU and the Massachusetts Energy Facilities Siting Council (Siting Council) have not been completed, but that because of construction deadlines and escalating construction costs, Boston Edison could not further delay its filing with this Commission. n7

n7 Boston Edison states that the Massachusetts DPU's Phase I hearing (concerning the formation of Edgar) is complete and a decision is expected in Spring 1991; the Phase II hearing (addressing the reasonableness of the Boston Edison-Edgar proposed transaction) is being held in abeyance until the completion of the Siting Council hearing, which should begin soon. According to Boston Edison, the Massachusetts DPU has indicated that it will rely heavily on the Siting Commission hearing record. Boston Edison Transmittal Letter at 6.

[**5]

Boston Edison requests that the Commission find the proposed rates (including both the price and the nonprice terms) are just and reasonable on two grounds: (1) the rate represents the least cost power supply alternative available to Boston Edison in an extremely competitive market; n8 and (2) under the Massachusetts DPU's preapproval contract process, the Massachusetts DPU will enter a "contract" with Boston Edison which will specify the price, risk and other terms for Boston Edison's purchase of Edgar's power. Boston Edison submits that the Massachusetts DPU would not enter into such a contract if it were not convinced that the terms of the proposed Edgar contract represent the best alternative available to Boston Edison.

n8 Boston Edison states that it lacks market power in the region and is not a dominant supplier: it owns only 10.6 percent of New England Power Pool (NEPOOL) capacity and is responsible for 13.5 percent of total NEPOOL load. Boston Edison adds that any adverse impact arising from Boston Edison's ownership of transmission is mitigated by the fact that, since 1979, Boston Edison's transmission system has been available to other parties under tariffs on file with the Commission.

[**6]

Boston Edison supports its assertion that the rate represents its least cost alternative by comparing the Edgar arrangement to four different historical benchmark groups: (1) 15 different suppliers with which Boston Edison negotiated contracts over a three-year period [*62,163] ending in 1990; (2) Boston Edison's Request for Proposals (RFP-2), a 1989 qualifying facility (QF) solicitation process conducted according to Massachusetts DPU procedures, in which Boston Edison received proposals from 48 QFs; (3) a group of 34 QF and independent power producer (IPP) projects negotiated by other Massachusetts utilities between December 1984 and December 1989; and (4) two IPPs in New England which have received wholesale rate approval from the Commission. n9 Boston Edison concludes from these comparisons that Edgar is the least cost power supply alternative available to Boston Edison, taking into account both price and nonprice terms.

n9 The IPPs are: Dartmouth Power Associates Limited Partnership (Dartmouth), 53 FERC P61,117 (1990); and Enron Power Enterprises Corp. (Enron), 52 FERC P61,193 (1990).

Boston Edison also submits a cost-of-service [**7] analysis which had been prepared in anticipation of direct Boston Edison ownership of the facility. Boston Edison maintains that the cost analysis merits confidential treatment n10 because it contains "commercial and financial information which could give other persons competitive and commercial advantages if it were publicly disclosed and . . . therefore [the information should be] exempt from public disclosure under 18 C.F.R. § 388.107 (d)." n11

n10 See 18 C.F.R. § § 388.107 (d) and 388.112 (1990).

n11 Boston Edison Transmittal Letter at 5.

Boston Edison requests waiver of the following regulations: the 120-day notice limitation; n12 the requirement to file cost-of-service data and estimates of monthly and annual transactions and revenues; n13 regulations regarding accounting and reporting requirements; n14 and regulations regarding the issuance of securities. n15 Boston Edison requests that the Commission approve the contract by July 1, 1991 so that construction may begin in August 1991. n16

n12 18 C.F.R. § 35.3 (1990).

n13 Id. § 35.12 (b) (1990).

n14 Id. Parts 41, 50, 101 and 141 (1990).

n15 Id. Part 34 (1990). Alternatively, Boston Edison requests permission to file an abbreviated application containing the following information: (1) a statement identifying the nature of the Part 34 transaction; (2) a description of the issuance; and (3) a verified statement, accompanied by a brief statement of reasons, declaring that the issuance would not impair Edgar's ability to serve as a public utility, and would be reasonably necessary or appropriate for such purposes. Boston Edison Summary at 31 (citing FERC Statutes and Regulations P32,456, at pp. 32,129-30). Boston Edison states that the proposed abbreviated filing will ensure that the issuance of short-term debt will not hinder Edgar's ability to provide reliable wholesale service to Boston Edison. Id. at 32.

[**8]

n16 Boston Edison explains that it seeks to obtain all necessary state and federal regulatory approvals by August 1991 in order to avoid the increase in construction costs that would occur if the contractor is not given notice to proceed with construction by that time. Additionally, if the contractor is not given notice to proceed by March 1, 1992, Boston Edison states that the contract will be terminated and the project will be canceled. Boston Edison Transmittal Letter at 6.

Notice of Filing

Notice of Boston Edison's filing was published in the Federal Register, n17 with comments due on or before February 20, 1991.

n17 56 Fed. Reg. 5999 (1991).

Interventions and Other Filings

On February 7, 1991, Boston Edison filed a proposed Nondisclosure Agreement concerning the submission of confidential information included in its cost-of-service data.

On February 20, 1991, the Town of Reading Municipal Light Department (Reading) filed a motion to intervene, protest, request for rejection or, in the alternative, request for investigation and hearing of the rates embodied in the proposed contract. Reading states that it is Boston Edison's only Contract [**9] Demand service customer. Reading argues that the Commission should reject the proposed Edgar contract because the safeguards the Commission has required in previous market-based rate cases are absent here. Reading argues that the proposed contract reflects anticompetitive practices, and could lead to excessive costs being passed through to Reading under the Contract Demand service tariff. n18 Reading alleges that Boston Edison's proposed agreement does not in fact contain a market-based rate, and that Boston Edison's anticompetitive actions n19 blocked alternative suppliers from bidding on a competitive basis against the Edgar facility project. n20 Reading alleges that the entire affiliate arrangement between Boston Edison and Edgar reflects self-dealing. n21 Reading also claims that Boston Edison's proposed agreement is unduly preferential toward Edgar, in contrast to Boston Edison's long-run standard [*62,164] contract. n22 Reading argues that Boston Edison assumes costs and risks in its arrangement with Edgar that it would not assume in arm's-length dealings with unaffiliated suppliers under its standard contract. Reading also alleges that Boston Edison has market power, particularly [**10] with respect to transmission facilities that potential competitors with the Edgar project would need. Finally, Reading submits that at the very least, the matter should be set for investigation and hearing under sections 205 and 206 of the Federal Power Act. n23

n18 Reading Intervention at 5.

n19 For example, Reading states that Boston Edison has sought Commission approval of the Edgar rates outside a normal bidding process.

n20 Reading Intervention at 8.

n21 Id. at 9. Reading requests Commission scrutiny of several indications of self-dealing on the part of Boston Edison, including: (1) the facility will be sited on Boston Edison property; (2) Boston Edison has already committed substantial funds before approval of the Edgar project -- something Boston Edison does not do for competing projects; and (3) Boston Edison has the option of buying the Edgar facility for one dollar at the expiration of the 20-year contract term.

n22 Reading alleges, inter alia, that Edgar is not required to pay certain deposits required under the standard contract, and that there are differences in the pricing terms as well.

n23 16 U.S.C. § § 824d, 824e (1988).

[**11]

On February 20, 1991, Cogen Technologies, Inc. (Cogen) filed a motion to intervene and protest. Cogen alleges that the contract shows self-dealing on the part of Boston Edison, that it does not reflect market conditions in New England, and that it fails to provide adequate limitations on the risks to Boston Edison ratepayers. Additionally, Cogen states that its response to RFP-2 was selected in December 1989 as the top-ranked project (Cogen project), but that the parties have failed to finalize that arrangement. Cogen believes that the Edgar project may preempt Cogen's planned sale to Boston Edison, or may interfere with Cogen's access to gas transportation capacity. Cogen states that Commission acceptance of the filing may adversely affect Cogen's ability to finalize and execute an agreement with Boston Edison concerning the Cogen project. Finally, Cogen requests that the matter be set for hearing.

On February 20, 1991, the Attorney General of Massachusetts (Massachusetts AG), in consideration of the interests of retail ratepayers of Boston Edison, filed a motion to intervene and protest. Massachusetts AG protests the proposed contract on two grounds: first, the contract may [**12] not reserve sufficient jurisdiction for the Massachusetts DPU to continue to exercise its statutory jurisdiction over Boston Edison's retail rates; second, the proposed contract did not come from a bidding procedure or other market test. n24 The Massachusetts AG argues that "[Boston Edison] has artificially constrained its least cost analyses of the Edgar Project in a way that effectively excludes the consideration of all viable market-based alternatives." n25 Massachusetts AG maintains that Boston Edison "has failed to demonstrate that the proposed Edgar project is currently the least cost alternative or the product of a market test, or that the contract is in the public interest." n26

n24 Massachusetts AG Intervention at 2.

n25 Id. at 3.

n26 Id.

On February 20, 1991, the New England Cogeneration Association (New England Cogen) filed a motion to intervene and a request that the Commission reject the filing. New England Cogen contends that market-based rates should not be allowed when the contract is not part of an arm's-length agreement: "Where, as here, a utility is purchasing from an affiliate, market-based rates should only be approved where the procurement is part [**13] of a neutral competitive solicitation, providing nonaffiliated suppliers with an opportunity to compete to supply the capacity." n27 New England Cogen submits that this case differs from prior cases where the Commission allowed market-based rates between affiliates. n28 New England Cogen asserts that the instant situation differs from Ocean State in that Boston Edison has no similar arm's-length contract with a nonaffiliate, and no one else was even offered the chance to bid against the Edgar project. n29 New England Cogen maintains that, in the absence of an opportunity for other producers to compete, it is uncertain at best whether the Edgar facility is actually the least cost supply available to Boston Edison's customers. n30 Finally, New England Cogen asserts that the Massachusetts DPU's review of the contract is not an adequate substitute for this Commission's review of the self-dealing and anticompetitiveness issues raised by the contract. New England Cogen notes that the Massachusetts preapproval contract process has never before been used for a supply side resource; thus, it is impossible to specifically state what will be required for approval of a [*62,165] supply side preapproval [**14] contract. Moreover, New England Cogen notes that at a hearing on the Edgar contract, the Massachusetts DPU did not allow New England Cogen to question Boston Edison witnesses about the competitiveness (or lack thereof) of the environment in which the Boston Edison/Edgar contract was executed. n31 New England Cogen points out that in this docket, Boston Edison is suggesting to the Commission that the approval process of the Massachusetts DPU and/or the Siting Council eliminates the need for thorough Commission review of whether the rates were negotiated in a competitive market. n32 New England Cogen states that it believes the Massachusetts DPU will find that the contract is contrary to the best interest of Boston Edison's ratepayers; however, New England Cogen also requests that this Commission carefully review whether the rates were negotiated in a competitive market.

n27 New England Cogen Intervention at 4.

n28 New England Cogen refers to Ocean State Power, 44 FERC P61,261 (1988) (Ocean State).

n29 New England Cogen Intervention at 7.

n30 New England Cogen claims that Boston Edison's own planning model shows that the next least-cost capacity expansion would be 200-MW of combustion turbines (not a 306-MW combined cycle unit). In addition, New England Cogen notes that the Edgar contract would allow Edgar to passthrough to Boston Edison ratepayers 100 percent of its actual fuel transportation and fuel costs (which are unknown because Edgar has no signed fuel contracts). Finally, New England Cogen states that no government agency has affirmed Boston Edison's contention that the Edgar facility is the least cost option considering both price and nonprice factors. New England Cogen Intervention at 8.

[**15]

n31 New England Cogen Intervention at 10. New England Cogen states that the Massachusetts DPU ruled that the issue of the competitiveness of the market should be addressed by the Siting Council. New England Cogen then filed a joint motion with the Massachusetts DPU and the Siting Council, asking in which forum the competitiveness issue could be properly raised. In response to that motion, Boston Edison stated that neither the

Massachusetts DPU nor the Siting Council should decide the competitiveness issue attempting to use this Commission's standards for approval of market-based rates. See, e.g., Commonwealth Atlantic Limited Partnership (Commonwealth), 51 FERC P61,368 (1990).

n32 New England Cogen Intervention at 11.

On March 7, 1991, Boston Edison filed an answer to the motions to reject the filing. Boston Edison maintains that the Edgar contract's rates meet the Commission's standards for market-based rates. Specifically, Boston Edison claims that competitive market conditions, least-cost analysis, the active involvement of the Massachusetts DPU (via the preapproval contract process), and cost-of-service data all demonstrate that the contract [**16] is just and reasonable and in the best interest of Boston Edison's customers. n33 Boston Edison maintains that it operates in a "vigorous, competitive power supply market and it lacks dominance in any facet of that market." n34 Boston Edison further asserts that the dominant role played by the Massachusetts DPU through the preapproval contract process precludes the possibility of self-dealing abuse.

n33 Boston Edison March 7 Answer at 3.

n34 Id. Boston Edison states that the New England market is influenced by the New England Power Pool (NEPOOL), which integrates a transmission network to facilitate transactions among the 73 NEPOOL members.

Boston Edison also argues that Cogen and Reading have failed to justify their requests for a hearing, because there are no disputed issues of material fact. n35 Boston Edison further asserts that the other issues raised by the parties afford no basis for rejecting the Edgar contract, holding a hearing, or even granting intervention. n36 Boston Edison refutes the other parties' arguments.

n35 Boston Edison March 7 Answer at 17.

n36 Id. at 20.

On March 8, 1991, J. Makowski Company, Inc. (Makowski) filed a motion to intervene out [**17] of time, raising no substantive issues. Makowski states that it is an energy project development and management company in the New England area, and a potential competitor of Edgar.

On March 11, 1991, the Towns of Concord and Wellesley, Massachusetts (Towns) filed a motion to intervene out of time and a protest. Towns first complain that Boston Edison has failed to comply with Commission regulations by not sending a copy of the proposed contract to Towns, n37 and that Boston Edison's request for waiver of the regulation concerning service of rate schedules should be denied. Towns also suggest that the contract should not be before the Commission at all:

n37 18 C.F.R. § 35.1 (1990) requires that a utility post and file rate schedules. Under 18 C.F.R. § 35.2 (1990), "posting" includes mailing a copy of the rate schedule to each purchaser thereunder on the date the rate schedule is sent to the Commission for filing. Since the Towns are not purchasers under the contract, there was no requirement to mail a copy to the Towns.

this Commission has not established a preapproval contract process, and Edison's attempt to have this Commission grant such approval by July 1, 1991, . . [**18] . is not only illegal but it is wholly unnecessary and frivolous as well. Whatever state agencies may do in their siting and certificating proceedings does not affect nor [sic] require the participation of this Commission. [n38]

n38 Towns Intervention at 4.

Towns further contend that the proposed rates are likely to be unjust and unreasonable:

at a very minimum, to even attempt to create a competitive market pricing system involving the Edgar Energy Park would require that Edgar pay to Edison the complete full market value for both the site and the existing plant utilized; and, then that payment would have to be credited above the line to Edison's ratepayers. [n39]

n39 Towns Intervention at 6.

[*62,166]

Towns further allege that Boston Edison has an incentive to pay Edgar the highest price regulators will accept because the higher price it pays to Edgar, the higher the profits for Boston Edison's shareholders.

On March 25, 1991, Boston Edison filed an answer to Makowski's motion to intervene. Boston Edison argues that for the reasons set forth in the March 7 answer, Makowski fails to state a direct interest in the outcome of this proceeding, as required by Rule 214(b)(2)(ii) of [**19] the Commission's Rules of Practice and Procedure. n40 Thus, Boston Edison argues, Makowski should not be permitted to intervene.

n40 18 C.F.R. § 385.214(b)(2)(ii) (1990).

On March 26, 1991, Boston Edison filed an answer to Towns' intervention. Boston Edison states that Towns' motion fails to state good cause for rejection of the rate, and that the motion should be denied. Boston Edison essentially reiterates arguments made in its earlier pleadings. Boston Edison emphasizes, however, that this proceeding involves only the rate to be charged to Boston Edison by Edgar, and that any flowthrough to Boston Edison's customers of Edgar costs could occur only with the Massachusetts DPU's approval (in the currently pending proceeding), or with this Commission's approval in a future proceeding involving Boston Edison's firm power wholesale rates. n41 Boston Edison suggests that, concerning retail customers, the only significance of Commission acceptance of the Edgar rate schedule would be to afford the Massachusetts DPU the chance to determine whether Boston Edison's proposed purchase of the Edgar power would be the most advantageous purchase for Boston Edison's customers. Boston Edison [**20] also notes that Commission acceptance of the filing in this proceeding would not preclude Towns (or anyone else) from challenging the inclusion of costs associated with the Edgar facility in their rates for electric service when Boston Edison files rates to recover those costs. n42 In short, Boston Edison maintains that "nothing can happen in this proceeding which will prejudice the Towns' litigation rights in a future proceeding." n43

n41 Boston Edison March 26 Answer at 4.

n42 Id. at 6.

n43 Id. at 7.

On April 3, 1991, Towns filed a motion to reject Boston Edison's March 26 Answer. Towns note that Rule 213(a)(2) of the Commission's Rules of Practice and Procedure n44 prohibits answers to protests. Towns acknowledge that the Commission has waived the prohibition where the answering party can show that the answer is useful and relevant; however, Towns assert that Boston Edison's answer is neither useful nor relevant. Towns insist that it is unnecessary for this Commission to accept the Edgar rate schedule before the Massachusetts DPU considers the transaction. n45

n44 18 C.F.R. § 385.213(a)(2) (1990).

n45 Towns Motion to Reject at 2.

On April 18, 1991, Boston [**21] Edison filed an answer to Towns' motion intervene and to reject Boston Edison's March 26 answer Boston Edison contends that Commission precedent permits answers to pleadings containing (as Towns' does) other elements as well as protests. Boston Edison states that it is not answering Towns' protest; it is answering Towns' motions to intervene and to defer action on the filing. n46 Boston Edison also refutes the arguments contained in Towns' March 11 pleading.

n46 Boston Edison April 18 Answer at 2, citing Vermont Electric Power Company, 48 FERC P61,330 (1989).

On May 21, 1991, Reading filed a notice of withdrawal of its February 20, 1991 pleading. See 18 C.F.R. § 385.216 (1990).

On May 21, 1991, Boston Edison filed a revised Appendix A n47 to the contract. The revised Appendix A contains slightly lower monthly demand charges than does the original Appendix A. Boston Edison states that the effect of the modification is to reduce the common equity return from 14.8 percent to 14.3 percent. Boston Edison requests that the Commission accept the rates as modified by the revised filing. Boston Edison also states that, because of a delay in the state regulatory [**22] proceedings, it does not expect to give the contractor notice to proceed with construction until December 1991. Nevertheless, Boston Edison reiterates its request that the Commission act on the instant filing before August 1991.

n47 Appendix A lists the monthly demand charges for each year of the contract.

Discussion

Under Rule 214 of the Commission's Rules of Practice and Procedure, n48 the timely, unopposed motions to intervene of Cogen, Massachusetts AG, and New England Cogen serve to make them parties to this proceeding. Additionally, we will grant the unopposed, untimely motion to intervene filed by Towns, given their interests in the proceeding and the absence of any undue prejudice or delay. Further, notwithstanding Boston Edison's opposition, we will grant Makowski's untimely motion to intervene given Makowski's interest in this proceeding (as a potential competitor of Edgar) [*62,167] and the absence of any undue prejudice or delay. Finally, we shall deny the Towns' April 3, 1991 motion to reject Boston Edison's March 26, 1991 answer. Although answers to protests are not permitted under the Commission's Rules of Practice and Procedure, n49 Boston Edison's March 26 answer [**23] responds to various motions of other parties.

n48 18 C.F.R. § 385.214 (1990).

n49 18 C.F.R. § 385.213(a)(2) (1990).

Ordinarily, upon receipt of an amendment such as that contained in Boston Edison's May 21, 1991 filing, the Commission would issue a notice of amended filing which extends the comment date. However, because the Commission is rejecting the proposed rates without prejudice and Boston Edison has renewed its request for Commission action before August 1991, we will depart from our usual practice and will not issue a notice of amended filing. This action will not prejudice any of the intervenors since we are rejecting the rates without prejudice.

1. Market-Based Rates

Under section 205(a) of the Federal Power Act, n50 all rates for the transmission or sale of electric energy at wholesale in interstate commerce must be "just and reasonable" n51 and not unduly discriminatory or preferential. Market-based rates for sales involving affiliates will be found to violate section 205(a) of the FPA unless there is a clear showing of lack of potential affiliate abuse. n52

n50 16 U.S.C. § 824d(a) (1988).

n51 Neither the FPA nor its legislative history defines "just and reasonable." Although historically the Commission has accepted rates under section 205 based upon the supplier's cost of service, nothing in the FPA limits the Commission to using cost-based methodologies. In a growing number of cases, the Commission has approved rates based not on the supplier's cost of service but on a competitive market rate for the supplier's energy. See, e.g., Commonwealth, supra; Dartmouth, supra.

[**24]

n52 See, e.g., Teco Power Services Corporation et al. (TECO), 52 FERC P61,191, reh'g denied and rates accepted on other grounds, 53 FERC P61,202 (1990).

Before allowing nontraditional pricing, the Commission has required a showing that there exists no potential abuse of self-dealing or reciprocal dealing. n53 If there has been a showing of no potential abuse of self-dealing or reciprocal dealing, the Commission has found that market-based rates may be acceptable if the seller can also demonstrate that it lacks market power (or has adequately mitigated its market power) n54 by showing that neither it nor any of its affiliates: (1) is a dominant firm in the sale of generation in the relevant market; (2) owns or controls transmission facilities through which the buyer could reach alternative sellers (or, if the seller or any of its affiliates does own such facilities, they have adequately mitigated their ability to block the buyer from reaching other sellers); and (3) can erect or control any other barrier to market entry. n55

n53 Id. See also Terra Comfort Corporation et al., 52 FERC P61,241 (1990); Portland General Exchange, Inc. et al., 51 FERC P61,108, order granting clarification, 51 FERC P61,379, order accepting compliance filing, 53 FERC P61,216 (1990).

[**25]

n54 The Commission has found that a seller has market power when the seller can significantly influence price in the market by restricting supply or denying access to alternative sellers. See, e.g., Commonwealth, 51 FERC at p. 62,244 n.43.

n55 See, e.g., Cleveland Electric Illuminating Co., 55 FERC P61,172 (1991).

Here, Edgar and Boston Edison have failed to make the requisite showing with respect to potential abuse of self-dealing. As discussed below, the benchmark price evidence Boston Edison offers in support of its filing does not persuade us that the proposed rates are free of the potential for self-dealing. Thus, we cannot find that Edgar's proposed rates are just and reasonable under section 205(a) of the FPA on a market basis.

Potential for self-dealing

The Commission has stated that in cases where affiliates are entering agreements for which approval of market-based rates is sought, it is essential that ratepayers be protected and that transactions be above suspicion in order to ensure that the market is not distorted. n56 In previous affiliate cases, which have involved the potential of unduly preferentially [**26] low market rates from the seller to its affiliate, the Commission has found that the mere opportunity for this type of affiliate abuse will lead to rejection of the proposed agreement. n57 The same analysis applies to the facts here, where the rate may not be just and reasonable because the buyer potentially may have unduly favored the rates offered by its affiliate [*62,168] seller over lower rates offered by other nonaffiliate sellers. n58

n56 TECO, 52 FERC at p. 61,697. The Commission's concern with the potential for affiliate abuse is that a utility with a monopoly franchise may have an economic incentive to exercise market power through its affiliate dealings. The potential abuses include such practices as affiliates selling products to a franchised utility at excessive prices or a franchised utility providing inputs to an affiliate at preferentially low prices -- both of which are examples of market power that is exercised to the disadvantage of captive customers and other potential nonaffiliated power suppliers.

n57 TECO, 53 FERC at p. 61,809.

n58 See generally Ocean State, 44 FERC at p. 61,983.

[**27]

In an arm's-length (unaffiliated) transaction, the buyer has no economic incentive to favor anyone but the least-cost supplier (considering price and nonprice factors). The Commission evaluates the market power of the seller to ensure that the seller is unable to limit supply or transmission options and therefore raise the price. By contrast, where a traditional utility is buying from an affiliate not subject to cost-of-service regulation, the buyer has an incentive to favor its affiliate even if the affiliate is not the least-cost supplier, because the higher profits can accrue to the seller's shareholders. Here, this incentive may exist for Boston Edison and Edgar regardless of the number of supply options available to Boston Edison and regardless of the fact that Boston Edison controls transmission facilities leading to other suppliers.

Boston Edison submits evidence comparing the instant filing to Dartmouth and Enron to show that it lacks market power. n59 Boston Edison apparently offers such evidence because, in considering market-based rates involving an unaffiliated buyer and seller, the Commission has considered whether there were sufficient supply options available to [**28] the buyer and whether the seller could limit those options by controlling transmission facilities. n60 In this case, however, we are dealing with a different set of circumstances: a subsidiary building a new plant whose power will be sold to the parent, in lieu of the parent self-building a new facility. In these circumstances, as in prior cases involving affiliate transactions (e.g., Ocean State, Terra Comfort and TECO), the critical first step of our analysis is to ensure lack of abuse of self-dealing. In addition, the market-power factors (the number of supply options and the seller's ability to control transmission) do not apply in the same manner here as in past cases, because the seller and purchaser are affiliated companies.

n59 See Vol. I Reed at pp. 34-6.

n60 Where the seller has met these standards, the Commission has found that the seller lacked the ability to demand an excessive rate. Thus, without reviewing the specific rates negotiated by buyer and seller, the Commission has, on this basis and other facts, found the seller's proposed rates to be reasonable.

Because the potential for self-dealing between Boston Edison and Edgar is critical here, the Commission [**29] must ensure that the buyer has chosen the lowest cost supplier from among the options presented, taking into account both price and nonprice terms (i.e., that it has not preferred its affiliate without justification). n61

n61 This does not involve a determination that the buyer has evaluated all supply and demand-side options and has prudently chosen from among them. As we have emphasized before, such determination primarily is a state commission matter. See, e.g., Commonwealth, supra, 51 FERC at p. 62,249; Doswell Limited Partnership, 50 FERC P62,251, at p. 61,758 (1990). Rather, what is involved here is a finding that from among the options cited as available, the buyer chose its affiliate seller as the lowest cost supplier taking into account price and nonprice factors.

In TECO, supra, the Commission relied on a market test to eliminate concerns about preferential pricing. That test, which applies a bid or benchmark standard to determine market value, is also applicable to the facts here:

Market value can be established by timely offering to all bidders the same services at the same price offered to the affiliate, or [**30] by providing the Commission with a benchmark of the market value of similar services based on contemporaneous data. (Footnote omitted). [n62]

n62 TECO, 53 FERC at pp. 61,809-10.

Under the market value standard there may be several ways in which a utility could demonstrate lack of affiliate abuse. The following are examples of ways to demonstrate lack of affiliate abuse and not necessarily an all-inclusive list. n63 One type of evidence that Boston Edison could offer would be evidence of direct head-to-head competition between Edgar and competing unaffiliated suppliers either in a formal solicitation or in an informal negotiation process. When such evidence is presented, the Commission seeks assurance that (1) the solicitation or negotiation was designed and implemented without undue preference for the affiliate, (2) the analysis of the bids or responses did not favor the affiliate, particularly with respect to evaluation of nonprice factors, and (3) the affiliate was selected based on some reasonable combination of price and nonprice factors. If the affiliate is not the lowest priced option, the applicant must provide sufficient justification [**31] for why the affiliate was chosen over alternative nonaffiliated sellers.

n63 As a general matter, they also do not necessarily indicate a lack of market power.

An alternative type of evidence that Boston Edison could provide would be the prices which nonaffiliated buyers were willing to pay for similar services from the Edgar project. n64 This second type of evidence is credible only to the [*62,169] extent that the nonaffiliated buyers are in the relevant market as the purchaser, and are not subject to market power by the seller or its affiliates.

n64 See generally Ocean State, 44 FERC at p. 61,983.

Another type of evidence that Boston Edison could offer would be benchmark evidence which shows the prices, and terms and conditions of sales made by nonaffiliated sellers. This evidence could include purchases made by Boston Edison itself, or by other buyers in the relevant market. Two major considerations with respect to the credibility of the benchmark evidence would be whether the benchmark sales are contemporaneous and whether they are for similar services when compared to the instant transaction. The Commission would expect that the applicant include [**32] in the benchmark evidence any relevant sales in order to support the purchase from the affiliate, i.e., all contemporaneous sales for similar services in the relevant market would be included in the benchmark evidence. n65

n65 In addition, the Commission would be concerned whether the benchmark sales in the relevant market reflect exercises of market power by the seller or its affiliates. In the TECO Rehearing Order, the Commission noted that before it "...will accept a market test for an affiliate transaction, the utility must show that it has not narrowed the market to validate a low transfer price." 53 FERC at p. 61,809. Here, the concern is that the transfer price between affiliates is too high. Therefore, the buying utility must show that it has not unduly favored its affiliate.

The Commission has carefully examined the benchmark evidence presented by Boston Edison. (See attached Appendix.) We find, as discussed below, that the benchmark data submitted here do not show the contract rates to be just and reasonable. The evidence does not support a finding that Edgar's price is similar to the price at which nonaffiliates sell comparable power. [**33]

The benchmark data submitted by Boston Edison call for an analysis of the price and nonprice terms reflected in the Edgar contract, as compared to those of other supply contracts in the region. Boston Edison has compared Edgar to four different historical benchmark groups: (1) 15 different suppliers with which Boston Edison negotiated contracts over a three-year period ending 1990; (2) Boston Edison's RFP-2, a 1989 QF solicitation process under Massachusetts DPU procedures where Boston Edison received proposals from 48 QFs; (3) a group of 34 QF and IPP projects negotiated by other Massachusetts utilities between December of 1984 and December of 1989; and (4) two IPPs, Dartmouth Power Associates Limited Partnership (Dartmouth), Docket No. ER90-278-000, and Enron Power Enterprise Corp. (Enron), Docket No. ER90-290-000, which have been approved by the Commission. See n.9, supra. Based on these comparisons, Boston Edison argues that Edgar is the superior alternative available to Boston Edison taking into account both price and nonprice terms.

A comparative analysis such as the one submitted by Boston Edison can be complicated because of the widely varying pricing structures, operating [**34] characteristics, and nonprice terms of the numerous alternatives. For example, Boston Edison's comparison of projects purchased by Massachusetts utilities includes projects as small as 0.7 MW and powered by wind, wood, waste, peat and hydropower. Moreover, because most prices are formulaic, the analysis will rely to a great extent on projections of formula variables (e.g., fuel cost, plant factors and economic indices) over the life of each project. The assumptions underlying these projections and the significance ascribed to nonprice factors are critical to the analysis. Accordingly, the comparative analysis will be more extensive than a standard cost analysis (which does not consider the buyer's alternatives) or market power analysis (which does not compare prices to those of competitors).

Boston Edison has not demonstrated that it will pay no more than a nonaffiliate would pay for comparable power. n66 Boston Edison's comparative analysis raises numerous questions about underlying assumptions because Boston Edison includes few details or explanations of the assumptions concerning variables (e.g., fuel cost, plant factor, and indices) used to compare the rates for various projects. [**35] In addition, almost all the benchmark data included in Boston Edison's comparative analysis reflect projects that are not contemporaneous and that do not provide similar services as compared to the Edgar facility. Accordingly, we find that the benchmark data submitted here do not show that there has been no abuse of self-dealing on the part of Edgar and Boston Edison. n67

n66 See Ocean State, 44 FERC at p. 61,983.

n67 Having found the rates unsupportable on this basis, we need not analyze market power issues involving transmission or other barriers to entry that could have been used to exclude competitors (e.g., power plant sites). We also have not considered the issue of how cross subsidies, if any, between Boston Edison and Edgar may affect the reasonableness of Edgar's rate, i.e., a comparison between Edgar's rate and rates offered by nonaffiliated suppliers. To the extent Boston Edison subsidizes any of Edgar's costs (e.g., site lease, personnel), Edgar's rates might appear reasonable in comparison to a benchmark because of these subsidies. Accordingly, to the extent the Edgar rate is refiled, Boston Edison must demonstrate all inputs and services it has or will provide to Edgar during the contract term and demonstrate that none has been or will be provided at below market prices.

[**36]

We disagree with Boston Edison's argument that the Commission need not worry about self-dealing because the Massachusetts DPU ultimately [*62,170] will have to approve the Edgar project. This Commission has an independent responsibility to protect against affiliate abuse. See TECO, 53 FERC at p. 61,811. While the Massachusetts DPU and Siting Council records may develop more useful benchmark evidence which may possibly demonstrate that the Edgar contract is just and reasonable under the FPA, such evidence is not presented in the current record. Accordingly, we reject the market-based rates without prejudice.

2. Alternative Cost-of-Service Rates

The Commission finds Boston Edison's cost-of-service analysis insufficient. The analysis is presented in summary fashion. For example, various assumptions about cost are made in the analysis, and no support or explanation is offered for those assumptions. n68 Moreover, the cost-of-service analysis provides no data concerning the return that is expected to be realized by Edgar as a separate Boston Edison subsidiary. Accordingly, we reject the alternative request for cost-based rate approval.

n68 The assumptions include fuel and O&M projections over the life of the facility, and the plant investment costs projected for 1994.

[**37]

3. Other Matters

Since we are rejecting the rates proposed herein, we shall dismiss as moot Boston Edison's request for waiver of the following requirements: the Commission's information filing requirements in 18 C.F.R. § § 35.12 (b)(ii) and (b)(5), the notice requirements in 18 C.F.R. § 35.3, and the requirements in 18 C.F.R. Parts 34, 41, 50, 101 and 141. We will also dismiss as moot the various requests for hearing.

4. Conclusion

The Commission finds that the rates proposed herein have not been shown to be just and reasonable under section 205(a) of the FPA because, on this record, Boston Edison has failed to demonstrate that the proposed contract between it and its affiliate, Edgar, does not provide the parties with the chance for abuse of self-dealing, and alternatively has failed to support the rates on a cost-of-service basis. Accordingly, we will reject the filing without prejudice.

We wish to stress that our action today should not be interpreted as barring all affiliated transactions where market-based rates are requested. In one of our earliest cases, Louisville Hydro-Electric Company, 1 FPC 130, 133 (1933), the Commission noted the need [**38] for a "searching inquiry" with respect to affiliate transactions. We have done no more here. That inquiry, however, indicates that the rates proposed have not been shown to be just and reasonable on the current record. Accordingly, our action today is based on the evidence presented, not on any rule (expressed or implied) barring affiliate transactions.

The Commission orders:

(A) The untimely motions to intervene of Towns and Makowski are hereby granted, subject to the Commission's Rules of Practice and Procedure.

(B) Boston Edison's submittal is hereby rejected without prejudice to its resubmittal of rates, as discussed in the body of this order.

APPENDIX:

Appendix

Staff's Review of Benchmark Comparisons

Attached are the benchmark comparisons furnished by Boston Edison. Attachment A is a price comparison of Edgar with 33 projects in Massachusetts which are already under contract. Attachment B provides nonprice information for 15 of the 33 which involve Boston Edison. Attachment C compares Edgar to the top 11 responses in Boston Edison's QF solicitation (RFP #2). Our review shows there are three problems with the benchmark comparisons: the methods and assumptions used to develop levelized [**39] prices in current dollars for each alternative are not documented; the benchmark sales are not for similar services compared to the Edgar contract; and many of the benchmark sales are not contemporaneous.

As to the first problem, in order to compare the cost of the alternatives, Boston Edison computes the levelized price (in current dollars) of each alternative. Boston Edison has not provided copies or extracts of the rates underlying the comparisons. It is likely that some of the rates included in the benchmark project analysis involve formula components. Formula rates vary to reflect changes in fuel costs or fuel cost indices, plant factors (the percent of capacity available), inflation indices, or other variables. Boston Edison has stated that in arriving at the levelized prices it assumed a rate of inflation of 5.1% and fuel price escalators of 1% for coal and 2.5% for oil and gas. Boston Edison does not indicate what escalation factors it used for such other expenses as O&M. Moreover the utility failed to explain how it derived its escalators. [*62,171]

Moreover, the rate includes a "penalty provision" which reduces the demand charge when the plant factor falls below a certain level. [**40] We do not know whether Boston Edison calculated Edgar's levelized price to take that into account. Boston Edison has reduced the price of Edgar by about 3 mills to reflect the fact that ownership of the unit will revert to Boston Edison in 20 years, but has not supported this adjustment. In sum, without details on the actual rate provisions included in the purchased power agreements, all of the assumptions utilized to develop the price benchmarks for Edgar and the alternatives, and the computations used to arrive at the levelized prices, we cannot make any conclusions regarding the price comparisons.

Boston Edison also concludes that Edgar is superior to the alternatives even including nonprice factors. However, the nonprice factors have not been reflected in the ranking of the projects shown on Attachment A. With respect to Boston Edison's other comparison, RFP #2, the alternatives are ranked on combined price and nonprice factors. Boston Edison, however, fails to provide details on how it comes up with the scores. Again, without supporting details and explanations, such as the criteria and the weight it gave to each factor, it is impossible to evaluate the conclusions reached. [**41]

The second problem is that Boston Edison has not demonstrated that the benchmark evidence reflects sales of similar services in the relevant market. Most of the benchmark projects were QF projects; thus, benchmark prices may, to a large extent, reflect the buyers' administratively determined avoided cost. In addition, because most of the benchmark sales are from QFs, we are not convinced that Edgar and the benchmark projects would compete in the same market. For example, there may be technical and size limitations on the QF projects, or there may have been size limitations in the formal solicitations or purchase procurement practices reflected in the benchmark evidence. If Edgar is not subject to the same limitations, the Edgar project would have an inherent advantage. The application also fails to explain how similar the benchmark projects are to the Edgar project with respect to nonprice terms, e.g., dispatch mode and contract term. When benchmark evidence is used to validate market-based prices, dissimilarities in nonprice terms must be taken into account so that the price comparisons are meaningful. Finally, Boston Edison has not shown that its benchmark data were not narrowed [**42] to validate a high transfer price by excluding similar services or projects.

The third problem is that the data include projects with offers that were not contemporaneous with the Edgar project. Boston Edison has not demonstrated that the data reflect all contemporaneous purchases in the relevant market.

Boston Edison also submitted a cost-of-service analysis providing the projected return on equity if Boston Edison were to build the unit itself, without creating a subsidiary. Boston Edison submitted the data with request for confidential treatment; therefore, the data are not shown in this Appendix. n1 We note, however, that the analysis is presented in summary fashion with no support or explanation for any line items in the summary and without any of the underlying assumptions. Additionally, Boston Edison has failed to compute the earned return that Edgar itself will realize as project owner.

n1 The failure to duplicate these data at this time reflects no finding on the merits of Boston Edison's claim to confidentiality.

[*62,171-] 2

Attachment A

Exhibit BE-JJR-5

Comparison of the Real Levelized Discounted Price of the EEEC Project With the Price of NUG Contracts Signed by Massachusetts [**43] Utilities

Project Name	Contract Signing Date	Purchasing Utility	Contract Amount	Contract Method
Down East Peat	12/18/84	BECO	23.0	Negotiated
Everett Energy	05/29/85	BECO	80.0	Negotiated
TD Energy	06/20/85	BECO	10.0	Negotiated
Bellingham Phase I	04/01/86	BECO	156.3	Negotiated
AES Riverside	12/19/86	MECO	81.0	Negotiated
PRS-MASS	12/23/86	BECO	22.6	Negotiated
O'Brien Cogen III	02/01/87	MECO	24.0	Negotiated
Pepperell Power Assoc.	04/13/87	COM/ELEC	38.0	Negotiated
Lee Maes Cogen	04/28/87	COM/ELEC	47.0	Negotiated
Gull Mountain Electric Co.	05/17/87	BECO	2.4	Negotiated
American REF-Fuel	07/17/87	BECO	40.0	Negotiated
Northeast Landfill	11/06/87	MECO	12.0	Negotiated
Altresco Pittsfield	12/09/87	MECO	161.0	Negotiated
Oxford	12/12/87	MECO	40.0	Negotiated
O'Brien Cogen V	12/16/87	MECO	46.0	Negotiated
SEMASS Expansion	01/15/88	COM/ELEC	22.5	Negotiated
Bellingham Phase II	01/28/88	BECO	84.0	Bid
Urban Woods Project	02/15/88	BECO	25.0	Bid
AES Riverside	03/17/88	BECO	81.0	Negotiated
Alder	05/27/88	MECO	10.0	Negotiated
Webster Resource Recovery	06/08/88	BECO	7.4	Negotiated
Patriot Energy	06/28/88	BECO	200.0	Bid
L'Energia	07/19/88	BECO	53.2	Negotiated
NEES Energy	07/28/88	BECO	41.1	Bid
MWRA Weston Aqueduct	03/16/89	BECO	1.0	Negotiated
Ware II	04/27/89	MECO	28.0	Negotiated
Brockton Wood	05/22/89	EUA	20.0	Bid
Eastern Energy	06/12/89	COM/ELEC	83.0	Bid
Commercial Union	07/20/89	EUA	26.0	Bid
Hunt Road	11/09/89	COM/ELEC	0.7	Bid
KES Fitchburg Ltd.	11/20/89	FGE	11.7	Bid
Bay State Wood Energy	12/15/89	COM/ELEC	10.0	Negotiated
Enron Power	12/19/89	MECO	81.2	Negotiated
Average - Excluding Edgar				
Edgar Electric Energy	Unsigned	BECO	306.0	Negotiated

[**44]

Project Name	Contract Signing Date	Real Levelized Price (1990 $)	Rank	Fuel	Status
Down East Peat	12/18/84	6.29	31	Peat	operating
Everett Energy	05/29/85	5.33	19	Coal	cancelled

Project Name	Contract Signing Date	Real Levelized Price (1990 $)	Rank	Fuel	Status
TD Energy	06/20/85	5.47	22	Wind	cancelled
Bellingham Phase I	04/01/86	5.32	18	Gas	under construction
AES Riverside	12/19/86	5.93	28	Coal	cancelled
PRS-MASS	12/23/86	5.24	15	Waste	cancelled
O'Brien Cogen III	02/01/87	6.08	29	Coal	cancelled
Pepperell Power Assoc.	04/13/87	5.03	14	Gas	operating
Lee Maes Cogen	04/28/87	4.75	7	Gas	under development
Gull Mountain Electric Co.	05/17/87	4.83	8	Waste	Inactive
American REF-Fuel	07/17/87	6.49	33	Waste	cancelled
Northeast Landfill	11/06/87	4.95	12	Landfill Gas	operating
Altresco Pittsfield	12/09/87	4.84	9	Gas	under construction
Oxford	12/12/87	4.86	11	Gas	cancelled
O'Brien Cogen V	12/16/87	4.60	4	Gas	under development
SEMASS Expansion	01/15/88	5.52	23	Waste	under development
Bellingham Phase II	01/28/88	4.85	10	Gas	under construction
Urban Woods Project	02/15/88	5.77	25	Waste	under development
AES Riverside	03/17/88	6.18	30	Coal	cancelled
Alder	05/27/88	4.54	3	Waste	under development
Webster Resource Recovery	06/08/88	5.29	17	Waste	cancelled
Patriot Energy	06/28/88	6.90	34	Coal	Inactive
L'Energia	07/19/88	5.87	26	Gas	under development
NEES Energy	07/28/88	5.63	24	No. 2 Oil	cancelled
MWRA Weston Aqueduct	03/16/89	5.35	20	Hydro	operating
Ware II	04/27/89	5.89	27	Coal	under development
Brookton Wood	05/22/89	3.83	1	Waste	cancelled
Eastern Energy	06/12/89	5.43	21	Coal	under development
Commercial Union	07/20/89	4.71	6	Gas	cancelled
Hunt Road	11/09/89	4.96	13	Landfill Gas	under development
KES Fitchburg Ltd.	11/20/89	6.36	32	Wood	under development
Bay State Wood Energy	12/15/89	4.22	2	Waste	under development
Enron Power	12/19/89	5.26	16	Gas	under development
Average - Excluding Edgar		5.53			
Edgar Electric Energy	unsigned	4.68	5	Gas	under development

[*62,171-] 3 [**45]

Attachment B

Exhibit BE-JJR-4

Long-Term Power Agreements Signed by BECO

Project Name	Contract Signing Date	Balance Account	Dispatchable	Operating Security
Down East Peat	12/18/84	yes	yes	no
Everett Energy	05/29/85	no	no	no
TD Energy	06/20/85	yes	no	no
Bellingham Phase I	04/01/86	yes	no	no
PRS-MASS	12/23/86	no	no	no
Gull Mountain Electric	05/17/87	yes	no	yes
American REF-Fuel	07/17/87	yes	no	yes
Bellingham Phase II	01/28/88	yes	no	yes
Urban Woods Project	02/15/88	yes	no	yes
AES Riverside	03/17/88	yes	yes	yes
Webster Resource Recovery	06/08/88	no	no	yes
Patriot Energy	06/28/88	yes	yes	yes
L'Energia	07/19/88	yes	no	no
NEES Energy	07/28/88	yes	no	no
MWRA Weston Aqueduct	03/16/89	no	no	no
Edgar Electric Energy	Unsigned	yes	yes	yes

Project Name	Contract Signing Date	Development Security	Capacity Deficiency	Fuel	Contract Method	Status
Down East Peat	12/18/84	no	yes	Peat	Negotiated	operating
Everett Energy	05/29/85	no	yes	Coal	Negotiated	cancelled
TD Energy	06/20/85	no	yes	Wind	Negotiated	cancelled
Bellingham Phase I	04/01/86	yes	no	N.Gas	Negotiated	under construction
PRS-MASS	12/23/86	no	yes	Waste	Negotiated	cancelled
Gull Mountain Electric	05/17/87	yes	no	Waste	Negotiated	inactive
American REF-Fuel	07/17/87	yes	yes	Waste	Negotiated	cancelled
Bellingham Phase II	01/28/88	yes	no	N.Gas	Bid	under construction
Urban Woods Project	02/15/88	yes	no	Waste	Bid	under development
AES Riverside	03/17/88	yes	yes	Coal	Bid	cancelled
Webster Resource						

Project Name		Contract Signing Date	Balance Account	Dispatchable	Operating Security	
Recovery	06/08/88	yes	no	Waste	Bid	cancelled
Patriot Energy	06/28/88	yes	no	Coal	Bid	inactive
L'Energla	07/19/88	yes	yes	N.Gas	Negotiated	under development
NEES Energy	07/28/88	yes	yes	No. 2 Oil	Bid	cancelled
MWRA Weston Aqueduct	03/16/89	no	no	Hydro	Negotiated	operating
Edgar Electric Energy	Unsigned	yes	no	N.Gas	Negotiated	under development

[*62,171-] 4 [**46]

Attachment C

Exhibit BE-JJR-6

REQUEST FOR PORPOSALS #2

SUMMARY OF PRICE AND NON-PRICE FACTOR SCORES

PROJECT	PRICE FACTOR	ECONOMIC CONFIDENCE FACTOR	DEVELOP-MENT CON-FIDENCE FACTOR	OPERATIONAL LONGEVITY CONFIDENCE FACTOR	SYSTEM OPTIMIZATION FACTOR	TOTAL SCORE PROJECT
*1	*-3.76	*48.98	*35	*20	*16	*116.22
*2	*-1.25	*46.18	*32	*20	*14	*110.93
3	11.59	50.00	18	11	19	109.59
4	3.15	42.80	32	15	14	106.95
5	1.60	50.00	32	7	16	106.60
6	5.33	46.52	27	12	14	104.85
7	8.90	46.30	19	17	12	103.20
8	6.33	48.55	14	15	19	102.88
9	7.55	48.87	17	15	14	102.42
10	0.89	40.40	28	15	13	97.29
11	-3.07	46.02	22	15	12	91.95
EDGAR	-11.27	43.69	44	20	16	112.42

*2 Project Awardees

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Boston Edison Company Re: Edgar Electric Energy Company, 55 F.E.R.C. P61382, 1991 FERC LEXIS 1322 (F.E.R.C. 1991)

SHEPARD'S Signal: Caution: Possible negative treatment
Restrictions: *Unrestricted*
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SHEPARD'S SUMMARY

CITING DECISIONS (19 citing decisions)

ADMINISTRATIVE AGENCY DECISIONS

1. **Cited by:**
Union Elec. Co., 114 F.E.R.C. P61255, 2006 FERC LEXIS 534 (F.E.R.C. 2006)

2. **Cited by:**
Union Elec. Co., 114 F.E.R.C. P61250, 2006 FERC LEXIS 530 (F.E.R.C. 2006)

3. **Cited by:**
Badger Power Mktg. Auth., Inc. v. Wis. Pub. Serv. Corp., 114 F.E.R.C. P61208, 2006 FERC LEXIS 430 (F.E.R.C. 2006)

4. **Cited by:**
Entergy Servs., Inc., 114 F.E.R.C. P61157, 2006 FERC LEXIS 315 (F.E.R.C. 2006)

5. **Cited by:**
FirstEnergy Solutions Corp., 114 F.E.R.C. P63014, 2006 FERC LEXIS 143 (F.E.R.C. 2006)

6. **Cited in Dissenting Opinion at:**
Conectiv Energy Supply, Inc., 109 F.E.R.C. P61385, 2004 FERC LEXIS 2752 (F.E.R.C. 2004)

109 F.E.R.C. P61385

7. **Followed by:**
Allegheny Energy Supply Company, LLC, 108 F.E.R.C. P61082, 2004 FERC LEXIS 1569 (F.E.R.C. 2004)

108 F.E.R.C. P61082

8. **Followed by, Explained by:**
Ameren Energy Generating Co., 108 F.E.R.C. P61081, 2004 FERC LEXIS 1571 (F.E.R.C. 2004)

Followed by:
108 F.E.R.C. P61081

Explained by:
108 F.E.R.C. P61081

9. **Followed by:**
Southern California Edison Company, On behalf of Mountainview Power Company, LLC, 106 F.E.R.C. P61183, 2004 FERC LEXIS 371 (F.E.R.C. 2004)

2004 FERC LEXIS 371

10. **Distinguished by:**
Ameren Energy Generating Co., 106 F.E.R.C. P63011, 2004 FERC LEXIS 210 (F.E.R.C. 2004)

2004 FERC LEXIS 210

11. **Followed by:**
Texas Eastern Transmission, LP, 99 F.E.R.C. P61308, 2002 FERC LEXIS 1226 (F.E.R.C. 2002)

99 F.E.R.C. P61308

12. **Followed by:**
Electric Generation LLC, 99 F.E.R.C. P61307, 2002 FERC LEXIS 1227 (F.E.R.C. 2002)

99 F.E.R.C. P61307

13. **Followed by:**
Ameren Energy Marketing Company, 99 F.E.R.C. P61226, 2002 FERC LEXIS 1125 (F.E.R.C. 2002)

99 F.E.R.C. P61226

14. **Followed by:**
Southern Power Company, 97 F.E.R.C. P61279, 2001 FERC LEXIS 2966 (F.E.R.C. 2001)

97 F.E.R.C. P61279

15. **Followed by:**
Southern Power Company, 95 F.E.R.C. P61201, 2001 FERC LEXIS 1082 (F.E.R.C. 2001)

95 F.E.R.C. P61201

16. **Followed by:**
MEP Pleasant Hill, LLC, 88 F.E.R.C. P61027, 1999 FERC LEXIS 1430 (F.E.R.C. 1999)

88 F.E.R.C. P61027

17. **Followed by:**
Aquila Energy Marketing Corp., 87 F.E.R.C. P61217, 1999 FERC LEXIS 1053 (F.E.R.C. 1999)

87 F.E.R.C. P61217

18. **Explained by:**
Ocean State Power II; Ocean State Power; Ocean State Power II, 69 F.E.R.C. P61146, 1994 FERC LEXIS 2343 (F.E.R.C. 1994)

69 F.E.R.C. P61146

of the prices.

So, driving towards price-only or price-mostly bids through the collaborative process, is a good step.

Again, the independent monitor, having an independent monitor that really can go toe-to-toe with a utility buyer, I think is a good defense.

Beyond that, all the standards work, things like codes of conduct. We'd run through every code of conduct, we'd identify every point of contact, okay, on this issue. Are you going to use corporate services on credit, for example? Who was going to be the bid team? Do they have any link to anyone in an affiliate who would bid?

Who would do the transmission? You'd just literally run through all of those things. We've used secure bid sites. We've gone to remote sites so that on bid day, they are in remote sites, so there are a lot of common sense things.

But, again, I think the collaborative process and having the IM, goes a long way to creating a credible bid and to combatting abuse by any party, really, not just the affiliate.

MR. COMER: What I'm struck by, listening to these questions and the answers to these questions, is that there is incredible involvement from the states, and I think that's good.

And there's clearly variety among the states. I mean, when you look to New England and New Jersey and Maryland, those are bidding situations in states with greater degrees of retail competition and more liquid markets. And those are different situations than you might find in Arizona.

But I think what you're hearing here is that there is a lot of involvement of the states, and, again, I would encourage the Commission to have a collaborative with the state commissions and hear their perspective about this and share best practices and good practices.

I think the price-only auction in New Jersey may not be a model for other portions of the country. I believe the New Jersey ones are relatively small and relatively shorter-term, but it would be useful to understand the difference in the nature of the auctions and what purposes they're supposed to serve.

MS. TIGHE: Thank you.

MR. WALTER: I agree with Ed, that I think the state commissions obviously have been getting involved with this, but I just look at the end results of a lot of these where affiliates have been involved, because without an independent monitor in an non-RTO situation, cross-subsidization has gone on, preferential access has been provided to the affiliate, replacement power alternatives have been available to an affiliate and not to an independent bidder.

And so the facts of the matter are that in spite of the fact that these commissions have gotten involved, these other aspects of preferential treatment have gone on and will continue to go on without some competitive procurement standards and guidelines that you all could put together.

So I think that I would agree with Craig very much, that having an independent entity looking at this whole process to make sure everybody is treated fairly, is a really critical part of it.

MR. PEDERSON: We have time for one more question. Dave?

MR. PERLMAN: I guess that yesterday we had a market-based rates conference and we talked about this topic a little bit, and there was a FERC-oriented component of that that's different than the state issues. And I'm curious about each person's view on that.

It really just came up in the conversation with Julie Simon of EPSA, and it was, if we have procurement of long-term capital assets that effectively reintegrates by contract, where the utility has control over a generator, does that create competitive issue or issues in that particular sense of market-based rates?

So, should there be a FERC criteria that relates to the impact on wholesale markets and wholesale competition of the outcome of these procurements? For example, is there 25 percent of the resources still free to trade? Or, can it still be dispatched by the non-utility owner, or something like that that we should keep in mind when we look at these issues?

MR. ROACH: Just quickly, you know, I just want to make the point again that your question sort of implies that the wholesale market is the spot market. That solicitation that was implicit in your question is as much a wholesale market as the spot market and deserves as much attention from state and federal commissions as the spot market.

You know, my view, specifically on your question, is that, yes, under -- if you sign a long-term PPA, under Appendix A standards, that would be allocated to the utility. But I would very much be willing to put that aside, that issue aside, if that long-term contract was competitively procured.

The competitive procurement is itself blocking market power abuse for that wholesale market, for that big transaction. So, I think that if the PPA is itself subject to a market test, then I wouldn't allocate it to the utility. I would say that that's been purged of market power.

MR. PEDERSON: We're going to take one more question. Sebastian?

MR. TIGER: I have a question for Mr. Comer. You had mentioned that the Edgar standard was sufficient as it exists today in regards to solicitations, but you made another argument that utilities have to look at buying distressed assets as another option to signing PPAs.

I was wondering whether that would suggest that in evaluating solicitations, whether it was necessary to look at the buy-first/build option -- buy/build versus PPA option, and if you are doing that, as you noted, there are distressed assets.

Do you have to look at why those assets are distressed before allowing for that other option?

MR. COMER: Well, two things: One, when I say the Edgar standard was sufficient, I did point out, I think, that the Edgar standard needs to be supplemented by looking very closely and giving deference to state determinations.

Where states are, as you have heard, we're conducting, reviewing and being very involved in the solicitations. In terms of -- are you saying apply Edgar to the purchase option, you're really saying it's the lowest of cost or market.

I think if there is an affiliate transaction and you're purchasing it, you do want to have a sense that the -- it puts you in a very funny position, and if the market is lower than a cost-based rate, then the solicitation process might give you better information.

MR. PEDERSON: I want to thank the panelists this morning. I think we had a very good discussion. I hate to cut it off at this point, but I think we need to --

CHAIRMAN WOOD: Jerry, hold on. We're going to override you for just a second.

(Laughter.)

MR. PEDERSON: I'm sorry.

COMMISSIONER KELLIHER: I had one question: A lot of the discussion this morning has been on how to make a formal solicitation work, how to make it work well.

But Ed pointed out that Edgar provided three means for a utility to prove the absence of abuse and self-dealing, and I wanted ask -- Ed's position is clear. Ed thinks all three means should be retained, but I wanted to ask the other panelists, do you agree that we should maintain all three means, or should we require a formal solicitation process? Should there be only one means?

MR. WALTER: I think we should require a competitive procurement process as a way to get to a fullness of market consideration, instead of just using this benchmarking, so I think it ought to be focused on competitive procurement.

MR. REITER: I would agree. I think my concern with the other two options, looking at benchmark purchases and benchmark sales, involves quite a subjective judgment about what constitutes a contemporaneous transaction or what constitutes a similar type of sale, service, or product.

It opens up the process, I think, for potential evasion and abuse. I mean, it's a second-best solution. I think the Commission has applied it in judging affiliate sales in the gas industry, historically, where there was a pretty thin market, looking at only certain identical transactions, but it is, I think, an inferior choice to a competitive bidding process, and as I mentioned before, I think it's inferior to a more structural solution.

MR. ROACH: I would agree that you should at least have a preference for competitive solicitations, and, just as a practical point, it's very hard to go out, and, as Edgar requires, get comparable benchmarks and comparable sales to others.

The best way to assure comparability is through the solicitation.

MR. HILKE: As I mentioned in my opening remarks, there are these other systems for finding comparables and then are -- if you've got a common type of transaction, there are econometric methods to look at the equivalency question. So, yes, I would divide it into very, very common types of transactions for which you probably can establish ready benchmarks, versus more esoteric ones in which there is so much art involved in it that you might not want to go there.

I guess I'm most comfortable with the idea that you have a preference for the competitive bidding situation, but, again, you usually look at these things in a cost/benefit framework. If it turns out that the costs of that type of arrangement are, you know, astronomically high compared to the others, and you can get these ready benchmarks, then maybe you don't need to go that far.

MR. COMER: Commissioner, if I could clarify? I don't know if you were here when I first spoke, but I did say that the competitive solicitation process probably makes more sense in the longer-term, more complex kinds of transactions.

But if you have a short-term transactions and a liquid market, I think the other elements of Edgar make perfect sense. I mean, if you're doing a day-ahead transaction in PJM, you don't need a competitive solicitation, you have to buy from an affiliate.

COMMISSIONER KELLIHER: Thank you very much.

CHAIRMAN WOOD: Where is the line drawn? Is it a year? I mean, we like bright lines because we've got put stuff in boxes and run it through chutes, once it gets to the door here, and these guys do all the hard work on it. Contract of a year or longer, two years or longer, 90 days or longer?

MR. COMER: I think you need to look at the market and see what's commercially available out there. I think you need to talk to the states and see what's out there, as well.

A year is a reasonable benchmark, but that may vary from market to market.

CHAIRMAN WOOD: Speaking of the states, my question was, based on your collective experience -- and I think that Ed has a good recommendation to continue that dialogue, although we have the very erudite Chairman Welch on the next panel, I know there are other states that are dealing with different versions of solicitation. What would be a good wish list for your dream panel to get a good cross section of, I guess, best practices at the state level, that we should discuss this with?

MR. ROACH: I depends on how you define "wish list," but right now, for example, Pennsylvania and, after yesterday, I believe, Ohio and Illinois are considering this issue and have done some considerable homework on the issue through a series of technical conferences.

I know, Mr. Chairman, you spoke at Illinois. I spoke on that panel also, or later in the day.

So those three states, I think, are in the middle of trying to decide. And they're tackling issues like, should we look at the Maryland or New Jersey type of process, or should we be at a process that looks more at asset-backed unit-contingent? So, they're at least really interested in these issues. It's very important for them and they will be making decisions.

They might be good folks to have on this. I think that beyond that, I thought the Arizona staff did a great job, and they had a good, independent monitor, so they might be someone, too.

MR. REITER: I guess I probably have some bias with respect to my own clients, but certainly you'll be hearing from Tom later, again, and I think Vermont has looked at some structural issues in this process, and I think you would get some good information from them.

I know that the State of Michigan has looked at competitive solicitations and is developing sets of rules, non-structural approaches with which they have had some considerable experience, and I think that Bob Nelson would probably be someone who would be interested in talking on the subject.

MR. COMER: I would think you would want a mix of states, certainly. Some have retail competition and more liquid markets, but I think you also want a number of states in the South and West that have more traditional structure, because the issues they face may be a little different.

And I don't know that I would limit it to -- obviously, you want those that have the best practices, but I think part of the usefulness of the session would be to help educate state commissions about what their colleagues are doing, as well.

MR. WALTER: I was just going to say that I agree with Craig. I think some of the best processes we've seen are developing in Maryland and Pennsylvania and in areas like that. Beyond that, I do believe that Texas is working well. It's a little different situation there, of course, but I'd like to obviously export that from Maryland and Pennsylvania and other areas.

I know that California has tried to take this subject up, but they have a bit of a distance to go yet.

MR. PEDERSON: I'd like to thank this panel again. Let's take a short, ten-minute break, and we'll begin again at 10:50.

(Recess.)

MR. PEDERSON: Okay, we'll continue the discussion from the earlier session, and I think we'll proceed in the same manner. I'll ask each of the panelists, in turn, to give a five- to six-minute presentation, followed by questions and discussions. I'll ask that you keep your comments within that five- to six-minute period.

And, with that, I would like to introduce Mr. Tom Welch, Chairman of the Maine Public Utilities Commission. Chairman Welch?

MR. WELCH: Thank you. I appreciate the opportunity to be here. My comments are going to focus on what I think is Maine's very successful experience with obtaining or default supply, what we call standard offer.

But I think that even though the particular product that we're seeking is a relatively limited one, there may be useful lessons to be learned from what we've done there in whatever procurement, whether it's a long-term procurement for supply adequacy or some other purpose.

By way of background, Maine has a fully open market. Any customer can enter into a bilateral contract with a competitive electricity provider.

The T&D utilities were required to divest all generation and have severely limited rights to market energy. The T&D utilities have no load-serving obligation and no prices for energy for any customer or set administratively.

The customers who do not choose to enter the bilateral market are served by the standard offer, and I'm going to describe the process by which we obtain it, and that's actually obtained by the Main Public Utilities Commission itself through an open bid process.

I'll also note -- and I think this is a precondition for the kind of process we have, that we are a part of a robust market, the New England ISO, soon to be, I hope, the New England RTO, which provides, I think, the necessary competitive vigor and transparency that is really essential, in our view, for any effective competitive solicitation.

And I'll answer the questions more or less in sequence. Our procurement is done by the competitive solicitation. We issue an RFP outlining the responsibilities of the winning bidder.

The selection process obviously has to be as transparent as possible, either administered or supervised by a disinterested party, for example, the State Commission. The particular features of the solicitation process used in Maine to obtain the standard offer of service, which is a default, all-residual requirement service, load-following service, is that we ask for bids by customer class, divided into residential, medium-sized and large customers.

The bids are either for the entire residual load within the class, that is, whatever the loads is, net of the people in the bilateral market, or for 20 percent increments of that entire load, whatever that happens to be. Following the RFP, we take indicative bids and negotiate -- the PUC itself negotiates the non-price terms such as security for performance.

Final bids are requested, and then the selection of the winning bidder actually takes place within three or four hours of the final submission of the bid. We do it on the same day.

The product solicited depends upon the customer class. For customers with larger loads, the medium and large customer classes, we seek bids for six months to a year, with the intent of having that price follow the market reasonably closely.

For residential customers, the bids are from one to three years. We try to time the market a little bit, not always successfully, and the prices are fixed throughout the period.

In all cases, the obligation is for the entire load, which is to say the supplier takes all the load risk. The Maine Legislature has recently asked the PUC to consider whether we should include asset-backed contracts with suppliers with renewable energy as part of the solicitation, and we haven't yet made a final determination on that.

Price is the most important selection element. It really dominates all the others, but the strength of security is vital.

There was a comment this morning that you could rely upon the strength of the ISO as security for performance. You might be able to rely on it to keep the lights on; you certainly cannot rely on it for price, because if the price rises in the spot market, the security questions become intensely interesting, and we've had some experience with that.

The affiliate of the T&D companies -- the T&D companies are permitted to have marketing affiliates. They can't own the generation, but they can market the product.

They actually are permitted to participate in the bidding, but they are restricted by statute to providing no more than 30 percent of the standard offer load within their own territories.

As a practical matter, both because of our rules against the T&D companies owning generation, and because we have extraordinarily strict structural separation and codes of conduct rules, none of the T&D companies have chosen to market or to bid in our standard offer solicitation.

The regulatory oversight is direct. We actually conduct the auction. We don't use any further independent observer.

We did have some early cases where we permitted the T&D utilities to conduct the auction because we didn't get enough bids in the early days of our market to get the procurement, and we had essentially hour-to-hour oversight over their activity. Every decision they made was directly reviewed by us.

There are no negotiations after the selection of the winning bidder. The contract has to be in a form agreed to by the PUC and the bidder, before the final bids are submitted.

We generally release the RFP about two months before the date for selecting the final bid, and there is a period of time when the staff will answer questions about the bids. We ask for indicative bids, and once we have a short list, we'll negotiate more intensely with those to get particular terms, and the security terms tend to vary from bidder to bidder, and some of the other terms do.

As I said, typically we get the final bids by 10:00 a.m. and decide by 1:00 p.m., who the winner is. The reason -- we started our process by actually allowing six weeks between the submission of bids and when we decided.

And in conversations with the bidders afterwards, they indicated that that put them at too much market risk, and we were paying a high premium, so they want to be able to lock in their supply, almost immediately after they submitted a bid, so it's an interesting but important feature.

We use both formal and informal rulemaking processes to develop the rules for the standard offer solicitation. It's extremely useful to have an open process for developing the solicitation process itself.

In the early years, we spent a lot of time talking to bidders after the bid to see what we could do to improve the process, and really that's how we learned that we were costing our ratepayers money by having this six-week window during which we could ponder which bid to accept.

That has, frankly, driven us to depend almost entirely on price in selecting it. We assume the other things have a minimum threshold, and once those are met, price is what determines the winner.

It is vital, in my view, to ensure that there is no incentive or ability to favor one bidder over another. Significantly, the bidders have told the Maine PUC that they find our process to be the best or among the best in the country, precisely because they do not fear that the T&D utility can give preference to its own, for the simple reason that the T&D utility has no role whatever in the selection, and, for the most part, does not even compete in the standard offer.

In my view, full structural separation is the minimum that is needed to avoid the prospect and perhaps the reality of discrimination, and I have a strong preference for full divestiture with no participation at all by T&D utilities.

One reason for -- my view has actually been hardened because we did have one circumstance where the T&D utility was marketing its own affiliate's product within its own territory, and we were almost immediately confronted with a bloody, inconclusive, and fact-intensive case about whether or not the T&D utility was sharing important information with its affiliate, so in the one case where the T&D utility was active, we had precisely the case that we feared. It was very difficult to resolve, and the end result was that they have gotten out of the market.

Contrary to concerns raised by utilities prior to the passage of Maine's restructuring law, we have found no dearth of people interested in bidding for the Maine standard offer supply.

To the extent that monopsony power is used to favor an affiliate, that prospect alone will dampen bidding interest. Frankly, we have been criticized by those selling in the bilateral market, that the prices we obtain in the standard offer solicitation are too low, because there is no customer acquisition costs, but, frankly, our current view is that the load risk undertaken by the standard offer supplier, acts as a sufficient counterweight.

I think the Commission, the Federal Commission, should ensure that a fully disinterested party, perhaps as the Maine PUC, actually conduct the bidding process and make the award, and the same disinterested party should have the final say on the bidding process itself, after full consultation with all interested parties.

If the state commission is unwilling or unable to perform the role, any monitor or bidding administrator should be at least as independent as the independent market monitor of the New England ISO or New England RTO; that is, the monitor must have no financial interest of any kind in the particular outcome of the bid process.

The selection should be approved by at least the relevant state regulators, and the monitor should have reporting responsibilities to the same. As for best practices, frankly, I think Maine is a best practice, and I encourage people to look at it, and we'll obviously be pleased to continue to work with the Commission. Thank you.

MR. PEDERSON: Thank you, Chairman Welch. Our next panelist is Betsy Benson, Principal of Energy Associates, and independent monitor of a number of solicitation processes, including CLECO. Betsy?

MS. BENSON: Thank you very much. I'm going to speak principally this morning about the experience in Louisiana and being an independent monitor, because I think that's probably the issue about which people are most interested.

In Louisiana, there is no retail access, and the independent monitor works in a situation where there is a market-based mechanism required by the Louisiana Public Service Commission, which requires bidding for all long-term bids, and, in general terms, that means everything over a year, although, of course, there are some exceptions to that, and we can go into that later, if you are interested.

The independent monitor's responsibilities -- let me speak first to how the independent monitor reports. As the independent monitor, I am recommended by the company to the Commission. The Commission has the right to either accept or reject, in other words, to say we accept this individual or you need to go back and get somebody else.

But the feeling in Louisiana is that the utility, because of the close working relationship that would be existent between the independent monitor and the utility, should have somebody who would work well with the utility. However, I do report, not the utility; I do report to the Commission, and, in fact, work very closely with the Commission staff. I also work very closely with the utility.

Let me talk a little bit about the market-based mechanism requirements, because, in fact, it is a highly collaborative process, and that has been described here this morning, although I think some of the issues that were discussed this morning were really within states that do have retail access, and this is a state that does not. So, again, I think it provides another perhaps interesting model, because, obviously, there are many states which have not gone to retail access and are looking for long-term bids.

There are competitive bid solicitations required for, as I mentioned, for virtually every term of long-term power supply. My responsibilities involve making sure that there's no undue preference towards affiliate bids, but also self-billed and self-supplied bids, which are often -- which are usually factors in these solicitations.

The collaboration process itself is the process of the utilities are required to submit forecast information, essentially information to justify why it is that they need more capacity, to provide information on their existing resources, to provide information on their self-billed options, if any; to provide an extensive RFP draft for the market.

And then there is the process of collaboration, which includes one or more technical and bidders' conferences. That is an informal, non-litigated process, but is conducted by the Louisiana Public Service Commission staff in that context.

I do want to say one thing about the collaborative process. Just as an interesting thing, obviously it is as good as those who are asked to collaborate make it. And I would say that there are many bidders, many of whom are represented by independent power producers who have already appeared here today, who do participate in that process, and, I believe, have taken seriously, their responsibility to comment during this process, the process really being to try to make the RFP better, the procedures better, the procedures more transparent.

I would also tell you that I spoke just the other day with a bidder who called me about a transmission issue and who commented that, well, he usually liked to wait until the final came out, before he paid much attention to it. And I said, well, I think that's certainly your right to do that, but the whole point of the collaboration process is to have you have an opportunity to influence the way the solicitation comes out.

So, what he chooses to do or not do -- and I should also mention, obviously, that we are right in the midst of the collaboration process right now for the particular RFP, which is seeking possibly up to 1800 megawatts for CLECO Power, so it's a solicitation of some note.

There is a Phase II of the market-based mechanism, and that, of course, is the fully-litigated portion of a certification process at the point at which a utility will present a capacity deal, but this first deal really is a collaborative process.

My own background and experience is that I believe very strongly in competitive solicitations, and, in fact, this is the fifth very highly competitive, long-term solicitation that I've been involved with, not all of which have been in the Southeast, but, actually, two others of which were in the Northeast and the Mid-Atlantic Regions.

So I believe very strongly in them. I also am very well aware of the complexities associated with virtually every long-term deal, and I should say that I started doing my first one in 1996, and the market has certainly changed a lot since then as well. The issues have certainly become more complex in many, many ways.

As far as what I do -- and I think this is perhaps useful, because it was commented on earlier this morning -- I am, as I think was termed this morning, all over this thing, this solicitation with, in this case, CLECO Power.

One of the things that this and many other utilities have are all sorts of internal complexities in terms of shared services, and those things need to be carved out, made to identify who can work on what, what employees are designated, who has access to what information.

You need to have -- in some cases, you need to actually carve people out from non-involvement, because they either have access to information that is going to be commercially sensitive, and, frankly, will or could potentially advantage an affiliate or not.

Also in the case of this and many other companies, obviously, employees get assigned from time to time from utilities to affiliates. So we really have a fairly extensive process of that. We also require people to adhere to a very extensive code of conduct with respect to the RFP, which is in addition to anything that they are also required to do by other codes of conduct.

We have training in protocol and everyone needs to sign a confidentiality agreement that indicates that he or she will adhere to the requirements of the protocol. We channel communication, and what I mean by that is that at this point, the RFP is out for comment, and as of the date that the RFP was submitted in a draft form, all communication from any potential bidder has to be channeled to a designated representative at CLECO Power or to me or to the Louisiana Public Service Commission staff, as may be appropriate.

And the reason that we do that is really to make certain, as much as we possibly can, that we stop discussions that are sidebar discussions that could well disadvantage the solicitation.

So there are all sorts of additional procedures. I would also say that in terms of the independent monitor's scope, in addition to monitoring these things and making sure that as the solicitation itself is developed, and if it's administered, I am also responsible for handling the bids when they actually come in and making certain that they are handled by a very small number of people, making sure that they are secure, making sure that they are redacted, making sure that the evaluation that is set up is independent, monitoring that evaluation.

If, in fact, there are affiliates involved in a short list that would come after a final bid procedure, I would be involved with the negotiations for those affiliates. So it's really a pretty intense, hands-on kind of activity.

That said, I am not myself evaluating things separately. I mean, the company is, in fact, doing that, and that's something that I'll be very happy to talk with people about, if you wish to talk about the pros and cons of that, because I do have some opinions about that.

I would say that in the end, a very strong effort has been made and is being made, and I would also say that the Louisiana Commission has actually reevaluated its market-based mechanism within the last year, and took the monitor position, which was a voluntary position a year ago, and made it a requirement, and then put the procedures in place that I just alluded to very briefly, in terms of managing.

I would just like to stop my comments by simply indicating and echoing what a lot of people have said here today. I think that any sort of effort to sort of tease out the jurisdictional complexities that exist between states and the Federal Government in power supply, can best be aided initially by a serious evaluation of the many different ways in which the states approach competitive solicitations.

You've heard some good examples today, principally, I think, from states that are already involved with retail access and go through competitive auctions. That also has been indicated here, and is quite distinct from long-term supply in states that have not done that.

Obviously, there are many other models, as well, and many increasing -- or many other models and many examples of what might be termed best practices, but I would indicate that I think it would be a wise thing for the FERC to try to look at these things very seriously and very intensely, and I'll stop here.

MR. PEDERSON: Thank you. Our next panelist is Ershel Redd, President of the Western Region of NRG Energy.

MR. REDD: Thank you, and thank you, Mr. Chairman and Commissioner Kelliher and the Staff for allowing me to come and speak about the wholesale power industry and also the procurement practices that we see, particularly as it relates to new development projects and current capacity.

This Commission and other Commissions that preceded you, have begun the process of replacing regulatory controls with competitive forces. That's a major win for this economy and also for the consumers as they are saving billions of dollars.

The process of disaggregating the vertically-integrated utilities has to continue. We do regulate to shift the burden of stranded costs from the ratepayers to the consumers -- I mean, from the ratepayers to investors and shareholders, and it's working.

By placing generation in the hands of entrepreneurs, you've unleashed the competitive forces and the innovation of a rational and competitive market. Competitive investment in the wholesale power sector has drastically reduced the effective cost of converting the Btu of energy into electricity, and, again, consumers are the beneficiaries and they are saving billions of dollars.

While the spark spreads are at unprecedented level and consumers are saving those billions, there are some unhealthy risks that are currently surfacing. Investment risk in this business today is high. The capital markets that I have spent a lot of time with over the last two years, are telling me that before they invest additional funds in this sector, they need some assurances that their loans will be repaid.

Encouraging the execution of longer-tendered power purchase agreements is one of the important steps the Commission can take today to ensure that capital flows into this sector, such that the development of a healthy and robust competitive market continues.

However, more critical will be the longer-term development of capacity markets such as what we see in New York. Today, for example, the California market is precariously perched on the edge of another major energy capacity problem, reminiscent of that which occurred in 2000/2001.

New generation needs to be built in California, and it must be built competitively, rather than by the inefficient, vertically-integrated utilities that operate as monopolies where costs to consumers are not considered.

To be competitively built, host utilities should issue requests for proposals that meet the basic standards of the competitive marketplace. FERC must establish the baseline standards.

Those standards must establish a fair and level playing field for all participants, open and transparent processes, and ensure discriminatory practices are not employed. The RFPs must carefully and articulate the products and services that are required, define and articulate the processes themselves, also define and articulate the bid evaluation standards, including weights applied to price and non-price components of the RFP.

They also need to define and articulate deliverability standards, and they must use a third-party entity to run the solicitation and to conduct the evaluation process to prevent affiliate abuses.

The evaluation process must give priority to contracts that provide the lowest cost, but fully burdened or all-in cost of the energy to the load center, and that also meet strict deliverability standards during those hours where the energy is needed the most.

Let me warn the Commission that the problem you identified in 1991 in the Edgar case, still exists, and I quote, "Where traditional utility is buying from an affiliate not subject to cost-of-service regulation, the buyer has an incentive to favor its affiliate, even if the affiliate is not the least-cost supplier, because the higher profits can accrue to the seller's shareholders," unquote.

This problem is particularly acute today, where there don't exist, workable and independently operated capacity markets. So that is almost everywhere, except New York.

Why does it continue to exist? Because the host utilities that contract for generation from an affiliate, can pass fixed costs along to retail ratepayers and they dump the wholesale power on the market at variable cost, thus suppressing rational market price signals.

In effect, the host utility and the affiliate enjoy private capacity rights that are recovered through the utility's retail rates, while other suppliers are left with only variable cost compensation or no incentive to stay in the business. This creates an unhealthy situation where innovative and competitive market participants are forced out of the business and the consumers are left at the economic mercy of the utilities.

Without the proper application of the Edgar principles, the above-described situation can be blatantly discriminatory, and without workable capacity markets, even PPAs that pass that Edgar test, will depress prices, asset values in a competitive market and continue to reinforce barriers to entry that exist.

Let me now leave you with two recommendations: One is rather short-term and it is to maintain the momentum of regulation that you so dutifully began, and the other is the longer-term solution to sustain the growth and sustainability of the wholesale power market in this country.

First, you must employ the Edgar approach to ensure transparent, objective, and fair PPA bidding processes are established up front and that will ensure the competitive wholesale market will continue to attract capital that they need to remain in this business.

Second, you must continue to pursue your quest to introduce independently managed and efficient capacity markets in this country that will ensure the long-term security of the power market in this country. Thank you for your time, and I look forward to the question and answer session.

MR. PEDERSON: Thank you, Mr. Redd. Our next panelist is Ted Banasiewicz, who is Principal of USA Power, a development and acquisition advisory firm. Mr. Banasiewicz.

MR. BANASIEWICZ: Thank you and good morning. My comments will focus on a recent experience that my company has had with a utility solicitation. I will address many of the issues on your agenda.

USA Power is a power plant development firm founded in 1997. We select specific site locations where we believe a competitive advantage exist, as well as a significant demand for generation resources.

We obtain all of the permits and approvals required to begin construction, and then bring in project-specific partners for the financing, construction, and operation phases of the project.

USA Power recently participated in an RFP by Pacificorp, which solicited peaking and baseload power for delivery into its Eastern Control Area, with the Mona Switching Station near Salt Lake City being identified as the most preferred delivery location.

USA Power had anticipated a significant shortfall of generation resources in that area, and began developing our Spring Canyon Energy Facility, two years before Pacificorp announced its RFP. We had previously chosen a site less than a mile from the Mona Switching Station and selected a 500-megawatt configuration with the flexibility to provide either peaking or baseload power.

We obtained all of the permits required to begin construction, including the air permit, water permits, and interconnection agreements, being first in the queue for transmission rights. The RFP sought approximately 500 megawatts of peaking power and 500 megawatts of baseload power, and our project as a perfect fit to meet Pacificorp's needs as identified in the RFP.

Our bid partners in the Spring Canyon Energy Project include Quips Corporation of Amarillo, Texas, which provides operation and maintenance services and its parent, Utility Engineering, a power plant design and construction company. We also have an equity partner in the Energy Investor Funds, which is a Boston-based equity fund that has invested more than $ 1 billion in power plant generation infrastructure since its inception in 1987.

In response to Pacificorp's RFP, we bid a project that had all aspects and risks of the development phase complete and our partners were able to provide the construction, operation, and all of the equity required for financing.

It is a very strong team which was put together specifically for the Pacificorp RFP. We felt we had to provide a very credible, experienced, and creditworthy team, in addition to bidding the very best project in terms of technology, operational flexibility, cost, and schedule.

Several months before Pacificorp announced the RFP, they had approached us in an attempt to purchase our Spring Canyon Project, which at that point consisted of a project site and various permits and approvals. We negotiated with Pacificorp for several months and shared all project-related information with them, including contracts for site acquisition, water agreements, all permits, including the technical aspects of the air permit, all technical design work, and all plant performance information.

Three days after reaching an agreement for Pacificorp to purchase our project, Pacificorp informed us that upper management would not approve the purchase, and that an RFP would be issued shortly. Although disappointed by that news, we were confident that our project would prevail amongst the competition for the RFP.

We put our bid team together and prepared our response. We submitted bids for both peaking and baseload portions of the RFP, and were short-listed for both.

During our short-list discussions, we were informed that Pacificorp had submitted a self-billed option that was more than very similar to our project. In fact, they had picked a project site only one half mile from ours, selected the exact technical configuration as ours, selected the exact same 13-mile gas pipeline route, and they had offered to purchase water at the exact same price that we had spent months negotiating.

In every way, the Pacificorp bid was an exact clone of the Spring Canyon Energy bid, despite the fact that we had a valid confidentiality agreement in place which prevented Pacificorp from utilizing our information for anything but evaluating the purchase of our Spring Canyon Energy Project.

Needless to say, we were astonished to learn of these facts. Finally, Pacificorp announced that their self-billed option was the winner because it provided the lowest-risk and lowest-cost alternative to the ratepayers, and that they would be seeking a Certificate of Convenience and Need from the Utah Public Service Commission, which was required to begin construction.

We initially intervened in the CCN process, not because we felt that Pacificorp had violated our confidentiality agreement, but because they stated that their project was lower risk and lower cost. At that time, we had a thorough understanding of their risk, however, we did not have a thorough understanding of their cost.

They did not have an permits or approvals required to begin construction, no air permit, no water permits, and their application for these permits were being fiercely challenged. We intervened because Pacificorp, in its bid evaluation process, gave no credit to projects that had secured permits, versus what they called virtual projects such as their self-billed option.

It wasn't until well into the intervention process that we learned just how far Pacificorp was willing to manipulate the process to ensure that they won. Today, I will give you just a few examples of their many ways.

MR. PEDERSON: Mr. Banasiewicz, I apologize for interrupting you, but if we can wrap up, so we can get to questions and answers?

MR. BANASIEWICZ: Absolutely.

Through the intervention process, we were able to obtain the economic models that Pacificorp used to evaluate its self-billed option and our Spring Canyon Energy Project. We found two very different models.

These models were overly complicated and were several hundred pages long. Models that we use to evaluate projects are about 30 pages long. Models our partners use are about 50 pages long. We had never seen models that were several hundred pages long.

Our team spent many long days analyzing the models, and we were astonished at the results of our analysis. First, we found that models were conceptually inappropriate.

Instead of looking at each alternative to determine which provided the lowest cost, these models calculated which alternatives make the most money by including a revenue component. You would think that two identical facilities, in an identical locatio, would have the same revenue. Not when Pacificorp does the evaluation.

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The two models used different pricing, and, to compound the problem, Pacificorp elected to operate its self-build option, 24 hours per day, whereas they elected to operate our project for 16 hours a day.

Further compounding the problem, Pacificorp evaluated its self-build option over a 38-year period, versus limiting our economic evaluation to 20 years. The RFP limited all bidders to 20 years, yet Pacificorp allowed its self-build option the benefit of an additional 18 years.

The result of all of this is that even though the two projects are identical, the Pacificorp self-build option had more than double the revenue of our Spring Canyon Project. This result is clearly absurd, especially when revenue should not be a component of the RFP evaluation.

Digging further into the models, we discovered that Pacificorp used incorrect values for the megawatt output of our facility, incorrect values for the availability, incorrect values for the heat rate, for the capacity charge, and for the cost of operations and maintenance.

Most troubling is that we never had an opportunity to verify the actual inputs used in the evaluation of our project, prior to them announcing themselves as the winner. It was only because of the intervention process that we were able to see these manipulations.

We were able to deliver our project at a lower cost than Pacificorp and we were willing to guarantee the cost of the facility, the output, the heat rate, availability, and the emissions. Pacificorp was unwilling to guarantee any of these.

We had all the permits, yet they boldly claimed that their project provided lower risk to the ratepayers. That brings me to the world of the independent consultant, which in this case was Navigant Consulting.

During the intervention process, we obtained several e-mails which Navigant sent to Pacificorp, offering instruction on how to make their self-build option score better in the evaluation process. Navigant did not offer this type of advice to us or any of the other bidders.

Also, during the hearings before the Commission, Navigant sat with Pacificorp and drafted many questions for Pacificorp's lawyers to ask of various witnesses. The independent consultant was anything but independent.

During the course of the proceedings, we developed the ability to run Pacificorp's models and we concluded that when we ran the models with the correct inputs, we win and we win by a huge amount. Our bid provided a lower-cost product than did Pacificorp's proposal, yet when Pacificorp runs the models, they claim they win by a huge amount.

This makes no sense, and adds credence to our assertion that their models are flawed. Remember that these are identical facilities in the identical location. One would think that this would be like a NASCAR race where you had two good drivers in similar cars with similar cars with the same horsepower, and after 500 miles, one wins by two-tenths of a second.

However, in this race, Pacificorp, according to their testimony before the Commission, would have you believe that our Spring Canyon facility is four and one half times less economical than their facility. Not only does this not pass the common sense test, but it begs the question of how do these models tell the public that the process is honest and believable?

I have identified a few concerns with the process. In my opinion, it was a disingenuous effort by Pacificorp to manipulate the evaluation to ensure that their self-build option would win.

We presented all of this to the Utah Public Service Commission in seven day of hearings. The result of those hearings was that Pacificorp was awarded the CCN that it had requested, even though two independent consultants hired by the ratepayer advocates also concluded that the Pacificorp bid evaluation process was seriously flawed, was skewed in favor of Pacificorp's self-build option, and could not be relied upon to determine the lowest cost option.

Only the Division of Public Utilities concluded otherwise, and they, by their own admission, did not do a substantive analysis of its own, but, rather, relied on Navigant Consulting.

We believe that the Utah Public Service Commission and its staff are not in a position to be able to evaluate economic models that are several hundred pages long. And while they appeared interested and generally concerned to do the right thing, they are not well versed in the technical aspects of power plant operation and did not grasp the importance of such mistakes.

To compound the problem, Pacificorp played the blackout blackmail card very well. They claimed that blackouts would occur if the Commission did not grant the CCN. With Pacificorp and us claiming to be right, and with the Commission under pressure to avoid blackouts and unable to determine who was actually right, the Commission felt it did not have any alternative but to issue a CCN.

Unless the Commission has a truly qualified and truly independent evaluator reporting to it, rather than to the utility, the utility can pull the wool over the

Commission's eyes every time.

In conclusion, I recently heard a politician describe the U.S. foreign policy as the U.S. thinking it's a hammer and all of its problems are nails. When I heard this, I immediately thought of Pacificorp.

Unless the FERC gets involved, Pacificorp will continue to believe itself to be the hammer, and all independent power producers to be nails. I believe an investigation by FERC regarding our allegation of Pacificorp's behavior is most appropriate and necessary to ensure the integrity of the RFP process in a regulated environment. Thank you.

MR. PEDERSON: Thank you, Mr. Banasiewicz. That was some war story. We've heard a little bit about that today, and I'd like to start the questioning.

If I could start with Mr. Redd, who mentioned in his comments about the proper application of the Edgar principles, which once we look into that a little more and establish that a little more, that may help out on situations like you just described.

So, Mr. Redd, can you discuss a little about -- when you mentioned proper application of Edgar principles, can you expand on that? What is, in your opinion, the proper application of that?

MR. REDD: I think one of my concerns is that the Edgar principles ask the utility, particularly when they are dealing with an affiliate, to do an ex post facto review about whether or not there was any kind of discriminatory practice.

That's kind of like sending the fox to the hen house to gather the eggs. It just doesn't work.

I think that what you need to do is probably establish even greater standards that you can affix to the current Edgar standards that create a level playing field so that you ensure that there aren't any discriminatory practices; that the process is, as I had said, clearly defined, the needs and resources are clearly articulated.

And then I think what you've got to do is establish an independent monitor to -- or maybe an entity to run the whole process and do the evaluation.

MR. PEDERSON: On the process itself -- and I'll throw this out to the whole panel -- what do you envision that process to be? We've heard collaborative process. Specifically, if we were -- we look at filings, at least my group does. What would that process -- what process should we be looking at that is a collaborative process that would work for everyone and avoid the kind of problems that we might see out there?

MS. BENSON: Are you speaking about specifically, what the Federal Energy Regulatory Commission would require as a separate process, or in collaboration with state commissions, or what?

MR. PEDERSON: In my mind, I guess, in combination with the state process. What is the process that will result in a fair and transparent RFP?

MS. BENSON: Well, you know, I will certainly make a plug, not just for what Louisiana is attempting to do, but what I see, having been involved in power solicitations that have not been under any regulatory review of the state because they initially involved municipal utilities, which typically are not jurisdictional, but for which it became very clear that in order to have the market be as competitive as it needed to be, that everybody participating in it, needed to feel that it was fair.

And in a regulated environment, that means that they need to participate prior to, I believe, the solicitation going live, if you will, in what that solicitation is going to look like.

And I think there are examples. Arizona is another one, and I think there are other examples around, because there are many states that are trying variations on this where the regulatory environments at the states has, in fact, set up a formal, but non-litigated collaborative process that simply says to people, these are the things that you need to provide and these are the things that you need to make transparent to the market, with appropriate redaction of confidential information, of course, as determined by the regulator.

And then rely upon the market, as I believe that these gentlemen would indicate, to participate actively, which was the point, of course, of my comments about the gentleman that I spoke with the other day, who commented that he would only wait until it was final, which, of course, obviated his participation in a collaborative process.

But that's his problem, and I think, to some degree, that is, you know, a process step that independent power producers who have been active in the market would see as valuable. I think there are others of them that may not see so, but in my view, it is trying to make that going-in process as transparent as possible.

MR. WELCH: I think the critical feature is who gets to make the final decision about what the process is going to be, what the RFP is going to look like, and I think it's absolutely critical that that -- that the person or the entity that makes the final decision about the RFP, and who makes the final decision about the winner, is a completely disinterested party, perhaps, optimally, a commission, but in any case, someone who has no ties of a financial variety with any market participant.

I think that once you establish that, it will be in the interest of that disinterested party, who, presumably, has some public interest objective, to get as much information from as many people as possible and will, in the normal course of things, develop an appropriate collaborative.

I think that if you think of a collaborative as something where the parties must reach agreement among themselves, that is a formula for failure. If you think of a collaborative as something where the decisionmaker has an appropriate opportunity to get all the information it needs, that's a recipe for success.

So I think the focus ought to be on who actually gets to make the decision and the financial links that that particular entity might have.

MS. BENSON: And I just would comment that I don't disagree with that, to the extent -- again, my experience has been that at the end of the train, there is a regulatory body that is legally responsible for making the decision.

There are lots of side rails along that particular train, but I certainly don't disagree with that.

MR. PERLMAN: Could you address the issue of complexity that we heard about, where there is a regulatory body that had to make the decision, but there is a contention that the regulatory body wasn't adequately sophisticated enough to wade through all these models and make that kind of judgment, whereas, if they had been involved in the process, as Mr. Welch seems to be saying, and were making the decision, not as having something presented to them, but as being part of a continuum of the information flow and the structure going in, they would be more efficient and effective in doing it.

That's what I hear him saying. Are you disagreeing with that and saying that as long as their is a regulator at the end of the line, that's good enough?

MS. BENSON: Obviously, I'm in no position to comment upon the particular case that was described here today, but if the facts as they are, there are regulators and there are regulators. I mean, clearly these are very complex decisions that have many working parts to them.

None of them, even in simple -- even simple ones are not simple. So, obviously, there needs to be individuals who are themselves fully capable of, as somebody said this morning, going toe-to-toe.

And whether that is a combination of regulatory staff or regulatory staff consultants, independent monitors, but also there are clearly people who are actually running these systems. In my view, to pull -- which is slightly moving the bar on your question, but to take the responsibility for evaluating a long-term power supply proposal completely out of the hands of those who have fiduciary responsibility for hundreds of millions and billions of dollars, is not the solution, even though I understand why those who feel that they have been badly burned by the process feel so.

MR. GALLICK: If you don't evaluate or participate in evaluating -- and I may not be using the right words here -- if you don't evaluate the bids yourself, how do you develop a confidence that the company is actually doing it in a fair way?

MS. BENSON: I don't run the models, because I'm not equipped to run them. You know, we all have our skills and our talents, but I am not -- I don't know how to run ProMod.

But I am not uninvolved in those particular -- I understand how the models work, and I spend time with the companies, understanding how those models work. In certain instances in this particular case, the transmission decisions are to some degree outside the immediate decisionmaking of this particular company, because of the way that particular area is configured.

As I'm sure you know, that particular company is somewhat transmission-dependent on a larger not-to-be-named company that --

MR. GALLICK: Oh, come on.

(Laughter.)

MS. BENSON: But that said, I mean, I mean I wanted you to understand specifically, really, that I do not -- I have to say I have participated in solicitations previously where I was part of a small team of people who basically did all the analyses and did all the evaluations. We were employed by the utility, but we did them independently.

And that model worked well, as well, but that model is not this model, and I would say it just -- in this case, I really am monitoring, but I do understand how these models work, and I think I'm able to determine --

MR. GALLICK: Just as a followup, when you reach -- I don't know if "disagreement" is the right word --

MS. BENSON: Could well be, yes.

MR. GALLICK: But if you really have a serious issue, how do you go about resolving that?

MS. BENSON: Ultimately, I am charged ultimately with making certain that any unresolved issue is made as close to immediately, that the Public Service Commission staff is aware that there's an unresolved issue.

I would say that in most cases, it has been enough of an incentive to help us all reason wisely together. But, again, you know, there are big issues and then there are non-big issues, and, again, these are complex things.

But, ultimately, I am charged with reporting any unresolved issue immediately to staff, and if chooses, obviously to the Commission.

MR. PEDERSON: Did you have a question?

MR. O'NEILL: Ms. Benson, would you care to comment on what would have happened if you would have been hired by Pacificorp?

(Laughter.)

MS. BENSON: A fair question?

(Laughter.)

MS. BENSON: Well, no, Utah is a lot drier than it is here, and I -- truly, I mean, the way the process was described here today, it sounds pretty horrific, but with no one here to defend the other side, I'm in no position to comment.

It seems as though there were a few process steps possibly that they missed, and, you know, looking at a self-build option as we do in Louisiana, I have learned that self-build is potentially radioactive as affiliate issues as well, so they need to be very, very carefully tended to as well, for some of the reasons that were stated here today.

I'm sorry that that's really not an answer, but --

MR. O'NEILL: I only asked if you cared to. I realize that --

MS. BENSON: Yeah, you're a bad guy.

(Laughter.)

MS. BENSON: And everybody knows it as well.

(Laughter.)

MR. BANASIEWICZ: When we prepare a bid response to a solicitation, it takes the effort of several folks with different types of backgrounds -- financial, technical, transmission issues, and they all culminates into an economic pro forma, if not a model that has a price attached to it.

I would think that the independent evaluator -- and my biggest point is that it truly be independent and truly be qualified. I don't see all of those talents residing in one individual. I think the independent evaluator is going to be a team approach that had that combined talent.

MR. TIGER: If I may follow up with Ms. Benson, maybe you could describe a little bit about the difference in the way you would evaluate or how you do an evaluation of self-build versus buy, buy through the PPA, essentially It would seem that there are so many different variables there that it would be hard to make it down to the price, essentially, or the ultimate sort of -- how would you go about trying to make sure that that's fair and reasonable, ultimately, to the consumer, as opposed to, you know, ultimately the shareholder of the utility.

MS. BENSON: Ultimately, really, my job is not the shareholder; that's not my job. My job is the ratepayer. So that -- I mean, in theory, that makes it all crystal clear and simpler, but -- your question?

MR. TIGER: I guess that what I'm trying to get at is, if you're trying to do some type of solicitation, right, and there -- the variables are so different when you consider the self-build versus PPA, you know, especially when you -- unless you're giving, you know, some fixed price to the ratepayer, I mean, most of the self-build, I would imagine, are cost-plus.

There's no way it can be apples-to-apples, in terms of comparison.

MS. BENSON: No.

MR. REDD: So, how do you -- how would you, as an advisor, essentially to the ratepayers, be able to make those apples to apples? If we were to be trying to figure out whether a solicitation was a fair process, you know, to evaluate a solicitation that has, you know, that huge difference, how would you get there?

MS. BENSON: I mean, you know, essentially you're asking the question, you know, all else equal, how do you -- you know, how do you evaluate something that a utility wants to build itself, through something that -- and I agree, it's difficult, and, to some degree, I'm going to probably take -- give a very general answer and take a specific pass, because this is a factor that existed in the solicitation that I was involved with last year.

But it wasn't, frankly, a very serious self-build option, so it really didn't end up showing in any particular way. I think that that's less likely to be the case this time.

I think that, again, it's -- you know, the general terms are understanding how the numbers work, and, you're right, there's a difference between a cost-based and ultimately a rate-based model and something that's coming in through the market.

In this particular instance, there are also issues, again, related with being able to deliver, that are real issues in this particular factor, but I have not, as I sit in this part of the process, I have not yet looked at any of the specific numbers in terms of the self-build, so all I can say now is that it's an issue to which I am alert, and I also know that the Commission staff is extremely -- is very alert to.

And I believe that the company is, too, increasingly. I think that they're -- this is -- this is, I think, virgin territory for them, as well, to do this within the context of a competitive solicitation. So that's as good as I can do here this morning.

MR. TIGER: Mr. Redd, do you have any suggestions as to how to -- how you would be able to show a sort of counterfactual that if you were putting in a bid, or maybe Mr. Banasiewicz as well, that it's even better, you know, in that type of context, or do you have to wait?

I guess, ultimately, it comes back to post factor litigation or that they made the wrong decision, which, eventually, is not necessarily, from societal perspective, the best way of getting there, I guess.

MR. REDD: Let me start out the comment by saying that $135 billion, by some estimates, is a legacy to that utility monopoly model, and the regulators have regulated them. I believe that a company like NRG or USA Power can go head-to-head and be the utility any day, because we're beholding to shareholders and we don't have a regulatory cushion to fall back on.

I think if we leave the evaluation to an after-the-fact evaluation, it's going to cost consumers a lot of money. We've got to realize that, you know, the first thing we need to start with is a well-defined and well-designed market mechanism that has a good congestion management system that is independently operated, where transmission access and congestion are fairly priced and access is equitable.

If you do that, then we can figure out exactly, you know, where the ideal spot to put that plant is, and then in terms of running the plant, we can run it a lot cheaper, we can manage the risk a lot better.

So I think you've got to start out with a well designed market. One of the problems that Betsy has is, she's doing business down in Louisiana, and we have that same problem.

(Laughter.)

MR. REDD: Bitterly, we --

MS. BENSON: It's very nice this time of year.

MR. REDD: I know, but we're sitting on a lot of low-cost generation where we can't get transmission access because that unnamed utility she was talking about wants to dispatch a lot of units out of Merit, and it doesn't make any sense. It's costing the ratepayers millions.

MS. BENSON: Can I just add one thing that maybe is relevant? I mentioned the individual from the market who chose not to comment during the collaborative period, there have, however, been several potential bidders who are, I think, specifically watching this self-build option, because they see themselves as potentially competing against it, who have chosen to comment quite actively on issues related to concerns that they have that are somewhat along the lines that you raised here.

And that's terrific, because they -- because they clearly believe, similar -- I mean, they're clearly people who are -- who need a sink in order to begin construction or if they are in construction, I mean, they would like to have some way to make their units pay.

And they have been quite specific in terms of making it clear to all of us that they're looking very closely at this particular aspect of it, not necessarily for some of the reasons that you raised, but for some others ones that have come up here today.

MR. BANASIEWICZ: Sebastian, one of your comments about the utility bid may not be an apples-to-apples bid and how do you deal with those differences, and from my perspective, I don't know that they have to be different.

A utility typically does things on a cost-plus basis, but I know of no reason that they couldn't do an EPC contract, construction contract on a fixed cost basis, much the way we do, and remove that risk in the same way that the independent power producers have removed that risk.

But if they're not going to do it that way, then at least the differences between the two of them need to be identified and some independent process needs to evaluate what is the potential for that risk to affect the ratepayer.

MR. O'NEILL: If I recall correctly, you said that your project got downgraded because it was unreliable?

MR. BANASIEWICZ: I'm not sure what you're saying.

MR. O'NEILL: I thought you said that it was declared less reliable as part of the --

MR. REDD: Why was it turned down?

MR. BANASIEWICZ: The utility declared themselves to be lower cost and a lower risk.

MR. O'NEILL: "Risk," meaning?

MR. BANASIEWICZ: We are still not sure what that means. To me, that meant -- in previous occupations where I worked for affiliates of utilities and was involved in evaluating bids to determine which of them were legitimate bids and which were not, that meant you have control of a piece of property.

Do you have an air permit? Do you have water permits? What is the reasonable chance that this project will find its way to completion? And if you don't have a site and you don't have an air permit and you don't have water, in my view, that project presents a higher risk than one that does have all of those.

MR. O'NEILL: So it was only a risk to completion, not a risk in operation?

MR. BANASIEWICZ: Yes, that would be an accurate statement.

MR. PERLMAN: Mr. Welch, I have a quick question for you. I actually did participate in your process, and was very impressed with the way it was run by the Commission. My reaction was that because it was run by the Commission, because it was open, because it had a lot of opportunities for people to participate and feel like they could succeed, you got a very competitive response.

And is that -- do you feel that the fact that you have precluded the utilities from participating, pretty much in most of the competitive types of activities in your state, as I think I heard you say earlier, and you have run this RFP process, has helped create a more robust competitive response from the marketplace, and do you think that if you hadn't, there would be less of a response?

MR. WELCH: Absolutely. In fact, one of the critical components of the auction process is the exchange of information between the utility about load and the competitors. We've been told that that process runs more smoothly in Maine than anywhere else, because the utility has no incentive to conceal anything, and the bidders have no reason to believe that the utility is concealing anything for the benefit of their own affiliates.

So, I think the practical exclusion of the affiliates from the process has been a very positive factor. Now, granted, we're a small market, so we had to do more than perhaps other people would have to do to attract players, but typically we're get eight or ten big players coming into our market, and all of them have indicated that they're very happy with the fact that they don't feel as if they have to be looking over their shoulder at possible relationships between the T&D utility and its affiliate.

May I may a brief comment on one of the other questions? It seems to me that if you -- that one of the critical aspects, if you're dealing, for example, with a long-term supply issue as opposed to the sort of things we deal with in our bid, is defining a product which everyone can offer.

And in a situation where you permit self-build by a rate-regulated component of a utility, you've just recreated PURPA. That is the description of PURPA.

You know, you figure out what that self-build is, call it avoided cost, let people bid against, that's PURPA. We had a very unhappy experience with PURPA in Maine, and it actually went to the inability of regulators to figure out what the self-build option cost. We missed by a factor of ten.

That was not good. If you are going to believe that you're going to get the benefits of competitive solicitations, the products that everyone can offer, including affiliates, if you let them into the market, have to be identical, however you define that.

And you cannot have people operating under different regimes in terms of cost recovery or in terms of their ability to go out after money for the ratepayers, without simply recreating something with which we had a rather unhappy experience.

MR. PEDERSON: We have time for one more question before we go to the audience. Dick?

MR. O'NEILL: I was just going to comment. I don't think you were the only one that had that PURPA experience.

MR. PEDERSON: Anything else?

(No response.)

MR. PEDERSON: At this point, I'd open it up to the audience, if the audience has any questions, if anyone has questions for the panel.

Please come forward, identify yourself and who you represent.

MR. TAHLMAN: Thank you. My name is Mark Tahlman. I work for Pacificorp. I'm Managing Director in the regulated function, the commercial end of the business. In fact, it's my responsibility to issue RFPs.

And I'd like to make some comments. I really don't have any questions for the panel, but I do feel a need to make some comments relative to the statements from the gentleman from USA Power.

Certainly it is true that Pacificorp held an RFP process, and it's also true that Navigant Consulting was our independent evaluator that we chose. It's also true that the Utah Public Service Commission thoroughly evaluated the outcome of that RFP in a very detailed, arduous process, and that I will just say that each and every assertion that the gentleman from USA Power made today, was addressed by the Utah Commission, and the Commission Order reflects their opinion of his assertions.

It's all a matter of public record, and, in fact, I have a copy of the Order with me. I'd be happy to make it available to Staff.

The testimony that was filed during the proceeding is also a matter of public record. It addresses each and every assertion that Mr. Banasiewicz has made.

And I do feel a need to, I think, correct one statement. Pacificorp never did agree to purchase their project, in any way, shape or form, and there was no cloning whatsoever that took place.

Now, as long as I have the microphone, I will say, I think, in the context of today's proceeding, just to help you understand the context of Pacificorp's solicitation process, that no affiliates were allowed to bid on our process, so they were barred from participation.

We did, as you know, retain an independent consultant, Navigant Consulting. It was our desire to retain a large nationally recognized firm. It was a blind bid process where the consultant served as the communication vehicle with the bidders, and the process itself was a result of a collaborative process on the front end, that was stipulated to between stakeholders and the Company and the State of Utah.

Having said all of that, I will be here for the balance of the day. Anybody that would like to have me e-mail them the testimony and the Commission decision and the

Order, I'd be happy to do that, and I'd be happy to answer any questions you might have.

MR. O'NEILL: Could you list the differences between the project that won and the USA Power Project?

MR. TAHLMAN: Well, that's where life gets blurry. The project that Mr. Banasiewicz refers to, that was discussed for purchase, was not the same project that they bid into our RFP process.

The projects are very similar, he is correct in that respect, but there were no trade secrets stolen, there was no cloning, and certainly USA Power doesn't have the monopoly on how to design a combined-cycle combustion turbine project, so -- and that, in fact, is included in the testimony and is addressed.

MR. PERLMAN: Could you tell us who Navigant reported to, how they were independent in this process? Did they have a relationship only with Pacificorp? Did they have one with the Utah Commission, and now was that structured and how were they brought to the table?

MR. TAHLMAN: Navigant was retained by us through a solicitation to find an independent evaluator. We went out and did a mini-solicitation and we evaluated three responding firms, and Navigant was chosen by us as what we felt was the best candidate.

And Navigant was retained by us, paid by us, but produces reports that are confidential reports that are made available to the Commission. In Utah, there's effectively three regulating bodies -- the Commission itself, the Division of Public Utilities, and the Committee for Consumer Services, all of which received the reports.

MR. PEDERSON: Thank you for your comments. Do we have any other questions from the audience?

MR. McDONALD: Steve McDonald with AES. The discussion on the CLECO RFP brought something to mind from sitting in yesterday's discussions, that these two topics are fairly closely related.

In the situation that you described with the CLECO RFP, is there any special screens or analysis done with relationship to an offeror's responses that might be made from a marketing affiliate of an entity that controls the transmission with which you are surrounded?

MS. BENSON: Actually, no, but there's nothing to preclude it, and thus far it has not been an issue, but that's an interesting question, and it's conceivably possible, as you know.

MR. PEDERSON: We'll take one more.

MS. BROWN: Carol Brown from California, but not representing the Commission.

But I heard a number of you talk about in the solicitation process, trying to keep it transparent. How do you balance transparency with the need to keep certain information confidential, so that certain things can be protected?

MS. BENSON: Well, I can tell you what is done in Louisiana. There are a number of things that are filed under redaction, but filed with the Commission. The Commission receives the full material. Self-build is an excellent example; the rules in Louisiana require that prior to the bids being received, prior to the bid due date.

The utility will have to file its full self-build analysis that will then be the full self-build analysis, but it will be filed under redaction. They have provided useful information to the market as to what it is they're contemplating doing, and it's quite clear to me from the responses that I have seen from potential bidders, that they understand full well, what that is.

But in terms of the actual numbers and so forth, those are filed under redaction. If that's responsive to your question --

MS. BROWN: It is. Once the bidding -- once a winner is announced, is the redacted information ever made public?

MS. BENSON: My understanding of the process is that they have to go through a certification procedure in Louisiana, and then whatever the rules of the certification would take.

MR. WELCH: In Maine, we actually have -- the information concerning the RFP is obviously public. All the load information is available to all the bidders, so it's not sort of generally publicly available, but require the utility to make it available to bidders.

There are private discussions with each of the bidders with respect to non-price terms, typically security. Those are not shared with other bidders, but the bidders understand that we have a level playing field, and each one can get pretty much what it wants, as long as it satisfies the criteria.

The final contracts are public. The bid -- the losing bids are never made public. The winning bid is made public two weeks after -- or the amount is made -- the amount of the winning bid is made public immediately; the identity of the winning bidder is actually withheld for two weeks so that they can go out in the market and cover their positions.

MS. BROWN: Thank you.

MR. PEDERSON: Commissioner Kelliher and Chairman Wood, do you have any comments or questions?

CHAIRMAN WOOD: Just thinking through the general questions that are raised with the self-build option in our jurisdiction, PPAs, purchasing of rate-based facilities, which we'll talk about this afternoon -- or purchasing of facilities to put into rate base, those truly invoke 2.05 and 2.03 of the Federal Power Act.

When you're dealing with a mix that includes those two things, and then this third thing, which really is a state rate base regulation issue, how does -- and Tom, I'm going to start with you on this, because it is one that we've tried to be very respectful of our overlapping jurisdiction with states on these types of issues, but how do you -- where's a forum to really hear that?

Does it start and stop at the state jurisdiction, since they're regulating the purchaser and ultimate seller? I mean, assume this self-build wins. If one of the others wins, then it's filed here under 2.05 and goes through whatever, but how -- it's awkward, and I'm wondering how does -- in looking for the long-term health of a competitive power market, which is what we do, how do we ensure that there's a proper forum for those issues to get vetted? Or has that forum, in fact, already been had at the state level?

MR. WELCH: I think, as a practical matter, where you have a situation -- I mean, the self-build option is only going to be available where you have a vertically integrated utility that's in some sense, price regulated.

And at that point, I think you sense the benefits and detriments of that decision really flow to the retail ratepayers. As a practical matter, you have to rely on the state commission.

I think the issue of jurisdiction becomes a little bit more tricky when you have -- and where I think the Federal Commission has the critical role, is, to the extent you are going to allow an affiliate to use market-based rates, as opposed to rate-of-return-based rates, then you have to be sure that the process by which they were selected was absolutely fair.

I'm not sure that there's a way to solve, really, from the Federal level, the former problem. If the state commission gets it wrong, that's sort of the state commission's problem, and I just don't see a way to avoid that.

You can certainly make the -- you know, if a non-affiliate wins the bid and it's filed here, you know, you have all the existing review protections, but in a sense, the fact that a non-affiliate wins already gives you some comfort that there's --

CHAIRMAN WOOD: We just say file that quarterly, right now, today. It's only when there's an affiliate winner that that triggers potential hearings and such here.

MR. WELCH: Right, and, as I said, I think that's

-- if what the -- you know, going back to the Edgar case, it seems to me that the weakness of that case is that it -- on the one hand, it describes a process for selecting bidders in a fully competitive market, which is a precondition for having market-based rates, and then it say, oh, by the way, if you don't have a fully competitive market to look at, you can use these other measures.

I seems to me that that's an internal contradiction. Either you have a fully competitive market, in which case, you can run a bid process and actually select a winning bidder, or you don't, in which case, you shouldn't be talking about market-based rates.

CHAIRMAN WOOD: Thank you.

MR. PEDERSON: I want to thank the panelists today and the audience for their participation, and with that, this conference is closed.

(Whereupon, at 12:05 p.m., the technical conference was concluded.)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Market Based Rates for Public Utilities	Docket No. RM04-7-000
Solicitation Processes For Public Utilities	Docket No. PL04-6-000
Acquisition and Disposition of Merchant Generation Assets by Public Utilities	Docket No. PL04-9-000
PPL Sundance Energy, LLC PPL EnergyPlus, LLC Arizona Public Service Company	Docket No. EC05-20-000
Brownsville Power I, L.L.C.	Docket No. ER05-263-000
Caledonia Power I, L.L.C.	Docket No. ER05-264-000
Cinergy Capital and Trading, Inc.	Docket No. ER05-265-000
Entergy Services, Inc.	Docket No. ER03-753-000
Union Light, Heat and Power Company	Docket No. ER04-1248-002
Cinergy Services, Inc.	Docket No. ER05-640-000
PJM Interconnection, LLC	Docket Nos. RT01-2-015, RT01-2-016, and ER03-738-003
ISO New England Inc.	Docket No. ER05-730-000
Montana Alberta Tie Ltd.	Docket No. ER05-764-000
Southern California Edison Company	Docket No. EL05-80-000
Pacific Gas and Electric Company	Docket No. ER05-807-000
Devon Power, LLC, *et al.*	Docket Nos. ER03-563-030 and EL04-102-000

Entergy Services, Inc.	Docket No. EL05-52-000 and EL05-52-001
Consolidated Edison Company of New York Inc.	Docket Nos. EL02-23-003 and EL02-23-006
PJM Interconnection, LLC	Docket Nos. EL03-236-001, EL03-236-002, EL03-236-003, EL03-236-004, EL03-236-005, and EL03-236-006
PJM Interconnection, LLC	Docket Nos. ER04-457-001, ER04- 457-002, and EL05-60-000
Niagara Mohawk Power Corporation	Docket No. ER05-572-000
New York Independent System Operator, Inc.	Docket No. EL05-84-000
Neptune Regional Transmission System, LLC v. PJM Interconnection, LLC	Docket Nos. EL05-48-000 and EL05-48-001
New York Independent System Operator, Inc.	Docket Nos. ER04-1144-002 and ER04-1144-003
ITC Holdings Corp. and International Transmission Company	Docket No. EC05-65-000
Trans-Elect NTD Path 15, LLC	Docket No. ER05-17-001
Southern California Edison Company	Docket No. ER05-410-001
Entergy Services, Inc.	Docket No. ER03-1272-003, ER03-1272-004, ER03-1272-005, ER03-1272-006, EL05-22-000, EL05-22-001, and EL05-22-002

NOTICE OF FERC COMMISSIONER AND FERC STAFF PARTICIPATION IN NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS RESOURCE PLANNING AND PROCUREMENT FORUM

(April 29, 2005)

The Federal Energy Regulatory Commission (FERC) hereby gives notice that FERC Commissioners and FERC staff may participate in the National Association of Regulatory Utility Commissioners (NARUC) Resource Planning and Procurement Forum noted below. The forum is expected to include discussion of issues relating to transmission infrastructure and to Commission and state coordination with respect to public utility power sales transactions and public utility dispositions of Commission-jurisdictional facilities. That discussion may address matters at issue in the above-captioned proceedings. The participation of FERC Commissioners and FERC staff is part of the Commission's ongoing outreach efforts.

NARUC Resource Planning and Procurement Forum –

May 16, 2005, 9:30 am – 4:30 pm (CST)

Hyatt Regency O'Hare
9300 W. Bryn Mawr Avenue
Rosemont, IL 60018

847-696-1234

The NARUC Resource Planning and Procurement Forum is open to the public.

For more information, contact Sarah McKinley, Office of External Affairs, Federal Energy Regulatory Commission at (202) 502-8368 or sarah.mckinley@ferc.gov.

Linda Mitry
Deputy Secretary

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Acquisition and Disposition of Merchant Generation Assets by Public Utilities	)))	Docket No. PL04-9-000
Solicitation Processes for Public Utilities	)))	Docket No. PL04-6-000

COMMENTS OF CINERGY SERVICES, INC.

Pursuant to the Commission's Notice Inviting Comments in each of the above-captioned dockets, Cinergy Services, Inc. ("Cinergy Services"), on behalf of its franchised public utility affiliates, The Cincinnati Gas & Electric Company ("CG&E"), PSI Energy, Inc. ("PSI") and The Union Light, Heat and Power Company ("ULH&P") (collectively "Cinergy"), submits comments on the Commission's review of acquisitions and dispositions by public utilities as well as solicitations by public utilities. While Cinergy shares the Commission's goal of ensuring a fair, competitive wholesale marketplace, Cinergy is concerned that the Commission's incursion into these areas will lead to a "federalization" of utility resource adequacy decisions. State regulatory commissions can and do govern the matters at issue in these dockets, and intervention by the Commission will create an unnecessary and potentially conflicting overlap with existing state processes. Before settling on a policy, Cinergy urges the Commission to consider state and regional differences, as well as the important role that state regulatory commissions already play in reviewing utility procurement to promote efficient utilization of resources for retail ratepayers. Specifically, Cinergy suggests that the Commission refrain from implementing a one-size-fits-all approach to utility acquisitions and procurement and adopt the following principles:

? When a state regulatory commission is empowered to and does oversee a utility's acquisition planning, the Commission should defer to the state commission and decline to review the transaction.

? When state law imposes integrated resource planning obligations that are overseen by a state regulatory commission, and the state commission concludes that the utility has achieved a least-cost method of ensuring resource adequacy, the Commission should defer to the state commission finding.

1. Background

(a) Interest of Cinergy Services, Inc.

Cinergy Services is a Delaware corporation and a wholly-owned direct subsidiary of Cinergy Corp., a registered holding company under the Public Utility Holding Company Act of 1935. Cinergy Services provides administrative, operational and other support services to Cinergy Corp.'s regulated public utility subsidiaries and non-utility subsidiaries. CG&E, an Ohio corporation, is a combination electric and gas public utility. ULH&P, a Kentucky corporation and electric utility, is a wholly-owned subsidiary of CG&E. Together, CG&E and ULH&P are engaged in the production, transmission, distribution, and sale of electric energy in the southwestern portion of Ohio and adjacent areas in Kentucky and Indiana. PSI, an Indiana corporation and wholly-owned direct public utility subsidiary of Cinergy Corp., is engaged in the production, transmission, distribution and sale of electric energy in north central, central and southern Indiana. Cinergy's regulated companies own roughly 12,056 MW of generating capacity in Ohio, Indiana, and Kentucky. Cinergy's merchant affiliates own 894 MW of peaking capacity in Tennessee and Mississippi. Together, Cinergy's regulated utilities are responsible for meeting 11,495 MW of peak load subject to the jurisdiction of the Ohio, Indiana and Kentucky state commissions.

(b) These Proceedings

On May 11, 2004, the Commission announced that it would convene a technical conference in Docket No. PL04-9-000 to discuss "issues associated with public utilities' acquisition and disposition of merchant generation assets, including the implications for the competitive landscape in general and for a region's wholesale competition in particular." This notice followed several proceedings in which the Commission either expressed concern about or set for hearing the effect of an affiliate acquisition on wholesale competition. *See Cinergy Services, Inc.*, 102 FERC ¶ 61,128 (2003); *Ameren Energy Generating Co.*, 103 FERC ¶ 61,128 (2003). That same day, the Commission announced that it would convene a second technical conference in Docket No. PL04-6-000 on solicitation processes to "address proposals for best practice competitive solicitation methods or principles that would be used to ensure that transactions filed with the Commission for approval are the result of an open and fair process." This conference followed a series of Commission orders affirming the so-called *Edgar* standards in cases involving power purchases by utilities from their affiliates. *Southern Power Co.*, 104 FERC ¶ 61,041 (2003); *Entergy Services, Inc.*, 103 FERC ¶ 61,256 (2003); *Southern California Edison Co.*, 106 FERC ¶ 61,183 (2004). After holding the technical conferences on June 10, the Commission invited comments from interested parties. Notice Inviting Comments, Docket Nos. PL04-9-000 & PL04-6-000 (June 10, 2004).

2. Comments

Cinergy appreciates this opportunity to comment on an area of Commission policy that directly affects Cinergy's operations. Indeed, an acquisition by a Cinergy subsidiary of affiliate-owned generation assets led to the order in *Cinergy Services, Inc.*, 102 FERC ¶ 61,128 (2003) that first expressed the Commission's concern regarding "the possible implications of affiliate transactions of the type proposed here for the competitive process in general and for the region's wholesale competition." *Id.* at P 23 (enunciating the "safety net" theory). Cinergy has combined its comments in the above-captioned dockets because it shares a common jurisdictional and regulatory overlap concern about the Commission's inquiries in these areas. In many cases, state regulatory commissions are empowered to and do regulate precisely the matters for which the Commission is considering policy in these dockets. If the Commission does not tread lightly, it will undermine the efficient procurement of resources to serve utility native load obligations, and overstep its jurisdictional authority in the process. These concerns are discussed in more detail below.

(a) Utility Acquisition and Disposition of Generation Assets

At the technical conference, the Commission heard opinions from various sectors of the industry regarding the relative benefits and detriments of utility acquisitions of affiliate power producers. From those who disfavor such transactions, the Commission heard calls for the Commission to tighten its Section 203 review of utility acquisitions to make them difficult, if not impossible, to consummate. *See, e.g.*, tr. at 35-41. Before considering the merits of these proposals, the Commission should examine whether it has sufficient jurisdiction to impose a one-size-fits-all approach to utility acquisitions. In most cases, state commissions have broad authority to examine a utility's plan for meeting its native load obligation, whether that plan involves building an asset, purchasing one, contracting for power, implementing demand-side management programs, or a combination of these methods. Where a state commission has concluded that a utility's decision is in the best interest of ratepayers, the Commission should give the state commission's finding deference.

(i) States have primary responsibility for protecting retail ratepayers and ensuring generation adequacy.

It is beyond dispute that state commissions have exclusive jurisdiction over retail ratemaking. "[T]he FPA does not give the Commission jurisdiction over sales of electric energy at retail." Order No. 888, FERC Stats. & Regs., Regs. Preambles, Jan. 1991-June 1996 ¶ 31,036, at 31,969 (1996); *see New York v. FERC*, 535 U.S. 1, 22 (2002). State commissions scrutinize utility acquisitions of generation assets, power, and non-power goods and services to ensure that uneconomic costs are not borne by retail ratepayers. In addition, state commissions examine utility resource portfolios for adequacy of supply. The Commission has recognized that these processes are within the province of the states. For example, in Order No. 888-A, the Commission explained that costs adjudged prudent by a state commission "cannot be relitigated" by the Commission. Order No. 888-A, 78 FERC ¶ 61,220, at 30,446 (1997); *see also* White Paper on Wholesale Power Market Platform at 5, 11 (issued April 28, 2003) (noting that it is not the Commission's prerogative to set levels of resource adequacy and that "the choice on the approach [to ensuring resource adequacy] is made by the states").

To be sure, state commissions possess varying levels of jurisdiction over utility acquisitions. While some have authority to approve or reject asset purchases, others are limited to jurisdiction to include or not include the costs of an asset in rate base. Indeed, the market structures in the states differ, and some market participants are regulated by other agencies with jurisdiction over procurement, such as the Rural Utility Service. Retail competition is present in some states, though implementation approaches differ. In short, no two markets are the same, and attempts to standardize regulatory review of utility acquisitions could result in a state commission concluding that an acquisition is necessary to ensure resource adequacy for native load and the FERC concluding that it is not in the public interest. A short review of just one state's statutory guidelines will demonstrate that this not only is possible, but likely if the Commission attempts to "federalize" utility acquisitions of generation assets.

In Indiana, for example, an electric utility cannot purchase or lease any facility for the generation of electricity to be directly or indirectly used to furnish public utility service without first obtaining a certificate from the Indiana Utility Regulatory Commission ("IURC"). Ind. Code § 8-1-8.5-2. To determine if the public convenience and necessity requires a new facility, the IURC is required to examine all of the utility's other arrangements, including its power purchases and other methods of providing service. *Id.* § 8-1-8.5-4. The IURC conducts its review in part by examining the utility's mandatory integrated resource plan ("IRP"), which must be filed bi-annually.[1] In Indiana, an IRP must determine the optimal combination of resources that can be used reliably and cost-effectively to meet retail customers' electricity requirements for the next twenty years. IAC § 4-7-1(s); *id.* § 4-7-4. The IRP must demonstrate the utility's consideration of numerous listed supply and demand side resources, including the identification and description of the resources considered. *Id.* § 4-7-6(b) & (c). The utility must fully explain and support its screening process and its decision to reject or accept a resource alternative. *Id.* § 4-7-7(a). The utility also must demonstrate that "the most economical

[1] Kentucky likewise requires an IRP, which must include "the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost." 807 KAR 5:058(8).

source of supply-side resources has been included in the integrated resource plan." *Id.* §4-7-8(6).

The Commission recognized the validity and primacy of these regulations in the *Cinergy* order. There, the Commission noted that the IURC had approved the proposed acquisition by PSI of the two generating units. 102 FERC at P24. The Commission further noted that the IURC's approval was motivated by "PSI's need to acquire secure supplies." *Id.* Thus, the Commission rightly deferred to the state's resolution of PSI's compliance with its resource planning and acquisition requirements. It should not depart from that course when the state is authorized to and does exercise such a significant level of oversight over asset acquisitions.

Duplicative federal and state review of generation acquisitions or power purchases (or conflicting decisions by different jurisdictions) will lead inevitably to reduced efficiency. At the June 10th technical conferences, representatives of the investment community made plain that Commission intervention into utility acquisitions of generation assets was undesirable from the vantage point of the financial markets. A representative from Charles Schwab opposed a federal mandate, noting that "if the procurement by a load-serving entity is reviewed by the state, I am not sure how those two things will mesh without conflict." Tr. at 67. A Citigroup representative predicted that restricting utilities' ability to purchase generation assets will result in the construction of excess capacity, which "will further impair the value of existing distressed power plants." *Id.* at 23-24. This in turn will increase the industry's cost of capital and reduce, rather than enlarge, competition – and raise, rather than lower, market prices.

(ii) The Commission Lacks Jurisdiction to Review Most Utility Acquisitions

In the Federal Power Act, Congress chose to restrict the Commission's jurisdiction to the regulation of transmission of energy in interstate commerce and the sale of energy at wholesale in interstate commerce. 16 U.S.C. § 824(a). The statute is plain that the Commission does not have jurisdiction over "facilities used for the generation of electric energy." *Id.* § 824(b)(1). Federal regulation is to "extend only to those matters which are not subject to jurisdiction by the States." *Id.* § 824(a). For this reason, the Commission has no jurisdiction over a utility's decision to construct a generating asset or to execute contracts for energy conservation and load management programs. *See, e.g., New England Power Pool,* 107 FERC ¶61,208 at P13 (2004); *Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States*, 94 FERC ¶ 61,272, at 61,972 (noting that federal policy encouraging demand reduction must be accomplished consistent with state jurisdiction over retail sales). These two elements of a utility's resource planning thus are wholly outside the Commission's control.

The Commission's sole basis for asserting jurisdiction over the third element of generation resource planning -- generation acquisitions and divestitures -- is its concurrent authority to review the sale or lease of jurisdictional facilities under Section 203. *Id.* § 824b(a). Most often, these transactions are submitted to the Commission because a jurisdictional transmission asset is being transferred along with the generation asset. Indeed, the Commission has recognized that it lacks jurisdiction over a generation transfer that does not include transmission assets. *See Duke Energy Moss Landing LLC*, 83 FERC ¶ 61,317, at 62,295 (1998). Nonetheless, in evaluating a proposed transfer on the basis of jurisdiction over transmission facilities, the Commission has examined not just impacts on vertical market power related to those transmission facilities, but also impacts on horizontal market power that may result from combinations of generating assets. *See, e.g., Oklahoma Gas & Elec. Co.*, 105 FERC ¶ 61,297 (2003); *Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,111 (2000). Though the Commission's jurisdiction to review such horizontal market power impacts has not yet been tested in the courts, the Commission lacks authority to indirectly regulate what it is without jurisdiction to regulate directly. *See Altamont Gas Transmission Co.*, 92 F.3d 1239, at 1248 (D.C. Cir. 1996) (overruling the Commission's attempt to "do indirectly what it could not do directly, that is, intercede in a matter that the Congress reserved to the State"). Such a tenuous basis for jurisdiction should not be used to impose an onerous federal regulation system, particularly when state statutory frameworks are enforced by state regulatory commissions.

(iii) "Safety Net" Concerns Are Unfounded

The primary asserted motivation behind the Commission's inquiry into acquisitions and dispositions between utilities and their affiliates is the so-called "safety net" theory. According to intervenors in the proceeding involving Cinergy's acquisition of a pair of generation stations from affiliates, transfer of generation assets from a merchant affiliate to a utility allows the affiliated merchant to avoid the competitive risks assumed by other generators because the utility effectively is a backstop. EPSA Comments, Docket No. EC02-113-000 at 12-13 (October 7, 2002). In its order approving those acquisitions, the Commission noted in *dicta* that the "ability of a franchised utility to assume its affiliated merchant's generation when market demand declines gives the affiliated merchant a 'safety net' that merchant generators not affiliated with a franchised utility lack." *Cinergy*, 102 FERC at P23. The order observed that this "may affect the incentive of new merchant generators to invest in new facilities and, given the likelihood of recovery of capital investment through rate base treatment, gives the franchised utility a competitive advantage in making market-based sales of the plants' generation that is not available to merchant generators unaffiliated with franchised utilities." *Id.* Based on these assumptions, the safety net "could be a barrier to entry." *Id.* The Commission repeated these concerns in an order setting a proposed affiliate transaction involving Ameren for hearing. *Ameren Energy Generating Co.*, 103 FERC ¶ 61,128 at P37 (2003).

The safety net theory is founded on a series of faulty assumptions, most notably that state regulatory commissions are powerless to determine whether a utility should acquire an uneconomic asset. In the words of Commission Staff economist Dr. Linda Boner, "the 'safety net' hypothesis as a theory of competition is theoretically unsound and, empirically, has not been demonstrated to exist." Exh. No. S-12 at 4:12-15 (filed in Docket No. EC03-53-000 on Sept. 16, 2003). The safety net hypothesis "fails because it requires that widespread, systemic regulatory failure occur. This assumption is unrealistic and unreasonable." *Id.* at 20:1-2. Moreover, the safety net theory depends on the assumption that capital markets are adversely affected by the alleged advantage conferred upon affiliated merchant generators. Again, Commission economist Dr. Boner disputed that unaffiliated generators are likely to be excluded from U.S. capital markets even if the regulatory lapses assumed by the Commission actually take place. *Id.* at 21:1-11. Finally, for the safety net to affect competition, any differences in the cost of capital favoring affiliate merchant generators would have to result in higher wholesale prices.

This could occur if unaffiliated generators were eliminated from the market or if their production costs increased to a level that affected the market price. Dr. Boner testified that neither of these outcomes is plausible. *Id.* at 24:1-8. She therefore concluded that the safety net hypothesis fails as a theory of potential market failure. *Id.*

In the *Ameren* proceeding at Docket No. EC03-53-000, the Commission also received testimony from Lehman Brothers Managing Director and former commissioner of the U.S. Nuclear Regulatory Commission James Asselstine, who explained that there are numerous factors that may lead to differences in the cost of debt capital between affiliated and non-affiliated generation. In his experience, "the notion of the 'option to retreat' is, simply put, not a consideration" in the investment decisions of the investors he has worked with during his career. Ex. No. AS-59 at 18:6-10 (filed in Docket No. EC03-53-000 on Oct. 16, 2003)

Presiding Judge Cintron credited this testimony in her initial decision approving the transactions proposed by Ameren. She found that the evidence demonstrated that

> Because of the overall size of the market in which new, unaffiliated generators could sell their output in the national market is so large, the potential competitive concern about a 'safety net' deterring such new, unaffiliated generation and thus raising a barrier to entry is unfounded. Thus, even assuming the investment community in a state where the 'safety net' prevails perceives a higher credit risk for unaffiliated generators (thus subjecting those entities to higher costs of capital), a 'safety net' would not create a barrier to entry for those entities in the national market.

106 FERC ¶ 63,011 at n.150 (2004). Judge Cintron concluded that, as in *Cinergy*, the state commission's decision to support the proposed transfer should be given substantial weight by the Commission. *Id.* at PP 49-51.

No evidence was submitted in *Cinergy*, *Ameren*, or at the technical conference in this proceeding to demonstrate that a safety net exists or that it has any effect on wholesale competition. Cinergy therefore urges the Commission to abandon its "safety net" hypothesis.

(b) Utility Solicitations

Cinergy's comments on the Commission's inquiry into utility solicitations of power mirror those provided with respect to utility acquisitions. These comments are prompted by the suggestions offered at the technical conference for the Commission to adopt generic solicitation processes with mandatory minimum standards. Again, Cinergy does not believe that a one-size-fits-all approach is authorized by the Federal Power Act, nor does Cinergy believe such an approach is efficient from a regulatory or financial perspective. As discussed above, many states have IRP requirements that confer sufficient jurisdiction on state commissions to oversee a utility's procurement process. When a state commission has concluded that the utility has achieved a least-cost method of acquiring adequate supply to serve retail ratepayers, the Commission should abstain from ruling on the question. This is consistent with the comments of Tom Welch, the chairman of the Maine Public Utilities Commission, at the technical conference on solicitations. In response to a question from Chairman Wood, Chairman Welch remarked that when price-regulated vertically integrated utilities are deciding whether to procure power or self-build, "the benefits and detriments of that decision really flow to the retail ratepayers. As a practical matter, you have to rely on the state commission." Tr. at 125-26.

In a related vein, Cinergy is concerned with any effort to impose an inflexible regulatory overlay on procurement decisions that are fundamental to utilities' operations, and which may affect their economic viability for decades to come. Major procurement decisions such as purchasing or building a generation facility, or entering into a long-term power purchase agreement, simply cannot be reduced to mathematical formulae. Such decisions inevitably are grounded in part in each company's *business judgment* about how to best meet its legal obligation to provide adequate and reliable electric utility service – including its expectations about future regulatory and market trends, predictions concerning load growth and economic conditions, the comparative reliability and risk associated with various resource options, and innumerable other factors. This Commission has sought for years, with Cinergy's strong support, to promote competitive electric and gas markets. Commission action that constrains a utility's ability to make procurement decisions does not promote competition and would lead ineluctably to less efficient and effective outcomes for all industry participants, including customers.

Cinergy suggests that the Commission modify its analysis under *Boston Edison Re: Edgar Electric Energy Co.*, 55 FERC ¶ 61,382 (1991) ("*Edgar*") to preserve the role of the states. Under the Commission's existing precedent, market-based rates are appropriate, and affiliate restrictions are unnecessary, when customers cannot be harmed by affiliate transactions. *See, e.g., Enron Energy Servs. Power, Inc.*, 81 FERC ¶ 61,267 at 62,318 (1997); *GS Elec. Generating Coop.*, 81 FERC ¶ 61,042 (1997); *Alcoa Inc.*, 88 FERC ¶ 61,045 at 61,119 (1999); *Illinova Power Marketing, Inc.*, 88 FERC ¶ 61,189 (1999); *Power Provider LLC*, 95 FERC ¶ 61,434 (2001); *Central Illinois Generation, Inc.*, 101 FERC ¶ 61,082 (2002); *see also Connecticut Light & Power Co.*, 90 FERC ¶ 61,195 (2000) (authorizing sales between utility and affiliate when no captive ratepayers could be affected by such sales); *PP&L Resources, Inc.*, 90 FERC ¶ 61,203 (2000) (same). For example, if retail competition is present in the state, the Commission has concluded that there is no potential for harm to captive customers, and has authorized an affiliate sale. *AmerGen Vermont, LLC*, 91 FERC ¶ 61,082 at 61,291 (2000); *AmerGen Energy Co.*, 90 FERC ¶ 61,080 at 61,282 (2000). The same analysis should be utilized in applying the *Edgar* standards in jurisdictions where a state commission has reviewed a utility's processes for acquiring purchased power and has concluded that they will result in prudent, least-cost alternatives. This is analogous to a state commission finding that customers will not be harmed.

3. Conclusion

As an active wholesale market participant, Cinergy welcomes the Commission's efforts to ensure a fair, open wholesale marketplace. But when a state commission has sufficient jurisdiction to act and has done so, the Commission should not overlay duplicative and potentially conflicting federal regulation on activities that are primarily conducted to serve retail ratepayers.

Respectfully submitted,

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Market-Based Rates For Public Utilities	Docket No. RM04-7-000
Solicitation Processes for Public Utilities	Docket No. PL04-6-000
Acquisition and Disposition of Merchant Generation Assets by Public Utilities	Docket No. PL04-9-000

POST TECHNICAL CONFERENCE COMMENTS OF EDISON ELECTRIC INSTITUTE AND ALLIANCE OF ENERGY SUPPLIERS

The Edison Electric Institute and our affiliated Alliance of Energy Suppliers (together, "EEI") are submitting these Comments in response to (a) the "Initiation of Rulemaking Proceeding On Market-Based Rates and Notice of Technical Conference" that the Federal Energy Regulatory Commission ("FERC" or the "Commission") issued on April 14, 2004; (b) the "Supplemental Notice Agenda For Technical Conference" that the Commission issued on June 3, 2004; and (c) the Technical Conference itself, which was held on June 9, 2004 in the above-referenced dockets. At the end of the Conference, the Commission invited interested parties to file comments on the issues raised at the Technical Conference by June 30, 2004.

In addition to filing its comments on the Technical Conference, EEI has attached as Appendix A the prepared testimony of Paul J. Bonavia, President, Commercial Enterprises for Xcel Energy, presented at the June 9th Technical Conference on behalf of EEI and as Appendix B the prepared testimony of Edward Comer, Vice President and General Counsel for the Edison Electric Institute on behalf of EEI in the June 10th Technical Conference on Solicitation Processes for Public Utilities (PL04-6). EEI has also filed extensive comments in a Petition For Rehearing addressing the market power screens adopted by the Commission on April 14, 2004 which we believe are directly relevant to this proceeding.

The Edison Electric Institute is the association of the nation's investor-owned electric utilities, most of which either directly, through affiliate power producers, or both, own electric generation facilities that may provide electricity to wholesale markets subject to Commission regulation. The Alliance of Energy Suppliers represents investor-owned electric energy suppliers and marketers nationwide, including affiliate and independent power producers who also own generation facilities that provide electricity to wholesale markets regulated by the Commission. Together, our members participate in all segments of the electric industry – generation, wholesale trading and marketing, transmission, distribution, and retail electric service. They provide the vast majority of the nation's electric energy, including electricity sold at wholesale subject to Commission's Market-Based Ratemaking ("MBR") authorization. All will be significantly affected by any new analytical methods adopted by the Commission for assessing markets and market power as a result of this proceeding. Therefore, EEI has a direct interest in this proceeding and to ensure that any analytical methods for assessing markets and market power that the Commission may adopt address our concerns and result in electric market-based rates that are just and reasonable under the Federal Power Act.

EEI supports the development of a robust, competitive wholesale market. We applaud the Commission for its commitment to these developing markets. We also believe that power purchase and sale transactions must be conducted in a fair manner, without bias or self-dealing to favor affiliates. EEI opposes unnecessarily jeopardizing the existing market-based rate authority of utilities. Any new regulations should preserve a wide range of business models and not constrain EEI members' corporate flexibility to serve customers efficiently.

We urge the Commission to achieve these goals by working cooperatively with the states. This is essential because the states have jurisdiction over many critical matters affecting electric markets. We believe that the recent California Independent System Operator decision issued by the United States Court of Appeals for the District of Columbia Circuit ("CA ISO Decision")[1] reinforces the need for close cooperation between FERC and the states. That decision clearly limits the Commission's authority to prescribe corporate structure as a "practice" affecting rates and holds that the Commission's statutory authority:

> "to assess the justness and reasonableness of practices affecting rates of electric utilities is limited to those methods or ways of doing things on the part of the utility that directly affect the rate or are closely related to the rate, not all those remote things beyond the rate structure that might in some sense indirectly or ultimately do so." Slip Opinion at 14-15.

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[1] California Independent System Operator Corp. v. FERC, ___ F.3d ___, 2004 WL 1379859 (D.C. Cir. June 22, 2004).

This decision makes clear that many of the approaches, which have been advocated in these proceedings, are simply not within this Commission's authority to impose.

As noted in the Commission's April 14th Order, the purpose of the Market Based Rate proceeding is to determine the adequacy of the current four-prong market power analysis and whether and how it should be modified to assure that electric market-based rates are just and reasonable under the Federal Power Act. At the June 9th Technical Conference, numerous witnesses addressed different aspects of the four-prong market power test, including offering proposals as to how the four-prong test should be modified as well as to respond to the issues raised by the Commission in the June 3rd agenda notice for the Technical Conference. Based upon a review of the proceedings to date, from the perspective of EEI, several overarching issues relating to vertical market power, State/FERC coordination and market power screens have emerged. These issues, which we believe will shape the rulemaking process on a prospective basis, as well as the related Solicitation and Acquisition proceedings, are discussed below.

I. Vertical Market Power

A. Existing FERC Regulations Offer Adequate Safeguards Against The Exercise Of Vertical Market Power By A Vertically Integrated Utility Operating In A Non-RTO Environment.

From EEI's perspective, the relevant issue before the Commission is whether, realistically, a vertically integrated utility operating in a non-RTO environment within FERC's existing regulatory protections exercises vertical market power in an anti-competitive manner.

Since 1996, the Commission has aggressively developed a regulatory framework designed to ensure that a vertically integrated utility cannot exercise vertical market power. Order No. 888, issued on April 24, 1996, requires that all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce must have on file an Open Access Transmission Tariff that makes transmission service available to all eligible entities on a non-discriminatory basis. As stated by the Commission at page 1 of that order, the Open Access Transmission rules were designed "...to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the nation's electricity consumers."

In Order Nos. 2004 (November 25, 2003) and 2004A (April 16, 2004), Standards of Conduct for Transmission Providers, the Commission delineated standards of conduct designed to govern the relationship between the Transmission Provider and its Energy Affiliates. These orders were designed to constrain the ability of the Transmission Provider to favor its affiliated businesses.

Order Nos. 2003 (July 24, 2003) and 2003A (March 5, 2004) require public utilities that own, control, or operate facilities for transmitting electric energy in interstate commerce to file revised Open Access Transmission Tariffs that contain standard generator interconnection rules and procedures. The intent of these orders is to further constrain the ability of the integrated utility to exercise or abuse vertical market power by limiting the access of competitive generation suppliers to the transmission system. Finally, the Commission's Office of Market Oversight and Investigation has developed a field audit program designed to check on transmission operators' compliance with these rules and procedures.

While various parties have made vague allegations that some utilities exercise vertical market power, the simple fact is that the Commission has rarely, if ever, made any confirmed finding of violations of the open access rules, let alone such an exercise of market power. This is particularly important since there are many legitimate reasons why parties may not be able to obtain the level of transmission access that they would hope for. We all know that the transmission system was not originally designed to market competitive power supplies, transmission capacity is scarce in many places, native load priorities still exist, and there have been fundamental disagreements over the responsibility to pay for interconnection costs.

Under these circumstances, and, given the time and effort that this Commission has taken since the issuance of Order No. 888 in 1996 to develop both structural and behavioral rules and regulations designed to constrain the ability of a vertically integrated utility to exercise vertical market power, it would be wrong at this point to jump to the conclusion that all vertically integrated utilities operating outside of an RTO can or do exercise vertical market power under the existing FERC regulatory framework and should therefore be denied MBR authorization. More appropriately, any entity asserting that a transmission provider's actions are not in compliance with these orders and result in the abuse of market power should pursue a remedy through the Commission's complaint procedure, where it would bear the burden of proving that the transmission provider has exercised vertical market power.

B. There Should Be No Requirement That Every Vertically Integrated Utility Operating Outside Of An RTO Turn Over Administration Of The OATT To An Independent Third Party As A Precondition For MBR Authorization.

The basic premise behind proposals requiring that a vertically integrated utility operating outside of an RTO turn over administration of the OATT to an independent third party as a precondition for MBR authorization is the assertion that the existing Commission regulatory protections designed to limit the exercise of vertical market power discussed above are ineffective and that the transmission provider will either discriminate against competitive suppliers or in favor of affiliates in terms of granting access to the transmission system.

To the extent that an applicant for transmission services believes that they have been unduly discriminated against by the transmission provider, the appropriate remedy and venue again is to bring a complaint action before the Commission. If, after an appropriate proceeding, the Commission finds undue discrimination, the transmission provider should be free to propose appropriate mitigation measures to prevent any reoccurrence in the future. Imposition by FERC of any specific *structural* remedy as a means of avoiding vertical market power (e.g. turning over administration of the OATT to an independent third party) may conflict with existing law as indicated by the <u>CA ISO Decision</u>. EEI believes that the Commission must allow for the transmission provider to propose and implement appropriate mitigation measures and to demonstrate that it no longer exercises vertical market power. FERC should not impose structural remedies.

C. Allegations Of So-Called "Market Foreclosure" And "Monopsony Power" Are Ill-founded Attempts to Disguise In An Antitrust Context Disagreements With State Retail Regulatory Policies. Compliance with State Regulatory Policies Provide No Basis To Conclude Market Power is Present.

At the Technical Conference, various witnesses discussed so-called "monopsony power" and "market foreclosure" issues. The essence of the complaint is that a vertically integrated, regulated utility has the ability to foreclose access by alternative suppliers to its end-use customers, provide favorable treatment to affiliates and therein negatively impact the growth of the competitive wholesale market. This was incorrectly characterized at the Technical Conference as an abuse of "monopsony power".

In particular, David DeRamus argued that there is a new type of monopsony power abuse that stems from a state regulated utility's use of its own generation to serve native load retail customers rather than purchasing energy from the wholesale market to serve its retail customers. EEI notes that panelist Diana Moss (Transcript at 213) was non-committal on this new interpretation. Panelist James Bushnell (Transcript at 214) indicated that this argument was inconsistent with the classic monopsony power argument where a monopsonist buys less to drive the price down, which does not apply because utilities cannot control their customers demand for electricity. We agree, a utility has an obligation to serve and meet the needs of its customers. It cannot curtail load to drive prices down. Thus, it cannot exercise monopsony power in its traditional sense.

This monopsony power argument and the broader allegation of "market foreclosure" are nothing more than pejorative terms using vague antitrust-like jargon to describe a situation where a vertically integrated utility is operating in a state which does not allow for retail competition. At their heart, the complaints raised are either that the state is not exercising its regulatory authority over retail rates properly or that the state erred in failing to adopt retail competition. In either case, these disputes should properly be resolved by the states, not this Commission. This Commission has no authority to regulate retail rates. Furthermore, the Supreme Court, in many cases enunciating the "state action doctrine" under the antitrust laws, has made clear that this doctrine immunizes from federal scrutiny conduct which is consistent with a clearly articulated state policy to displace competition and which is actively supervised by the state.

The market foreclosure argument ignores the fact that state commissions regulate the recovery of power costs that are incurred by the vertically integrated utility thereby eliminating the potential for the exercise of vertical market power through market foreclosure.

Where a state decides not to allow for retail competition and its commission is actively supervising the provision of retail service and the regulation of retail rates, including the purchased power cost component of such rates, this Commission would have no authority to act, let alone any basis to conclude that the vertically integrated utility subject to such regulation is exercising market power in its purchasing decisions. The Commission regulates rates for sales at wholesale, but does not have the authority to regulate purchasers of electricity, let alone the procedures they use to make their purchase decisions.

While some advocate that this Commission should deny market based rate authority to utilities subject to such state regulation, such a policy is totally counter-productive. The end-result would be that such utilities would continue to sell at cost-based rates and therein inhibit the growth of the competitive wholesale energy market.

II. Regional Issues

EEI encourages the Commission to reinstate the exemption for sales into a Commission-approved RTO/ISO from the new horizontal market power screens. Currently, the RTO/ISOs diligently perform analysis of the markets to identify and remedy any abuses or potential abuse of market power. In addition, the Commission has instituted an on-going review of RTO/ISO market monitoring and mitigation plans, receives periodic reports from market monitors, and clarified its policy allowing for direct dialogue with Commission-approved market monitors. Any concerns the Commission may have could be addressed through these on-going efforts.

If the Commission insists on continuing down a path that constantly changes the regulatory landscape for RTO participants and prospective participants, the end result would be to impede the further development of RTOs/ISOs throughout the country. However, if the RTO exemption is eliminated, at a minimum, the RTO or ISO should be used to constitute the geographic market to which the new screens will apply for applicants located in RTO/ISOs with sufficient market structure.

In response to the Commission's question on regional approaches, EEI believes that the Commission should allow utilities to voluntarily file in groups or even on a regional basis for market-based rate authority, if they decide this appropriate. Since a filing for market based rate authority is a Section 205 filing, it must be initiated by the utility seeking such authority, or its designated representative. This could be very helpful, particularly, if the Commission refuses to reinstate the RTO/ISO exemption for generation market power. However, allowing neighboring utilities to make joint filings on a voluntary basis should not foreclose the rights of applicants to file individual market-based rate applications.

Additionally, in regions of the country where non-jurisdictional entities make up a substantial portion of the market's participants, we recommend that the Commission convene a technical conference to explore the impact such a dynamic has on the market and any attempts by the Commission to accurately assess these markets. Because the Commission's oversight of market-based rate authority extends to only a subset of wholesale market sellers, i.e. jurisdictional utilities, policy changes in this area could very well lead to unintended consequences and market distortions. Any revaluation of the Commission's four-prong approach to evaluating and granting market-based rate authority should include an assessment of the implications of the mix of jurisdictional and non-jurisdictional market participants within the same market.

III. State Regulatory Commission/FERC Coordination

EEI is pleased that Chairman Wood, in his remarks at the Technical Conference, agreed with EEI and acknowledged the usefulness of holding joint workshops with state regulators to discuss common issues. We believe this is particularly important in regard to affiliate transactions, competitive bidding, resource adequacy and potential mitigation measures that might be required by the Commission prior to granting an applicant MBR authorization.

For example, there is considerable overlap between the issues being considered by the Commission in the PL04-6 Solicitation Processes For Public Utilities proceeding and the proposed competitive solicitation mitigation measure advocated by the proponents of the market foreclosure issue. Most of the competitive solicitations that take place at the state level are intended to serve native load purposes and are conducted with considerable oversight and direction from a state commission (e.g., the resource mix procured, selection criteria used, resource-related risk management strategies used, financial qualifications/credit standards for bidders.) In addition, matters involving transmission planning, siting and resource adequacy processes also come under state jurisdiction.

Finally, there has been extensive discussion within this and other Commission proceedings about transactions between affiliates. The states have substantial authority and actively address the issues relating to the sales of power to utilities from their affiliates. In addition, Section 32 (k) of PUHCA prohibits sales of electricity from an exempt wholesale generator to an affiliated utility, unless specifically approved by every state commission having jurisdiction over the rates of the electric utility. States have also implemented affiliated codes of conduct to govern affiliate transactions involving marketing and sales to end-use customers. Thus, this is an area in which close state/FERC coordination would be productive.

IV. Generation Market Power Screens

A. The Use Of The Market Share Screen Was Disavowed At The June 9th Technical Conference By One of the Primary Experts Relied Upon By The Commission To Justify The Adoption Of That Screen.

EEI, in its Rehearing Motion filed in the SMA proceeding on May 14th, has already delineated in great detail the numerous flaws and deficiencies in the market share screen that was adopted by the Commission in the April 14, 2004 "*Order on Rehearing and Modifying Interim Generation Market Power Analysis and Mitigation Policy Order*." Rather than repeat our analysis of the deficiencies in the market share screen, EEI would urge the Commission and any interested party to simply review that filing.

It is interesting to note, however, that one of the primary experts relied upon by the Commission in the April 2004 Order to justify the adoption of the market share screen as a means to address collusive or coordinated market power disavowed the use of that screen for that purpose at the June 9th Technical Conference.

In the April 2004 Order the Commission asserted that the market share screen was needed to complement the pivotal supplier screen:

> "The pivotal supplier analysis focuses on the ability to exercise market power unilaterally. It essentially asks whether the market demand can be met absent the applicant during peak times. ... The uncommitted market share analysis indicates whether a supplier has a dominant position in the market, which is another indication of whether the supplier has unilateral market power and may indicate the presence of the ability to facilitate coordinated interaction with other sellers." (April 2004 Order, paragraph 72.)

As expert support for that assertion, the Commission cited a comment by FTC witness Wroblewski from the January Technical Conference that "market share screens are an improvement over the pivotal supplier in that they allow a look at coordinated behavior."

However, at the June 9th Technical Conference, that same witness disavowed the use of the market share test actually proposed by the Commission as a means to determine whether a market is conducive to coordinated interaction among sellers:

> "We note that FERC has adopted screens and not only focused

> on unilateral exercises of market power, but also the risk of coordinated interaction. This is a sound addition to FERC's analysis. *Although for assessing the risk of coordinated interaction, it may be better to focus on a concentration measure such as HHI rather than solely on a market share test that does not reflect whether a market is conducive to coordination.*" (Transcript at page 89, emphasis added)[2]

It is clear that FTC Witness Wroblewski has validated the objections that EEI has raised to the use of the market share test by the Commission as a market power screen. We would therefore urge the Commission to immediately drop any use of a market share screen.

B. EEI Supports The Commission's Decision To Exclude Native Load Requirements and Other Contractual Obligations From The Market Power Analysis Performed Using The Pivotal Supplier Screen. However, We Encourage The Commission To Be Consistent In Its Application And Also Exclude Native Load Requirements From The Delivered Price Test Analysis.

In the April 2004 Order, the Commission found that it agreed with arguments raised by numerous parties that the inclusion of capacity committed to serve native load obligations (and other firm commitments) in the SMA screen would overstate the generation capacity available to an applicant to sell in the wholesale market. (April 2004 Order, paragraph 67.) For that reason, the Commission explicitly found that native load obligations should be excluded from both the pivotal supplier and market share market

[2] Indeed, even the earlier comments by FTC Witness Wroblewski, cited by the Commission as support of the use of an individual market share screen, actually demonstrate a strong preference for market concentration analysis. Referencing the deregulation of the oil pipelines, Mr. Wroblewski suggested the use of a higher HHI to test for the risk of collusion, and not the use of individual market shares. The HHI suggested in the proceedings mentioned by Mr. Wroblewski was 2500. [RM94-1, OR92-6]."

power screens and that such screens should focus on uncommitted capacity. (Id., paragraph 88.)

The Commission failed, however, to similarly exclude native load obligations from the Delivered Price Test. Under the process outlined in the order, if an applicant fails either the pivotal supplier or market share screens based on uncommitted generation capacity, a rebuttable presumption of market power is established. If the applicant chooses not to proceed directly to mitigation, it must next present a more detailed market power analysis using the Commission's Delivered Price Test. The Delivered Price Test is currently used in Section 203 proceedings to assess the impact on competition of jurisdictional asset transfers and uses the framework as described in Appendix A of the Merger Policy Statement and revised in Order No. 642. (65 Fed. Reg. 70,983 (2000).)

The Delivered Price Test, which incorporates capacity that can be delivered into a destination market at a price less than or equal to 105% of the market price in the destination market, is applied in two prongs – one looking at "economic capacity" and the other looking at "available economic capacity." Economic capacity includes all capacity for suppliers who can compete in the market using the 105% threshold, while available economic capacity excludes the supplier's native load and other retail and wholesale obligations. For both the economic and available economic capacity situations, the applicant will be required to file pivotal supplier, market share, and market concentration analyses.[3] The market concentration analysis must be calculated using the

[3] The Commission states at paragraph 108 of the April 2004 Order that "The applicant will be considered pivotal if the sum of the competing suppliers' <u>economic capacity</u> is less than the load level (plus a reserve requirement that is no higher than State and Regional Reliability Council operating requirements for reliability) for the relevant period. The analysis should <u>also</u> be performed using <u>available economic capacity</u> to account for applicants' and competing suppliers' native load commitments. <u>In that case, native load in the relevant market would be subtracted from the load in each season/load period</u>." The Commission states at Paragraph 109 that "Each suppliers' market share is calculated based on economic

Hirshman-Herfindalhl Index ("HHI"), which is based on relative market shares. The Delivered Price Test analysis thus explicitly still requires a market power analysis for the "economic capacity" situation, which continues to make no adjustment for native load and other commitments.

EEI therefore urges the Commission to be consistent in its application and also exclude native load requirements from the delivered price test analysis for market based rate purposes.

C. EEI Encourages The Commission Not To Pursue The Development Of Dynamic Market Simulation Models To Be Used As Market Power Screens In The MBR Authorization Process.

Also discussed at the June 9th Technical Conference was the general question of whether the Commission should consider the use of dynamic simulation models to screen for potential market power.

Market simulation models seek to predict market outcomes based upon the modeling of participants behavior in the market. Development of such models would be neither simple nor straightforward. The underlying theory and structure would need to be based on peer-reviewed advanced research in several economic disciplines; and the models built for each regional market would require extensive engineering-based modeling of the transmission and supply systems, extensive data requirements, and numerous behavioral assumptions—many of which would likely be controversial. This

capacity" and that "[a]pplicants must also present an analysis using available economic capacity (the Delivered Price Test's analog to uncommitted capacity) and explain which measure more accurately captures conditions in the relevant market." (Emphasis added.)

type of market screen, contrasts with the relatively simple static pivotal supplier test that has been adopted by the Commission as an interim screen.

EEI encourages the Commission not to pursue the development of such models at this time given that such modeling techniques, while of academic interest, have not been proven, properly tested nor accepted for use in regulatory proceedings, and implementing them would only serve to create additional compliance costs that would ultimately be borne by consumers.

V. Conclusion

The issue of whether further structural or behavioral constraints should be placed on a request by a vertically integrated utility to receive MBR ratemaking authorization due to concerns over the ability of the utility to exercise vertical market power is essentially factual and not theoretical in nature. We believe that existing Commission regulatory protections are effective in limiting the ability of a vertically integrated utility to exercise vertical market power.

From EEI's perspective, starting with Order No. 888 in 1996, the Commission has built a regulatory framework that has effectively limited the ability of a vertically integrated utility to exercise vertical market power. Therefore, as part of this rulemaking process, EEI would argue that the burden of proof should be on any party seeking to impose further constraints on the ability of a vertically integrated utility to offer market-based rates to <u>factually</u> demonstrate that the existing regulatory framework has been inadequate to protect against the exercise of vertical market power by that specific utility.

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Any proposed revisions to the existing regulatory framework should not be based on abstract academic economic arguments.

EEI urges the Commission to hold joint workshops with state regulators to discuss issues of common interest. Finally, as noted in the Request For Hearing filed by EEI in the SMA proceeding in regard to the market power screens, EEI urges the Commission to eliminate native load obligations from the Delivered Price Test, for market based rate purposes, as well as to eliminate the Market Share Screen in total.

If you have any questions about these comments, please contact EEI's Director of Regulatory Legal Issues Henri Bartholomot at 202/ 508-5622, or EEI's Chief Economist Timothy McClive at 202/ 508-5085.

Respectfully submitted by

- signature -

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Testimony of

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Xcel Energy

On Behalf of the Edison Electric Institute and its

Alliance of Energy Suppliers

Before the Federal Energy Regulatory Commission

"Market-Based Rates For Public Utilities"

June 9, 2004

Good morning. I am Paul Bonavia, President, Commercial Enterprises, for Xcel Energy. I am appearing before the Federal Energy Regulatory Commission ("Commission") today on behalf of the Edison Electric Institute, a trade association that represents the shareholder-owned electric utilities, and its affiliated Alliance of Energy Suppliers, a division of EEI that specifically represents unbundled, bundled and independent power suppliers (together "EEI").

Xcel Energy is a member of EEI. There are four primary utility operating company subsidiaries of Xcel Energy: Northern States Power Company; Northern States Power Company -Wisconsin; Public Service Company of Colorado; and Southwestern Public Service Company. These companies are geographically diverse with operations in the MISO, WECC, and SPP regions. The Commission has granted the Xcel Energy Operating Companies market-based rate authority.

EEI's members serve substantial retail loads that are subject to state jurisdiction and serve nearly 70 percent of the nation's ultimate customers. As the largest segment of buyers in wholesale power markets, EEI members have a significant interest in a market-based rate authorization process that protects against the abuse of market power and undue discriminatory behavior.

EEI's members also represent the largest segment of sellers in wholesale power markets subject to the Commission's jurisdiction and have a considerable interest in a fair, practical market-based rate authorization approach. EEI seeks to ensure that any new regulations in this area preserve a wide range of business models and do not constrain its members' corporate flexibility to serve their customers efficiently.[1]

For more than a decade, the Commission has encouraged the use of market-based rates, having recognized the associated benefits of improved asset utilization, new power supply options, and productivity enhancing innovation. The Commission carefully implemented a four-prong review process to allow a seller to demonstrate that it lacks market power or has adequately mitigated its market power before awarding that seller market-based rate authority. We are here today to address the adequacy of this four-prong analysis and whether it should be modified to assure that electric market-based rates are just and reasonable. EEI offers the following observations on the Commission's approach to granting market based rate authority.

As for the first prong – generation market power- two years ago, the Commission abandoned its hub-and-spoke approach to assessing generation market power in favor of the supply margin assessment ("SMA"). This new SMA approach improperly assumed that a utility's generating capacity committed to meeting native load requirements was

[1] EEI supports the Order No. 2000 policy that RTO participation should be voluntary.
EEI supports the ongoing development of RTOs and wholesale markets throughout the country and most of its members have joined or are committed to joining an RTO. There has been steady progress towards the Commission's goal of establishing competitive wholesale markets -- some RTOs and ISOs are now operational and others are in advanced stages of development.

fully competing in the wholesale market. As a result, utilities with significant native load commitments were put at risk of losing their ability to sell their excess supplies at market-based rates.

Responding in part to industry concerns, in April, the Commission again modified its interim generation market power analysis. EEI is pleased that the new approach explicitly accounts for native load commitments. However, we recently filed a Request for Rehearing to correct many problems with this new approach. We urge the Commission to postpone applying this approach until the Commission resolves the problems in the rehearing request. This is necessary because the new approach is seriously defective in many different respects. First, the pivotal supplier screen needs numerous adjustments. Second, the new wholesale market share screen is fatally flawed. Applying a simple market share screen without accounting for wholesale market supply and demand conditions will produce many false results - generation market power will be found where there is none - and the existing market-based rate authority of many utilities will be unnecessarily jeopardized. The wholesale market share screen should be eliminated because it is a misleading predictor of the potential to exercise generation market power. Third, the economic capacity screen of the delivered price test should not be used because it fails to adjust for committed capacity. This is inconsistent with this Commission's own recognition of the need to account for such commitments. Fourth, the Commission should reinstate the RTO/ISO exemption since sellers participating in these organized markets are subject to oversight by Commission approved market monitors.

The Commission should proceed with a corrected version of a pivotal supplier screen. It may also wish to consider applying either a simplified version of the delivered price test focusing only on the available economic capacity screen or a pivotal supplier screen in the off-peak period if it continues to believe that more than one screen is desirable. However, the Commission also still needs to allow applicants who may fail a corrected screen to demonstrate that they still do not have market power. Furthermore, the Commission needs to take great care in fashioning any mitigation measures that may apply to a market-based rate applicant, to avoid inappropriate harm to the applicant, its customers, and the electricity markets. The Commission should recognize that mitigation through the imposition of "cost plus" and "up to" rates will fail to send proper price signals to the market, thereby reducing demand response, failing to encourage new supply, and increasing economically inefficient arbitrage. Imposition of these rates should be carefully limited to minimize negative impacts. Furthermore, by imposing cost-based prices – especially for long-term sales, the Commission could be impeding new entry by other suppliers because they might not be able to compete with the mitigated cost-based prices.

The second prong of the Commission's review focuses on transmission market power. Long-standing Commission policy requires an applicant that owns or controls transmission access or is affiliated with an entity that owns or controls transmission access to have an Order No. 888 Open Access Transmission Tariff on file with the Commission, which provides the presumption that transmission market power has been mitigated. Furthermore, the Commission has taken additional significant steps that support its open access policy which are designed to preclude the exercise of transmission market power. The Order No. 889 open-access same-time information system requirements and Order No. 2000 RTO policies are good examples. In addition, the new Order No. 2004 Standards of Conduct rule establishes additional measures to ensure that energy affiliates of transmission providers do not gain access to preferential transmission information. Order No. 2003, the Large Generator Interconnection Rule, facilitates open access by standardizing interconnection procedures, managing the huge growth in new generation proposals, and by helping to clarify cost responsibility when new transmission facilities are needed. In addition, the Commission's proposed pricing policy includes financial incentives for new transmission investment that enhance grid performance. Compliance with all of these measures, reinforced by the Commission's complaint and oversight processes, should suffice to address any concern the Commission may have about the abuse of transmission market power.

We point out that there are a significant number of wholesale market participants who are not subject to the Commission's jurisdiction, particularly in the West where large Federal agencies and municipalities own transmission and sell power at wholesale. It is important that the Commission continue to seek to apply its policies uniformly to all market participants using reciprocity and any other tools that are available to the Commission.

In addition, in some areas, independent transmission is provided through RTOs, ISOs, and ITCs. Until recently, the Commission's longstanding approach has been that membership, or a commitment to form and participate, in an RTO alleviates concern about transmission market power. So we are frankly confused why a commitment to join an RTO is not adequate to mitigate concern about the abuse of transmission market power.

The third prong of the Commission's analysis considers whether an applicant can impose any other barriers to entry. Clearly the addition of many different competitive electric suppliers throughout the nation in recent years demonstrates the ease of entry in long-term capacity markets. In the short-term, the Commission has rightly focused on the ability of an applicant or its affiliates to erect barriers to fuel supplies to competing electric generators. Other than that, we believe that barriers to entry will be so isolated and case-specific and that the burden of showing a barrier to entry must be on any party which objects to an applicant receiving market-based rates.

In looking at barriers to entry, the Commission must acknowledge that state statutes provide state commissions with significant regulatory jurisdiction in areas such as transmission planning, siting, and resource adequacy. The Commission lacks jurisdiction over these areas and an attempt to exert its authority would only heighten the federal-state jurisdictional impasse and not be constructive in facilitating the Commission's goal of supporting competitive wholesale markets. The Commission should defer to the states' jurisdiction over these areas.

The fourth prong to the Commission's review of market-based rate authority seeks to ensure that there is no affiliate abuse or reciprocal dealing. EEI believes that affiliate transactions must be conducted in a fair manner, without bias and favor to the affiliates of regulated utilities. The Edgar standard provides three ways to demonstrate fairness.[2] In addition, each state has its own approach to assessing the fairness and reasonableness of purchasing power to serve native load. This is particularly important where a utility's unregulated affiliate is seeking to sell energy to its affiliated utility.

EEI believes that when a utility is purchasing power to serve its native load requirements, the Commission should give deference to state decisions approving the transaction and the fairness of the procedures which lead up to it. The Federal Power Act preserves for the states substantial authority to regulate retail electric service, new generation additions, and to establish the conditions and criteria they believe necessary to assure adequate service with just and reasonable terms and conditions.

In addition, Section 32(k) of the Public Utility Holding Company Act specifically gives states the authority to protect against abusive affiliate transactions. This provision prohibits sales of electricity from an exempt wholesale generator to an affiliated utility, unless specifically approved by every state commission having jurisdiction over the rates of the electric utility. Congress clearly looked to the states to address the potential for affiliate abuse. We urge this Commission to act in concert by giving deference to state decisions regarding affiliate transactions when they involve jurisdictional issues.

Thank you and I look forward to our discussion.

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[2] The Commission has set the *Edgar* standard as a threshold standard that a utility must meet when conducting competitive solicitations to demonstrate a lack of affiliate abuse. *Edgar* considers three forms of evidence in **Section 205** proceedings: evidence of direct head-to-head competition, evidence of prices that non-affiliated buyers were willing to pay for similar services from the affiliate, and benchmark evidence taking into full account the non-price factors hence the importance of supporting data and explanations. The Commission cited its "independent responsibility to protect against affiliate abuse." Also it categorically stated that *Edgar* should not be "interpreted as barring all affiliated transactions where market-based rates are requested."

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Testimony of

EDWARD COMER

Vice President and General Counsel

Of the Edison Electric Institute

On Behalf of the Edison Electric Institute and its

Alliance of Energy Suppliers

Before the Federal Energy Regulatory Commission

"Solicitation Processes for Public Utilities "

June 10, 2004

Good morning. I am Ed Comer, Vice President and General Counsel for the Edison Electric Institute. I am appearing before the Federal Energy Regulatory Commission ("Commission") today on behalf of the Edison Electric Institute, a national trade association that represents shareholder-owned electric utilities, and its affiliated Alliance of Energy Suppliers, a division of EEI that specifically represents unbundled, bundled and independent power suppliers (together "EEI").

EEI members serve about 70 percent of all ultimate customers in the nation and the majority of our members are both federal and state jurisdictional. EEI members also represent the largest segment of buyers and sellers in wholesale power markets. We therefore have a considerable interest in whether the Commission should establish a solicitation process for public utilities, particularly with respect to situations where public utilities sell to or buy from their affiliates.

EEI believes that all power purchase and sale transactions must be conducted in a fair manner, without bias or self-dealing to favor affiliates, to achieve the deal for utility customers with the best cost/risk balance. The Edgar standard provides three ways to demonstrate that the buyer has chosen the lowest-cost supplier from among the options presented, taking into account both price and non-price factors.

1. Head-to-head competition through a formal solicitation or informal negotiation process;
2. Demonstration of prices that non-affiliated buyers were willing to pay for similar services; or
3. Benchmark evidence that shows the prices, terms and conditions of sales made by non-affiliated sellers.

All of these are valid methods of demonstrating that the buyer has chosen the best option.

When a utility chooses an affiliate over other competitors as a supplier, there is heightened concern about the potential for self-dealing or unfairness in the selection process. However, the choice of an affiliate in and of itself may be the best option in a given circumstance. In fact, the Commission has a long-history of approving such transactions. Thus, as long as the process is fair, any proposal to prohibit or restrict affiliate transactions could harm customers.

The ultimate goal of a solicitation process for public utilities is to enable the utility to balance both cost and risk in providing the best service possible at the best price. Sometimes the answer will be to build new generation or to buy a distressed asset: other times the best approach will be to enter into a purchase power agreement with power marketers or either an independent or affiliated producer.

The big deficiency in the Edgar standard is that it fails to recognize that most of the competitive solicitations that take place are issued by load serving entities ("LSE") for the purpose of serving native load. Since most of these entities are state regulated, the process is usually conducted with considerable oversight and direction from state commissions and the full knowledge that an imprudent decision can lead to cost recovery disallowance by the applicable state commission. In addition, some entities are regulated by multiple state commissions, which further heightens the scrutiny of the procurement processes. We believe such state involvement provides strong assurances that the process will be conducted in a fair and unbiased fashion and will achieve the best results for customers.

In making the evaluation between building a power plant, buying an existing power plant, or executing a long-term power purchase agreement, the buying LSE must take into consideration and justify to its state commission a variety of factors. These may include renewable energy requirements, the construction risk of building a plant, the credit risk of the counterparty, the cost associated with direct or inferred debt,[1] transmission and reliability issues, the likelihood of regulatory approval, and the cost to mitigate unwanted risks. All of these factors culminate in ascertaining the costs and risks that a given resource may result in for end-use customers.

At this point in the utility business cycle, there is a surplus of distressed generation assets at very attractive prices in some markets. In comparison, long-term contract purchase options can raise substantial questions about the long-term financial health of the entities involved. This Commission should be well aware of such credit and default risk issues. Unfortunately, uncertainties about these issues have become exacerbated by the Commission's failure to resolve important credit issues in the WSPP tariff. Given these

[1] Direct debt due to capital lease accounting under Emerging Issues Task Force 01-08 (EITF 01-08) and/or consolidation under Financial Interpretation No. 46R (FIN 46R), or inferred debt due to rating agency inference of debt associated with long-term power purchase agreements.

circumstances, generating asset purchases may prove to be the best business alternative. The Commission should not exhibit a bias against this choice when it proves to be the best alternative for utilities and their customers.

States have many different competitive solicitation processes that they use to determine the best way to serve their retail customers. Many have very specific bidding procedures, including the successful New Jersey and Maryland programs. Others are examining new or revised programs. Some states may use independent monitors: other commissions believe their role assures fairness. We regret that representatives of many of these states are not here to discuss their processes and the benefits to customers that they have produced. There is no one right solution, practice or process common to all the states as each state may hold differing views on the exact criteria and mechanics a procurement process should possess.

The generators vying to sell power are very active in state proceedings that address procurement issues. They have a forum and remedies in the states if they are convinced that the process is unfair. Thus, when the state is involved, FERC does not need to rely upon a market monitor or other independent entity to evaluate the fairness of the outcome because that is the state's role.

For all of these reasons, the Commission, in its review of wholesale rates under Section 205 of the Federal Power Act, should defer to state decisions regarding how a utility best procures power to serve its native load. While the Federal Power Act gives this Commission responsibility to assure that wholesale rates are just and reasonable, it also preserves for the states substantial authority to regulate retail electric service and to establish the conditions and criteria that they believe necessary to assure adequate service, fair procedures, no self-dealing, and just and reasonable terms and conditions.

In addition, Congress clearly looked to the states, not FERC, to address the potential for affiliate abuse in sales of power to utilities from their affiliates. Section 32(k) of the Public Utility Holding Company Act, enacted in 1992, prohibits sales of electricity from an exempt wholesale generator to an affiliated utility, unless specifically approved by every state commission having jurisdiction over the rates of the electric utility.

In conclusion, we urge this Commission to act in concert with these provisions and modify its Edgar approach in a manner that explicitly recognizes and compliments the responsibilities of state commissions. We also recommend continued cooperation and communication with the state commissions.

Finally, we urge the Commission to avoid moving in a direction that requires a uniform approach for competitive solicitations. Such an approach would intrude upon state responsibilities for how a jurisdictional utility meets its obligation to serve, as well as for EWG affiliate transactions under PUHCA. Any effort to force states into a process not of their own choosing, risks states turning to resource solutions that are not FERC jurisdictional so that their judgment will not be second-guessed.

Thank you and I look forward to our discussion.

OTHER FEDERAL DECISIONS

19. **Followed by:**
Electric Generation, LLC, 101 F.E.R.C. P63005, 2002 FERC LEXIS 2120 (2002)

101 F.E.R.C. P63005

LEXSEE

Southern California Edison Company, On behalf of Mountainview Power Company, LLC

Docket No. ER04-316-000

FEDERAL ENERGY REGULATORY COMMISSION - COMMISSION

106 F.E.R.C. P61,183; 2004 FERC LEXIS 371

ORDER CONDITIONALLY ACCEPTING PROPOSED RATE SCHEDULE AND REVISING AFFILIATE POLICY

February 25, 2004

CORE TERMS: cost-based, affiliate, plant, heat, escalation, wholesale, competitive, formula, annual, target, market-based, regulation, customer, buyer, recovered, decommissioning, winter, reclassification, ratepayers, monthly, output, intervene, protesters, seller, calculated, ratemaking, collection, protest, energy, informational

PANEL:
[**1] Before Commissioners: Pat Wood, III, Chairman; Nora Mead Brownell, and Joseph T. Kelliher

OPINION:
[*61,637]

1. In this order, we are conditionally accepting for filing a Power Purchase Agreement (PPA) between Southern California Edison Company (Edison) and Mountainview Power Company, LLC (Mountainview), an exempt wholesale generator (EWG). We will condition our acceptance, among other things, on Mountainview submitting a compliance filing reflecting ordered changes to the PPA, committing to filing a FERC Form 1 annually, maintaining its books and records in accordance with the Uniform System of Accounts, and limiting its market activity to cost-based sales to Edison. This action benefits customers by accommodating the construction of new generation in California while ensuring that Mountainview's rates are just and reasonable.

BACKGROUND

2. On December 19, 2003, Edison filed, on behalf of Mountainview, its to-be-acquired subsidiary, a proposed PPA between itself and Mountainview. Mountainview owns a yet-to-be completed 1054 MW state-of-the-art generating plant. n1 Edison seeks to exercise an option to purchase the project by purchasing Mountainview from its current owner, Sequoia Generating [**2] LLC (Sequoia). n2 Edison claims that its purchase of Mountainview will restore stability to the marketplace, enhance reliability and provide substantial benefits to Edison's ratepayers, but Edison requests Commission approval of the PPA before it will exercise its option. The PPA is not a market-based contract; instead, it is a cost-based rate schedule which includes ratemaking features that give Mountainview incentives to control discretionary costs that it will incur and pass on to Edison. The PPA is structured as a tolling agreement, giving Edison the responsibility for gas procurement, hedging, and plant dispatch.

n1 The plant will consist of two units. Unit 1 will be completed before Unit 2; both units are estimated to be completed in March 2006 (Full Commercial Operation Date).

n2 Sequoia bought the project from AES Corporation in March 2003. Construction was suspended in March 2002 when AES Corporation experienced financial difficulties. Prior to that, AES acquired it from Thermo-Ecotek in 2001.

3. Edison [**3] states that it has elected to use this subsidiary-PPA structure because it is just beginning to return to financial health, and because significant unresolved policy issues in California "demand the increased assurance of cost recovery that a FERC-filed, cost-based PPA provides." n3 In other words, Edison "requires greater security of investment recovery than is available under traditional state-jurisdictional ratemaking." n4 The utility asserts that this is a unique request, unlikely ever to be repeated, because of the urgent need for new generating capacity in California. Edison notes that the Public Utilities Commission of the State of California (CPUC) has found that this transaction is in the public interest. n5 In summary, the CPUC ruled that ratepayers will be better off with Mountainview than without it. n6

n3 Edison transmittal letter at 3.

n4 Id. at 5.

n5 Specifically, the CPUC found that the proposed transaction will benefit consumers and that Edison has established an immediate need for dispatchable peaking and intermediate capacity. See id. at 20-28.

n6 CPUC Decision 03-12-059 at 40-41, attached to CPUC comments (CPUC Decision).

[**4]
4. The Energy Policy Act of 1992 amended the Public Utility Holding Company Act of 1935 [*61,638] (PUHCA) to allow an EWG to sell power to an affiliated utility only if the state regulatory authority makes certain findings, described in Section 32(k) of PUHCA (Protection Against Abusive Affiliate Transactions). n7 The CPUC has made the requisite PUHCA findings, noting among other things that: (1) the PPA does not violate any state law; (2) the PPA does not confer any unfair competitive advantage; and (3) the CPUC

n7 15 U.S.C. § 79z-5a(k) (2000).

has sufficient regulatory authority, resources, and access to books and records of both Edison and Mountainview. n8

n8 CPUC Decision at 40-46.

5. Applicants request that the PPA be made effective upon execution, which is expected to be at the financial closing. Because the closing [**5] may not occur within 120 days from the date of the filing, Applicants seek waiver of the 120-day advance notice requirement.

NOTICE, INTERVENTIONS AND COMMENTS

6. Notice of Edison's filing was published in the Federal Register, 69 Fed. Reg. 63 (2004), with motions to intervene and protests due on or before January 9, 2004. The CPUC filed a notice of intervention and comments in support of the proposal. Timely motions to intervene raising no substantive issues were filed by AES Corporation, Constellation Power Source, Inc. and Constellation New Energy, Inc., and Pacific Gas and Electric Company. Timely motions to intervene and comments in support of the filing were filed by California Small Business Roundtable and California Small Business Association (CSBR/CSBA), Consumers First, Electric Consumer Alliance, Sequoia Generating LLC (Sequoia), and The Utility Reform Network (TURN). The following filed timely motions to intervene and protests: California Manufacturers and Technology Association (CMTA), Calpine Corporation (Calpine), Cogeneration Association of California (CAC), Electric Power Supply Association and Western Power Trading Forum (jointly, [**6] Competitive Suppliers), Energy Producers and Users Coalition (EPUC), FPL Energy, LLC (FPL), Independent Energy Producers Association (Independent Producers), Reliant Resources, Inc. (Reliant), and the Silicon Valley Manufacturing Group (SVMG).

7. In addition, members of Congress submitted comments supporting the proposal stressing the need for new generation capacity in California. One Congressman opposed the filing. Several California Assemblymen also commented, requesting a full evidentiary hearing.

8. On January 14, 2004, Water and Energy Consulting filed a late motion to intervene on behalf of Black Mesa Trust and To' Nizhoni Ani' (WEC).

9. On January 26, 2004, Edison, Sequoia, and TURN filed answers responding to the protests. Independent Producers, Calpine, and CMTA subsequently filed replies.

POSITIONS OF THE PARTIES

10. Supporters of the filing, including several organizations representing consumer interests, n9 claim that the Mountainview project is needed so that Edison can meet its immediate requirements for dispatchable peaking and intermediate capacity and its long- term need for baseload resources. Supporters also state that the PPA will not have an adverse [**7] effect on competition. The CPUC concludes that Mountainview is "a very good deal for Edison's customers" n10 and that the plant's location in Edison's load center makes the plant an efficient addition to its system. The CPUC also notes that the Mountainview project has already received a license for the project and an environmental review has been concluded. Consumers First and the Electric Consumer Alliance state that the PPA will promote reliability of California's energy supply and foster a more cost-effective, consumer-responsive energy market. Finally, while the CPUC and TURN both would prefer that the development of the Mountainview project be completed as a traditional utility-owned rate-based investment, they support the proposed PPA since it is cost-based and in many respects mirrors the cost recovery treatment of a rate-based investment.

n9 These groups include Consumers First, TURN, CSBR/CSBA, and the Electric Consumer Alliance.

n10 CPUC comments at 5.

11. Opponents of the filing argue that Edison has [**8] not shown that the Mountainview project is either needed or in the public interest. Additionally, opponents argue that Edison has failed to have an open and fair competitive bidding process prior to completing the Mountainview transaction and that the absence of competitive procurement will strike a blow to competitive markets in California. Specifically, Calpine and FPL argue that, had a request for proposals been available, they would have participated. Opponents also argue that Edison should be required to satisfy the Commission's Edgar standard n11 regarding affiliate transactions as well as affiliate abuse concerns. The Independent Producers raise numerous concerns regarding the PPA. For example, they argue that the terms and conditions are unjust, unreasonable and unduly discriminatory or preferential. They also raise issues regarding the development of the PPA's rates and charges such as its use of incentives, escalation indices, and other cost- of-service concerns. SVMG argues that the approval of the Mountainview PPA will initiate re-regulation in California. CAC and EPUC argue that the Mountainview project must not displace the need for existing and future qualifying [**9] facility (QF) [*61,639] needs and must comply with the provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA).

n11 See Boston Edison Co. Re: Edgar Electric Energy Co., 55 FERC P 61,382 (1991) (Edgar) (requiring a showing that a sale of power at market-based rates to a franchised utility from an affiliate is reasonably priced compared to alternatives in the market).

DISCUSSION

Procedural Matters

12. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2003), the CPUC's notice of intervention and the timely, unopposed motions to intervene of the entities that filed them make them

parties to this proceeding. We will grant WEC's late motion to intervene, given its interest in the proceeding, the early stage of the proceeding, and the absence of any undue prejudice or delay.

13. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2003), prohibits an answer to a protest unless otherwise [**10] ordered by the decisional authority. We are not persuaded to accept Edison's, Sequoia's and TURN's answers and Independent Producers', Calpine's, and CMTA's replies, and will, therefore, reject them.

Cost of Service Issues

14. The PPA, as well as the rulings of the CPUC, provide that certain cost items and terms of service are subject to the CPUC's regulatory review. We note that the Commission is the ultimate arbiter of the rates, terms and conditions of service of a power purchase agreement that is subject to our jurisdiction.

Description of the Proposed Charges

15. As noted above, the proposed PPA is a cost-based rate schedule which includes ratemaking features that give Mountainview incentives to control discretionary costs that it will incur and pass on to Edison. Edison will buy the natural gas for the unit. The primary set of charges in the PPA include formula rates for the recovery of capital costs and certain specified other costs, stated operation and maintenance charges (O&M) and incentive rates for plant availability and heat rate.

16. The PPA has a Capital Recovery Charge that will be billed monthly on a formula rate basis and is intended to recover [**11] the Return on Investment, Book Depreciation, and Federal and State Income Taxes based on the original cost of the plant. Beginning on the Full Commercial Operation Date, Edison will pay the Monthly Capital Recovery Charge. However, between the time Unit 1 enters service and the full Commercial Operation Date, Edison will pay an Initial Monthly Charge which is calculated in the same manner as the Monthly Capital Recovery Charge, but is based on only the investment associated with the first unit that is placed into service. The initial investment reflects the purchase price to Sequoia plus the costs incurred by Mountainview to complete the construction of the project including amounts associated with Allowance for Funds Used During Construction (AFUDC).

17. In addition to the Capital Recovery Charge, the PPA provides for recovery of O&M charges. Edison states that the O&M charges under the PPA are divided into two categories: (1) Pre-Authorized Charges and (2) Fixed and Variable O&M Charges. n12 Edison states that the Pre-Authorized charges are recovered on a formulary basis and a majority of these expenses are effectively pre-committed at the outset. Edison will also pay Mountainview [**12] a monthly stated Fixed O&M Charge and a monthly stated Variable O&M Charge, which are intended to recover all O&M costs not recovered through the Pre-Authorized charges and which will remain constant, except for an escalation factor for inflation, during the intervals between Overhaul Cycles. n13 Additionally, by being stated rates, the Fixed and Variable O&M rates are intended to act as an incentive to Mountainview to control the amount of costs incurred for the types of expenses recovered by these charges.

n12 The Commission's Uniform System of Accounts would not include all items that will be recovered under these charges as O&M expenses. For example, property taxes would be booked to Account 408 of the Uniform System of Accounts.

n13 An Overhaul Cycle is defined as the period which begins on the Full Commercial Operation Date and ending on the last day of the month in which all four combustion turbines at the Facility have completed a Hot Gas Path Inspection and have been released for dispatch. Each Overhaul Cycle is expected to occur every 3-4 years.

[**13]
18. The PPA also includes two separate incentive rate mechanisms: (1) an availability incentive and (2) a heat rate incentive. The availability incentive provides bonus or penalty payments for performance by Mountainview above or below an availability standard, with the purpose of providing an incentive to Mountainview to maintain plant availability. The heat rate incentive is designed to provide financial rewards and/or penalties to Mountainview to maintain the plant

in a reasonable condition so that the heat rate does not unreasonably degrade and the plant functions at an efficient heat rate.

Capital Costs

19. Edison has projected a total initial rate base for Mountainview of approximately $ 703 million which includes $ 84 million for AFUDC. n14 The CPUC ruled that if Mountainview's actual plant-in-service amount (excluding AFUDC) exceeded $ 624 million, Mountainview cannot include such amounts in its rate base without first receiving CPUC approval. n15 As an initial matter, we note [*61,640] that this Commission is the ultimate arbiter of the reasonableness of costs included in a rate subject to our jurisdiction, such as the PPA. In any event, our review indicates that the Independent [**14] Producers' concerns regarding the 5 percent contingency in excess of the $ 595 million capital cost limit is misplaced in a cost-based ratemaking environment. Under the Commission's regulations, the amounts associated with plant-in-service are those prudently incurred costs and only those costs that are found to be imprudently incurred are disallowed. Therefore, to the extent that any costs are found by the Commission to be imprudently incurred, they will be excluded from the capital recovery charge. We further note that preliminary estimates of the initial facility investment will be trued-up within twelve months following the date of Full Commercial Operation. n16

n14 Edison states that AFUDC will be calculated monthly in accordance with electric plant instructions included in FERC's Uniform System of Accounts. See, Attachment 1 to Schedule 7.01 of the PPA (Original Sheet No. 49).

n15 The $ 624 million was developed using an original cost of $ 595 million plus a 5 percent contingency ($ 29 million).

n16 See Article VIII, Section 8.01 and Schedule 7.01 Original Sheet No. 44.

[**15]

Rate of Return

20. The formula rate specifies that the return on rate base will be the CPUC- approved annual return, including the CPUC cost factor for long-term debt and the CPUC current return on common equity for Edison. Mountainview's cost support indicates a rate of return of 9.75 percent, including a return on equity (ROE) of 11.6 percent.

21. The Independent Producers argue that this 11.6 percent ROE warrants further review, stating that it was previously approved for only transmission facilities, and therefore should not be used to justify the to-be-acquired generation asset. We note that Edison has committed that Mountainview will make a Section 205 filing prior to commercial operation and a filing with the Commission each January 1 coincident with or subsequent to CPUC changes in Edison's return on utility assets that will support the then applicable cost of capital regardless of whether the current return has been modified. The Commission in that filing will determine the just and reasonable capitalization and return components. At that time, we will address Independent Producers' concerns as to the basis for the ROE, including whether it is appropriate for the [**16] ROE to be based on the regulated utility assets. Furthermore, the future filing commitment ensures that the actual return utilized for billing purposes, whether it be the current return or a different return, will be subject to further Commission review, under Federal Power Act (FPA) Section 205. We will direct Edison, on behalf of Mountainview, to revise the PPA to reflect this commitment.

Phase-in of Monthly Charges

22. Edison notes that the Mountainview project consists of two units that will be placed into service with the expectation that Unit 1 will enter into service before Unit 2. Accordingly, the PPA is structured to include an Initial Monthly Capital Recovery Charge that will reflect recovery of costs associated with Unit 1 and a full Monthly Capital Recovery Charge that will recover the costs associated with both Units 1 and 2. The Independent Producers raised a concern that, based on their reading of the PPA, Mountainview would charge for the costs associated with both Units even though only Unit 1 would be in service.

23. Schedule 7.01 of the PPA requires clarification. The Initial Monthly Charge should allow for recovery of the initial unit that is in service. [**17] Schedule 7.01 states: ". . . Plant-In-Service will be equal to the Initial Facility Investment

associated with the each Unit that becomes operational." The phrase "the each Unit" should read "the Unit" so as to remove any confusion. Therefore, we will condition our acceptance of the PPA on Edison, on behalf of Mountainview, submitting a compliance filing correcting Schedule 7.01.

State Income Tax Treatment

24. The Independent Producers note that the recovery of State Income Taxes is calculated using flow through of book and tax depreciation differences in accordance with CPUC regulations, rather than the FERC required full normalization of such timing differences. The Independent Producers argue that this is inappropriate and inconsistent with the Commission's regulations regarding tax normalization. We agree with the intervenor that the use of flow through is inconsistent with our regulations, however, due to the characteristics of the PPA a waiver is appropriate in this case. Inasmuch as Mountainview is a single asset entity whose output will be purchased by Edison over its entire useful life, the use of flow through in calculating state income taxes will not result in excess [**18] revenues over the life of the plant. As such, it is unnecessary to record tax timing differences between state tax and book basis differences. Based on these facts, we find Edison's proposal to be reasonable in these specific circumstances and will grant waiver of Section 35.24 of the Commission's regulations regarding normalization of state income taxes.

Decommissioning Costs

25. Finally, the PPA includes as a line item expense, decommissioning costs. However, Mountainview has not included any decommissioning costs at this time. The Independent Producers note that no decommissioning costs seem to be reflected in the charges, and therefore state that further review and discovery is necessary to determine the potential impact of decommissioning costs on the Capital Recovery Charge.

26. Our review indicates that salvage cost associated with this unit may be an appropriate cost item. However, inasmuch as Mountainview has not included any support for such cost at this time, we will require Mountainview to make a filing, [*61,641] with appropriate workpapers and justification, pursuant to Section 205 of the Federal Power Act when it seeks to include the recovery of decommissioning costs [**19] under the PPA. This filing requirement will ensure that all parties will have an opportunity to review and comment on the proposed level of such costs.

27. In conclusion, our review of the proposed formula rate for the recovery of capital costs, return, depreciation and associated income taxes for Mountainview indicates that it is generally reasonable. This finding is predicated on Mountainview including only the actual purchase cost with no premium or acquisition adjustment thereto for inclusion in capital costs. However, we will require that Edison, on behalf of Mountainview, make a compliance filing that modifies the formula rate for the recovery of these capital costs which includes more specificity by including the specific FERC Account numbers in the Capital Cost section of the PPA, e.g., the PPA should specifically reference amounts booked to Account 101, Plant-in-Service, amounts booked to Accounts 282-283, Accumulated Deferred Federal Income Taxes, amounts booked to Account 403, Depreciation expense, etc. The use of the FERC Uniform System of Accounts will ensure that the Commission and all interested parties will be able to track all changes to Capital Recovery [**20] Charge under the proposed formula rate.

O&M Charges

Pre-Authorization Charges

28. As noted previously, the PPA includes a collection for Pre-Authorization Charges. These charges include twelve specific costs which include, among other things, property taxes, government charges, insurance, A&G and General Plant expenses related to Edison's corporate center and costs associated with a third party service agreement - the Contractual Services Agreement (CSA) - for Mountainview's combustion and steam turbine generators. Edison states that these costs are beyond Mountainview's control, and will be passed on through a formula rate as incurred. The estimated charges for first year of operation are approximately $ 20.7 million.

29. Our review indicates that the collection of these types of expenses on a formula basis that essentially flow through the actual costs incurred is generally reasonable. However, we will require some modifications to the PPA to ensure that it will result in just and reasonable rates. First, the A&G and General Plant expenses related to Edison's corporate center, designated in the PPA as Buyer Overhead Costs, are proposed to be recovered as a Pre-Authorized [**21] Charge and allocated to Mountainview by SCE. However, the method of allocation is not included in the PPA. We will require

the PPA to be modified to include a description of the method to be utilized to allocate these Buyer Overhead Costs to Mountainview on a non- discriminatory basis. Additionally, another one of the twelve categories of Pre-Authorized charges are costs associated with Betterment Work, n17 Compliance Work, Facility Refurbishment Work or Major Equipment Repair or Replacement Work. Section 8.09 permits the Seller to include costs associated with such work in either the Capital Recovery Charge or as a Pre-Authorized Charge. We find that the decisions by Mountainview to either expense or capitalize any of these listed work items must be in accordance with the requirements of the Commission's Uniform System of Accounts.

n17 Betterment Work means improvements or additions undertaken by or on behalf of Seller with respect to the Facility or any Unit for the purpose of increasing or improving the electrical output or operating efficiency of the Facility or Unit, or extending the life thereof, but excluding any maintenance work performed in the ordinary course of operations.

[**22]
30. Regarding the collection of Pre-Authorized costs as provided for in section 7.02 of the PPA, we note that section 8.08 of the PPA permits the reclassification of Pre-Authorized costs to Fixed and Variable O&M expenses or alternatively, the reclassification of Fixed and Variable O&M costs to Pre-Authorized Costs. Furthermore, the PPA provides that SCE, as the buyer, may seek CPUC regulatory review of any reclassification of Pre-Authorized costs by Mountainview. The Independent Producers raise concerns regarding any possible reclassifications. Our review indicates that both the discretion and the delegation of review of any reclassifications are inappropriate. Any reclassification of Pre-Authorized costs or Fixed and Variable O&M expenses must be filed with the Commission for its review and approval.

31. The Independent Producers also raise concerns about potential lack of future review of these costs. We believe that such concerns are best addressed by imposing additional requirements on Mountainview. Accordingly, we find that in order to ensure that the collection of costs included in the PPA as Pre-Authorized costs are just and reasonable, Mountainview will be required to [**23] modify section 7.02 of the PPA to include FERC account numbers for these specifically identified cost categories. This requirement is consistent with our requirement regarding the recovery of Capital Costs under the PPA and will work to ensure that there will be no double recovery of costs. Additionally, in order to allow all parties adequate review of the operation of this formula rate and to prevent the collection of costs that are not specifically identified by current cost categories and associated account numbers, we will require Mountainview to make an annual informational filing and an annual filing of a FERC Form No. 1. n18

n18 The annual informational filing and the filing of FERC Form No. 1 should be made by May 1 of each year.

[*61,642]

Fixed and Variable O&M Charges

32. Edison will pay a Fixed O&M charge to Mountainview of $ 636,000/month following the Full Commercial Operation Date, subject to annual escalation and adjustment following each Overhaul Cycle. n19 Edison's estimate of $ 636,000/month for Fixed [**24] O&M is derived based on projected administrative costs incurred in connection with the operation of the Facility and includes staff and labor costs, routine maintenance costs, periodic maintenance costs, and SCE provided support services costs. The $ 636,000/month rate will not be subject to increase during the course of an Overhaul Cycle, except for escalation. Edison states that these charges are subject to escalation to reflect cost increases due solely to inflation. The charges will then be reset to reflect recorded costs once the Overhaul Cycle is completed. Edison's derivation of the initial costs used to derive the monthly rate of $ 636,000 was based on costs incurred by similar units. Additionally, this cost estimate was reviewed and found reasonable by Stone & Webster consulting firm.

n19 However, beginning at the end of the month in which the first Unit Commercial Operation Date occurs and continuing each month until the end of the month in which the Full Commercial Operation Date occurs, Edison will pay Mountainview a prorated share of the $ 636,000/month Fixed O&M Charge based on the number of Units in Commercial Operation in such month.

[**25]
33. The Variable O&M Charge that Edison will pay to Mountainview shall be based on the Net Electrical Output delivered in such month at the rate of $ 0.44/MWh, subject to annual escalation and adjustment following each Overhaul Cycle. These costs are classified as consumables, disposal of waste and other major maintenance costs and are intended to recover monthly water and wastewater costs, chemical costs, feed water pumping costs, and heat recovery boiler costs and other variable costs not recovered under the Pre-Authorized costs. Again, the $ 0.44/MWh rate was based on Edison's review of such costs for similar units and was reviewed and found reasonable by Stone & Webster consulting firm.

34. Regarding the proposed Fixed and Variable O&M Charges, the Independent Producers note that while the charges are based on estimates that were reviewed and found to be reasonable by Stone & Webster, it does not appear that the Stone & Webster comparison was included in the filing. Additionally, the Independent Producers raise concerns regarding double recovery of costs in this category as well as costs under the Pre-Authorized charge.

35. These stated rates for Fixed and Variable O&M costs [**26] are intended to serve as a mechanism to control Fixed and Variable O&M costs during each overhaul cycle, except for inflation.

36. Our review of the proposed Fixed and Variable O&M stated rates indicates that such rates have not been shown to be just and reasonable and may result in unjust and unreasonable rates. Accordingly, we will reject these stated rates for Fixed and Variable O&M and require Mountainview to bill out, as part of this cost-based formula rate, the actual costs incurred, by FERC account number, for fixed and variable O&M expenses. We are not persuaded that the purported incentive to control these cost types with stated rates in intervals between Overhaul cycles is necessary or desirable. Mountainview has an obligation to operate the planned facilities in a prudent and least-cost manner. As such, the recovery of actual costs incurred for Fixed and Variable O&M expenses is appropriate. Accordingly, Mountainview must amend the PPA to reflect this finding and include the specific FERC Account Nos. for Fixed and Variable O&M expenses.

Incentive Components

37. There are two performance measurements in the PPA. The availability measurement which has both a Summer [**27] Availability and Winter Availability provision and a heat rate measurement. Regarding the availability incentive, the maximum combined payment from Mountainview or to Mountainview is $ 1.56 million annually, subject to escalation. In order to determine the Availability Payments, actual winter or summer availability is measured against the contract's availability target, which is 97 percent for summer periods and 92 percent for winter periods. n20 The Summer Availability Payment is calculated by multiplying $ 360,000 by the summer availability achieved minus the summer target availability. Similarly, the Winter Availability Payment is calculated by multiplying $ 60,000 by the winter availability achieved by the facility minus the winter target availability. n21

n20 Conversely, the PPA provides for the incentives to be measured with a minimum Summer Target Availability of 94 percent and a Winter Target Availability of 84 percent so as to limit the potential payment by Mountainview to not exceed $ 1,560,000.

n21 Edison states that the winter availability target of 92 percent is reduced in years where a maintenance overhaul is scheduled.

[**28]
38. Additionally, the PPA includes a target heat rate incentive for the Mountainview Project of 7000 Btu/kWh. Section 12.03 of the PPA adjusts payments under the PPA based on a comparison of the actual facility heat rate, as determined by twice-annual testing, against the Contract Heat Rate. As long as the test results are within 3 percent of the Contract Heat Rate, no incentives or penalties are assessed. Performance above or below the 6 percent deadband results in either incentive payments to Mountainview or payments by Mountainview to Edison for failure to meet these targets.

39. The Independent Producers argue that the type of incentive ratemaking contained in the PPA is inconsistent with Commission precedent and [*61,643] not appropriate for use when a competitive wholesale electric market exists. The Independent Producers further argue that in both the availability and heat rate incentive proposals, the potential payment/penalty is unsupported and does not appear to include a provision for Commission review. This sale under the PPA is a cost-of-service contract and not a sale at market-based rates. We therefore find the use of incentives appropriate in this instance. Regarding the [**29] Independent Producers' claim that there is no provision for Commission review, the Commission has at this time reviewed these incentive provisions and found them reasonable.

40. Our review indicates that the heat rate incentive is reasonable. Mountainview and Edison have agreed that amounts above or below the target heat rate will result either in additional payments by Mountainview to Edison that will be used to offset the additional gas costs incurred or payments by Edison to Mountainview to reflect savings as a result of maintaining the target heat rate. The target heat rate is reasonable in that it is representative of a base line expectation for this type of unit, and the additional payments

or savings are done on a 50/50 sharing basis. As such, the incentives are consistent with prior sharing of incentive rates. n22

n22 See Pacific Gas and Electric Company, 90 FERC P 61,314 (1999), sharing of secondary uses of jurisdictional assets on a 50/50 basis.

41. With respect to the [**30] incentive for availability targets, our review indicates that this incentive payment, roughly 1 percent of the total projected annual non-fuel revenue requirement, was developed using a base line availability that was based on similar units with the same plant characteristics. We find that the target availability relied upon is a valid comparable measure. If in the future, based on the required annual informational filings, parties believe these incentives are not just and reasonable, they are free to file a complaint with the Commission detailing their concerns.

Cost to Supply Gas

42. The PPA is structured as a tolling agreement, giving Edison the responsibility for gas procurement and hedging for the life of the unit. Edison states that it will recover the fuel costs through the CPUC's Energy Resource Recovery Account (ERRA), which is a CPUC-approved balancing account in which Edison records fuel costs relating to Edison-owned generation stations.

43. SVMG n23 argues that since the fuel cost comprises roughly two-thirds of the total cost of electricity, the Commission's focus should be on whether or not the gas supply is cost-effective. SVMG concludes that if the proposal [**31] is approved, then the risk associated with the volatility of natural gas will be borne entirely by the ratepayers.

n23 SVMG is a voluntary association of industrial customers of PG&E and Edison.

44. The issue raised by SVMG appears to be largely a matter that will be subject to state oversight and regulation. The CPUC decision found that it is in the interest of the Edison ratepayers to have Edison recover the costs of operating Mountainview through the ERRA. The CPUC can exercise regulatory control by reviewing Edison's fuel acquisition practices in a manner similar to a utility-owned generating plant. With regard to the concern raised by SVMG, the Commission acknowledges that cost-based regulation may not always provide the clearest incentives to the utility to minimize costs for the end-use customer.

Other Miscellaneous Issues

45. As previously noted, the summer and winter availability incentives are subject to annual escalation. Our review indicates that these annual escalations are reasonable. With respect [**32] to the remaining two PPA items that are sub-

ject to escalation (allowance for SCR catalyst replacement and a minimum cost requirement for major equipment repair), we believe that these escalations have no direct impact on customer costs. The escalation of the equipment cost threshold only changes the limit on which costs are considered major, and the escalation of the SCR catalyst replacement simply addresses how much of these costs are to be recovered through the Pre-Authorized and Variable O&M charges.

46. The Commission finds good cause to grant waiver of Section 35.3(a) of its regulations to allow the PPA to be filed more than 120 days in advance of the proposed effective date. Accordingly, the Commission accepts the PPA for filing and allows it to go into effect without suspension or hearing on the date the parties execute the PPA. Edison should inform the Commission promptly of the effective date and the date when service commences, and file an executed version of the PPA with the Commission.

Affiliate Transaction Issues

47. Edison asserts that the Commission's rules regulating affiliate transactions made at market-based rates are not applicable to the instant proposal. [**33] First, Edison notes that the PPA itself is a cost-based rate schedule and argues that rates based on costs of service (so long as they provide a return on investment that reflects a reasonable balance of consumer and investor interests) are held to be just and reasonable whether or not they are between affiliates. Second, Edison states that its purchase of Mountainview was negotiated at arm's length between non-affiliated companies, and the Commission's affiliate abuse standards apply only to market-based rates. Third, Edison observes that the PPA dedicates all of the output of the project solely to Edison for the project's life (30 years). Edison concludes that, from a competition standpoint, the PPA is equivalent to Edison purchasing Mountainview from Sequoia at arms' [*61,644] length and passing through the costs to its ratepayers at cost-based rates.

48. Even if the Commission were to apply its affiliate standards to this transaction, Edison contends that it would meet them. Edison presents a benchmark analysis that it asserts demonstrates that the rates, terms and conditions of the PPA are low-cost and reasonable when compared to comparable alternatives selected by buyers in the competitive [**34] market. n24

n24 See Edison transmittal letter at 63-67 and Attachment F.

49. Finally, Edison rebuts supplier arguments that they could have offered the same power at a better price noting that other suppliers failed to come forward either with evidence in the California Commission proceeding of a willingness to provide a proposal or with a commercial proposal directly to Edison.

50. Sequoia's comments in support mirror Edison's remarks, and in addition, Sequoia argues that because Edison will be a sole shareholder of Mountainview and Mountainview will sell power only to Edison under a PPA subject to this Commission's jurisdiction, the Commission need not worry about benefits being transferred improperly from ratepayers to shareholders of an unregulated affiliate. Further, Sequoia asserts that because sales will be exclusively to Edison, the Commission need not address impacts on other wholesale customers.

51. Protesters argue that the Commission must scrutinize this proposal closely because of the potential [**35] harm that could occur to competitive wholesale markets. California Manufacturers comment that because no other competitor is likely to secure the type of favorable arrangements that Edison accorded to Mountainview, the proposal is likely to further discourage private investment in new power plants. Similarly, SVMG asserts that removing 1054 MW from the pool of demand for which independent generators would otherwise compete will dampen suppliers' enthusiasm for doing business in California. EPUC notes that the issue of whether Mountainview will compete in the market is not what provides it with an unfair competitive advantage; rather, the advantage is the long term of the PPA plus the special terms and conditions and the lack of opportunity for others to seek to provide that power. EPUC continues that market participants cannot participate where a fair and level playing field does not exist. SVMG observes that everyone except Edison's shareholders will bear the risk of Mountainview being under-utilized or of volatile gas prices, and Independent Producers object that Edison drafted the PPA unilaterally so that there was not the "'natural tension' typical of contract negotiations between [**36] unaffiliated companies that disciplines prices, terms and conditions." n25

n25 Independent Producers at 47.

52. Protesters cite several recent Commission orders addressing affiliate transactions and commenting on their potential impact on wholesale competition. These cases include two in which franchised utilities sought approval under FPA Section 203 to acquire generating facilities initially developed and marketed as merchant generation by a power marketer affiliate n26 and two others where franchised utilities entered into market- based PPAs involving affiliated merchant generators. n27

n26 See Cinergy Services, Inc., 102 FERC P 61,128 (2003), reh'g pending (Cinergy); Ameren Energy Generating Co., et al., 103 FERC P 61,128 (2003), reh'g pending (Ameren).

n27 See Entergy Services, Inc., 103 FERC P 61,256, reh'g denied, 105 FERC P 61,208 (2003) (Entergy); Southern Power Co., 104 FERC P 61,041 (2003), reh'g pending (Southern).

[**37]
53. Thus, several protesters assert that the Commission should not approve the proposal without applying the Edgar n28 standard. Competitive Suppliers conclude that the Commission must ensure that a market test has been met to the extent necessary for Commission approval. Independent Producers argue that the PPA should be scrutinized as an affiliate transaction even though the initial purchase was negotiated at arm's length because the two transactions are inextricably linked. They contend further that review under Edgar is not limited to market-based agreements, but believe that the larger purpose underlying the review of affiliate transactions is "the protection of competitive wholesale markets from the distorting influence of self-dealing between a utility and its affiliate." n29

n28 See infra note 12.

n29 Independent Producers at 11.

54. Even if an Edgar review is not required, several protesters suggest other standards that should be met. California Manufacturers assert that the only [**38] way Edison can demonstrate that it procured the lowest cost, most reliable resources that are available is through an open and fair competitive bid process. Independent Producers contend that Edison must show that no reasonable alternatives from non-affiliated entities were available.

55. Independent Producers object to alleged monopsonistic behavior by Edison, charging that Edison's refusal to buy from non-affiliates is anti- competitive. Other concerns raised include that the record does not show that Edison needs the capacity Mountainview offers, and that the proposed PPA is not consistent with the Commission's Code of Conduct.

Commission Determination

56. The rate presented in the PPA is a cost-based rate, which, heretofore, has not triggered the type of analysis laid out in Edgar. The issue in this case is whether the proposed cost-based formula is a just and reasonable rate based on traditional cost-based principles. This is what is [*61,645] required under the Commission's current policy and precedent.

57. Protesters' concerns about whether Edison's need for the capacity has been established and whether the PPA is consistent with Edison's Code of Conduct are not relevant [**39] The Commission need not examine the need for power in a proceeding filed under FPA Section 205. Moreover, Edison's need for capacity is one to be decided by a state regulatory authority. Edison's Code of Conduct pertains to its market-based transactions, and the PPA is strictly cost-based.

58. While we are conditionally accepting the PPA on the basis that it is consistent with the Commission's current policy, we will henceforth require that all affiliate long-term (one year or longer) power purchase agreements, whether at cost

or market, be subject to the conditions set forth in Edgar. There have been significant changes in electricity markets since the Edgar policy was announced more than twelve years ago. For a variety of reasons, including competitive supply entry, transmission open access, and other factors, in many regions of the country market prices are below cost-based rates. In Edgar, the Commission was concerned that the "buyer potentially may have unduly favored the rates offered by its affiliate seller over lower rates offered by other nonaffiliated sellers." n30 That concern remains. In order to protect wholesale power customers and guard against potential abuse [**40] of self-dealing in a market where cost-based rates may exceed market rates, the Commission will apply Edgar to all future power purchase agreements involving affiliates. This policy will be applied prospectively to avoid regulatory impact on transactions already filed for Commission approval, i.e., filed as of the date of issuance of this order.

n30 Edgar at 62,167.

59. We are also concerned that granting undue preference to affiliates, whether through cost-based or market-based transactions, could cause long-term harm to the wholesale competitive market Affiliate preference could discourage non-affiliates from adding supply in the local area, harming wholesale competition and, ultimately, wholesale customers.

60. In addition, Edison makes several commitments regarding its transaction. Edison states that because the PPA is cost-based, it provides a hedge against market volatility and eliminates the risk that Edison's shareholders could earn excess returns. n31 Edison states that the PPA does not confer [**41] any unfair competitive advantage because Mountainview will not compete in the competitive market and is prohibited from doing so for the 30-year term of the contract. Rather, Mountainview will dedicate its full output to Edison's customers at cost-based rates for the life of the contract. Edison goes on to explain that Mountainview will not receive compensation on a market basis. Moreover, Edison will need to purchase additional power from other resources and Mountainview will not be competing against those sources in the marketplace. n32

n31 Id. at 6.

n32 Id. at 26-27.

61. We will accept these commitments. To ensure that these commitments are implemented, we will condition our approval on the applicants agreeing to the following. Mountainview will be created and formed solely for the purpose of owning the Mountainview project and selling the output of the facility to Edison at cost-based rates under the PPA. Mountainview will not be eligible to sell at market-based rates and will not be entitled to any [**42] waivers typically granted by the Commission under that program. As discussed earlier in this order, Mountainview will be required to follow all Commission regulations and reporting requirements (e.g., filing FERC Form 1, and maintaining its books and records in accordance with the Uniform System of Accounts) applicable to traditional public utilities.

62. Independent Producers argue that Edison is harming wholesale competition by exercising its monopsony power as the sole buyer in its territory. Independent Producers state that Edison, by choosing only to deal with an entity that would become its affiliate, has succeeded in removing 1000 MW of demand from the competitive wholesale market and has extended its market power to other markets through preferential affiliate transactions and effectively pre-empted the market. However, Independent Producers have cited no case in which the Commission made such a finding under the FPA; more importantly, Independent Producers have asserted, but not demonstrated, that Edison has exercised such power here. Independent Producers have not shown why the relevant market in this case is so constrained and why a seller in Edison's territory does [**43] not have the ability to sell to utilities in other parts of California or the West. This is particularly relevant when a utility's transmission facilities are operated by an ISO or RTO, as here.

63. Aside from Independent Producers' concerns about monopsony power, the Commission is concerned that there is nothing to prevent Edison from marketing its purchased power from Mountainview and receiving market- based compensation, an action that is effectively contrary to the stated purpose of the PPA. Edison could change market outcomes

by bidding any energy or capacity from the Mountainview project into the California Independent System Operator's market below its costs. Because Edison is assured full cost recovery of its cost from Mountainview, it could benefit from this bidding strategy if it depresses a clearing price and it is a net buyer in that market. n33 This example also demonstrates [*61,646] the ability of the two affiliates to gain an advantage over other competitors by engaging in both cost-based and market-based sales. For example, an independent power producer without the cost recovery assurances that Edison enjoys here could not sustain bidding below its marginal cost. Moreover, [**44] lowering a clearing price below a competitive outcome will serve to dampen competitive price signals. Restricting Edison's resale of the output from Mountainview to spot market sales bid at the marginal cost of each unit will address these potential concerns. n34

n33 Edison would have had this incentive when participating as a net buyer prior to entering into the PPA; the existence of the PPA could merely magnify the incentive.

n34 We note that section 5.05 of the PPA recognizes that any energy from the project that is available and not already dispatched for the buyer (Edison) may be subject to dispatch by CAISO in real-time or on a day-ahead basis.

PURPA Issues

64. CAC and EPUC argue that the Commission must enforce PURPA in this proceeding by either rejecting the PPA or by conditioning its acceptance in a way that would require continued purchase of QF power by Edison. Contrary to these assertions, the Commission is not required to make any findings here regarding Edison's obligations under PURPA [**45] since Mountainview will not be selling as a QF. The standard for evaluating a cost-based rate schedule is whether the rate is just and reasonable.

The Commission orders:

(A) The proposed PPA is hereby accepted, as conditioned in Paragraphs B and C, to become effective on the date Edison and Mountainview execute the PPA, as discussed in the body of this order.

(B) Edison, on behalf of Mountainview, is hereby directed to submit a compliance filing within 30 days of the date of this order reflecting the modifications discussed in the body of this order.

(C) Mountainview is hereby directed to comply with applicable Commission regulations including complying with the Uniform System of Accounts, filing a FERC Form No. 1 on an annual basis, and making an annual informational filing by May 1 of each year detailing the prior calendar year's costs, as discussed in the body of this order.

By the Commission. Commissioner Kelly not participating.

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Session Name: GP060404

Date: April 04, 2006

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LexisNexis® Get & Print Summary Report

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Citation #1
106 FERC 61,183

Southern California Edison Company, On behalf of Mountainview Power Company, LLC, 106 F.E.R.C. P61183, 2004 FERC LEXIS 371 (F.E.R.C. 2004)

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SHEPARD'S SUMMARY

CASE HISTORY (2 citing references)

1. **Same case at:**
Southern California Edison Company on behalf of Mountainview Power Company, LLC, 109 F.E.R.C. P61086, 2004 FERC LEXIS 2223 (F.E.R.C. 2004)

2. **Same case at:**
S. Cal. Edison Co. ex rel. Mountainview Power Co. LLC, 110 F.E.R.C. P61319, 2005 FERC LEXIS 683 (F.E.R.C. 2005)

CITING DECISIONS (5 citing decisions)

ADMINISTRATIVE AGENCY DECISIONS

3. **Cited by:**
Union Elec. Co., 114 F.E.R.C. P61250, 2006 FERC LEXIS 530 (F.E.R.C. 2006)

4. **Cited by:**
Entergy Servs., Inc., 114 F.E.R.C. P61157, 2006 FERC LEXIS 315 (F.E.R.C. 2006)

5. **Followed by:**
Ameren Corporation, Dynegy Inc., Illinova Corporation, Illinova Generating Company, Illinois Power Company; Dynegy Midwest Generation, Inc., Dynegy Power Marketing, Inc., 108 F.E.R.C. P61094, 2004 FERC LEXIS 1572 (F.E.R.C. 2004)

108 F.E.R.C. P61094

6. **Followed by:**
Ameren Energy Generating Co., 108 F.E.R.C. P61081, 2004 FERC LEXIS 1571 (F.E.R.C. 2004)

108 F.E.R.C. P61081

7. **Distinguished by:**
Montana Megawatts I, LLC, NorthWestern Energy Division of NorthWestern Corporation, 107 F.E.R.C. P61140, 2004 FERC LEXIS 937 (F.E.R.C. 2004)

2004 FERC LEXIS 937

108 FERC ¶ 61,082
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, Joseph T. Kelliher,
and Suedeen G. Kelly.

Allegheny Energy Supply Company, LLC Docket No. ER04-730-000

ORDER GRANTING AUTHORIZATION TO MAKE AFFILIATE SALES

(Issued July 29, 2004)

1. In this order, we grant an application under section 205 of the Federal Power Act[1] by Allegheny Energy Supply Company, LLC (AE Supply) requesting Commission authorization to make market-based rate sales to its affiliate, The Potomac Edison Company (Potomac). AE Supply will make these sales pursuant to a master Full Requirements Service Agreement (FSA) and three transaction confirmations resulting from a Maryland Public Service Commission (Maryland Commission) supervised request for proposal (RFP) process. This order concludes that this competitive solicitation, as described below, satisfies the Commission's concerns regarding affiliate abuse. This order benefits customers by providing further guidance as to the Commission's standards by which it reviews market-based rate affiliate sales resulting from RFP processes.

Background

2. On April 13, 2004, AE Supply filed the instant application stating that as part of a RFP process supervised by the Maryland Commission, AE Supply had been selected to supply Potomac with full requirements service to fulfill some of Potomac's standard offer service obligations. For this reason, AE Supply seeks Commission authorization to make wholesale power sales to its affiliate, Potomac. AE Supply also requests waiver of the 120-day prior notice of filing requirement to allow an effective date of January 1, 2005.

3. AE Supply and Potomac are both wholly-owned subsidiaries of Allegheny Energy, Inc. AE Supply owns and operates generating facilities and markets energy and energy products at market-based rates. Potomac is a franchised electric utility that has transferred functional control of its transmission system to PJM Interconnection, L.L.C.

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[1] 16 U.S.C. § 824d (2000).

Potomac is required to provide standard offer service to any customer that does not choose an alternate supplier under Maryland's retail choice program.

4. On April 29, 2003, the Maryland Commission approved a consensus settlement agreement between twenty parties, including Potomac, setting forth a plan that established the framework for a competitive solicitation process to procure standard offer service supplies in Maryland after utility rate caps expire.[2]

5. On September 30, 2003, the Maryland Commission approved another settlement agreement that defined the specific requirements and processes necessary to implement the competitive solicitation. The settling parties collaborated to design a uniform, state-wide RFP process whereby Maryland's franchised electric utilities procured supplies to provide standard offer service to their retail customers.[3]

6. Subsequently, Potomac issued its RFP, soliciting bids for the provision of standard offer service supplies for several different customer classes. AE Supply responded to Potomac's request for proposals in the first, second, and fourth rounds of a four-round process. AE Supply won bids to provide Potomac a total of 187.6 MW for its commercial/small industrial customer class and a total of 227.2 MW for its large commercial/industrial customer class.[4] AE Supply bid to provide these services beginning January 1, 2005 for a 5-month and a 12-month term respectively. AE Supply lost its bids to provide Potomac with supplies for its small commercial customer class.

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[2] Maryland Commission Order No. 78400 at 5.

[3] Maryland Commission Order No. 78710 at 1-3.

[4] AE Supply won three bids in total. AE Supply will provide 94.6 MW for Potomac's commercial/small industrial class at $41.90/MWh for summer energy, $565.00/MW-month for summer demand, $52.00/Mwh for non-summer energy, and $550.00/MW-month for non-summer demand. Under its second bid, AE Supply will provide 93 MW for Potomac's commercial/small industrial class at $42.25/MWh for summer energy, $565.00/MW-month for summer demand, $52.80/Mwh for non-summer energy, and $550.00/MW-month for non-summer demand. Lastly, AE Supply will provide 227.2 MW for Potomac's large commercial/industrial class at $50.10/MWh for summer energy, $1025.00/MW-month for summer demand, $50.85/Mwh for non-summer energy, and $510.00/MW-month for non-summer demand.

AE Supply states that, as a result of the competitive solicitation, it will serve about half of Potomac's 2005 energy obligation.

7. AE Supply states that the Maryland Commission is deemed to have approved the results of Potomac's RFP because it issued no order to the contrary within two business days of receiving the results, as required by the settlement it had previously approved.

Notice of Filing and Pleadings

8. Notice of AE Supply's filing was published in the *Federal Register*, 69 Fed. Reg. 22,783 (2004), with protests and motions to intervene due on or before May 4, 2004. None was filed.

Discussion

9. As noted, AE Supply asks the Commission to accept a master FSA and three transaction confirmations allowing AE Supply to make sales to its franchised electric utility affiliate, Potomac. In order to meet the Commission's requirements for sales between affiliates, AE Supply offers evidence that these transactions are the result of direct head-to-head competition between itself and competing unaffiliated suppliers. More specifically, AE Supply offers evidence that the Maryland Commission-supervised RFP process satisfies the Commission's concerns regarding sales between affiliates.

10. As discussed above, this RFP was designed through settlement agreements between many diverse and interested parties. As stated in the Maryland Commission's order accepting the second settlement agreement, the settlement "reflects the outcome of extensive and exhaustive negotiations between informed parties of diverse and traditionally adverse interests."[5]

11. Each of Maryland's four electric utilities, including Potomac, issued RFPs through their websites. First-round bids were due more than three months after this posting, giving interested parties sufficient time to respond.

12. To qualify to submit bids, potential suppliers, whether affiliated or not, were required to submit: a signed confidentiality agreement; documentation that the potential

[5] Maryland Commission Order No. 78710 at 3.

supplier is a member of PJM and a qualified market buyer and market seller in good standing; documentation that the potential seller is authorized at the federal level to make wholesale sales of energy, capacity, and ancillary services at market-based rates; submission of a credit application and associated financial information to the relevant utility; and provision of liquid bid collateral to assure the commitment of the bidder.[6] By qualifying potential suppliers before they submitted bids, the RFP-issuing utilities guaranteed that all submitted bids met a minimum standard for certain non-price factors. An entity that did not qualify was given an opportunity to correct any problems, resubmit for qualification, and, if then qualified, submit bids.

13. Bids were submitted to each franchised electric utility in standardized spreadsheets. For each bid submitted to Potomac, potential suppliers were allowed to input a volume (in bid blocks of approximately 50 MW each), a price for summer energy (in $/MWh), a price for non-summer energy (in $/MWh), a price for summer demand (in $/MW-month), and a price for non-summer demand (in $/MW-month). Bidders were only able to choose the volume and price of their bids. For certain customer classes, Potomac solicited bids for different, set contract lengths. Potential suppliers were able to submit bids for any of the set contract lengths and could submit as many different bids as they chose. Bidders were not allowed to submit bids with terms other than those set by Potomac in the RFP.

14. Winning bids were selected on the basis of a single, calculated price for each individual bid. This number, specific to the Maryland RFP process, is called Discounted Average Term Price (DATP). The calculation to determine DATP involved creating a weighted average of different period prices for energy and demand, as well as discounting prices based on contract term and discount factors set by the RFP issuing utility. This calculation was applied using the same weighting method and discount factors for each bid regardless of affiliation. The only changes in this calculation from bid to bid were the values entered by the bidders (*i.e.*, volume and prices). Winning bids were then selected based on DATP alone.

15. Bids submitted in the Maryland RFPs were binding. Winning bidders received the actual price in their offers for each year of the term of their supply contract. Bidders were required to accept the terms of a master FSA. Winning bidders were not permitted to revise prices or any other terms and conditions of their supply contracts.

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[6] *Id.* at 10.

16. Potomac's RFP was monitored by an independent consultant. The Maryland Commission determined the consultant selection qualifications and evaluated potential candidates. The Maryland Commission then directed Potomac as to which candidate to hire and as to the terms and conditions under which the consultant was to be hired. The consultant was selected by, took direction from, and reported to the Maryland Commission. Its duties included monitoring the bid evaluation under the criteria set forth in the settlement agreements approved by the Maryland Commission.

17. In an effort to eliminate the need for bidders to incorporate a risk premium in their bid prices, the Maryland Commission approved a volumetric risk mechanism in the RFPs. To implement this volumetric risk mechanism, Potomac is required to trace standard offer service load served on a daily basis. An increment is triggered when standard offer service load increases more than 5 MW per bid block above the contracted load, while a decrement is triggered when this load decreases more than 3 MW below the contracted amount. In the case of an increment, the wholesale supplier will be paid the PJM spot market price for energy, capacity, and ancillary services plus $3 per MWh. In the case of a decrement, a new base load is established, and the wholesale supplier is released from its obligation to supply the decrement load at the original contract price. This mechanism allows bidders to make offers without considering the risk of standard-offer service demand shifts.

18. The Commission has stated that, in cases where affiliates are entering into market-based rate sales agreements, it is essential that ratepayers be protected and that transactions be above suspicion in order to ensure that the market is not distorted.[7] The Commission has approved affiliate sales resulting from competitive bidding processes after the Commission has determined that, based on the evidence, the proposed sale was a result of direct head-to-head competition between affiliated and competing unaffiliated suppliers.[8] When an entity presents this kind of evidence, the Commission has required assurance that: (1) a competitive solicitation process was designed and implemented

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[7] *See* Boston Edison Co. Re: Edgar Electric Energy Co., 55 FERC ¶ 61,382 at 62,167 (1991) (*Edgar*).

[8] *See* Connecticut Light & Power Company and Western Massachusetts Electric Company, 90 FERC ¶61,195 at 61,633-34 (2000); Aquila Energy Marketing Corp., 87 FERC ¶61,217 at 61,857-58 (1999); MEP Pleasant Hill, LLC, 88 FERC ¶61,027 at 61,059-60 (1999); *Edgar*, 55 FERC ¶61,382 at 62,167-69.

without undue preference for an affiliate; (2) the analysis of bids did not favor affiliates, particularly with respect to nonprice factors; and (3) the affiliate was selected based on some reasonable combination of price and non-price factors.[9]

19. We believe Potomac's RFP meets the *Edgar* standards. Designing Potomac's RFP (and the RFP's of Maryland's other franchised electric utilities) through a Maryland Commission proceeding increased the transparency of this process by keeping the design process public. Further, Potomac's RFP was part of the Maryland Commission's public record before it was issued, which allowed easier access to information such as the details of the bid selection process and potential supplier qualification criteria. Potomac was not allowed to change the terms of its RFP during the implementation phase, meaning that relevant information was available to potential bidders before the issuance of the RFP.

20. We believe the collaboration of parties with diverse interests helped ensure that affiliates of Maryland's franchised electric utilities were not given undue preference in the design phase of this competitive solicitation. Posting the RFPs publicly and providing ample response time helped ensure that affiliates of the franchised electric utility issuing the RFP did not receive undue preference during the bid submission phase of the RFP. Further, by pre-qualifying bidders using publicly available criteria, the franchised electric utilities eliminated the need to evaluate bids on certain non-price factors, thereby allowing bid selection based on price alone. Selecting bids based on only price ensured that affiliates were not given preferential treatment during the selection phase of the process.

21. Accordingly, we conclude that the Maryland Commission competitive bid process described by AE Supply satisfies the Commission's concerns regarding affiliate abuse. Therefore, we will grant AE Supply's request for authorization to make sales to its affiliate Potomac as part of its participation in this Maryland Commission-approved RFP process.

22. We also provide here guidance as to the standards the Commission will use in the future to evaluate whether an RFP such as the one in the instant filing meets the *Edgar* criteria. The underlying principle when evaluating an RFP under the *Edgar* criteria is that no affiliate should receive undue preference during any stage of the RFP. The

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[9] *Edgar*, 55 FERC ¶61,382 at 62,168.

following four guidelines will help the Commission determine if an RFP satisfies that underlying principle.[10]

a. Transparency: the competitive solicitation process should be open and fair.

b. Definition: the product or products sought through the competitive solicitation should be precisely defined.

c. Evaluation: evaluation criteria should be standardized and applied equally to all bids and bidders.

d. Oversight: an independent third party should design the solicitation, administer bidding, and evaluate bids prior to the company's selection.

Transparency principle

23. Transparency is the free flow of information to all parties. No party, particularly the affiliate, should have an informational advantage in any part of the solicitation process. The RFP and all relevant information about it should be released to all potential bidders at the same time. Instead of individually inviting specific bidders, the utility should allow all interested parties to bid on the RFP. All aspects of the competitive solicitation should be widely publicized. For example, the issuer can post the RFP on its website and issue a press release to that effect and/or advertise in the trade press. To compete effectively, bidders should have equal access to data relevant to the RFP. Any communication between RFP issuer and bidder that are not part of the bid should be made available to all other bidders. For example, the answers to clarifying questions should be released to all other bidders, but proprietary bid information should not be released.

24. These principles enhance the fairness and transparency of the entire process. Specific steps in the solicitation process may require more guidance to achieve optimal transparency. Two such examples are when a collaborative design is used or when post-bidding negotiation occurs.

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[10] Concurrently, the Commission is issuing an order that sets out the Commission's new guidelines for evaluating affiliate transactions under section 203 of the FPA. *See* Ameren Energy Generating Company and Union Electric Company, d/b/a AmerenUE, 108 FERC ¶ 61,081 (2004).

25. If the RFP is to be designed through a collaborative process, the entire process should be widely publicized and open. An independent third party can ensure meaningful participation by nonaffiliates and eliminate characteristics that improperly give an advantage to the affiliate, *e.g.*, the only acceptable interconnection point for a new nonaffiliate plant is at an affiliate's existing plant.

26. Negotiation may occur after the bidding; for example, when a shortlist has been compiled or a winner has been selected. If the affiliate is on the shortlist or wins, it is important to ensure that the affiliate has no undue advantage resulting from its affiliate relationship. One way to prevent such an advantage from occurring is for the independent third party to be the RFP issuer's agent in the negotiation with the affiliate.

Definition principle

27. The product or products sought through the RFP should be defined in a manner that is clear and nondiscriminatory. The RFP should state all relevant aspects of the product or products sought. At a minimum, these aspects include capacity and term, but other characteristics are usually necessary, among them fuel type, plant technology (*e.g.*, simple cycle gas turbine), and transmission requirements. If there are changes in the product specification, rebids should be allowed.

28. An RFP should not be written to exclude products that can appropriately fill the issuing company's objectives. This is particularly important if such exclusions tend to favor affiliates.

Evaluation principle

29. To fulfill the evaluation principle, RFPs should clearly specify the price and non-price criteria under which the bids are evaluated. Price criteria should specify the relative importance of each item as well as the discount rate to be used in the evaluation. Non-price criteria should also specify the relative importance of items such as firm transmission reservation requirements, including acceptable delivery points; credit evaluation criteria, such as the bond rating; the plant technology if more than one technology is listed in the RFP; plant performance requirements, such as availability; and the anticipated in-service date if the plant needs to be constructed.

30. Naturally, these criteria are not meant to be exhaustive; they are merely illustrative. Keeping in mind that affiliates should have no informational advantage, all

criteria should be specific and detailed so that all bidders can effectively respond to the RFP. Clear evaluation criteria will ensure that the RFP does not give an advantage to the affiliate.

31. RFP issuer and bidders will usually need to divulge commercially sensitive information in the solicitation process. Confidentiality agreements between the issuer and bidders can be signed to address this concern.

Oversight principle

32. Effective oversight of competitive solicitations can be accomplished by using an independent third party in the design, administration, and evaluation stages of the competitive solicitation process. Ensuring that the third party is independent and granting it at the outset the responsibility of ensuring that these guidelines are followed throughout the process will also minimize perceptions of affiliate abuse. Minimum standards for assuring independence and the scope of the third party's role are set forth below.

33. A minimum criterion for independence is that the third party has no financial interest in any of the potential bidders, including the affiliate, or in the outcome of the process.[11] Preferably, the independence criterion would be the same as that of an ISO or RTO.[12] In this context, "independence" means that the third party's decision-making process is independent of the affiliate and all bidders.[13] Without such independence, the third party could be biased towards the affiliate in order to enhance its financial position.

[11] Conference on Solicitation Processes for Electric Utilities, Docket No. PL04-6-000, June 10, 2004 (PL04-6 Conference), Comments of Maine Public Service Commission Chairman Welch, Tr. 78.

[12] PL04-6 Conference, Comments of John Hilke, Federal Trade Commission, Tr. 4.

[13] Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (2000), FERC Stats. & Regs., Regulations Preambles July 1996 – December 2000 ¶ 31,089 at 31,061 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12, 088 (2000), FERC Stats. & Regs., Regulations Preambles July 1996 – December 2000 ¶ 31,092 (2000), *affirmed sub nom.* Public Utility District No. 1 of Snohomish County, Washington, *et al.* v FERC, 272 F. 3d 607 (D.C. Cir. 2001).

Obviously, a similar concern could arise regarding an actual or potential financial interest link between the third party and any potential bidder. Independence can also be satisfied if the state commission has approved the selection of a third party on the basis of established independence criteria. In addition, the third party should not own or operate facilities that participate in the market affected by the RFP.

34. The independent third party should be able to make a determination that the RFP process is transparent and fair and that the RFP issuer's decision is not influenced by any affiliate relationships. For example, if the RFP issuer wishes to use a collaborative RFP design process, the independent third party should be the clearinghouse for comments by potential bidders on a draft RFP and should evaluate those comments as possible revisions to the RFP. The independent third party's role as the sole link for transmitting information between potential bidders and the RFP issuer would also help to ensure that the RFP design will not favor any particular bidder, particularly an affiliate. The independent third party should continue to be a conduit of information between utility and bidders in determining which of the original bid responses are qualified bids or may be included in a short list.

35. At the evaluation stage of the RFP process, the third party should be able to credibly assess all bids based on both price and non-price factors. It should be able to consider both generation asset bids and power purchase agreements. Also, it should be able to independently verify transmission characteristics that may limit the suitability of certain alternatives. The third party should have access to the same information that the RFP issuer uses in its evaluation and should be able to independently verify its correctness. The third party should also be able to evaluate non-price traits of various alternatives.

Potomac's RFP

36. Potomac's RFP process is an example of an RFP process that would meet the foregoing guidelines. We believe that the design, administration, and bid evaluation phases of Potomac's RFP were transparent. Potomac achieved transparency in the design phase through a collaborative process involving informed parties with diverse interests and an on-the-record, public Maryland Commission proceeding. Potomac was not allowed to change the terms of its RFP during its administration, meaning that relevant information was available to potential bidders before its issuance. Further, Potomac's RFP was part of the Maryland Commission's public record before it was issued, which

allowed easier access to information such as the details of the bid selection process and potential supplier qualification criteria.

37. We believe that Potomac's RFP was clearly defined. By including information such as bidder qualification criteria and bid evaluation method in the RFP, Potomac helped ensure that the parameters of the RFP were clearly defined prior to the solicitation of bids. Bidders had knowledge of the process through which they could bid and through which their bids would be evaluated before they were called upon to submit them. We believe that Potomac's RFP was clearly defined.

38. We believe Potomac evaluated bids based on standardized criteria and applied that criteria equally to all bids regardless of affiliation. By setting a minimum standard for non-price factors, Potomac was able to select bids based on price alone. Further, all bidders were required to accept the terms of the master FSA. Selecting bids based only on price ensured that affiliates were not given preferential treatment during the selection phase of the process. Potomac applied the above mentioned DATP calculation to each bid in the same manner and evaluated the bids based on the resulting discounted price. We believe Potomac applied its evaluation criteria to all bids equally.

39. We believe Potomac's RFP had sufficient independent oversight. As described above, Potomac's RFP was monitored by an independent consultant. The fact that this consultant was selected by the Maryland Commission and that the consultant's compensation was determined by the Maryland Commission before the issuance of the RFP helped ensure the consultant's lack of financial interest in the outcome of the RFP. This consultant reported its findings directly to the Maryland Commission. We believe the presence of this independent third party, as well as the involvement of the Maryland Commission, provided sufficient independent third-party oversight of the design, administration, and bid evaluation stages of Potomac's RFP.

40. Finally, we note that AE Supply is in an RTO. Part of the concern about affiliate transactions is that competitors can be foreclosed from the market. In regions with an RTO-operated market, there is less of a risk of foreclosure if all parties have the option of selling into that market. Therefore, we take added comfort here from the fact that this transaction takes place in a region with an RTO-operated market.

The Commission orders:

AE Supply's application for authorization to make sales to its affiliate, Potomac, pursuant to the master Full Requirements Service Agreement included in the instant filing is hereby granted, as discussed in the body of this order.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.

LEXSEE

Conectiv Energy Supply, Inc.

Docket No. ER05-121-000

FEDERAL ENERGY REGULATORY COMMISSION - COMMISSION

109 F.E.R.C. P61,385; 2004 FERC LEXIS 2752

ORDER ACCEPTING AND SUSPENDING POWER PURCHASE AGREEMENT, SUBJECT TO REFUND, AND ESTABLISHING HEARING PROCEDURES

December 30, 2004

CORE TERMS: bid, bidder, affiliate, supplier, customer, solicitation, retail, bidding, competitive, winning, documentation, subject to refund, undue preference, third party, oversight, market-based, wholesale, load, purchase contract, Federal Power Act, energy, standardized, administer, effective, non-price, nominal, entity, unduly, non-negotiable, transmission

PANEL:
[**1] Before Commissioners: Pat Wood, III, Chairman; Nora Mead Brownell, Joseph T. Kelliher, and Suedeen G. Kelly

OPINION:
[*62,738]

1. In this order, we will accept for filing a power purchase agreement (PPA) between Conectiv Energy Supply, Inc. (CESI) and its affiliate, Delmarva Power & Light Company (Delmarva), suspend it for a nominal period, to become effective on January 1, 2005, as requested, subject to refund, and establish hearing procedures. This order benefits customers by assuring sales among [*62,739] affiliates adhere to the Commission's standards for evaluating market-based rate affiliate sales resulting from RFP processes.

I. Background

2. On October 29, 2004, CESI filed the instant application under section 205 of the Federal Power Act. n1 CESI states that as part of a Request for Proposal (RFP) process, CESI has been selected to supply Delmarva with full requirements service to fulfill Delmarva's Virginia retail customer load obligation. For this reason, CESI seeks Commission authorization to make wholesale power sales to its affiliate, Delmarva, pursuant to the PPA. CESI requests an effective date of January 1, 2005.

n1 16 U.S.C. § 824d (2000).

[**2]
3. CESI and Delmarva are both wholly-owned subsidiaries of Pepco Holdings, Inc. CESI is a power marketer that owns no generation, transmission or distribution facilities, but has authority to sell power and energy at market-based rates. n2 Delmarva is a franchised electric utility that has transferred functional control of its transmission system to PJM Interconnection, L.L.C. (PJM). Delmarva is required to provide standard offer service to any customer that does not choose an alternate supplier under the Virginia Electric Utility Restructuring Act until 2010. n3 Delmarva provides standard offer service at fixed prices that are established by the Virginia Commission based on Delmarva's cost of purchased power.

n2 *See Conectiv Energy Supply, Inc.*, 83 FERC P 61,090 (1998), and *Conectiv Energy Supply, Inc.*, 91 FERC P 61,076 (2000), *order on reh'g*, 94 FERC P 61,068 (2001)

n3*See* § 56-576 et. seq. of the Code of Virginia.

[**3]

4. CESI states that on August 27, 2004, the representatives of Delmarva met with senior staff members of the Virginia Commission to discuss the power purchase contract, other documentation and the procedure that would be used to select the wholesale power supplier for Delmarva's retail customer load after December 31, 2004. n4 During that meeting, the Delmarva representatives described the RFP processes that had been used in Maryland and in the District of Columbia and suggested that those RFP processes might also be used in Virginia. Upon learning that the Virginia Commission would not be opening a formal proceeding to establish an RFP process for Virginia, Delmarva commenced implementation of an RFP process that CESI states was virtually the same as those that were used in Maryland and the District of Columbia. n5

n4 CESI's obligation to meet Delmarva's Virginia customer requirements under a master agreement that provided for CESI to sell power to Delmarva Power required to meet its obligation as the provider of last resort (PLR transaction) is scheduled to terminate on December 31, 2004.

n5 The RFP process ultimately adopted in Maryland was reviewed by the Commission in *Allegheny Energy Supply Company, LLC*, 108 FERC P 61,082 (2004) (*Allegheny*).

[**4]

5. Subsequently, Delmarva issued its RFP (Delmarva RFP), notifying sixty-two potential suppliers by letters dated September 2, 2004, that it would be seeking bids to provide 97.5 MW of full requirements service for its Virginia retail customer load for a term of seventeen months, beginning January 1, 2005. n6 Nine power suppliers qualified to bid. CESI states that the power purchase contract terms and conditions were established prior to bidding and because such terms and conditions were non-negotiable, bidders competed on the basis of price only. On October 6, 2004, Delmarva received seven bids from well-known energy suppliers. It awarded the power purchase contract to CESI, the lowest bidder, on October 7, 2004.

n6 CESI states that this contract term was used to synchronize Delmarva's power purchase contracting process with the PJM annual planning periods, which begin on June 1 and extend through May 31 of the next calendar year.

6. CESI states that Delmarva filed an application with the Virginia Commission seeking [**5] approval of the PPA under the Virginia Affiliates Act and seeking retail rate adjustments that reflect the prices that Delmarva will pay to CESI as the low price bidder. The Virginia Commission set a public hearing for these filings to convene on March 16, 2005. The Virginia Commission further permitted the implementation of an interim fuel rate, subject to refund, on and after January 1, 2005, applicable on a uniform basis to all of Delmarva's Virginia jurisdictional customers. n7

n7 *See Public Order of the Virginia State Corporation Commission, Order for Notice and Hearing*, CASE NOS. PUE-2004-00124 PUE-2004-00125, issued November 17, 2004. Delmarva's application with the Virginia Commission discloses, on a confidential basis, the prices that were bid by other prospective suppliers. Delmarva will disclose the identity of the bidders to the Virginia Commission and its staff, if requested, as provided in the Confidentiality Agreement that is part of the Delmarva RFP.

II. Notice of Filing and Pleadings

[**6]

7. Notice of CESI's filing was published in the *Federal Register*, n8 with protests and motions to intervene due on or before November 19, 2004. None were filed.

n8 69 Fed. Reg. 65,422 (2004).

III. Discussion

8. As noted above, CESI asks the Commission to accept a PPA allowing CESI to make sales to its franchised electric utility affiliate, Delmarva. In order to meet the Commission's requirements for sales between affiliates, CESI offers evidence that the RFP process applied to this PPA satisfies the standards announced by the Commission in *Allegheny* for determining when an RFP satisfies the Commission's concerns regarding affiliate abuse. n9

n9 *Allegheny*, 108 FERC P 61,082.

9. The Commission has stated that, in cases where affiliates are entering into market-based rate sales [**7] agreements, it is essential that ratepayers [*62,740] be protected and that transactions be above suspicion in order to ensure that the market is not distorted. n10 The Commission has approved affiliate sales resulting from competitive bidding processes after the Commission has determined that, based on the evidence, the proposed sale was a result of direct head-to-head competition between affiliated and competing unaffiliated suppliers. n11 When an entity presents this kind of evidence, the Commission has required assurance that: (1) a competitive solicitation process was designed and implemented without undue preference for an affiliate; (2) the analysis of bids did not favor affiliates, particularly with respect to non-price factors; and (3) the affiliate was selected based on some reasonable combination of price and non-price factors. n12

n10 *See Boston Edison Co. Re: Edgar Electric Energy Co.*, 55 FERC P 61,382 at 62,167 (1991) (*Edgar*).

n11 *See Connecticut Light & Power Company and Western Massachusetts Electric Company*, 90 FERC P 61,195 at 61,633-34 (2000); *Aquila Energy Marketing Corp.*, 87 FERC P 61,217 at 61,857-58 (1999); *MEP Pleasant Hill, LLC*, 88 FERC P 61,027 at 61,059-60 (1999); *Edgar*, 55 FERC P 61,382 at 62,167-69.

[**8]

n12 *Edgar*, 55 FERC P 61,382 at 62,168.

10. In *Allegheny*, the Commission provided guidance as to the standards the Commission will use to evaluate whether an RFP such as the one in the instant proceeding meets the *Edgar* criteria. As the Commission stated, the underlying principle when evaluating an RFP under the *Edgar* criteria is that no affiliate should receive undue preference during any stage of the RFP. The Commission indicated that the following four guidelines will help the Commission determine if an RFP satisfies that underlying principle:

a. Transparency: the competitive solicitation process should be open and fair.

b. Definition: the product or products sought through the competitive solicitation should be precisely defined.

c. Evaluation: evaluation criteria should be standardized and applied equally to all bids and bidders.

d. Oversight: an independent third party should design the solicitation, administer bidding, and evaluate bids prior to the company's selection.

11. As discussed above, Delmarva commenced implementation of [**9] an RFP process that was similar to those used in Maryland and the District of Columbia. On September 7, 2004, Delmarva activated a website n13 which provided detailed information to prospective bidders. The PPA terms and conditions were established prior to bidding and because such terms and conditions were non-negotiable, bidders competed on the basis of price only.

n13 (www.conectiv.com/varfp).

12. To be eligible to submit bids, potential suppliers were required to submit: an expression of interest; a signed confidentiality agreement; documentation that the potential supplier is a member of PJM and a qualified market buyer and market seller in good standing; documentation that the potential seller is authorized at the federal level to make wholesale sales of energy, capacity, and ancillary services at market-based rates; and submission of a credit application and associated financial information. n14 By pre-qualifying potential bidders before the bid process began, CESI states that Delmarva eliminated the need [**10] to evaluate bidders based on non-price factors, thereby allowing bid selection based solely on price. An entity that had any deficiencies in its submittal was notified by Delmarva by email. The entity then had the opportunity to correct deficiencies, if resubmitted in a timely manner.

n14 *Delmarva RFP* at 6-7 (October 4, 2004).

13. Bids were submitted in standardized Bid Form Spreadsheets. For each bid submitted to Delmarva, potential suppliers were allowed to input bid blocks information, price period within contract term, price quote for bid block offered, volume weighing factors, discount factors, load weighted prices, discounted price for evaluation purposes, tag number, and complete/incomplete flag. Bidders could submit as many different bids as they chose. Bidders were not allowed to submit bids with terms other than those set by Delmarva in the RFP.

14. The winning bidder was selected on the basis of a single, calculated price for each individual bid. This single parameter used to compare all bids is called [**11] Discounted Average Term Price (DATP). The winning bidder, CESI, was selected based on DATP alone.

15. Bids submitted were binding. The winning bidder received the actual price and volume quotes entered on their Bid Form Spreadsheet. Bidders were required to accept the terms of the pro forma Full Requirements Service Agreement. Winning bidders were not permitted to revise prices or any other terms and conditions of their supply contract.

16. CESI explains that an independent third party did not design the solicitation, administer bidding or evaluate bids prior to Delmarva's selection. However, CESI states that it believes this RFP process meets the Commission's oversight principle because it utilized the documentation and process adopted through the collaborative process in Maryland and approved by the Commission in the *Allegheny* order. n15 CESI submits that since that same RFP process as was adopted in Maryland was used here, there can be no assertion that CESI had any undue preference in the design phase of the competitive solicitation, including, but not limited to, the form of the PPA and the standards for qualifying bidders. CESI [*62,741] contends that it was not necessary to use [**12] an independent third party to evaluate bids in this case since the process was standardized such that Delmarva's only role was to select the lowest price submitted by the bidders.

n15 *Allegheny*, 108 FERC P 61,082.

17. CESI further states that, in an effort to mitigate wholesale suppliers' exposure to volumetric risk associated with non-residential customer migration, the Virginia Commission provided that certain restrictions will apply to customers who, having left standard offer service, then return to standard offer service. This is outlined in the RFP. According to CESI, this mechanism allowed bidders to make offers without considering the risk of standard offer service demand shifts. However, at this time, no retail customers within Delmarva's Virginia service area are being served by a competitive service provider. Delmarva's RFP also stated that Delmarva will not adjust the prices paid to the winning bidder during the procurement term of the transaction due to changes in PJM or [**13] other market factors with a corresponding, contemporaneous change in retail rates. CESI states that, by statute, Delmarva may not request that the Virginia Commission change its retail rates more than one time in a twelve-month period.

18. CESI acknowledges in its filing that an independent third party did not design the solicitation, administer bidding or evaluate bids prior to Delmarva's selection. Because the RFP does not meet the oversight principle as announced in *Allegheny*, the Commission is unable to determine that no affiliate received undue preference during any stage of the RFP. For example, prospective bidders were required, among other things, to submit a credit application and associated financial information. Without independent third-party oversight, such criteria could be used to limit potential competitors from submitting bids. On this basis, the Commission's preliminary analysis indicates that the PPA between CESI and Delmarva that resulted from the Delmarva RFP has not been shown to be just and reasonable, and may be unjust, unreasonable, unduly discriminatory or preferential or otherwise unlawful. CESI's application raises issues of material fact that cannot [**14] be resolved based on the record before us and are more appropriately addressed in the hearing ordered below.

19. Therefore, we will accept the PPA for filing, suspend it for a nominal period, to become effective on January 1, 2005, as requested, subject to refund, and establish hearing procedures.

20. The hearing should determine: (1) whether in the design and implementation of the Delmarva RFP unduly preferred its own affiliate, CESI; and (2) whether the credit criteria and analysis unduly favored CESI.

The Commission orders:

(A) The PPA is hereby accepted for filing, suspended for a nominal period, to become effective on January 1, 2005, as requested, subject to refund, as discussed in the body of this order.

(B) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and by the Federal Power Act, particularly sections 205 and 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R., Chapter I), a public hearing shall be held concerning the justness and reasonableness [**15] of the PPA between CESI and Delmarva that resulted from the Delmarva RFP.

(C) A Presiding Judge, to be designated by the Chief Judge, shall, within fifteen (15) days of the date of the Presiding Judge's designation, convene a prehearing conference in these proceedings in a hearing room of the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, DC 20426. Such conference shall be held for the purpose of establishing a procedural schedule. The Presiding Judge is authorized to establish procedural dates, and to rule on all motions (except motions to dismiss) as provided in the Commission's Rules of Practice and Procedure.

By the Commission. Commissioner Kelliher dissenting with a separate statement attached.

DISSENTBY: KELLIHER

DISSENT:

Joseph T. KELLIHER, Commissioner *dissenting*:

[Issued December 30, 2004]

I dissent from the decision in this order to set the power purchase agreement (PPA) between Conectiv Energy Supply, Inc. (Conectiv) and its affiliate, Delmarva Power & Light Company (Delmarva) for hearing.

The Commission has explained that its concern in cases where affiliates are entering into market-based rate sales agreements is that ratepayers be protected and that transactions [**16] be above suspicion in order to ensure that the market is not distorted. n16 The Commission has approved affiliate sales resulting from competitive bidding processes where the Commission determined that the proposed sale was the result of direct head-to-head competition between affiliated and competing unaffiliated suppliers. n17 In *Allegheny Energy Supply Co., LLC*, 108 FERC P 61,082 at P22 (2004)(*Allegheny*) the Commission stated that "the underlying principle when evaluating an RFP under the *Edgar* criteria is that no affiliate should receive undue preference during any stage of the RFP" and outlined four "guidelines," as opposed to requirements, to "help" the Commission determine if an RFP satisfies that underlying principle. [*62,742] *Allegheny* did not indicate that failure to meet all four "guidelines" mandated a hearing.

n16 *Boston Edison Co. Re: Edgar Electric Energy Co.*, 55 FERC P 61,382 at 62,167 (1991)(*Edgar*).

n17 *See Connecticut Light & Power Co. and Western Massachusetts Electric Co.*, 90 FERC P 61,195 at 61,633-34 (2000); *Aquila Energy Marketing Corp.*, 87 FERC P 61,217 at 61,857-58 (1999); *MEP Pleasant Hill, LLC*, 88 FERC P 61,207 at 61,059-60 (1999); *Edgar*, 55 FERC at 62,167-69.

[**17]

Here, the Commission's concern appears to be with only one of the four guidelines:

> oversight by an independent third party. However, the RFP process used here was the same process that had been reviewed and approved by the Commission in *Allegheny*. Moreover, in this instance, sixty-two potential suppliers were notified, nine power suppliers qualified to bid, and seven bids were submitted. Significantly, <u>no</u> protests were filed. In these circumstances, it is reasonable to find the absence of undue preference. For that reason, I would accept the PPA rather than set it for hearing.

Finally, I emphasize my view that the four criteria set forth in *Allegheny* constitute guidelines the Commission will consider on a case-by-case basis in evaluating an RFP in an affiliate situation rather than a "bright-line" test that must be satisfied to avoid a hearing.

Joseph T. Kelliher

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1	109 FERC 61,385	done	done

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Conectiv Energy Supply, Inc., 109 F.E.R.C. P61385, 2004 FERC LEXIS 2752 (F.E.R.C. 2004)

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Citing Ref. Signal: *Hidden*

SHEPARD'S SUMMARY

CASE HISTORY (3 citing references)

1. **Connected case at:**
Conectiv Energy Supply, Inc., 83 F.E.R.C. P61090, 1998 FERC LEXIS 803 (F.E.R.C. 1998)

2. **Connected case at:**
Conectiv Energy Supply, Inc., 91 F.E.R.C. P61076, 2000 FERC LEXIS 857 (F.E.R.C. 2000)

3. **Connected case at:**
Delmarva Power & Light Company, Conectiv Delmarva Generation, Inc., Atlantic City Electric Company, Conectiv Atlantic Generation, LLC, Conectiv Energy Supply, Inc., Conectiv Energy Supply, Inc., Delmarva Power & Light Company, 94 F.E.R.C. P61068, 2001 FERC LEXIS 123 (F.E.R.C. 2001)

LEXSEE

Wisconsin Public Service Corporation

Docket No. ER05-164-000

FEDERAL ENERGY REGULATORY COMMISSION - COMMISSION

109 F.E.R.C. P61,319; 2004 FERC LEXIS 2661

ORDER ACCEPTING AND SUSPENDING RATE SCHEDULES AND ESTABLISHING HEARING AND SETTLEMENT JUDGE PROCEDURES

December 21, 2004

CORE TERMS: settlement, affiliate, protest, megawatt, customer, purchase agreement, transmission, wholesale, Commission's Rules of Practice, market-based, calendar year, non-affiliated, effective, replace, subject to refund, tariff, non-affiliate, affiliated, comparable, cost-based, trial-type, long-term, nominal, motion to intervene, natural gas, intervene, energy, paying, Federal Power Act, evidentiary hearing

PANEL:
[**1]

Before Commissioners: Pat Wood, III, Chairman; Nora Mead Brownell, Joseph T. Kelliher, and Suedeen G. Kelly

OPINION:
[*62,521]

1. In this order we accept for filing a power purchase agreement between Wisconsin Public Service Corporation (WPSC) and its affiliate Upper Peninsula Power Company (UPPCo), suspend it for a nominal period, to become effective January 1, 2005, subject to refund and establish hearing and settlement judge procedures. This order benefits customers by ensuring the justness and reasonableness of this power purchase agreement between affiliated companies and by protecting non-affiliated customers against undue discrimination.

I. Background

2. This case involves a power purchase agreement between WPSC and its affiliate UPPCo. n1 Currently, UPPCo purchases 65 megawatts of power from WPSC under the terms of a 2002 power purchase agreement (PPA 1) which expires on December 31, 2007. WPSC and UPPCo have renegotiated their agreement and now seek permission to terminate PPA 1 early and to replace it with a second power purchase agreement (PPA 2) that would take effect on January 1, 2005 and continue at least until December 31, 2014. n2

n1 Both companies are subsidiaries of Wisconsin Public Service Resources Corporation.

[**2]

n2 PPA 2 does not have a fixed termination date. Instead, there is a 10-year fixed term, after which the agreement renews automatically until a party gives three years written notice of termination.

3. WPSC states that UPPCo's service area is in the Upper Peninsula of Michigan and lies in a constrained portion of the interstate transmission network known as the Wisconsin-Upper Michigan System (WUMS). n3 Since 1999, UPPCo has

on three occasions issued a request for proposals for 65 megawatts of firm power, which have not resulted in any responsive bids, other than WPSC. WPSC indicates that due to the unique transmission constraints present in the WUMS area, it is unlikely that another request for proposals would yield a different result.

n3 The transmission constraint problems present in WUMS have been well documented. *See, e.g.*, *Wisconsin Electric Power Co.*, 79 FERC P 61,157 (1997) (rejecting a proposed merger in WUMS and discussing market concentration issues); *Midwest Independent Transmission System Operator*, 108 FERC P 61,163 at P 73, 90-94, 296-98, *order on reh'g*, 109 FERC P 61,157 (2004) (discussing transmission constraints in WUMS and how to accommodate them).

[*62,522] [**3]
4. After the failure of UPPCo's 1999 request for proposals, it entered into PPA 1 with WPSC. n4 Under PPA 1, UPPCo receives 65 megawatts of capacity from WPSC. Because of greater than expected price volatility in the cost of natural gas, the price UPPCo is paying for energy under PPA 1 is greater than either UPPCo or WPSC anticipated. n5 Hence, the parties seek to replace PPA 1 with PPA 2.

n4 PPA 1 was set for hearing by the Commission in *Wisconsin Public Service Corp.*, 101 FERC P 61,402 (2002), and the parties reached a settlement which was approved in *Wisconsin Public Service Corp.*, 104 FERC P 61,192 (2003).

n5 WPSC states that UPPCo's capacity charges under PPA 1 are relatively low, but the energy charge is tied to the cost of power production at Pulliam-31. As the price of natural gas has increased over the past several years, so has the total price UPPCo is paying for its power.

5. WPSC states that most of the terms of PPA 2 are similar to those [**4] found in PPA 1, but that a few differences exist. Under PPA 2, UPPCo is permitted to unilaterally adjust its power requirements annually so long as it takes at least 40 megawatts and not more than 65 megawatts of power.

6. The other major difference is that under the proposed PPA 2 UPPCo's rates are based on an Average Rate Provision (ARP) rather than the costs of a specific generating unit. The ARP is the average price WPSC charges, under its market based rate authority, n6 to all non-affiliated wholesale long-term power purchasers in the Eastern Wisconsin region of WUMS. n7 By using the ARP as a proxy, WPSC contends that the rates under PPA 2 will accurately reflect the current market price for power in the Wisconsin portion of WUMS and should satisfy any affiliate abuse concerns the Commission may have. According to WPSC, PPA 2 will result in a 10-15 percent decrease in UPPCo's power costs during calendar year 2005. n8 In exchange for this lower rate, UPPCo agrees to purchase the power at this rate for at least 10 years beyond what was contemplated in PPA 1.

n6 The Commission most recently granted WPSC market based rate authority in *Wisconsin Public Service Corp.*, 81 FERC P 61,072 (1997). WPSC states that it filed its three-year market-based rate authority update in September of 2004.
[**5]

n7 WPSC notes that, even though the ARP is based on market based rate contracts, WPSC is prohibited from directly negotiating a contract with an affiliated company such as UPPCo under the Commission's market-based rate policies.

n8 WPSC's filing does not address potential cost savings beyond the calendar year 2005 timeframe.

II. Notices and Interventions

7. Notice of WPSC's filing was published in the *Federal Register*, 69 Fed. Reg. 67,337 (2004), with protests or interventions due on or before November 22, 2004. Algoma Group WPS Wholesale Customers n9 jointly with Great Lakes Utilities (collectively Algoma) and Upper Peninsula Transmission Dependent Utilities n10 (Upper Peninsula TDUs) filed motions to intervene and protest. Wisconsin Public Power Inc. (WPPI) filed a motion to intervene and also submitted comments. UPPCo filed a motion to intervene. WPSC filed an answer to the protests.

n9 Algoma Group is a group of municipally-owned electric utilities and electric cooperatives purchasing power from WPSC. For purposes of this filing, the Algoma Group includes the Wisconsin cities of Manitowoc and Marshfield, as well as Alger Delta Electric Cooperative.

[**6]

n10 The Upper Peninsula TDUs include the Village of L'Anse Electric Utility, Baraga Municipal Water & Light Plant, City of Escanaba, City of Gladstone, Negaunee Electric Department and Ontonagon County Rural Electrification Association.

8. Upper Peninsula TDUs and WPPI argue that the WUMS is a highly concentrated, constrained market and note that the Midwest Independent Transmission System Operator, Inc.'s (Midwest ISO) Independent Market Monitor (IMM) has classified this area as a Narrow Constrained Area. In this vein, Upper Peninsula TDUs take issue with WPSC's contention that the proposed sale is made at a verifiably competitive rate. n11

n11 Upper Peninsula TDUs Protest at 7-10, 15; WPPI Comment at 3-4. A "Narrow Constrained Area" is defined under the Midwest ISO's Transmission and Energy Markets Tariff § 63.4.1(b) as "an electrical area identified by the IMM that is defined by one or more Binding Transmission Constraints that are expected to be binding for at least five hundred (500) hours per year during a given twelve month period and within which one or more suppliers are pivotal."

[**7]

9. Upper Peninsula TDUs provide anecdotal information of unsuccessful requests for proposals in this area. They note that, when two of their members, Alger Delta and Ontonagon, sought bids from 25 potential suppliers in 1999, they received no responses. n12 Ontonagon then attempted to obtain one megawatt of capacity from WPPI, but was informed that Wisconsin Electric Power Company (WEPCO) had reserved all of the available transmission capacity between Wisconsin and the Upper Peninsula for its marketing affiliate. Ultimately, Ontonagon negotiated a deal with WEPCO at rates comparable to those offered by WPPI. n13

n12 Upper Peninsula TDUs Protest at 5.

n13 Upper Peninsula TDUs protest at 15.

10. Upper Peninsula TDUs state that WPSC's request for approval of a market-based rate sale to an affiliate is outside the framework of the market-based rate authority that WPSC has obtained from the Commission (*i.e.*, not pursuant to WPSC's market-based rates tariff) and that WPSC's claim of a significant rate reduction [**8] for UPPCo is limited and speculative given that WPSC only asserts that for a single calendar year, out of at least a ten-year term, UPPCo's charges will be reduced from the PPA 1 level by approximately 10-15 percent. n14

n14 Upper Peninsula TDUs protest at 6, 7 and 11.

11. Upper Peninsula TDUs request that, if the Commission accepts PPA 2, that it impose several additional conditions, including that UPPCo's energy costs be capped at cost-based levels and that [*62,523] WPSC and UPPCo be required to make power available to Upper Peninsula TDUs on rates, terms, and conditions no less favorable than those at which WPSC makes power available to UPPCo. Upper Peninsula TDUs suggest that the rates charged under PPA 1 be used as the cost-based ceiling until December 31, 2005 (when PPA 1 would have expired). After December 31, 2005, Upper Peninsula TDUs suggest that WPSC be required to file a cost-based rate ceiling for Commission review.

12. Upper Peninsula TDUs explain that they are concerned that, as their members' long term power [**9] purchase agreements expire, these members will find that WPSC and UPPCo have monopolized all the available transmission capacity into WUMS, leaving none for other utilities to meet the TDU members' native load needs. n15

n15 Upper Peninsula TDUs protest at 5, 6 and 16.

13. Algoma requests that the Commission set the matter for investigation and hearing. Algoma notes that, in addition to affiliate abuse concerns, PPA 2 raises basic issues for WPSC's other wholesale customers, including concerns that the sale: 1) may shift costs to other wholesale customers' service under WPSC's W-2A tariff; and 2) appears to confer upon UPPCo impermissible advantages vis-a-vis WPSC's other non-affiliate customers receiving service under market based rates.

14. Algoma also raises concerns that, in contrast to PPA 1, which required the agreement of both parties to change UPPCo's 65 megawatts capacity reservation, PPA-2 grants UPPCo the unilateral right to adjust demand nominations annually within a bandwidth of 40 megawatts to 65 [**10] megawatts. Hence, if UPPCo were to take only 40 megawatts of power in a given year, up to 25 megawatts of firm capacity would be removed from the denominator of the Algoma settlement formula rate, representing a potential cost shift of 0.8 percent for Algoma customers. n16 This result, says Algoma, would be unfair to WPSC's non-affiliated wholesale customers taking service under the W-2A tariff.

n16 Algoma protest at 4 and 5.

15. Algoma also objects to the fact that they have been subject to the same market forces that rendered UPPCo's deal uneconomical, and yet it is unclear why UPPCo should be afforded the opportunity to replace its deal with a better one, other than the fact that UPPCo is a WPSC affiliate. n17

n17 Algoma protest at 8.

III. Discussion

16. Pursuant to Rule 214, of the Commission's Rules of Practice and Procedure, 18 C.F.R. [**11] § 385.214 (2004), the timely, unopposed motions to intervene serve to make Algoma, Upper Peninsula TDUs, UPPCo, and WPPI parties to this proceeding. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2004), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We are not persuaded to accept WPSC's answer, and therefore will reject it.

17. Since this is an affiliate transaction, the Commission's affiliate abuse standards as discussed in the *Edgar* case apply. n18 Under the *Edgar* policy, a company bears the burden of demonstrating a lack of affiliate abuse in transactions between affiliated companies. n19 Generally, the easiest way to demonstrate lack of affiliate abuse is to conduct an inde-

pendently-administered request for proposals bidding process. n20 However, we agree with WPSC that the unique circumstances in WUMS, n21 and the failure of prior requests for proposals, means that conducting another request for proposals is not a realistic option for UPPCo at the present time. n22 Accordingly, we reject WPSC's proposal that we accept PPA 2 subject to UPPCo's conducting a new request for proposals [**12] in early 2005 instead of setting the matter for hearing.

n18 *See Boston Edison Co. Re: Edgar Electric Energy Co.*, 55 FERC P 61,382 (1991) (*Edgar*).

n19 *See Edgar*, 55 FERC P 61,382 at 62,167.

n20 *See, e.g., Ameren Energy Generating Co.*, 108 FERC P 61,081 (2004); *Allegheny Energy Supply Co.*, 108 FERC P 61,082 (2004). *See also Southern California Edison Co. on behalf of Mountainview Power Co. LLC*, 106 FERC P 61,183 (2004), *reh'g pending*.

n21 *See supra* note 3.

n22 *Allegheny Energy Supply Co.*, 108 FERC P 61,082 at P 18 (2004) (explaining that while a request for proposals is not the only way to demonstrate lack of affiliate abuse, a properly structured request for proposals is an effective method of demonstrating that the "head-to-head" prong of the *Edgar* test has been met).

18. Aspects of WPSC's proposed [**13] PPA 2 raise issues of material fact that cannot be resolved based on the record before us, and are more appropriately addressed in the hearing and settlement judge procedures ordered below. n23

n23 Among the issues that should be considered at the hearing or before a settlement judge are: 1) whether the ARP is based on a sufficiently large sample of comparable long-term market rate contracts to preclude affiliate abuse given the unique circumstances in WUMS; 2) whether power purchase agreements between WPSC and similarly-situated non-affiliate wholesale customers allow comparable variations in annual power nominations to those proposed in PPA 2; 3) whether a similarly-situated non-affiliate wholesale customer would be permitted to terminate an unfavorable long-term power purchase agreement and replace it with a power purchase agreement with terms and conditions similar to those found in PPA 2; 4) whether PPA 2 is reasonably likely to reduce UPPCo's power costs beyond the calendar year 2005 timeframe; 5) whether an automatic renewal clause is appropriate in a power purchase agreement between affiliates; and 6) whether UPPCo's wholesale power customers are likely to be put at a competitive disadvantage if PPA 2 is accepted given the transmission constraints present in WUMS and the formula-based rates employed by several of UPPCo and WPSC's existing non-affiliated wholesale customers.

[**14]
19. The Commission's preliminary analysis indicates that PPA 2 has not been shown to be just and reasonable, and may be unjust, unreasonable, [*62,524] unduly discriminatory or preferential or otherwise unlawful. Therefore, we will accept PPA 2 for filing, suspend it for a nominal period, to become effective January 1, 2005, as requested, subject to refund, and set it for hearing and settlement judge procedures as further described below.

20. While we are setting these matters for a trial-type evidential hearing, we encourage the parties to make every effort to settle their disputes before hearing procedures are commenced. To aid the parties in their settlement efforts, we will hold the hearing in abeyance and direct that a settlement judge be appointed, pursuant to Rule 603 of the Commission's Rules of Practice and Procedure. n24 If the parties desire, they may, by mutual agreement, request a specific judge as a settlement judge in the proceeding; otherwise the Chief Judge will select a judge for this purpose. n25 The settlement judge shall report to the Chief Judge and the Commission within 60 days of the date of this order concerning the status of settlement discussions. Based on this [**15] report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions or provide for the commencement of a hearing by assigning the case to a presiding judge.

n24 18 C.F.R. § 385.603 (2004).

n25 If the parties decide to request a specific judge, they must make their request to the Chief Judge by telephone at 202-502-8500 within five days of the date of this order. The Commission's website contains a listing of Commission judges and a summary of their background and experience (www.ferc.gov - click on Office of Administrative Law Judges).

The Commission orders:

(A) WPSC's proposed PPA 2 is hereby accepted for filing and suspended for a nominal period, to become effective January 1, 2005, as requested, subject to refund, as discussed in the body of this order.

(B) Pursuant to the authority contained in and subject to the jurisdiction conferred on the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and the Federal [**16] Power Act, particularly sections 205 and 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R. Chapter I), a public hearing shall be held concerning the justness and reasonableness of WPSC's proposed PPA 2. However, the hearing will be held in abeyance to provide time for settlement judge procedures, as discussed in Paragraphs (C) and (D) below.

(C) Pursuant to Rule 603 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.603 (2004), the Chief Administrative Law Judge is hereby directed to appoint a settlement judge within fifteen (15) days of the date of this order. Such settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene a settlement conference as soon as practicable after the Chief Judge designates the settlement judge. If the parties decide to request a specific judge, they must make their request to the Chief Judge in writing or by telephone within five (5) days of the date of this order.

(D) Within sixty (60) days of the date of this order, the settlement judge shall file a report with the Commission and the Chief Judge on the status of the [**17] settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions, if appropriate, or assign this case to a presiding judge for a trial-type evidentiary hearing, if appropriate. If settlement discussions continue, the settlement judge shall file a report at least every sixty (60) days thereafter informing the Commission and the Chief Judge of the parties' progress toward settlement.

(E) If settlement judge procedures fail and a trial-type evidentiary hearing is to be held, a presiding judge, to be designated by the Chief Judge, shall, within fifteen (15) days of the date of the presiding judge's designation, convene a prehearing conference in these proceedings in a hearing room of the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426. Such conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates, and to rule on all motions (except motions to dismiss), as provided in the Commission's Rules of Practice and Procedure.

By the Commission.

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Wisconsin Public Service Corporation, 109 F.E.R.C. P61319, 2004 FERC LEXIS 2661 (F.E.R.C. 2004)

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SHEPARD'S SUMMARY

CASE HISTORY (3 citing references)

1. **Same case at:**
   Wis. Public Serv. Corp., 110 F.E.R.C. P63042, 2005 FERC LEXIS 434 (F.E.R.C. 2005)

2. **Same case at:**
   Wis. Pub. Serv. Corp., 111 F.E.R.C. P63031, 2005 FERC LEXIS 1164 (F.E.R.C. 2005)

3. **Same case at:**
   Wis. Public Serv. Corp., 112 F.E.R.C. P63003, 2005 FERC LEXIS 1824 (F.E.R.C. 2005)

CITING DECISIONS (3 citing decisions)

ADMINISTRATIVE AGENCY DECISIONS

4. **Cited by:**
   Badger Power Mktg. Auth., Inc. v. Wis. Pub. Serv. Corp., 114 F.E.R.C. P61208, 2006 FERC LEXIS 430 (F.E.R.C. 2006)

5. **Cited in Dissenting Opinion at:**
   Xcel Energy Servs., Inc., 111 F.E.R.C. P61343, 2005 FERC LEXIS 1495 (F.E.R.C. 2005)

   111 F.E.R.C. P61343

6. **Cited in Dissenting Opinion at:**
   S. Cos. Energy Mktg., S. Cos. Servs., 111 F.E.R.C. P61144, 2005 FERC LEXIS 1147 (F.E.R.C. 2005)

   111 F.E.R.C. P61144

Federal Energy Regulatory Commission
Docket Sheet
Docket PL04-6 (ALL Subdockets)

Applicant(s)/Docket: Power Solicitation Processes For Public

Sub Docket: 000

Docket Description: Notice of a technical conference to be held on 6/10/04 regarding the solicitation processes for public utilities under PL04-6.

Issued By:	OFFICE OF THE SECRETARY, FERC
Filed Date:	5/11/2004
Accession No:	20040511-3019
Description:	Notice of a technical conference to be held on 6/10/04 regarding the solicitation processes for public utilities under PL04-6.
Source:	eLibrary
Federal Register Citation:	69 FR 27919 Date: 5/17/2004

Issued By:	SECRETARY OF THE COMMISSION & STAFF
Filed Date:	5/28/2004
Accession No:	20040528-3005
Description:	Supplemental notice of agenda for technical conference scheduled for 6/10/04 re Soliciation Processes for Public Utilties under PL04-6.
Source:	eLibrary
Federal Register Citation:	69 FR 31992 Date: 6/8/2004

Issued By:	OFFICE OF THE SECRETARY, FERC
Filed Date:	6/3/2004
Accession No:	20040603-4005
Description:	Supplemental notice for Technical Conference on 6/10/04 re Solicitation Processes For Public Utilities, Entergy Services, Inc & EWO Marketing, L.P et al under PL04-6 et al.
Source:	eLibrary
Federal Register Citation:	69 FR 32543 Date: 6/10/2004

Issued By: OFFICE OF THE SECRETARY, FERC

Filed Date: 6/10/2004

Accession No: 20040610-3052

Description: Notice inviting comments re Solicitation Processes for Public Utilities under PL04-6.

Source: eLibrary

Federal Register Citation: 69 FR 34158 Date: 6/18/2004

Issued By: FERC

Filed Date: 6/10/2004

Accession No: 20040610-4069

Description: Transcript of 6/10/04 technical conference at FERC regarding Solicitation Processes For Public Utilities under PL04-6 et al.

Source: eLibrary

Filed By: ELECTRIC POWER SUPPLY ASSOCIATION

Filed Date: 6/10/2004

Accession No: 20040610-5010

Description: Comment of the Electric Power Supply Association under PL04-6 ET AL.

Source: eLibrary

Filed By: BOSTON PACIFIC COMPANY, INC.

Filed Date: 6/30/2004

Accession No: 20040630-5007

Description: Comment on Filing of Boston Pacific Company, Inc. under PL04-6.

Source: eLibrary

Filed By: NATIONAL GRID USA

Filed Date: 6/30/2004

Accession No: 20040630-5009

Description: Comment of National Grid USA under RM04-7 ET AL.

Source: eLibrary

Filed By: EDISON ELECTRIC INSTITUTE, ET AL.

Filed Date: 7/1/2004

Accession No: 20040630-5104

Description: Post Technical Conferene Comments of Edison Electric Institute and Alliance of Energy Suppliers, Et al. under RM04-7 ET AL.

Source: eLibrary

Filed By: CALIFORNIA PUBLIC UTILITIES COMMISSION

Filed Date: 7/1/2004

Accession No: 20040630-5111

Description: Notice of Intervention of California Public Utilties Commission under PL04-6 ET AL.

Source: eLibrary

iled By: ALLEGHENY ENERGY, INC.

Filed Date: 7/1/2004

Accession No: 20040701-5001

Description: Rulemaking Comment of Allegheny Energy, Inc. under PL04-6.

Source: eLibrary

Filed By: INDIVIDUAL

STINSON MORRISON HECKER LLP

Filed Date: 7/1/2004

Accession No: 20040701-5004

Description: Rulemaking Comment of Harvey Reiter under PL04-6.

Source: eLibrary

Filed By: PROGRESS ENERGY, INC.

'iled Date: 7/1/2004

Accession No: 20040701-5010

Description: Comments of Progress Energy in PL04-6.

ɔurce: eLibrary

Filed By: SCHWAB CAPITAL MARKETS LP, WASHINGTON RESEARCH GROUP

Filed Date: 7/1/2004

Accession No: 20040701-5011

Description: Rulemaking Comment of Schwab Capital Markets LP, Washington Research Group under PL04-9 ET AL.

Source: eLibrary

Filed By: LOUISIANA PUBLIC SERVICE COMMISSION

Filed Date: 7/1/2004

Accession No: 20040701-5017

Description: Rulemaking Comment of Louisiana Public Service Commission under PL04-6.

Source: eLibrary

Filed By: CINERGY SERVICES, INC.

Filed Date: 7/1/2004

Accession No: 20040701-5059

Description: Comments of Cinergy Services, Inc. under PL04-9 ET AL.

Source: eLibrary

Filed By: TRANSMISSION ACCESS POLICY STUDY GROUP

Filed Date: 7/1/2004

Accession No: 20040701-5060

Description: Comments of Transmission Access Policy Study Group under PL04-6 ET AL.

Source: eLibrary

Filed By: IEU-OHIO ET. AL.

'iled Date: 7/1/2004

Accession No: 20040701-5061

Description: Motion to Intervene and Comments of IEU-Ohio et. al. under PL04-6.

ɔurce: eLibrary

Filed By: DUKE ENERGY CORPORATION

Filed Date: 7/1/2004

Accession No: 20040701-5064

Description: Comments of Duke Energy Corporation under PL04-6.

Source: eLibrary

Filed By: CALPINE CORPORATION

Filed Date: 7/1/2004

Accession No: 20040701-5074

Description: Post Technical Conference Comments of Calpine Corporation under PL04-6.

Source: eLibrary

iled By: ARIZONA PUBLIC SERVICE COMPANY

Filed Date: 7/1/2004

Accession No: 20040701-5075

Description: Comments of Arizona Public Service Company under Docket Nos. PL04-6 et al.

Source: eLibrary

Filed By: PACIFICORP

Filed Date: 7/1/2004

Accession No: 20040701-5076

Description: Post-Technical Conference Comments of PacifiCorp on Solicitation Processes for Public Utilities under PL04-6.

Source: eLibrary

Filed By: COGENERATION ASSOCIATION OF CALIFORNIA

'iled Date: 7/1/2004

Accession No: 20040701-5077

Description: Rulemaking Comment of Cogeneration Association of California, Energy Producers and Users Coalition, Nevada Independent Energy Coalition, March Point Cogeneration and Sumas Energy under PL04-6.

Source: eLibrary

Filed By: INTERGEN SERVICES, INC.

Filed Date: 7/1/2004

Accession No: 20040701-5080

Description: Post Technical Comments of InterGen Services, Inc. under PL04-9 et al

Source: eLibrary

Filed By: KEYSPAN-RAVENSWOOD LLC

Filed Date: 7/1/2004

Accession No: 20040701-5083

Description: Post-Technical Conference Comments of KeySpan-Ravenswood LLC under AD04-5 ET AL.

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Filed By: SOUTHERN COMPANY SERVICES, INC.

Filed Date: 7/1/2004

Accession No: 20040701-5084

Description: Post-Technical Conference Comments of Southern Company Services, Inc. under PL04-6.

Source: eLibrary

Filed By: CONSTELLATION NEWENERGY, INC.

Filed Date: 7/1/2004

Accession No: 20040701-5085

Description: Comments of Constellation Power Source, Inc., Constellation Generation Group, LLC and Constellation NewEnergy, Inc. under PL04-6.

Source: eLibrary

Filed By: INDIVIDUAL

Filed Date: 7/2/2004

Accession No: 20040701-5090

Description: Comment on Filing of Susan F. Tierney and Paul J. Hibbard under PL04-9 ET AL.

Source: eLibrary

Filed By: CINERGY SERVICES, INC.

Filed Date: 7/2/2004

Accession No: 20040702-5045

Description: Errata to Punctuation on Page 2 of Comments of Cinergy Services, Inc. submitted under PL04-9, et al., at accession number 20040701-5059

Source: eLibrary

Filed By: FEDERAL TRADE COMMISSION

Filed Date: 7/14/2004

Accession No: 20040714-5023

Description: Rulemaking Comment of Federal Trade Commission under PL04-9 ET AL.

Source: eLibrary

Issued By: OFFICE OF THE SECRETARY, FERC

Filed Date: 4/29/2005

Accession No: 20050429-4000

Description: Notice of FERC Commissioner & FERC Staff participating in National Association of Regulatory Utility Commissioners Resource Planning & Procurement Forum scheduled for 5/16/05 under RM04-7 et al.

Source: eLibrary

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Solicitation Processes For Public Utilities Docket No. PL04-6-000

NOTICE INVITING COMMENTS

(June 10, 2004)

On June 10, 2004, the Commission Staff held a technical conference to discuss the solicitation processes for public utilities. All interested persons are invited to file written comments no later than July 1, 2004 in relation to the issues that were the subject of the technical conference.

Filing Requirements for Paper and Electronic Filings

Comments, papers, or other documents related to this proceeding may be filed in paper format or electronically. The Commission strongly encourages electronic filings. Those filing electronically do not need to make a paper filing.

Documents filed electronically via the Internet must be prepared in MS Word, Portable Document Format, or ASCII format. To file the document, access the Commission's website at www.ferc.gov, click on "e-Filing" and then follow the instructions for each screen. First time users will have to establish a user name and password. The Commission will send an automatic acknowledgement to the sender's e-mail address upon receipt of comments. User assistance for electronic filing is available at 202-502-8258 or by e-mail to efiling@ferc.gov. Do not submit comments to this e-mail address.

For paper filings, the original and 14 copies of the comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426 and should refer to the above-referenced docket number.

All written comments will be placed in the Commission's public files and will be available for inspection at the Commission's Public Reference Room, 888 First Street, N.E., Washington, D.C., 20426, during regular business hours.

Linda Mitry
Acting Secretary

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

SOLICITATION PROCESSES FOR : Docket No. PL04-6-000

PUBLIC UTILITIES :

- - - - - - - - - - - - - - - - -x

Commission Meeting Room
Federal Energy Regulatory
Commission
888 First Street, N.E.
Washington, D.C.

Thursday, June 10, 2004

The above-entitled matter came on for technical conference, pursuant to notice, at 9:05 a.m., Jerry Pederson, presiding.

APPEARANCES:

JOHN HILKE, FTC

CRAIG ROACH, Principal, Boston Pacific Company, Inc.

APPEARANCES CONTINUED:

HARVEY REITER, Partner, Stinson, Morrison, Hecker LLP

RON WALTER, Executive Vice President - Development, Calpine Corporation

ED COMER, Vice President and General Counsel, Edison Electric Institute

TOM WELCH, Chairman, Maine Public Utilities Commission

ELIZABETH BENSON, Energy Associates, CLECO Independent Monitor

ERSHEL REDD, President, Western Region, NRG

Ted Banasiewicz, Principal, USA Power LLC

P R O C E E D I N G S

(9:05 a.m.)

MR. PEDERSON: Good morning. My name is Jerry Pederson. For those of you that do not know me, I work in OMTR as an Manager of the group that processes market-based rate filings.

The topic of this morning's conference is issues associated with solicitation processes, including solicitations whereby public utilities sell to their affiliates.

In Boston Edison-Edgar, the Commission held that in analyzing market-based rate transactions between an affiliated buyer and seller, the Commission must ensure that the buyer has chosen the lowest-cost supplier from among the options presented, taking into account, both price and non-price factors.

The purpose of this conference is to address proposals for the best practice competitive solicitation methods or principles that could be used to ensure that transactions filed with the Commission for approval, are the result of an open and fair process.

This conference is being transcribed, and transcripts will be placed in the public record, ten days after the Commission receives the transcripts.

We have two panels this morning, so we'll take a short break between the panels. We're also a little tight on time, so panelists will be giving five- to six-minute presentations.

We'll pause for clarifying questions, but before opening the floor for a fuller discussion, we will have all the panelists make their presentations, so we'll go through the whole panel and then we'll have open discussion.

With that, I'd like to introduce our first panelist, Mr. John Hilke. John is the Electricity Project Coordinator from the Federal Trade Commission, Bureau of Economics, Division of Economic Policy Analysis. Mr. Hilke?

MR. HILKE: Good morning and thank you for the invitation. Before I begin, I would like to state the usual disclaimer, that these are my personal views and they do not purport to be the views of the Federal Trade Commission or any individual Commissioner.

Another preliminary point is that the context of my comments is the assumption that we're already in a market situation in which affiliate relationships are a potential way that transactions take place, because the full divestiture has not already occurred.

In my few minutes this morning, I would like to make two points about potential market distortions associated with utility solicitation processes that result in transactions with unregulated affiliates.

First, affiliate transactions, like the make-by decisions of other firms, often enhance efficiency and benefit consumers when they are based on objective analysis and criteria.

Conversely, these transactions may reduce efficiency and harm consumers, if they are based on discriminatory analysis and criteria, because the transactions may then allow the utility to exercise market power by evading rate regulation or to allow the utility to expand or prop up an unregulated affiliate by evading rules against cost subsidization.

I'd also like to note that the issues involved in assuring objective make-buy decisions are not really unique to FERC or to the state utility regulators. I'll just mention a couple of other examples where the FTC has been active:

One is in privatization initiatives of municipal, state, and federal agencies, and the other is the workshare discounts offered by the U.S. Postal Service. Both of these contexts are ones in which the same types of issues arise.

My second general point is that evasion of rate regulation or cross-subsidization and solicitation processes potentially create serious long-term inefficiencies in wholesale and retail el electricity markets, above and beyond the immediate price effects.

Given the short-term and long-term potential harmful effects of discrimination, it seems to me that this is a worthwhile topic for FERC to be investigating more thoroughly as it seeks to assure that wholesale rates are just and reasonable.

Having said that transactions between a regulated utility and its unregulated affiliates need not pose a threat to competition and may, in fact, enhance competition and benefit consumers, I'd like to address the more specific situations in which that might not be the case, in which there is potential harm to consumers and to competition through discrimination, and also mention some potential approaches for detecting and discouraging such discrimination in utility solicitation processes.

Let me start by talking briefly about evasion of rate regulation: In a market with cost-based regulation of prices, in which the regulatory utility has market power, and some of which is not exercised, that is that the rate regulation is binding, some mechanism is appropriate to assure that transactions between an unregulated affiliated generator and the parent utility, do not take place at inflated prices.

Rate-regulated parent utilities with market power have incentives to make such transfers and that the mechanism here basically be that the inflated price is passed along through the regulated rate.

A supply contract with an inflated price would be a form of regulatory evasion because it would result in the exercise of more of the potential market power of that utility, with captive customers paying higher regulated rates to cover the regulated utility's inflated costs.

The evasion of cost-based regulation could also involve selling to an unregulated affiliate at below market prices. That would also increase the prices in the market and lead to higher profit margins for the unregulated affiliate.

Hence, evasion of rate regulation may involve both types of transactions, that is, both sales and purchases. The same framework may also apply where a wholesale customer depends on a regulated transmission provider with generation assets in the same geographic market to act as its agent in acquiring electric power or to provide reliable access to generators from which to obtain power.

In this scenario, the utility gains by arranging for power supplied from its own generators or by inhibiting access to non-affiliated generators. Here, the discriminating utility evades the rate regulation that applies to its customer, and so it's a secondary tier effect, but one which is also potentially of concern.

One way to help prevent and -- to detect, and, therefore, to prevent the evasion of rate regulation is to develop methods of establishing market-based values for the affiliate transactions, establishing estimated market values for transactions is an important task in many contexts, as I mentioned a few moments earlier.

There are several approaches which are used in various contexts, and let me just mention a few of those: One approach is to hold an open solicitation of bids with announced objective criteria for selecting the winning bidder.

This is the most direct and often the most effective approach. Issues include obtaining several bidders, so that you actually establish a competitive price, assuring that bids are realistic from the affiliates, and penalizing any bid reneging that occurs after the fact.

A second approach is for the regulators to check the utility's selection of a supplier, after the fact or before the contract is signed. And these don't necessarily involve using a bidding approach. There are techniques which use a list of comparables, there are various econometric techniques for establishing values based on a number of transactions in different areas, and all of those are approaches that can be used and don't involve the direct RFP type approach.

Another approach is to evaluate the profitability of a prospective contract to the affiliate and to prohibit bids by which the affiliate would earn a higher rate of return than allowed for the parent utility. This effectively expands the range of the cost-based rate approach to the affiliate.

Existing prudencey reviews are another approach, although doing it after the fact risks not detecting things, and, therefore, allowing a lot of it to go through which might not otherwise occur.

Another thing about prudencey reviews is if they have sufficiently large penalties attached to them, they may have deterrent effects, even if they don't catch all instances.

A direct method of preventing discriminatory contracts with affiliates is to utilize third-party analysis to compare supply bids and to determine the winning bid. This is much like the independence requirement for RTOs and ISOs.

A modification of this approach would be to allow the utility to select the winning bid, but to effectively require that a third party review the bid, if they decide that the affiliate is going to be the winner.

All of these approaches present challenges, but they are likely to constrain at least the most blatant potential discriminatory solicitation decisions of utilities.

Cost subsidization is another issue. Here, the concern is that you expand, effectively, the less efficient suppliers. The techniques for cross-subsidization may include buying from an affiliate at inflated prices, or selling at a price less than the market value.

Other examples would include offering free goods or services to the affiliate, or giving preferences to supplying an affiliate when the service or product involved is in short supply. A parent utility whose ability to exercise market power is constrained by cost-based rate regulation, may find it profitable to cross-subsidize an unregulated affiliate.

Various examples are available. One of the most pertinent is the possibility that that cost subsidization will avoid a bankruptcy from the unregulated affiliate and the costs associated with that.

Approaches to preventing cross-subsidization include cross-subsidization include establishing market values for transactions, much as in the case of the other types of discrimination.

As FERC has heard from FTC staff before, we favor a cost/benefit approach for considering alternative forms of separation as a technique to prevent cross-subsidization, but, again, the context here is one in which that structural approach has been rejected.

Now, let me turn very briefly, as my last point, to the long-term inefficiencies due to favoritism in solicitations. I mentioned three potentially important losses of efficiency associated with such favoritism.

The first adverse impact of discrimination in solicitation in inefficient expansion of the market position of the affiliates, resulting higher social costs, such as higher average production costs, because a less efficient, subsidize firm has a larger market share.

Another is slower diffusion of innovation because the entry based on innovation is less profitable.

Another is less consumer choice, because some suppliers are forced out of the market that would otherwise be in the market, and there could be an average lower quality because the lower quality subsidized firm has a larger market share.

The second adverse impact that I'd like to mention is increased concentration in wholesale electricity markets, caused by the relative decline of stand-alone suppliers. To the extent that a utility is the most attractive customer in its distribution franchise area, and the independent suppliers are foreclosed from doing business with the buyer or face discrimination in selling to this customer, the stand-alone suppliers are more likely to exit or not to enter to begin with.

Increased concentration where concentration is already high and entry is impeded, can contribute to an increase in market power, either from unilateral anticompetitive effects or coordinated interaction.

The third adverse impact stems from distortions in wholesale and retail electricity prices, which send inefficient investment signals to wholesale and retail customers. Customers faced with inefficient price signals are likely to make inefficient consumption and investment decisions regarding energy conservation investment, location of facilities, choices between production methods, and other examples.

Since some of these investments are likely to have long-term market presence, the inefficient price signals initially result in some long-term changes and basically inefficient choices on the demand side, which will have longlasting effects.

In summary, both the evasion of rate regulation and cross-subsidization are concerns when utilities engage in transactions between the utility and its unregulated affiliates. Although structural separation is the remedy most likely to reduce the incentives to evade rate regulation or to cross-subsidize, other approaches are available.

All of these focus on detecting discrimination by establishing market values for affiliate transactions. Open market solicitations using third parties to analyze the bids, are a potentially attractive approach, but techniques that compare the proposed affiliate transaction to comparable transactions are another option.

Inefficiencies that stem from discrimination in solicitations include expansion of less efficient suppliers, increased concentration, and distortion in pricing signals and related investment incentives for customers, which my have long-term effects. Thank you. That's the end of my comments.

MR. PEDERSON: Thank you, John. Our next panelist is Mr. Craig Roach, who is Principal of Boston Pacific Company, and independent monitor of the Maryland RFP process. Craig?

MR. ROACH: Good morning, everyone. Thank you for inviting us, and thank you for having this proceeding. We think that these competitive solicitations are as much a marketplace as the spot markets.

They involve thousands of megawatts, sometimes sales that involve multiple years, so they mean a lot to consumers, so we really appreciate the attention being given today.

Before I get to your eight questions, let me just state a couple of principles: The principle that I use to guide us in our thinking on solicitation is really simple. Anytime we think about whether to have a solicitation or how to conduct it, we have one goal in mind.

That goal is to get the best deal possible for consumers in terms of price, risk, reliability and environmental performance. We think, based on our experience, that these solicitations can serve consumers.

Our involvement has ranged from being in several Edgar cases here, to being in state cases across the country, and, as Jerry mentioned, most recently, we were the independent monitor for all of the Maryland solicitations.

So, with that introduction, let me try to give at least short answers to your questions. Your first question listed was, is Edgar enough? Is the Edgar precedent enough?

My answer is no. Now, it's not because I don't like what's said in the Edgar precedent. There's a lot of good concepts there, but my concern is that we can no longer rely on after-the-fact, case-by-case enforcement of these Edgar standards.

It's too expensive for intervenors and it's too late, too late in the sense that harm to wholesale competition has already been done. What I'd really like to see the Commission do is give a very detailed, strong, before-the-fact guidance on what is expected.

What I'd like to see is, out of the cases that are now pending before the Commission, that the Commission would come out and say, look, if you're going to bring an affiliate transaction to us, we want it to be market tested through a competitive solicitation and that competitive solicitation must meet certain minimum standards.

One of your other questions asked about jurisdiction. It's an important issue.

I think that with that method that I just stated, I think that FERC is not telling the states what to do and it should not tell the states what to do. What it's saying is what the Commission will do if a docket is opened on a transaction.

I think that if the Commission takes that consumer point of view when it defines minimum standards, then they are going to be in sync with the states and it's going to be a basis for cooperative federal-state partnership.

I mentioned minimum standards. Two of your questions raise two minimum standards that I would certainly include: One, you asked whether the solicitation should be designed through a collaborative process? My answer is yes, absolutely.

And it should not just be going through the motions. If someone comes to you and says we use the collaborative process, there should be evidence of consensus, evidence of compromise.

You asked whether an independent monitor should oversee the solicitation. Again, my answer is, yes, absolutely. My preference is that that monitor be hired by the state commission and work for that state commission.

Some of your questions asked about safeguards, and, you know, I want to say up front that there is no foolproof solicitation. Any solicitation can be abused by affiliates and non-affiliates.

But there are ways to put safeguards in place, and I want to close by mentioning three concepts: The first is that the solicitation itself can be designed to minimize the opportunity for abuse by any bidder. Clearly, the most innovative solicitations in that respect are those that have been held in New Jersey and Maryland.

Secondly, solicitations can involve safeguards that target the areas that are most likely to be abused. We know those now; we know from experience, what they are.

Again, two of your questions lead me to two examples: You asked about transmission. I think this is one of the most troublesome areas in solicitation outside of RTOs, and within transmission, the most troublesome area is network resource status.

One of the minimum standards I'd like to see come out of the Commission is that every bidder should have access to a network resource assessment on terms comparable to that provided to affiliates. They all have to be done on the same standards in the same way.

Another one of your questions talks about the rules of the game or monopsony power, and, again, let me give an example an area that's been troublesome. Let me just explain it in basic terms:

What I've seen that I think is trouble, is that I've seen utilities invite bids and they'll say, look, I want a ten-year offer with fixed prices, a reliability or availability guarantee, and I want you to guarantee replacement costs.

They then receive those bids, and then proceed to compare them to a cost-plus utility offer which has none of those consumer protections. Again, another minimum standard that has to be set is that all bids must meet the same requirements, and all must be evaluated on the same criteria.

My third and final concept on safeguards is to say that there's a phrase that the Commission has been using in its Edgar Orders or Hearing Orders. It says that Edgar require the affiliate deal to be above suspicion.

I'd like to see that made functional,

operational, and with the notion that there are always ways to get around whatever rules you set up. What I'd like to see is the Commission set a requirement for an affirmative effort that the buyer come in to show the Commission that the process has been transparent, that they have taken an affirmative effort to make it transparent and that they have done all that needs to be done to assure that it's the best deal for consumers.

With that, let me again thank you, and I'd be happy to go into detail on any of those points.

MR. PEDERSON: Thank you, Mr. Roach. Our next panelist is Harvey Reiter, a Partner at Stinson, Morrison and Hecker, LLP. His practice has involved laying the legal groundwork for competitive restructuring in the natural gas and electric industries. Mr. Reiter?

MR. REITER: Thank you. I want to extend my thanks to the Staff and to the Commission for inviting me here to speak today and to express my views on the questions posed in the Notice.

There are eight questions and I prepared some written comments. I haven't addressed all of them, but I think that my questions do address the central concern expressed by the Commission, mainly, how to devise competitive solicitation processes that are fair and produce good outcomes, where affiliates, utilities and their affiliates are involved.

I should give a disclaimer at the outset, too. Much of my work has been on behalf of state public utilities commissions, and so my world view is probably informed to some degree by that experience.

But I'm here expressing my own views and not necessarily those of my clients, regardless of how persuasive and logical you may find them. I did want to say -- and with a representative of the FTC here today, that I didn't expect to be a more aggressive proponent of a structural approach than someone else on the panel, but my own preference in approach the questions that were posed is to look for structural solutions that are legal and politically viable to addressing affiliate relationships with utilities, as opposed to more intrusive regulatory procurement rules and regulations.

I think the Commission or any commission at the state level interested in the subject can devise a pretty good set of rules, but they will never be able to detect all forms of discrimination, something that Craig mentioned, but there are enforcement costs that go with any set of guidelines.

And so even if you devised the best set of rules, you need to devote sufficient resources to prosecute violations. Those are problems that are avoided in large part by structural solutions.

Let me tell you what I have in mind, though, by structural solution. It's simply this: In competitive solicitations by utilities seeking supply from affiliates, what I would suggest is the following; that affiliates interested in obtaining market-based rate authority, would have to agree in advance that they are not permitted to sell to their utility affiliates, except in instances where the presence of the affiliate is necessary to provide a sufficient number of bidders to produce a competitive outcome in a bidding process.

I would add, too, that there are circumstances, and the Commission, I know, is aware of it, where there aren't enough bidders in the marketplace, even with the presence of affiliate. And in those instances, I think the answer is that the affiliate should be selling at a cost-based, not a market-based rate.

Now, if the Commission decides not to pursue a structural approach, I think there's still some structural elements and alternatives. And even under -- the approach I have suggested is that affiliates could sell into the solicitation process if their presence was necessary to provide a competitive outcome.

You needed a sufficient number of bidders. But in those instances, and also if the Commission generally concludes that affiliates should be eligible to participate in the process, when there are some of what I would call structural safeguards -- and both of the prior speakers have touched on them -- mainly, that there ought to be some independent party, both designing the bidding process and conducting the evaluation.

That's a structural solution of sorts, and it helps ensure that the process itself is neutrally devised and implemented. I should add, though, that the concern about structure -- I think my concern is somewhat less in the context of sales by utilities to their affiliates in instances where the utility may have excess capacity or stranded capacity and where the sale of that excess power helps defray the costs to ratepayers.

In that instance, what I think you're looking for is the highest price that can be obtained through the bidding process, and with a blind bidding process, independently run by a third party, I don't see the same kinds of concerns about structure as I would in the context where the utility is buying from the affiliate.

In that case, if you had a blind bidding process, independently conducted, adding additional bidders, including affiliates, could benefit consumers.

I also wanted to touch on a couple of the questions that were asked in the outline about the role of state commissions, and I think a number of states have addressed the issue of competitive bidding, both in the context of purchases of power supply and other services and goods from affiliates.

And the Commission, I think, should draw from their experiences in designing its own rules. Some of them have gone through these processes several times and they have learned from their experiences, and the Commission could learn from what those states have done.

Last, I think that the Commission needs to carefully tailor any rules that it adopts to ensure that it doesn't interfere with efforts by states to avoid cross-subsidization, something that our first speaker touched on.

I have addressed these topics in a little more detail in the written comments, and hopefully in the open discussion, we'll have a chance to talk about those in more detail, but, again, I want to thank you for inviting me here today.

MR. PEDERSON: Thank you, Mr. Reiter. Our next panelist is Ron Walter, who is the Executive Vice President of Development at Calpine Corporation. Mr. Walter?

MR. WALTER: Thank you, Mr. Chairman and Commission Staff. It's my pleasure to have the opportunity to provide a statement at this important conference. Calpine is the largest independent power company in the United States, and so we have some very specific views on this subject.

The Notice of this technical conference, I think, rightly focuses on assuring the lowest-cost supply of electricity to consumers. This worthy goal has been the primary focus of the Commission in doing competition over the last decade.

You've taken some important steps to create a level playing field, but the job is far from done. The industry is straddling between the old and the new.

The old is the vertically integrated monopolies that control wholesale supply, and the new era is competitive suppliers trying to enter into markets. At this critical juncture in this murky middle ground that we have, the achievement of the Commission's goals is at severe risk.

The current situation is untenable and sharply at odds with the Commission's pro-competitive goals. It is virtually impossible for an independent power producer to finance the construction of a generation project without a contract from a buyer in these days.

In most areas of the country, independent companies do not have access to a fair process to get those contracts. In addition, litigating at FERC, all these disputes over biased or nonexistent procurement processes is very costly, time-consuming, and leads to uncertainty among all market participants.

Competitive suppliers like us, we don't have the deep pockets or the captive customers to pass on these litigation costs like the utilities do.

The Commission must adopt procurement standards. The very foundation of the competitive wholesale markets is at risk without Commission action, and customers will not have access to the lowest-cost supply of power.

I'd like to give you some of our experiences that we've seen out there in the marketplace. Given the downturn in the market over the past several years, Calpine has seen more and more utilities finding ways to use their monopoly status to protect their own generation, or to assist their affiliates.

In several regions of the country, we've experienced the following examples of discriminatory conduct and sham processes on competitive bidding: One, utilities that deal only with themselves or their affiliates, with no competitive procurement at all;

Two, utilities that use an RFP process that looks good on paper. Some even have a, quote, "independent monitor," for appearance purposes, but then choose their own affiliate or a self-billed;

Three, solicitation processes where good-faith bids are made, but the utility merely uses the bids as a benchmark for a build/own transfer into their own system;

Four, utilities refusing to deal with competitive suppliers, in turn, creating distressed assets that are then bought by the utilities themselves;

Five, a variety of other preferences to utility affiliates, including preferential sharing of information, preferential access to transmission, preferential transfers of fully-developed and permitted construction sites to their affiliates; also devices such as a service company arrangement to favor an affiliate and to circumvent the standards of conduct.

A utility choosing itself, No. 7, or an affiliated supplier to build it, and justifying it by playing this reliability card in the wake of the August 14th blackout last year, even though this is a false justification.

I took a scorecard of some of the competitive procurements that we've been involved with in the last 36 months. I've noted 17 separate competitions or flat-out utility choices that exhibited one or more of the above characteristics.

They are in 12 states: Georgia, Alabama, Florida, Louisiana, Wisconsin, California, Utah, Idaho, Nevada, Washington, Oregon, and Arizona. This represents over 12,000 megawatts of opportunities denied to independent power producers, and also denied access to the lowest cost to the consumer.

Another scorecard that I took was to look at the independent power companies themselves. Four years ago, there was a growing number of IPPs and they themselves were growing. Today, I took a look at 12 companies as a sample, who subsequently failed in the business in that short, four-year timeframe. Four have gone bankrupt.

Five sold all or a majority of their assets. One sold out altogether. Two canceled their projects and exited the business.

Now, I admit that some of these companies had poor strategies and they would have died on their own, but I contend that a number of these companies were not successful because they didn't have good access to selling their power to consumers and customers.

Since 1992, the independent power industry has invested $100 billion in new power plants, based on the concept that we have access to customers. That simply hasn't happened in a lot of areas of the country.

If I leave one point today, it's that now is the time to act. Deliberating and litigating and extending this process too much further into the future, there won't be much to fix.

What are my recommendations? The Commission has the obligation arising from the Federal Power Act, to ensure that wholesale power is free from undue discrimination and preferences, and the customers have the benefit of a market that functions well.

While RTO development is important, it's been slow. There are some things, in the meantime, that the Commission should do to improve competitive markets:

First, permission to sell at market-based prices is a privilege, not a right. Utilities that do not engage in competitive wholesale procurement and fail to comply with FERC standards prohibiting affiliate abuse, or erect transmission or other barriers to entry, should be denied this privilege.

Second, the Commission must strengthen Edgar. Fair, competitive procurement should be the rule for affiliate transactions. Edgar is all about making sure affiliate abuse is not present in transactions among affiliates.

And the competitive procurement process should be made the standard, rather than some other benchmark.

Third, and, more generally, the Commission should adopt competitive procurement standards. They should include an independent evaluator, equal access to the transmission system, openness and transparency of the process. It should also include a specific definition of needed products, so that people can respond.

Fourth, the Commission, without delay, should implement the new standards of conduct for transmission providers and closely monitor and investigate affiliate abuses. Fair, impartial, and transparent wholesale competition solicitation standards promulgated by FERC are absolutely critical to continuing the progress towards broader customer benefits and to help move this industry forward, not backward.

I'd like to close with the comment that some who support the old way of doing business and want to retain vertical monopolies, will say that competitive procurement is the business of the states and not the Federal Government. I say that it's FERC's responsibility when we see the level of discrimination that's taking place in many areas around the country.

This development of fair and open competitive processes can, and I hope will not end up being a battle between the states and the Federal Government, but a partnership, because, after all, the one thing we have to remember is that we have the same goal of getting the lowest-cost, most-reliable product to the consumer. So, with that, I'll close. Thank you.

MR. PEDERSON: Thank you, Mr. Walter. Our fifth and final panelist for this morning's session is Ed Comer. He's Vice President and General Counsel for Edison Electric Institute. Mr. Comer?

MR. COMER: Thanks very much. Let me just start off with the point that I think is fundamental: All power purchase and sale transactions have to be conducted in a fair manner, without bias and without self-dealing that favors affiliates. And the goal is to achieve the best deal for utility customers with the best cost/risk balance.

The Edgar Standard provides three ways to demonstrate that buyer has chosen the best supplier from among the options, taking into account both price and non-price factors -- and that's important.

Most folks this morning have talked about the first of those standards of head-to-head competition, either through a formal solicitation or an informal negotiation process. That's probably what you're going to do for your longer-term deals.

But Edgar has two other criteria that we think are perfectly valid -- demonstration of prices that non-affiliated buyers were willing to pay for similar services, and benchmark evidence that shows prices, terms, and conditions of sales made by non-affiliated sellers.

These certainly are going to make a lot more sense in RTOs with liquid markets and other places, and certainly for shorter-term transactions, and they continue to be valid. Now, I recognize that when a utility chooses an affiliate over other competitors as it supplier, there is heightened concern about the potential for self-dealing and about unfairness in the selection process.

But the choice of an affiliate, in and of itself, may well be the best option in a given circumstance, so I don't think you should just ban them or throw them out. In fact, the Commission itself has a long history of approving such transactions, and as long as the process is fair, any proposal to prohibit or restrict affiliate transactions could harm consumers.

Now, the ultimate goal of the solicitation process is to enable the utility to balance both cost and risk in providing the best service at the best price. Now, sometimes the answer may be to build new generation.

These days, it may be to buy a distressed asset. Other times, the best approach may be to enter into a purchase power agreement with a power marketer or an independent or an affiliated producer.

The big deficiency in the Edgar Standard is that it fails to recognize that most of the competitive solicitations that take place are issued by load-serving entities for the purpose of serving native load. Most of these entities are state-regulated.

The process is usually conducted with considerable oversight and direction from the state commissions, and it's always conducted with the full knowledge that an imprudent condition can lead the applicable state commission to disallow cost recovery, as some utilities are regulated by multiple state commissions, which further heightens the scrutiny of the procurement process.

We believe the state involvement provides strong assurances that the process will be conducted in a fair and unbiased fashion, and will achieve the best results for customers. In listening to Mr. Walter talk about 12 states where there have been affiliate transactions, I personally find it hard to believe that there will be 12 states that are all not doing their jobs to decide what's the best deal for their customers. I think it's strong evidence of the fact that affiliated transactions could be very beneficial for customers.

Now, why might there be an affiliate transaction or why might an independent power producer's proposal be rejected? In making the evaluation between building a power plant, buying an existing power plant, or executing a long-term power purchase agreement, you have to look at a variety of factors:

Certainly these include a lot of factors that are established by your state like renewable energy requirements. You do have to look at the construction risk of building a plant, you also have to look at the credit risk of your counterpart.

You also have to take into consideration, accounting standards dealing with direct or inferred debt, and you also have to look at what S&P's and Moody's and the bond rating agencies will say about the impact of debt, long-term contracts as debt.

You have to look at transmission, reliability issues, you have to look at the likelihood that your regulator is going to approve the transaction, and that does include FERC. And, of course, you have to look at the cost to mitigate unwanted risks.

Now, at this point in the business cycle, there is a surplus of distressed generation with assets at very attractive prices in some markets, and, in comparison, long-term contract purchase options can raise substantial questions about the long-term financial health of the entities involved.

This Commission is well aware of such credit and default risk issues. Unfortunately, uncertainties about some of these issues have been exacerbated by the Commission itself's failure to resolve what constitutes reasonable assurances when a party's credit rating is downgraded under the Western Systems Power Pool tariff.

You can't solve all the credit issues, but you can help clarify the rules and contracts. Given these circumstances, generating asset purchases may well prove to be the best business alternative.

The Commission should not exhibit a bias against this choice when it proves to be the best alternative for utilities and their customers.

Now, let's talk about the states. I agree, I think, with virtually everybody on the panel who has said that it's very important for this Commission to work closely with the states in a cooperative manner. States have many different competitive solicitation processes that they use to determine the best way to serve their retail customers.

Some of the successful ones, very successful ones, for instance, the New Jersey and Maryland programs that were mentioned today. Other states are examining new programs or looking to revise their programs. Some states use an independent monitor, others don't. They believe that their role is sufficient to assure fairness of the process and to assure the adequacy of the process.

Frankly, I regret that you haven't invited more states to this conference, because I think that a continued discussion between the Commission and the states to develop best practices and to understand how each approaches the issues, would be very useful.

There is no one right solution or practice or process common to all of the states. Each state may hold differing views on the exact criteria and the mechanics that a procurement process should posses.

It's also important to note that the parties vying to sell power are very active in the state proceedings that address procurement issues. They have a forum and they have remedies in the states, if they are convinced that those processes are not fair. Thus, when a state is involved, FERC doesn't need to rely upon its own independent monitor or other independent entity to evaluate fairness. That's the state's role.

Now, for all these reasons, the Commission -- and it does have a responsibility to review wholesale rates under Section 205 of the Federal Power Act -- should still defer to state commissions regarding how a utility best procures power to serve its native load.

While the Act gives this Commission responsibility over wholesale transactions, it preserves the retail electric service responsibility for the states. And it's the states' role to ensure adequate service, fair procedures, no self-dealing, and just and reasonable terms and conditions.

In addition, I'd like to point out, because we're talking about affiliate transactions here, that the last time Congress addressed this issue it clearly looked to the states, not to FERC, to address the potential for affiliate abuse in sales of power.

Section 32(k) of PUCHA, enacted in 1992, prohibits sales of electricity from an EWG to an affiliated utility, unless it is specifically approved by every state commission having jurisdiction over the rates of that utility. In conclusion, we urge the Commission to act in concert with these provisions, and to modify its Edgar approach in a manner that explicitly recognizes and complements the responsibilities of state commissions.

We recommend continued cooperation and close communication with state commissions. We urge the Commission to avoid moving in a direction that requires a uniform approach for all competitive solicitations.

I think a one-size-fits-all approach would intrude upon state responsibilities for how jurisdictional utilities, state jurisdictional utilities meet their retail obligations to serve load, would also intrude upon the EWG affiliate transactions under PUCHA that Congress told the states to regulate.

We fear that any effort to force states into a process that they don't feel comfortable with, risks that the states will turn to resource solutions that are not FERC-jurisdictional, so that their judgment would not be second-guessed. This would not be in anybody's interests. With that, thank you, and I look forward to our discussion.

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MR. PEDERSON: Thank you, Mr. Comer. At this point, I'm going to open up the questions and discussion for the staff and the panelists as well. I encourage everyone to participate.

The focus of this conference, I think, is to come up with the -- we've heard a lot today. We've heard a number of folks talk about fair and unbiased solicitations. We've heard the differences in the way these solicitations are being conducted. I think that one of the main things that we want to get out of this conference is to start establishing the criteria of what are the standards for a fair and unbiased solicitation process.

That's kind of what I'd like to focus on, and I'm going to direct my first question to Craig Roach.

To start this off, I guess that the first thing that I would like to understand is if you could contrast a solicitation process, an RFP that might be conducted within an RTO area, versus a non-RTO area. What are the differences between those types of approaches?

MR. ROACH: Well, they needn't be really different. You just have to do things a bit differently.

You know, the Maryland and New Jersey approaches are -- you know, we view them as innovative. They are consumer-focused. In fact, the bids are to take responsibility for a percentage share of a customer class need. They are that consumer-focused, so they are innovative in that sense.

They are designed to avoid any opportunity for abuse because, in the end, they are price-only bids. You literally get the bids on Monday and the session is over on

Friday. You can choose the bids.

And as to your question, I'll say that those innovative solicitations are not by accident in the most innovative RTO and in PJM. PJM helps tremendously. And they're just willing to help, but they help tremendously in areas like transmission assessments.

They help tremendously in prequalification. You know, when you bid, you have to be accepted as a buyer and seller in PJM. So there's a lot of accommodation or infrastructure that the RTO provides that is truly beneficial.

But when you're outside an RTO, you just have to get that accommodation another way. If there's not an RTO, for example, taking care of transmission, I think that either an independent third party transmission assessor or assessment has to be done or, at a minimum, the independent monitor has to be capable of going toe-to-toe with the utility transmission assessment. This is especially important, as I mentioned, in network resources.

Another point thing in PJM or any RTO is that a bidder has a spot market to turn to, a bidder can turn to that to fill in and purchase power. A bidder can turn to that spot market to lay off capacity, if they have too much, especially as is true in Maryland and New Jersey where the supplier is taking market risk.

Well, again, if you don't have that, you may want to have an accommodation in a non-RTO location. And that accommodation might involve transparency and economic dispatch.

So, you know, I take your question and I agree that perhaps my experience is that things go better in an RTO, especially on transmission, especially on the spot market access, but you can accommodate, you can create those same accommodations outside an RTO, if all the parties are willing to do it.

MR. PERLMAN: Can I ask a followup question on that? I guess my experience and understanding is that in an RTO, what you're really doing in bidding on the things like Maryland and New Jersey, is, you're providing the economic wherewithal to stand behind the default risk for the price guarantee you gave, because there's fungible products in ICAP, ancillary services, energy, what have you, and you could, if you wanted to, lean on the spot market every day for everything, and just pay the bill and the RTO would effectively undertake the supply for you.

Now, that's probably not a good business strategy, but you could do that. In a non-RTO region, you're going to have to, like you said, get a network resource that meets the test, that can do an integration agreement, that can deliver, and that deals with the transmission issue. There's much more physical orientation than the RTO structure. Do you agree with that?

MR. ROACH: I think there's some truth in what you're saying. I think that if you go out there and you talk to state regulators, for example, in non-RTO states, you will, as your question implies, talk more about asset-backed solicitations, often meaning unit-contingent solicitation.

It's a feeling, as implied by your question, that they want to have a place to go kick the tires. They want to see the power plant, so I think that's generally true.

At the same time, financially firm -- I think that's what you're saying -- financially firm products like firm LD sales, you know, summer blocks of power, they're sold all over the country.

So, financially firm is accepted, too, but your point is a firm one.

MR. PERLMAN: I guess the bottom-line question is, does that cut down -- if you're in the more physical world, does that cut down on the number of competitors you might have to participate in that kind of arrangement, as opposed to the RTO where anybody with an adequate balance sheet can show up. They will have to sign up to the PJM agreement or whatever, but they can play and they can be effective.

MR. ROACH: I think it really depends. It depends on the product. If you're in an area -- if you're outside an RTO and you have a solicitation for a product defined as unit-contingent gas-fired, combined cycle, I bet you get a lot of bidders, just by the nature of the fact that people own those power plants.

If you were to attempt to get system power, you know, take a percentage share of a customer and take responsibility for that customer class percentage share, I think that would be difficult, outside of an RTO, although accommodations could be made.

MR. PEDERSON: Continuing with that them, so, what I'm hearing, I think, is that within an RTO, the RTO can participate a little bit and help out on those solicitations, especially on the non-price factors like transmission and so forth.

I'd like to address a question to Ron on that, on outside of an RTO. What kind of process needs to be -- what kind of collaborative process needs to be developed so that solicitations outside of an RTO can be reliable in terms of when there is affiliate bidding in there?

What kind of collaborative process needs to be established so that these non-price terms, non-price factors are evaluated fairly?

MR. WALTER: This is our view: We think that in the ideal world, that state commissions would tell their utilities what standards they need to meet with respect to reliable supply of electricity; in other words, establish what a reserve margin ought to be for that particular state and that particular area.

Then I think it would be the responsibility of the utilities to design a process to acquire the necessary generation to supply that, specify the timing, where it should be, and how many megawatts.

And at that point, it's our view, in a non-RTO situation, to create a fair and open and level process, is to turn the solicitation of that new generation over to an independent monitor, manager, entity, whatever you want to call it.

A process would thereby be conducted where all suppliers would have an opportunity to respond to that need that's been established. And we're not saying that we don't think affiliates should be allowed to bid in those processes.

We're not saying that even in a case where a utility might be able to bid in a rate-based asset at that solicitation; all we're asking is that all the bidders, all the potential suppliers, live under the same set of rules; that they all have the same access to transmission; that they all have the same access to whatever sites they want to offer up; that they have the ability to include and the independent monitor has the ability to evaluate all of the factors, including credit, including financial stability, including all of these non-price factors, and that they all be treated equally and not preferentially, which we are finding in these 12 states, that that is happening.

MR. PERLMAN: May I ask a followup question on that as well? You had said earlier that you thought it would be difficult to finance a project without a long-term contract from the utility. Mr. Comer talked about the balance sheet impact on that and how that's viewed as debt by the rating agencies for the utility.

So, in the fair analysis you're talking about, should the alternative supplier's bid be burdened with the debt consequences that the S&P or Moody's is placing on the utility by entering into what would be effectively a capital lease or something like that, in their eyes in calculating the results?

MR. WALTER: A couple of points on that: In responding to a couple of RFPs, we've faced this issue of debt equivalency. We have created a lease structure that satisfies the rules, and we've gone to, you know, our accounting agency and they have endorsed that.

So we have been able to figure out a structure to make that work. But even more so than that, I think that when you look at this whole debt equivalency issue and what was created by S&P, what I would like to do is to ask you to step back and look at the bigger picture.

A lot of the issues that S&P is worried about is what happens after the fact? Does the Commission get along with the utility? Are they going to disallow in the future? Is there uncertainty related to recovery?

Now, in my view a contract has a lot more certainty in the front end than a rate-based plant, or one that's BOT'd and put into the rate base, because, as you know, in a lot of cases -- and I will just mention Mountain View here -- with that particular power plant, there are no limitations or liabilities for late delivery.

They are allowed to overrun by $30 million. They are allowed to pass through all the environmental and operational costs that may occur, that were unknown at the time of the transaction.

And there is an opportunity later on for the Commission to disagree with the utility on that, creating a risk that -- so far, the S&P has only been focused on the power purchase agreement side.

Our argument in the Mountain View case is that if we were to enter into a power purchase agreement -- and this applies to other cases, as well, and I didn't want to single that out -- where we would enter into a power purchase agreement, we would take full responsibility for construction, for the cost of it, to schedule it.

We'd pay LDs if it didn't get done on time. We would take on environmental risk, we would take on operational risk, we would take on delivery risk, and in some cases, providing replacement.

This creates a lot more certainty, in my view, for the utility and their relationship with the Commission, and perhaps a rate-base plan. I'm encouraging S&P and Moody's and others -- and Moody's is looking at this, too -- to look at the broader picture of this whole debt equivalency issues.

MR. PERLMAN: Was that a yes or a no?

(Laughter.)

MR. PERLMAN: I mean, it would seem to me that you couldn't avoid having to burden this contract, if there was, in fact, a cost of capital impact on the utility by using up some of their debt capacity and being looked at with their ratios and all that, for this contract. Would you agree that that's something that, in a fair analysis, should be considered as in --

MR. WALTER: Yes, as long as it's considered for the alternatives, as well.

MR. COMER: Can I just say one thing there? There are some utilities that would love to address this by receiving an equity adjustment to help compensate for the debt equivalency issue. That is a state issue, whether or not the state decides to do it.

And that's one of the reasons, you know, the state involvement in this and how you set it up is very important.

MR. PEDERSON: Dick?

MR. O'NEILL: As a matter of fact, I agree with you that the asymmetry between the purchase agreement and the rate base treatment is a serious problem that needs to be dealt with. Ed, I assume from what you said, that the affiliates are winning these procurements because they have some combination of the best technology, the best risk, the best price, or whatever, in these procurements?

MR. COMER: I would assume so, too. And in some cases, this may be the better credit profile. You know, I'm not involved in the individual procurements. They are not all affiliate-won by any means.

MR. O'NEILL: Well --

MR. COMER: There are lots of ones that --

MR. O'NEILL: -- affiliates --

MR. COMER: -- independent generators who are either selling long-term contracts or selling their plants.

MR. O'NEILL: Right, maybe we don't have a problem. I guess the statistics could bear that out, but if we believe some of the other people here, especially Ron, that it seems that the affiliates are winning a significant portion of their own company's bids.

If they are really the best, from some combination of factors, why aren't they winning in other procurements?

MR. COMER: Because they are fair procurements, the states are involved.

MR. O'NEILL: But if they're offering the best deals --

MR. COMER: You can look in New Jersey and there are deals in New Jersey where sometimes the utility -- that everybody sets up as, you know, a role model, sometimes the affiliates win and sometimes they don't.

MR. O'NEILL: Those procurements are --

MR. COMER: Now --

MR. O'NEILL: -- than some -- I'm talking about the longer-term procurements, you know, for long-term capital assets.

I mean, it looks like the affiliates are winning a huge portion of those procurements, and yet they are only winning them when they're affiliates. And if they are offering the best technology or the best of that litany of issues that you gave, they should be winning in other places, shouldn't they?

MR. COMER: Each transaction and each party is different. I would not generalize across the board.

MR. O'NEILL: So there are no good producers;

there's no --

MR. COMER: I mean, I just don't know how you generalize like that.

MR. REITER: Can I make a comment on that? I mentioned before that I thought a structural solution was a better one, and it was based on this thought that it's not at all unfair where there's a sufficient market, where there are enough bidders to say, well, affiliates, you're just not going to compete in this market.

I go back to an example, I think, unfortunately, where the government didn't take up on the communications industry. When the first broke up AT&T, the Bell Operating Companies said, you know, how about letting us offer long-distance service in those regions of the country where we don't have a local exchange network?

If we're good, we'll obtain the business, and if we're not, well, then we'll fail on the merits. And the settlement ultimately adopted, didn't allow them in at all. Ultimately in '96, the Communications Act was passed and they established this elaborate check list of competitive conditions that had to be met before an operating company, one of the historical ones, could enter into long distance, but they could offer it in their own service territory.

Now, over time, the FCC has approved most of the -- given permission to most of the companies that offer long distance service, to offer them in their local territories, and virtually overnight, they have obtained huge shares of the long distance business in their own territories.

And it makes you suspicious. I mean, it may be that they just won on the merits, but the concern is that if there's enough competition out there without them participating in the market, why not just say -- you know, adopt a rule saying, well, okay, this is one area where you're not allowed to compete, and if you're good, you'll still make a lot of money in the other markets where you would on the merits.

MR. O'NEILL: I would feel a lot more comfortable in this debate if the affiliates were winning outside their own territory, but that doesn't seem to be the case.

MR. PERLMAN: If the affiliates wanted to charge sort of an under-market price, because they wanted to win and were willing to accept a sub-optimal return, is that something that regulator should be concerned about for your competition issue?

MR. REITER: I think so, long-term. You know, you get into an area in antitrust policy where it talks about predatory pricing, and it's a difficult concept to establish on the facts, that someone has entered into a market, selling low-cost or below some average embedded cost in order to obtain market share and then drive out competitors, long-term.

In the short term, consumers are going to benefit, but, long-term, it may make others who are interested in entry, reluctant to participate, because they figure, well, you know, this is just isn't worth my while. If the utility's got staying power, they -- you know, there's also the potential for cross-subsidization that may make them be able to sustain that type of a strategy, longer term than some other entity might.

MR. COMER: Dick, you just said something that I want to make sure I understand. Are you saying that affiliates are not winning outside their service territory?

MR. O'NEILL: Not in the same proportion that they're winning inside their own.

MR. COMER: So you're saying that companies like Constellation or Mission Energy or, you know, any of the others that are, you know, affiliates --

MR. O'NEILL: There may be exceptions, and I can feel very comfortable with the exceptions, but they're not the rule.

MR. PEDERSON: Let me swing the questioning over. We've got a question for Mr. Hilke regarding affiliates that we've been discussing.

Has the FTC conducted any study or are you aware of any study that has looked at the effect of affiliates participating in competitive solicitations, whether it's the electric market or other markets?

MR. HILKE: Well, we have, as I mentioned in my opening remarks, looked at privatization as a general area, and there, there is a clear concern about whether the affiliate offer is a realistic one, and what sort of guarantees there are that once the offer has been accepted that it will be able to carry forward on that same basis.

The same issues have arisen in the federal privatization efforts for the A-76 program, and in both of those instances, the techniques which have been used to try to make sure that the inside bid, essentially is a fair one, have involved either some third-party assessment of that bid or severe penalties for reneging on the contract after it's been signed.

MR. PEDERSON: That's after the fact.

MR. HILKE: No, in the case of third-party review, it's before the fact; in the case of the reneging penalties, that's after the fact.

MR. PEDERSON: Okay.

MR. HILKE: So, both techniques have been used in different contexts.

MR. PEDERSON: And, Mr. Roach, a question for you: What demonstration needs to be made so that we could be comfortable that the solicitation process is a good process?

MR. ROACH: Well, again, I think there are minimum standards. I think, first, that the design of the process has to be done through a collaborative process. And that's not just bumper sticker stuff.

You know, a good one is, we participated in Arizona, and one of the approaches was, the first thing that was done there was, we tackled the issue of product design, which is hugely important in ensuring a fair solicitation.

The utility came into a meeting; it's off the record; it's a lot of people that are in the market, you know, a lot of consumer groups, suppliers, et cetera. Anyhow, you tackle this first question on product design. The utility brings in a forecast of their needs.

That's then discussed. Certain issues can be resolved through consensus. If there are issues that can't be resolved -- and there were -- the staff then opined officially. It went to the Commission and the Commission decided.

MR. PEDERSON: So the idea is, you go out with the products, here's a proposal, get folks in, discuss it, work out the details, get to an agreement to move forward, so we have that set aside.

MR. ROACH: That's right, and then we tackle transmission. In the West, there are lots of RMR issues.

The staff, again, the Arizona staff was really on top of this, did some transmission -- they were in the middle of transmission assessment, so we tried to tackle that issue and we really tried to tackle the RMR issue.

Again, you know, there were issues that resolved, some remained unresolved, and it goes to the Commission. Then we took up the issue of the criteria. What's the RFP going to look like? You know, what are the criteria?

Again, in a true collaborative process, a good way to start is the buying utility comes in and says here's my draft, and then lets all parties, all stakeholders, in a multi-day meeting, say what they feel and try to resolve issues. What's not resolved, goes to the Commission and it's resolved pretty quickly.

That's a collaborative process that really, I think, works, and, again, shows signs of consensus, shows signs of compromise. I didn't mean to go off on that song.

But the second one of minimum standards is to have an independent monitor. Again, I like it that the monitor is hired by the Commission and works for the Commission. That's the way it worked in Maryland.

That monitor has to be real, too. You know, I've seen monitors that can't go toe-to-toe with the buying utility. Well, you need that level of experience in your monitor.

They have to have access to every part of the solicitation, and they have to have the capability to go toe-to-toe, and that includes transmission monitoring. So you want an experienced independent monitor.

Thirdly, you want all bids evaluated on the same criteria. And that sounds so simple, but, you know, again, you're going to run into a difficult problem with cost-plus versus pay-for-performance contracts, and you're going to want to consider, if all bidders except the utility must come up with fixed prices, reliability guarantees, you know, payments for replacement costs, then everybody's got to do it. There can be no exceptions.

Fourth, you've got to have equal access to transmission assessments. I've talked about network resources. We find that there is not a lot of comparability.

I used to think that network resource status could be defined pretty readily, but that's not the case. We're seeing out there that there's lots of flexibility.

Sometimes some parties are given network resource status, but it involves redispatch. Sometimes they are given network resource status, but in involves an operating guide, meaning you're a network resource, but if you don't show up for these five hours, that's okay.

Sometimes we're beginning to see a utility say, well, I have network resource for that power plant, but I'm going to transfer it to another power plant. So there's lots going on.

Whatever that utility buyer does for its own affiliates, it must do for others, so that transmission assessment has to be in there. And I know that there are five, and I'm thinking of the fifth one.

By the way, everything I'm saying is in this little pamphlet that you can get at bostonpacific.com for free.

(Pause.)

MR. ROACH: Well, the fifth one is escaping me right now, but I think those -- I'll add what is a sixth, and maybe the fifth will come to me as I --

MR. PEDERSON: Let me ask a followup question. Maybe you said this and I just missed it.

Referring to the independent monitor, who pays that monitor? How is the compensation set and who pays?

MR. ROACH: You can do it any way. In Maryland, we work for the Commission, but we're paid for by the utilities. In Arizona, the monitor worked for the Commission, the Commission staff, but was paid for by bid fees.

MR. HILKE: Let me mention one other thing here. Another comparable institution is sort of the arbitrator groupings and various forms of certification and payment systems that are used in that context. They are also relevant to this type of concern.

MR. REITER: If I could, I just wanted to raise one cautionary note about the collaborative process. I don't disagree with Craig's suggestion about the importance of that process, introducing consensus, but I think there's a significant difference between producing consensus and producing a neutral outcome.

And in my written comments, I made note that one example that came to my mind was in Ohio where the utility had, in the restructuring process -- and customers agreed that it would be able to recover something like $7 or $8 billion in stranded costs, but half a billion dollars of that would be put at risk, nominally, if within five years, it wasn't able to achieve a switchover of 20 percent of its customers to competitive suppliers.

The idea, in theory, was, you know, that this would help ensure a neutral approach by the utility to non-affiliated suppliers, because it would have to make way for them. But, in fact, the way the collaborative process defined competitive suppliers, it included affiliates, so the utility got credit for meeting the 20 percent switchover target by including in those switches, shifts to its affiliate.

To me, that struck me as hardly a neutral outcome. They was, I'm sure, give-and-take in the consensus process, but ultimately I think that even though the Agency's decision ought to be informed by collaborative processes, the ultimate decision to ensure neutrality has to be made by a neutral party.

MS. TIGHE: Just to follow on that idea of a safeguard or a provision that provided at least no incentive or disincentive for abusing the affiliate relationship, Harvey, could you and Craig and really the whole panel, tell us about the solicitation that you have been involved in, or the processes that you've been involved, whether affiliates were allowed to participate and what particular feature assured you or the Commission, the person who had the oversight, that there had been fair dealing for all participants? Harvey, if you want to start?

MR. REITER: I guess you will probably hear more from Tom Welch later, but I know that in Maine, they don't permit affiliates to participate in the bidding process. And in Vermont, they have adopted a program called Efficiency Vermont, dealing with distributed -- not distributed, but demand management services.

Utilities were excluded from bidding to offer demand management services because the state concluded that they had an inherent conflict in performing those services and in selling power.

And the state found that it got a sufficient number of bids from those willing to offer the services. Those bidders, in turn, had to agree to another condition, and that was that if at any point, the state decided to adopt a retail access program -- and they don't have one in Vermont, which is the exception in New England -- but, if at any point they did, then entities who were contract to provide these services in the state, could not also sell power through any marketing division.

They'd have to make a choice. Either they participated in demand management services or they offered power supply. Again, it comes back to whether there's a sufficient market for competitive solicitations, absent the affiliate. And I think that in many instances, there are.

MR. ROACH: Again, I think some of the things we've already mentioned. A lot of the potential for abuse is worked out through the collaborative process, again, product design, transmission, and evaluation criteria.

If those can be addressed up front, the opportunities for abuse can be limited. Now, in the case of Maryland, and, I believe, New Jersey, in that design, they came up with a solicitation so that the evaluation was price only, and that is very strong structural defense against abuse because it's literally on bid day, just a comparison