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November 16, 2012

Public Utility Commission
Attn: Filing Center
550 Capitol Street NE #215
PO Box 2148
Salem, OR 97308

Re: UM 1182 –Northwest and Intermountain Power Producers Coalition's Direct Testimony and Exhibits

Dear Filing Center:

Enclosed please find the Northwest and Intermountain Power Producers Coalition's direct testimony and supporting exhibits for filing in the above-referenced docket. The confidential portions of the testimony and exhibits are separately contained in the sealed envelopes. This enclosure contains:

- Direct Testimony and Exhibits of William Monsen: NIPPC/100 - NIPPC/133
- Direct Testimony and Exhibits of Camden Collins: NIPPC/200 - NIPPC/202

We are providing the Commission with an original and (5) copies of each redacted and each confidential exhibit.

Please contact me with any questions. Thank you for your assistance.

Sincerely,

Gregory M. Adams
Attorney for the Northwest and Intermountain Power Producers Coalition

Enc.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 16th day of November, 2012, a true and correct copy of the within and foregoing THE NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION'S DIRECT TESTIMONY AND EXHIBITS was served as shown to:

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Signed
Chynna C. Tipton

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 100
Direct Testimony of William A. Monsen

REDACTED VERSION

November 16, 2012

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Exhibit 112: San Diego Gas & Electric Advice Letter 2126-E, Submitted to the California Public Utilities Commission November 16, 2009

Exhibit 113: Northwest and Intermountain Power Producers Coalition Data Requests to PacifiCorp, Portland General Electric, and Idaho Power Company, January 20, 2012

Confidential Exhibit 114: Confidential Exhibit Accompanying Direct Testimony of Stefan A. Bird (excerpt), on Behalf of PacifiCorp, Before the Public Utility Commission of the State of Oregon, Proceeding UE-217, Exhibit PPL/801, March 2010, Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-3

Confidential Exhibit 115: Confidential Cost Information Related to the Application for Certificate of Public Convenience and Necessity for the Dunlap I Wind Project, filed with Wyoming Public Service Commission in Docket No. 2000-xx-EA-09, July 24, 2009, Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-5

Exhibit 116: Direct Testimony of William J. Fehram (excerpt) on Behalf of Rocky Mountain Power, Before the Idaho Public Utilities Commission, Proceeding PAC-E-07-05, June 2007, Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-2

Exhibit 117: Direct Testimony of Mark R. Tallman (excerpt) on Behalf of PacifiCorp, Before the Public Utility Commission of Oregon, Proceeding UE 200, Exhibit PPL 200, April 2008, Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-2

Exhibit 118: Direct Testimony of Mark R. Tallman Before the Utah Public Service Commission (excerpt), Proceeding 04-035-30, May 2004, Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-4

Confidential Exhibit 119: Confidential Exhibit Accompanying Direct Testimony of Stefan A. Bird on Behalf of PacifiCorp, Before the Public Utility Commission of Oregon, Proceeding UE 210, Exhibit PPL/503, April 2009, Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-3

Confidential Exhibit 120: Confidential Cost Information Related to the Application for a Certificate of Public Convenience and Necessity of the Seven Mile Hill, Wind Energy Development Project, filed with the Wyoming Public Service Commission in Docket No. 20000-285-EA-07, August 31, 2007, Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-5

Exhibit 121: Wyoming Industrial Development Information and Siting Act Section 109 Permit Application for the Dunlap Energy Project (excerpt), June 15, 2009, filed with the Wyoming Public Service Commission in Proceeding 20000-xx-EA-09, July 24, 2009, Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-4

Exhibit 122: Idaho Power Company's Response to Request No. 20 of Idaho Public Utilities Commission Staff's First Production Request, Idaho Public Utilities Commission, Proceeding IPC-E-09-03, April 14, 2009

Exhibit 123: Portland General Electric, Form 1 filing to the Federal Energy Regulatory Commission for the year 2011, pages 402-403

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Confidential Exhibit 125: Confidential Portland General Electric Response to Northwest and Intermountain Power Producers Coalition Data Request 2.4 (renamed DR 010), Attachment B

Confidential Exhibit 126: Confidential Idaho Power Company's Response to Northwest and Intermountain Power Producers Coalition Data Request in responses 2.4(a), 2.4(b), and 2.4(c)

Exhibit 127: Direct Testimony of Mark R. Tallman (excerpt) on Behalf of Rocky Mountain Power, Before the Idaho Public Utilities Commission, Proceeding PAC-E-10-07, May 28, 2010

Exhibit 128: Rebuttal Testimony of Mark R. Tallman (excerpt) on Behalf of PacifiCorp, Before the Public Utility Commission of the state of Oregon, Proceeding UE 200, Exhibit PPL/203, August 22, 2008

Exhibit 129: Rocky Mountain Power Quarterly Compliance Filing Public Service Commission of Utah, Proceeding 03-035-14, January 31, 2007

Exhibit 130: Rebuttal Testimony for Phase II of Charles E. Peterson, Exhibit 3.2, On Behalf of the Division of Public Utilities Department of Commerce, State of Utah, Before the Public Service Commission of Utah, Proceeding 09-035-15, September 15, 2010

Exhibit 131: Direct Testimony of Mark Widmer on behalf of PacifiCorp, Before the Public Service Commission of Utah, Proceeding 99-035-10, September 20, 1999

Confidential Exhibit 132: Confidential Exhibit Accompanying Direct Testimony of Mark R. Tallman, on behalf of PacifiCorp (excerpt), Before the Public Utility Commission of the State of Oregon, Proceeding UE-210, Exhibit PPL/406, April 2009, provided by PacifiCorp to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-3

Confidential Exhibit 133: Confidential Exhibit Accompanying Direct Testimony of Mark R. Tallman, on behalf of PacifiCorp, Before the Public Utility Commission of the State of Oregon, Proceeding UE-217, Exhibit PPL/902, March 2010, provided by PacifiCorp to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-3

I. Background

Q. Please state your name and business address.

A. My name is William A. Monsen. I am a Principal and Executive Vice-President at MRW & Associates, LLC (MRW). My business address is 1814 Franklin Street, Suite 720, Oakland, California.

Q. Please describe your professional background.

A. I have been an energy consultant with MRW since 1989. During that time, I have assisted independent power producers (IPPs), electricity consumers, financial institutions, and regulatory agencies with issues related to power project development, project valuation, electricity procurement, and regulatory matters. I have directed or worked on projects in a number of states in the United States, including Colorado, California, Massachusetts, Nevada, and Wisconsin. Prior to joining MRW, I worked at Pacific Gas and Electric Company (PG&E). At PG&E, I held a number of positions related to energy conservation, forecasting, electric resource planning, and corporate planning. I hold a Bachelor of Science degree in engineering physics from the University of California at Berkeley and a Master of Science degree in mechanical engineering from the University of Wisconsin-Madison. Additional information about my qualifications is provided in Northwest and Intermountain Power Producers Coalition (NIPPC) Exhibit 101.

Q. On whose behalf are you testifying?

A. I am submitting testimony on behalf of NIPPC.

Q. What is NIPPC's interest in this proceeding?

A. NIPPC is a non-profit corporation and trade association of IPPs in the Pacific Northwest and the Intermountain West. NIPPC's interest in this proceeding is to support a fully competitive electric power supply marketplace by addressing biases in the utilities' current power solicitations.

Q. What is the purpose of your testimony?

A. My testimony responds to the Commission's directive to "determine an analytic framework and methodologies to better evaluate and compare utility ownership of resources to the purchase of power from IPPs."[1] The Commission's directive was intended to improve upon the report of the independent evaluator (IE) in Oregon RFPs. Guideline 10(d) currently states:

> *d. If the RFP allows affiliate bidding or includes ownership options, the IE will independently score the utility's Benchmark Resource (if any) and all or a sample of the bids to determine whether the selections for the initial and final short-lists are reasonable. <u>In addition, the IE will evaluate the unique risks and advantages associated with the Benchmark Resource (if used), including the</u>*

[1] Order No. 12-324, Appendix A at 4. Docket UM 1182, August 23, 2012.

> *regulatory treatment of costs or benefits related to actual construction cost and plant operation differing from what was projected for the RFP*.[2]

In particular, my testimony proposes refinements to the bid evaluation process to account for the risk differential between utility-owned generation (UOG) and power purchase agreements (PPAs) related to cost over- and under-runs, heat rate degradation, and wind capacity factor. NIPPC witness Ms. Camden Collins addresses the topic of counterparty risk and credit in separate testimony.

Q. Please summarize your recommendations.

A. Consistent with NIPPC's Comments filed March 19, 2012, I propose that bid adders should be incorporated into the Guideline 10(d) analysis and that the Commission should require the IE, as part of the analysis to create an RFP's shortlist, to apply each adder to the price evaluation of any bid that would result in utility ownership after commissioning the plant. Under unique circumstances, a particular bid adder may not be applicable to a particular utility ownership bid (e.g., if the utility were to reflect future increases in heat rate for the UOG proposal, then a heat rate adder may not be needed). Therefore, NIPPC proposes that Guideline 10(d) should provide that the utility may prove a particular adder should not be used for a particular bid, and the utility will bear the burden of demonstrating to the Commission (after opportunity for comment by the IE, Commission Staff, and non-bidding stakeholders) that the utility ownership proposal properly takes into account the potential cost increase addressed by the particular bid adder.

[2] Order No. 06-446 at 12, Docket UM 1182, August 10, 2006 (emphasis in original, underline added).

Following the approaches described below, the IE should apply the following bid adders:

- Cost over-runs or under-runs: The IE should apply a bid adder of 7.0% to the estimate of initial construction costs for UOG projects. In addition, because the final cost of utility plants might not reflect latent defects or upgrades omitted from final project estimates and since these repairs are made shortly after the plants enter ratebase, I also recommend that cost calculations for UOG projects should include an incremental bid adder equal to at least 5.7% of the initial construction costs (including the 7.0% adder) per year for the first five years of plant operations to account for capital expenditures that that occur shortly after the plant's commercial operating date but that are likely deferred capital expenditures that should have occurred before the plant came online.

- Heat rate: The IE should apply a bid adder to heat rate estimates for gas-fired UOG plants such that the average expected plant heat rate over the course of the analysis period is at least 8.0% above the starting heat rate to account for heat rate degradation.

- Capacity factor: The IE should reduce expected capacity factors for UOG wind projects by [redacted] to account for systemic capacity factor overestimates.

II. <u>Need for Bid Adders</u>

Q. Why are bid adders needed to level the playing field between IPP and UOG bids?

A. UOG projects tend to pose higher ratepayer risk than both new IPP projects and recontracting existing IPP facilities. If this risk is not reduced to be more comparable to the risk from IPP projects and if the cost of this risk is not reflected in bid evaluations, a utility could select a UOG project whose total cost to ratepayers (i.e., incorporating the cost of risk) is higher than competing bids from IPPs.

Q. Are there incentives for the utilities to select UOG projects over IPP projects even if the ratepayer risk is greater from UOG projects?

A. Yes. The Commission found in UM 1276 that the utility procurement process favors the development of UOG projects over entering into PPAs. As noted in Order 11-001:[3]

> We too accept the premise that a bias exists in the utility resource procurement process that favors utility-owned resources over PPAs. This bias is really a logical inference drawn from an understanding of ratemaking practices and the effectiveness of incentives. As Staff explained in its opening comments about the lack of a return on PPAs:
>
> > [U]nder cost of service regulation, a utility's 'profit' is the opportunity to earn a return on the rate base and by purchasing a PPA in lieu of building a power plant, it is foregoing the potential to earn some amount of profit.

Q. Why are there differences in the amount of ratepayer risk associated with UOG projects and IPP projects?

A. Since the Oregon utilities recover costs associated with their UOG projects on a cost-of-service basis, ratepayers are at risk for any differences between the utilities' projected versus actual costs and operational characteristics. PPAs typically are not cost-of-service agreements, and IPPs absorb the risk of many cost over-runs. For example, if a utility priced a UOG bid based on an expected heat rate of 7,000 Btu/kWh but the plant ended up having a heat rate of 7,500 Btu/kWh because of unforeseen but reasonable factors, ratepayers would generally be required to pay for the higher fuel costs associated with the

[3] Order No. 11-001 at 5, Docket UM 1276, January 3, 2011.

UOG project. Were the project selling to the utility under a PPA with a guaranteed heat rate of 7,000 Btu/kWh and the IPP's actual heat rate was 7,500 Btu/kWh, the IPP would generally need to compensate ratepayers for its failure to meet its guaranteed heat rate. Accordingly, the ratepayer risk for a project selling pursuant to a PPA is less than that typically seen in UOG projects.

Q. What are uncertain factors in UOG projects for which ratepayers may be at risk?

A. Uncertain factors in UOG projects for which ratepayers may be at risk include the following:

1. Cost of operations (initially and over time);
2. Fuel prices;
3. Plant performance (initially and over time);
4. Plant availability on critical days;
5. Cost of future capital additions;
6. Potential changes to rate of return over time;
7. Risk of technological obsolescence;
8. Cost of construction;
9. Project completion risk; and
10. Potential impacts on cost of capital.

Q. Will you be proposing bid adders to address each of these elements?

A. No. Pursuant to Order 12-324, I will be proposing bid adders to address only cost over-and under-runs, heat rate, and wind capacity factor risk. The need for each of these bid adders and my bid adder proposals are described below.

A. Construction Cost Over-Runs

Q. Please describe the risk of construction cost over-runs and under-runs.

A. Order No. 12-324 described this issue as follows:

> Item 1- Cost Over- or Under-Runs: An IPP contractually guarantees construction cost, while a utility Benchmark resource may have cost over- or under-runs that are allowed into rates.[4]

No matter how precise and careful the initial estimate, there is always the potential for unexpected findings that require a change of plans or more expensive materials, increases to material costs over the course of the project, delays due to weather or the unavailability of specialized labor or supplies, interest rate increases that affect interest costs during construction, permitting delays and requirements for additional studies, and any number of other unexpected events that slow down the construction project and increase costs.[5] This is the case for virtually any construction project, whether building a combined cycle power plant or remodeling a kitchen and all the more so for projects deploying new technology.

Q. Is there a recent history of cost over-runs for power projects?

A. Yes. A 2007 Edison Foundation study prepared by The Brattle Group found that utility infrastructure construction costs were on the rise at that time in large part due to dramatic

[4] Order No. 12-324, Appendix A at 2. Proceeding UM 1182, August 23, 2012.
[5] In some cases, construction costs may also turn out to be lower than expected.

increases to the prices of steel, cement, and other raw materials triggered by higher global demand, higher production and transportation costs, and a weakening U.S. dollar. For example, the cost of gas turbines increased by 17% in 2006 alone. They also found that labor costs were rising and that a growing backlog of contracts at large engineering, procurement, and construction (EPC) firms were starting to increase EPC bids.[6] Utilities that had not anticipated these cost increases faced significant cost over-runs, oftentimes even before construction began.

Q. Can you provide a specific example of such a cost over-run?

A. Yes. Estimates for the Big Stone II power plant and transmission line increased from $1 billion to $1.6 billion on account of higher-than-expected costs and design refinements.[7] Otter Tail Power Company, the lead utility on the project, ultimately withdrew its support, and the project was cancelled.[8]

Q. How did this particular cost over-run affect ratepayers?

A. Since this was a UOG project, Otter Tail's customers in North Dakota are currently paying for their share of this failed project, including interest and return on equity.[9] Had this been an IPP project, it is likely that Otter Tail's customers would not currently be facing a Big Stone II Cost Recovery Charge of nearly $1 per MWh for power that they

[6] Mark Chupka and Gregory Basheda. *Rising Utility Construction Costs: Sources and Impacts*. Prepared by The Brattle Group for The Edison Foundation, September 2007 (Chupka and Basheda), pages 1-2. http://www.edisonfoundation.net/IEE/Documents/RisingUtilityConstructionCosts.pdf
[7] Chupka and Basheda, 10.
8 "SD's $1.6B Big Stone II power plant project kaput." The Seattle Times. November 2, 2009. http://seattletimes.nwsource.com/html/businesstechnology/2010187634_apusbigstoneiisouthdakota.html
[9] "Tied to a Big Stone: Shelved power plant may cost ratepayers millions." The Bismarck Tribune. March 7, 2010. http://bismarcktribune.com/news/local/article_21ace140-29a1-11df-abe8-001cc4c002e0.html

will never receive.[10]

Q. If Big Stone II had been an IPP project, how would ratepayers have been affected by the cost increase?

A. If this had been a typical IPP project, the IPP would have borne the cost increase and been responsible for damage payments to cover delays in project operations. Moreover, if the IPP were unable to complete the project, it is likely that the IPP would have been responsible for liquidated damage payments.

Q. Couldn't the IPP have renegotiated its agreement in order to pass along the cost increases to the offtaker's customers?

A. The IPP could have tried to renegotiate the agreement but there is no guarantee that (1) the offtaker would have agreed to renegotiate the PPA and (2) that the Commission would have found this renegotiated agreement to be just and reasonable.

Q. Do ratepayers always pay for cost over-runs at UOG projects?

A. This is a matter of regulatory discretion. In general, cost over-runs are passed onto ratepayers when management error is not the cause of the over-run. For example, when cost over-runs result from large increases to the costs of raw materials, it can be reasonably argued that these increases are outside of management control and should be passed on to ratepayers under cost-of-service ratemaking principles. However, even when

[10] Big Stone II Cost Recovery Rider, effective as of August 1, 2010. https://www.otpco.com/RatesPricing/Documents/PDF/ND/ND_13.06.pdf

management error is responsible for the cost increase, it is possible that cost over-runs are passed through to ratepayers.

For example, Southern California Edison (SCE) was authorized in August 2006 by the California Public Utilities Commission (CPUC) to build 250 MW of black-start, dispatchable generation capacity. These projects were to be online by the summer of 2007.[11] SCE estimated that the costs for five peaking units would be around $250 million, or $50 million each.[12] SCE initially completed only four units[13] for a total cost of $260 million,[14] or $65 million each. SCE attributed the 30% cost increase to "the limited time available to have the units operational by August 1, 2007," explaining that with more time to scope out the project its original estimate would have been higher and that the labor costs increased as a result of the limited time available.[15] In other words, SCE admitted that its original estimates were simply too low. The CPUC found this error to be reasonable and allowed the utility to fully recover the higher construction costs in rates.[16]

[11] Assigned Commissioner's ruling addressing electric reliability needs in southern California for summer 2007. California Public Utilities Commission (CPUC) Rulemaking (R.) 05-12-013. August 15, 2006.
[12] CPUC Resolution E-4031, November 9, 2006, Finding 6 on page 8, presented in NIPPC Exhibit 102.
[13] The fifth unit was completed more than five years later, in November 2012, on account of a protracted dispute with the City of Oxnard, where this unit is located. SCE incurred $42.5 million for the design, engineering, permitting and equipment procurement for this unit through 2009 and estimated that it would need an additional $20 million to complete the work. A final construction cost will not be available until SCE files a cost recovery application for the plant. "Oxnard pull plug on efforts to fight power plant." Ventura County Star. October 25, 2011; and SCE 2012 General Rate Case application, SCE-02 Volume 9 – Peakers Power Plants Operation and Maintenance Expenses and Capital Expenditures, filed November 2010 in CPUC Proceeding A.10-11-015, page 14, excerpt presented in NIPPC Exhibit 106.
[14] CPUC Decision D.10-05-008 in proceeding A.07-12-029, May 6, 2010, page 3, presented in NIPPC Exhibit 103.
[15] SCE. Peakers Cost Recovery Testimony in CPUC Proceeding A.07-12-029, December 31, 2007, pages 27-28.
[16] CPUC Decision D.10-05-008, page 5, Finding 1, and page 6, Ordering Paragraph 1, presented in NIPPC Exhibit 103.

Q. How might bid adders have shielded SCE and Otter Tail ratepayers from these construction cost over-runs?

A. Had these utility projects been bid into competitive solicitations against IPPs, and had appropriate bid adders been applied to the UOG bids, the IPP bids may have been selected instead. This would have saved ratepayers from these higher costs, since, under a PPA, the IPP that was chosen to build the units would have been obligated to absorb the cost over-runs.

Q. Have you developed a proposed bid adder for construction cost over-runs?

A. Yes. I derived a cost-overrun bid adder based on a comparison between the rate-based installed costs for a number of UOG projects with the costs that the utility regulator approved as part of the plant approval process.[17] The adder is calculated as the capacity-weighted average percentage change in the installed cost relative to the cost that was initially proposed or approved.

Q. What data did you rely on for your capital cost bid adder?

A. For this analysis, I relied on publicly available data for the 11 UOG projects located in California that have entered service in the last ten years. The following table lists these projects, along with the plants' installed capacity and the percentage increase in costs relative to the costs that the utility initially proposed. I found that construction costs approved for ratepayer recovery were, on average, 7.0% higher than initial cost estimates.

[17] If the projects had been selected from competitive solicitations, the bids submitted in these solicitations would be the appropriate starting point instead of the regulator-approved costs.

Q. What do you recommend?

A. The IE should assign a bid adder of 7.0% to the assumed installed costs of a utility-owned project. For example, a UOG project with an estimated installed cost of $500 million would have its bid evaluated at a cost of $535 million.

Table 1: UOG Plants Used in Installed Cost Analysis

Plant	Capacity (MW)	Owner	Technology[18]	Plant History	Difference from Estimated Cost
Barre	49	SCE	CT	Developed with EPC	30%[19]
Center	49	SCE	CT	Developed with EPC	30%
Grapeland	49	SCE	CT	Developed with EPC	30%
Mira Loma	49	SCE	CT	Developed with EPC	30%
Gateway	580	PG&E	CCCT	Bought Before Online	26%
Miramar I	48	SDG&E	CT	Bought as Turnkey	12%
Mountainview	1,050	SCE	CCCT	Bought Before Online	3%
Palomar	566	SDG&E	CCCT	Bought as Turnkey	2%
Colusa	659	PG&E	CCCT	Bought Before Online	-2%
Humboldt Bay	146	PG&E	Recip.	Developed with EPC	-5%
Miramar II	48	SDG&E	CT	Bought as Turnkey	-8%
Capacity-Weighted Avg.					7%

Sources for the data in this table are provided in the footnote and in attached exhibits.[20]

[18] CT: Combustion Turbine (simple cycle); CCCT: Combined Cycle Combustion Turbine; Recip.: Reciprocating Engine

[19] Cost data for the Barre, Center, Grapeland, and Mira Loma peaker plants were estimated and recorded on a consolidated basis. The 30% difference from estimated cost reflects the difference between the total cost for all four peaker plants and the expected cost for all four peaker plants.

[20] The data sources for Table 1 are as follows.

- For the Barre, Center, Grapeland, and Mira Loma peaker plants, estimated costs were obtained from California Public Utilities Commission (CPUC) Resolution E-4031, dated November 9, 2006, Finding 6 on page 8 (scaled to reflect the development of just four of the five approved peaker plants), presented in NIPPC Exhibit 102, and actual costs were obtained from CPUC Decision D.10-05-008, May 6, 2010, page 4, presented in NIPPC Exhibit 103.

Q. Please describe these UOG plants in more detail.

A. Each of these projects is a gas-fired generation project that has come on-line since 2005. Four of the projects (Gateway, Mountainview, Palomar, and Colusa) are combined-cycle combustion turbine projects. Six of the projects (Barre, Center, Grapeland, Mira Loma, Miramar I, and Miramar II) are simple cycle combustion turbine projects. One project (Humboldt Bay) is a set of reciprocating engines.

At least four of the projects (Gateway, Mountainview, Palomar, and Colusa) were originally proposed as IPP projects but were acquired by a California investor-owned utility before the project started operations. The change in cost for these projects was relative to the acquisition price that the utility announced when it proposed to purchase the project.

- For Gateway, Colusa, and Humboldt Bay, estimated and actual costs were provided by PG&E on June 24, 2011, in response to Data Request IEP_002-02 submitted by the Independent Energy Producers Association in CPUC Proceeding R.10-05-006, presented in NIPPC Exhibit 104.
- For Mountainview, estimated costs were obtained from the Federal Energy Regulatory Commission Order Conditionally Accepting Proposed Rate Schedule and Revising Affiliate Policy in Docket No. ER04-316-000, February 4, 2004, page 7 (provided as Attachment A to CPUC Decision D.04-03-037, March 16, 2004, excerpt presented in NIPPC Exhibit 105), and actual costs were obtained from SCE's 2009 General Rate Case Application in CPUC Proceeding A.07-11-011, Exhibit 2, Volume 9, page 52, excerpt presented in NIPPC Exhibit 106.
- For Palomar, estimated costs were obtained from SDG&E Advice Letter 1778-E submitted to the CPUC on June 28, 2006, Attachment B, excerpt presented in NIPPC Exhibit 107, and actual costs were obtained from SDG&E Advice Letter 1796-E submitted to the CPUC on May 30, 2006, Attachment B, presented in NIPPC Exhibit 108.
- For Miramar I, expected costs were obtained from SDG&E Advice Letter 1621-E submitted to the CPUC on September 8, 2004, page 3, presented in NIPPC Exhibit 109, and actual costs were obtained from SDG&E Advice Letter 1711-E submitted to the CPUC on September 25, 2007, Attachment B, presented in NIPPC Exhibit 110.
- For Miramar II, expected costs were obtained from SDG&E Advice Letter 2099-E submitted to the CPUC on July 30, 2009, page 1, presented in NIPPC Exhibit 111, and actual costs were obtained from SDG&E Advice Letter 2126-E submitted to the CPUC on November 16, 2009, page 3, presented in NIPPC Exhibit 112.

Q. Why have you relied on data from California plants?

A. NIPPC requested documents and data from the Oregon utilities regarding the expected and actual costs of their UOG projects but did not receive sufficient data to include these results in our analysis.

Q. Please describe the data that you requested from the Oregon utilities and the data received in response to these requests.

A. In January 2012, NIPPC requested that the utilities provide, for each UOG plant placed into service in and after 2006, the initial application or document containing cost projections submitted to a regulator announcing the utility's intent to construct or acquire a generating plant and the Commission order allowing the plant to be entered into rate base.[21] In response, NIPPC received documents that, in most cases, did not have the cost data needed to compare initial cost estimates to final, in-service costs. For example:

- Idaho Power (IPC) provided links to its Certificate of Public Convenience and Necessity (CPCN) application for the Danskin plant. The application shows the company's "commitment estimate" for constructing the plant, but it is not clear whether this is the same value as was used in the bid for this plant.

- Portland General Electric (PGE) provided links to several pieces of testimony regarding the Biglow project, but the testimony was filed while the units were already under construction, and again it is not clear whether the cost estimate shown had been revised

[21] NIPPC data requests to PacifiCorp, PGE, and IPC, January 20, 2012, presented in NIPPC Exhibit 113.

subsequent to the project's bid submittal.

- PacifiCorp provided links to numerous filings but, for many plants, PacifiCorp did not provide any documents with cost projections that were dated prior to the plant's construction.[22] For other plants,[23] PacifiCorp provided CPCN applications or testimony filed prior to plant construction containing cost projections, but it is still not clear whether these cost projections are the same as the bid prices [redacted].[24] Only for a few plants did PacifiCorp provide an internal project approval document or IE report showing the bid value for the plant.[25] Only for one of these plants, Glenrock III, did PacifiCorp provide a document showing the rate-based value for the plant upon project completion.

Q. What steps did NIPPC take to try to clarify the data provided by the Oregon utilities?

A. NIPPC followed up with further data requests in September 2012 but received very limited information related to initial cost estimates in response. None of the utilities provided data in response to NIPPC's requests for the solicitation bid scoring results and

[22] These plants include Leaning Juniper, Marengo, Marengo II, and McFadden Ridge.
[23] These plants include Currant Creek, Glenrock I, Goodnoe Hills, Lake Side, Rolling Hills, and Seven Mile Hill I.
[24] Pacific Corp response to NIPPC Data Request 2.1, Attachment 2.1-3, Confidential Exhibit Accompanying Direct Testimony of Stefan A. Bird on behalf of PacifiCorp, before the Public Utility Commission of the State of Oregon, Proceeding UE-217, Exhibit PPL/801, March 2010, page 2, excerpt presented in NIPPC Confidential Exhibit 114; and PacifiCorp response to NIPPC Data Request 2.1, Attachment 2.1-5, confidential cost information related to Dunlap CPCN, filed with the Wyoming Public Service Commission in Docket No. 20000-xx-EA-09, July 24, 2009, presented in NIPPC Confidential Exhibit 115.
[25] This applies to Dunlap, Glenrock III, and High Plains.

the IE or independent consultant reports for their power solicitations. Neither did they respond to NIPPC's request to provide documents used as part of management's project approval process for their UOG plants, except in some cases to provide references to Commission orders for the plants. IPC did provide CPCN documents related to additional plants, but these again showed only commitment estimates, not bid values.

Q. Based on the data received from the Oregon utilities, what did you conclude?

A. Given the limited information that NIPPC was able to obtain from the Oregon utilities, I relied on the California dataset instead. That dataset includes all of the plants developed or acquired by the California investor-owned utilities in the last ten years. It is therefore not subject to selection bias, which could be a factor in the data received from the Oregon utilities, since the utilities have provided data for only select plants.

Q. Are the data from the California plants relevant for the Oregon utilities?

A. Yes. As shown in Table 1, some of the California plants came in below budget and some came in above budget. This suggests that the California utilities are not systemically poor at estimating or controlling plant costs but that they are subject to the many risks for cost over-runs that are always a part of large, complex construction projects, including the projects built by the Oregon utilities.

Q. Do you have any evidence from your limited data from the Oregon utilities that indicate cost over-runs in their projects?

A. Yes. Documents from PacifiCorp show an estimated construction cost for the Goodnoe Hills wind plant prior to plant operations of $151.9 million[26] and an actual cost of $196.6 million,[27] which is 29% higher than the original cost estimate. [redacted].[28]

Q. If there is the possibility for both cost over-runs and cost under-runs, why is a risk adder appropriate?

A. As demonstrated in the California analysis, the risk for cost over-runs and for cost under-runs is not symmetric. This is shown graphically in Figure 1, which charts the cost over-

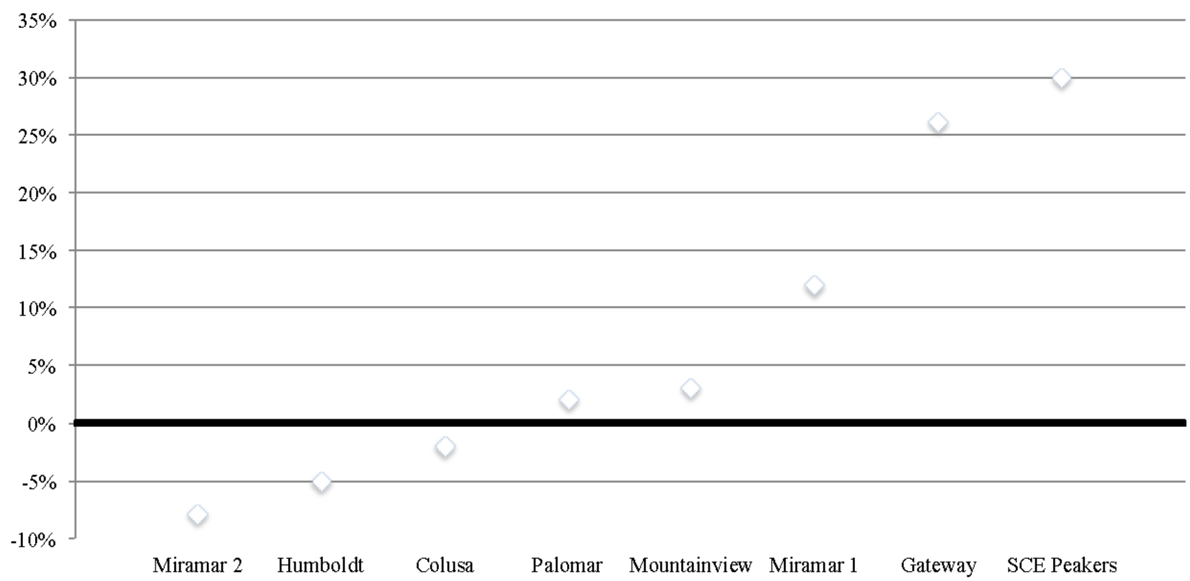
[26] PacifiCorp response to NIPPC Data Request 2.1, Attachment 2.1-2, Direct Testimony of William J. Fehram on behalf of Rocky Mountain Power, before the Idaho Public Utilities Commission, Proceeding PAC-E-07-05, June 2007, page 19, excerpt presented in NIPPC Exhibit 116. Note that it is not clear whether this expected cost is the same as the bid value.

[27] PacifiCorp response to NIPPC Data Request 2.1, Attachment 2.1-2, Direct Testimony of Mark Tallman on behalf of PacifiCorp, before the Public Utility Commission of Oregon, Proceeding UE-200, Exhibit PPL/200, April 2008, page 19, excerpt presented in NIPPC Exhibit 117.

[28] These cost over-runs were calculated based on the cost estimates shown in the plants' CPCN or permit applications, not the solicitation bids. If cost estimates increased between bid selection in the solicitation and the filing of the CPCN or permit application, these cost over-run figures underestimate actual cost over-runs. Data sources: PacifiCorp response to NIPPC Data Request 2.1, Attachment 2.1-4, Direct Testimony of Mark Tallman, before the Utah Public Service Commission (Lake Side CPCN Application), Proceeding 04-035-30, May 2004, page 12, excerpt presented in NIPPC Exhibit 118; PacifiCorp response to NIPPC Data Request 2.1, Confidential Attachment 2.1-3, Exhibit Accompanying Direct Testimony of Stefan A. Bird on behalf of PacifiCorp, before the Public Utility Commission of Oregon, Proceeding UE-210, Exhibit PPL/503, April 2009, presented in NIPPC Confidential Exhibit 119; PacifiCorp response to NIPPC Data Request 2.1, Confidential Attachment 2.1-5, cost information for the Seven Mile Hill Wind Energy Development Project, August 31, 2007, presented in NIPPC Confidential Exhibit 120; PacifiCorp response to NIPPC Data Request 2.1, Attachment 2.1-4, Wyoming Section 109 Permit Application for the Dunlap Wind Energy Project, before the Wyoming Public Service Commission, Docket No. 20000-xx-EA-09 June 2009, pages 1-10, excerpt presented in NIPPC Exhibit 121.

runs and under-runs for each of the California plants analyzed.[29] As shown, the final costs for all three plants that came in under budget were within 10% of the approved values for these plants. Of the five plants that came in over budget, only two had final costs within 10% of the budgeted amounts and two had final costs more than 25% above their budgeted amounts. This illustrates that cost over-runs have the potential to be much greater in magnitude than cost under-runs. This creates significant risk for ratepayers, who are generally liable for cost over-runs, as they were for the cost over-runs represented in the figure below.[30]

Figure 1: Distribution of Construction Cost Changes in California Plants



[29] The four SCE peaker plants are shown on a consolidated basis.
[30] None of these plants had costs disallowed by regulators, even though they exceeded original cost estimates.

Q. Does your proposed 7% bid adder fully cover the ratepayer risk from cost over-runs?

A. No. The 7% adder covers only costs of construction up to the date that the plants entered ratebase. In many cases, it appears that significant construction activities actually continue for several years after a plant comes online. For example, IPC faced $14 million in deferred capital expenditures on the $60 million Bennett Mountain Plant, which were needed to correct a latent construction defect that manifested itself only after commercial operations had commenced.[31] This was, in effect, a construction cost that was recorded only after the commercial operation date of the plant. Had this been an IPP project, it is very difficult to imagine this $14 million expense being passed onto IPC's customers.

Q. What do you conclude from this?

A. The costs of over-runs during the first five years of plant operations should be included in the calculation of the final over-run cost adder.

Q. Why did you select a period of five years for this analysis?

A. It is not unreasonable to expect that during the first several years of a major project there may continue to be latent defects that should have been corrected prior to the plant coming online. Any major cost during the first five years of plant operations is a cost that should have been expected and included in the costs presented to regulators at the time of project approval. This is in contrast to a capital addition that occurs many years into the

[31] IPC's response to Idaho Public Utilities Commission Staff's First Production Request in Case No. IPC-E-09-03, April 14, 2009. Response to Request No. 20, presented in NIPPC Exhibit 122.

future due to an unforeseen regulatory change, for example.

Q. Is there a possible incentive for a utility to understate its capital costs estimates by deferring such capital expenditures until after the plant comes online?

A. Yes. It is possible that a utility could plan to upgrade a plant after commissioning but not include those costs in the evaluation at the project approval stage. This would reduce the plant's bid cost below ratepayers' actual costs. The Bennett Mountain example and the data discussed below indicate that this is not a mere hypothetical and demonstrate that these over-runs occur during at least the first five years of operation.

Q. Have you developed an adder for cost over-runs related to deferred capital expenditures during the first five years of operations?

A. Yes. For consistency, I developed the adder based on the same set of California plants used in the initial cost over-runs adder.

Q. How did you derive the adder?

A. I calculated estimates of deferred capital expenditures during the first five years of operations for each of these plants by comparing year-to-year changes in the Cost of Plant shown in the appropriate FERC Form 1 filings.[32] The Cost of Plant increases when new capital expenditures are made and decreases on account of depreciation and the retirement of capital components. To estimate capital expenditures from the Cost of Plant

[32] Form 1 Filing to the Federal Energy Regulatory Commission (FERC), Pages 402-403, line 17. An example of one such document is presented in NIPPC Exhibit 123.

values, I calculated the Cost of Plant that would be expected if the only change from the prior year were due to depreciation and compared this value to the actual Cost of Plant. Any increase to the Cost of Plant above the expected value is assumed to be due to capital expenditures that are deferred plant construction costs.

Q. Do you believe that this is a reasonable approach?

A. Yes. If plant assets were taken out of service in a given year, there may be additional capital costs not captured in this calculation, so this is a conservative estimate for deferred capital expenditures.

Q. Would you provide an example demonstrating your approach for estimating deferred capital expenditures from the FERC Form 1 data?

A. Yes. Consider a plant with a Cost of Plant in Year 1 of $50 million and an annual depreciation rate of 3.5%.[33] From Year 1 to Year 2, the plant would accrue $50 million * 3.5% = $1.75 million in depreciation, leaving a remaining Cost of Plant of $50 million – $1.75 million = $48.25 million. If the recorded Year 2 Cost of Plant is $49 million, this implies that there were at least $0.75 million[34] in deferred capital expenditures during the year.

Q. Were there any additional steps in your analysis?

A. Yes. For each plant, I summed the deferred capital expenditures for the first five years or,

[33] For my analysis, I used depreciation rates from FERC Form 1 filings, page 337. An example of one such document is presented in NIPPC Exhibit 124.
[34] $49 million - $48.25 million = $0.75 million.

if less, for as many years as these data were available. I compared the total of these deferred capital expenditures to the Cost of Plant in the in-service year to obtain a percent increase over the initial cost. I then calculated an annual average rate of deferred capital expenditures for each plant and took a capacity-weighted average of these results to obtain a bid adder.

Q. What was your result?

A. I found that deferred capital expenditures averaged 5.7% of initial Cost of Plant each year over the first five years of operations.

Q. Did you use the complete California dataset for this analysis?

A. No. I was unable to include the Mountainview plant because consistent Cost of Plant data are not available for this plant for its first four years of operations. I was also unable to include the Humboldt Bay Generating Station because it consists of two units that were placed in service in 2010 and 2011, and I was unable to separate out the initial cost of the second unit in 2011 from capital costs to the first unit in that year.

Q. Do these omissions bias your results?

A. It is unclear how the omission may bias the results. However, excluding these two plants from the analysis of initial construction cost over-runs results in a bid adder for initial construction costs of 10.0%, which is greater than the 7.0% bid adder derived from all plants. Therefore, using the 7.0% adder to account for initial construction costs together with the 5.7% per year adder to account for deferred capital expenditures that are made over the first five years of operations may be conservative.

Q. How do you recommend that the 5.7% per year adder be applied?

A. I recommend that in the calculation of the plant's ongoing costs, the IE should estimate deferred capital expenditures of at least 5.7% of the initial plant cost (after application of the initial construction cost over-run bid adder) for each of the first five years of plant operations. If the utility had assumed a different level of capital expenditures in its bid, the utility's estimate should be used if the five-year total of those capital expenditures sum to at least 28.3% of the initial plant cost (after application of the initial construction cost over-run bid adder).[35] Otherwise, the utility's values should be scaled up to sum to this value.

Q. Do you have any evidence that this level of assumed deferred capital expenditures is applicable to the Oregon utilities?

A. Yes. I performed the same type analysis described above for all the Oregon utilities' plants that have been developed since 2001 for which the necessary data were available from the FERC Form 1s.[36] For the seven gas-fired plants and 12 wind plants that had sufficient data, I found that those plants had combined average annual deferred capital expenditures of 4.3% during the first five years of plant operations. This is of the same

[35] The 28.3% is obtained from summing 5.7% annual capital additions over five years.

[36] I excluded the Chehalis plant since it was not a utility-owned plant during its first years of operations. I excluded the West Valley plant because its significant Cost of Plant increases were offset by rent decreases, which suggested that some of the Cost of Plant increase may be due to accounting changes and not capital additions. I excluded the Beaver plant since data on the unit that was developed in 2001 is recorded together with data on older units, and I could not separate out which capital additions applied to which units. I excluded Biglow Canyon because Cost of Plant data was not provided for this plant.

order of magnitude as found for the California plants (i.e., 5.7%).

Q. Why do you recommend that the California value be used in place of the Oregon value?

A. I recommend that the California values be used for consistency with the initial construction cost over-runs calculation. If sufficient data is provided by the Oregon utilities to perform a calculation of initial construction cost over-runs for the Oregon UOG projects, Oregon data should be used for the analysis of both the initial construction cost over-runs and the deferred capital expenditures that occur during the first five years of plant operation.

B. Heat Rate Adder

Q. Why is there a need for a heat rate adder for gas-fired plants?

A. Heat rate is a key input into the calculation of the cost of a gas-fired plant. If a plant uses more fuel than expected to generate a set amount of power (i.e., has a higher-than-expected heat rate), the cost of fuel increases for the plant and the cost of emissions credits may increase as well. Heat rate tends to degrade (i.e., increase) through plant usage and then to improve when major plant maintenance is performed. For UOG projects, ratepayers are liable for the cost increases associated with heat rate degradation. Under PPAs, the IPP or ratepayers may be responsible for fuel costs, depending on the terms of the contract. However, even in tolling agreements, it is typical for the IPP to be liable for heat rate degradation.[37]

Q. Did you derive a heat rate adder?

A. Yes. I derived a heat rate adder that should be applied to proposed projects that burn natural gas whenever ratepayers would be responsible for cost increases associated with higher-than-anticipated heat rate.

Q. What source did you use to derive the heat rate adder?

A. I derived the heat rate adder from a database of annual cost and operating characteristics of utility-owned generation for the years 1981 and 1999, inclusive.[38]

Q. Please describe your approach for developing your proposed heat rate adder.

A. I compared each heat rate recorded in the dataset to the minimum recorded heat rate for that plant, and I used this as a proxy for the change in heat rate compared to the initial heat rate. The average of all the heat rate changes obtained in this manner for a plant is a conservative assessment of the plant's average lifetime change from the initial heat rate, since in most cases the plant lifetime extends beyond the years shown in the dataset, and further degradation beyond that observed in the dataset is likely.

I averaged together all the observed heat rate changes across all the plants, weighted by

[37] See, for example, the All Source RFP Tolling Agreement provided in PacifiCorp's All Source RFP-Resource 2016 soliciation, Section 16.1 on page 56.
[38] Data files for Fabrizio, Rose, and Wolfram. "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency." *American Economic Review*, 2007, Vol. 97 (September): 1250-1277. Available at http://faculty.haas.berkeley.edu/wolfram/

capacity factor, to develop a proxy for the average heat rate increase above the expected heat rate.

Q. Why did you use the minimum heat rate from the dataset?

A. I used the minimum heat rate observed in the dataset as a conservative proxy for the initial heat rate. This is a conservative proxy since the minimum heat rate in the dataset may already reflect significant heat rate degradation from the years prior to 1981.[39]

Q. What plants were included in the data you used to derive the heat rate adder?

A. I filtered the original database to include only natural gas-fired plants for which there were at least three heat rates reported in the database. The resulting filtered dataset includes data for 245 plants.[40] In addition, I excluded from the analysis all heat rate values below 7,000 Btu/kWh, which would be physically unrealistic for plants of this vintage.

Q. Why did you weight the average by capacity factor?

A. If a plant has a higher-than-expected heat rate for a small number of MWh, the cost to ratepayers is less than if the plant has a higher-than-expected heat rate for a large number of MWh. Weighting the average by capacity factor weights the degradation by a measure

[39] I would have liked to compare the heat rate for each plant in each year to the heat rate assumed in the project's bid or when the project received regulatory approval or, absent that data, the starting heat rate for the plant. However, none of these data were readily available.

[40] Whenever a plant had a capacity change of 20 MW or more from one year to the next, I treated the plant in the second year as a new plant so that heat rate changes caused by unit additions would not be confused with heat rate degradation. Counting these split plants individually increases the dataset from 245 plants to 290 "plants."

of the cost of the heat rate degradation to ratepayers.

Q. What heat rate adder does NIPPC recommend?

A. Based on my analysis, I recommend that the IE should include a heat rate adder of 8.0% when evaluating proposed gas projects for which ratepayers would be liable for the cost of heat rate degradation.

Q. How should this adder be applied?

A. If ratepayers would be at risk for the higher costs associated with heat rate degradation, the IE should incorporate the expected heat rate increase in the bid evaluation. This can be done as an 8.0% heat rate adder or as a heat rate forecast that reflects anticipated degradation resulting in an 8.0% increase in the average heat rate over the bid evaluation period. If the utility or IPP provides a heat rate forecast showing degradation of less than 8.0% over time and the fuel costs will be passed on to the utility's ratepayers under the project structure, the 8.0% adder should be adjusted so that the degradation included in the heat rate forecast plus the additional heat rate adder sum to a 8.0% increase in the average heat rate over the bid evaluation period.

Q. Do you have any indication that this adder is relevant to the Oregon utilities?

A. Yes. I collected actual heat rate data for the utilities' gas-fired plants (i.e., Currant Creek, Lake Side, Gadsby, Chehalis, West Valley, Port Westward, Danskin, and Bennett

Mountain) from their FERC Form 1 filings.[41] With these data, I calculated the difference between the actual heat rate and the minimum recorded heat rate for each plant. I obtained a capacity factor-weighted deviation from minimum heat rate of 10.4%.

In addition, I calculated the difference between the actual and expected heat rate at the Danskin and Port Westward plants using confidential data provided by IPC and PGE on the heat rate values used in the bid evaluations for these plants. [redacted][42] [redacted][43]

These analyses indicate that the Oregon utilities' plants are not immune from the heat rate degradation seen in the nationwide database of power plants. The heat rate degradation seen in the Oregon analyses may not be as certain as what we see from the broader nationwide database because of their smaller sample sizes and because they cover only the early years of plant operations. Additional degradation will likely be observed as these plants age. For these reasons, it is appropriate to apply the results from the

[41] I excluded dual-fuel units from this analysis.

[42] The expected heat rate was obtained from PGE's response to NIPPC Data Request 2.4 (renamed DR 010), Confidential Attachment B, presented in NIPPC Confidential Exhibit 125. Actual heat rates were obtained from FERC Form 1 filings, page 402, and example page is provided in NIPPC Exhibit 123.

[43] The [redacted] and [redacted] values were both calculated by comparing the anticipated average heat rate (as provided in IPC's confidential response to NIPPC data request 2.4) to the actual heat rates reported for the plant. The [redacted] value comes from using for the actual heat rates data that IPC reported to FERC in Form 1 filings, page 402. The [redacted] value comes from using for the actual heat rate data that IPC provided in response to NIPPC Data Request 2.4(a), 2.4(b), and 2.4(d), presented in NIPPC Confidential Exhibit 126.

nationwide dataset to the gas-fired plants developed by or for the Oregon utilities. However, the Commission could instead choose to use the heat rate degradation seen in Oregon-specific plants.

Q. Do you have any suggestions for extending the heat rate analysis?

A. Yes. Aside from affecting fuel-related costs, heat rate degradation would increase a plant's carbon dioxide emissions, which could impose operational risks and larger than expected greenhouse-gas related costs. Additional analysis would be required to quantify these risks for use in the heat rate adder.

C. Wind Capacity Factors

Q. Why is there a need for a capacity factor adder for wind plants?

A. Capacity factor is a key input into the calculation of the per-MWh cost of wind generation since wind plant costs are dominated by fixed costs. If a wind plant generates less power than expected (i.e., has a lower than expected capacity factor), the fixed costs of the wind plant are spread over a smaller amount of output, resulting in a higher unit cost of power. For UOG projects, ratepayers are generally liable for the project costs regardless of the actual project output. With PPAs, IPPs typically pay for the project costs and charge ratepayers only for delivered generation. As such, PPAs shield ratepayers from the capacity factor risk that ratepayers bear from UOG projects.

Q. Did you develop a capacity factor adder for renewable generation?

A. Yes. I developed a capacity factor adjustment for utility-owned wind projects based on the observed performance of PacifiCorp's wind plants compared to the capacity factors that PacifiCorp originally anticipated for the plants.

Q. Which plants did you examine for this analysis?

A. As an initial analysis, I examined publicly available data associated with all 12 of PacifiCorp's wind plants that began operating prior to 2010: Foote Creek, Glenrock. Glenrock III, Rolling Hills, Goodnoe Hills, Leaning Juniper I, Marengo, Marengo II, Seven Mile Hill, Seven Mile Hill II, High Plains, and McFadden Ridge I.[44]

Q. What data sources did you use for this analysis?

A. I collected annual capacity factors for the plants from PacifiCorp's FERC Form 1s and obtained public values for expected capacity factors from various regulatory filings and regulatory Commission staff reports.[45] I compared the reported capacity factor in each

[44] The Dunlap wind farm, which went into service in October 2010, is not included in the public analysis because I was unable to locate a publicly available expected capacity value for this plant.

[45] These include:

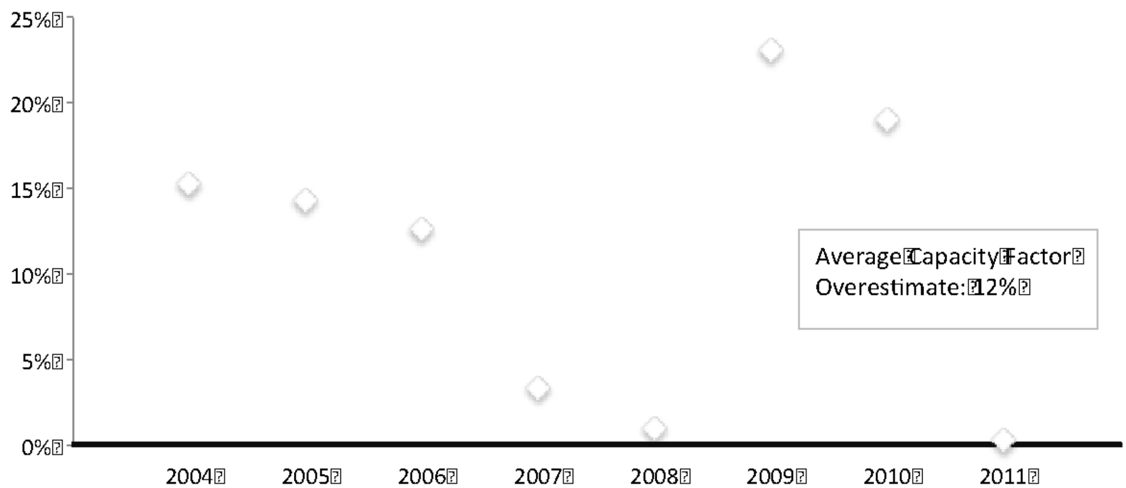
1. Direct Testimony of Mark R Tallman on behalf of Rocky Mountain Power, before the Idaho Public Utilities Commission, Proceeding PAC E-10-07, page 13, May 28, 2010, excerpt presented in NIPPC Exhibit 127.
2. Rebuttal Testimony of Mark R Tallman on behalf of PacifiCorp, before the Public Utility Commission of state of Oregon, Proceeding UE-200, Exhibit PPL/203, August 22, 2008, page 12, excerpt presented in NIPPC Exhibit 128.
3. Rocky Mountain Power Quarterly Compliance Filing to the Public Service Commission of Utah, Proceeding 03-035-14, January 31, 2007, presented in NIPPC Exhibit 129.
4. Rebuttal Testimony for Phase II of Charles E. Peterson on behalf of the Division of Public Utilities, Department of Commerce, State of Utah, before the Public Service Commission of Utah Exhibit 3.2R, Proceeding 09-035-15, September 15, 2010, presented in NIPPC Exhibit 130.

year for which this data was available to the expected capacity factor for the plant to obtain the observed under- or over-estimate. I took a capacity-weighted average of all of these data points to obtain an overall average capacity factor over-estimate of 11.7%.

Q. Please describe your findings.

A. The following figure illustrates the capacity factor over-estimates on an annual basis, beginning in 2004.

Figure 2: Annual Capacity Factor Over-Estimates for PacifiCorp Wind Projects



5. Direct Testimony of Mark Widmer on behalf of PacifiCorp, before the Public Service Commission of Utah, Proceeding 99-035-10, September 20, 1999, page 11, excerpt presented in NIPPC Exhibit 131.

The fourth source, Exhibit 3.2R of the Rebuttal Testimony for Phase II of Charles E. Peterson, includes a list of expected wind capacity factors that is cited "from an unsourced spreadsheet in possession of Division." Since the data source is unclear, as is the meaning of "expected" in this context, when data were available from an alternate source, I relied on the alternate source in place of this source. Had I instead used this data source as my primary data source, I would have calculated a higher capacity factor over-estimate, so my capacity factor adder is a conservative value.

This figure demonstrates that the expected average capacity factor used for the justification and approval of PacifiCorp's wind plants has exceeded the actual capacity factor for these plants in each year (on a capacity-weighted basis). The amount of overestimate has ranged from 0.3% in 2011 to 23% in 2009, with an average overestimate of 11.7% over the entire period.

Q. Were you able to refine the analysis using confidential information provided by PacifiCorp?

A. Yes. [redacted][46] [redacted][47] [redacted][48] [redacted]

When I updated my analysis to incorporate these confidential data points, the average capacity factor over-estimate [redacted]

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[46] PacifiCorp's response to NIPPC Data Request 2.1, Attachment 2.1-3, Confidential Exhibit Accompanying Direct Testimony of Stefan A. Bird on behalf of PacifiCorp, before the Public Utility Commission of the State of Oregon, Proceeding UE-217, Exhibit PPL/801, March 2010, page 2, excerpt presented in NIPPC Confidential Exhibit 114.

[47] PacifiCorp's response to NIPPC Data Request 2.1, Attachment 2.1-3, Confidential Exhibit Accompanying Direct Testimony of Stefan A. Bird on behalf of PacifiCorp, before the Public Utility Commission of the State of Oregon, Proceeding UE-210, Exhibit PPL/406, April 2009,page 19, excerpt presented in NIPPC Confidential Exhibit 132.

[48] PacifiCorp's response to NIPPC Data Request 2.1, Attachment 2.1-3, Confidential Exhibit Accompanying Direct Testimony of Mark R. Tallman on behalf of PacifiCorp, before the Public Utility Commission of the State of Oregon, Proceeding UE-217, Exhibit PPL/902, March 2010, page 3, presented in NIPPC Confidential Exhibit 133.

Q. What do you recommend?

A. I recommend that the IE should reduce the capacity factor for proposed utility-owned wind generation projects by [redacted] when comparing utility-owned projects against IPP bids.

III. Conclusion

Q. Please summarize your recommendations.

A. I recommend that the following bid adders should be applied:

- Cost over-runs: A bid adder of 7.0% adder should be applied to the estimate of initial construction costs for UOG projects. In addition, cost calculations for UOG projects should include annual over-run additions equal to at least 5.7% of the initial capital costs (including the 7.0% adder) for the first five years of plant operations to account for deferred capital expenditures that should have occurred prior to the plant's commercial operating date.

- Heat rate: A bid adder should be applied to heat rate estimates for gas-fired UOG plants such that the average expected plant heat rate over the course of the analysis period is at least 8.0% below the starting heat rate to account for heat rate degradation.

- Capacity factor: Expected capacity factors for UOG wind projects should be reduced by [redacted] to account for systemic capacity factor overestimates.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

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Northwest and Intermountain Power Producers Coalition Exhibit 101

Witness Qualification Statement of
William A. Monsen

November 16, 2012

WITNESS QUALIFICATION

STATEMENT NAME: William A. Monsen

EMPLOYER: MRW & Associates, LLC

TITLE: Principal and Executive Vice President

ADDRESS: 1814 Franklin Street, Suite 720, Oakland, CA 94612

EDUCATION: M.S., Mechanical Engineering, University of Wisconsin-Madison.
B.S., Engineering Physics, University of California, Berkeley.

EXPERIENCE:

Principal at MRW & Associates, LLC (1989 - Present) Expert in electric utility resource planning, independent power issues, retail power procurement, power market evaluations, due diligence for power generation projects, and evaluation of energy cost management options. Typical assignments include: expert testimony and strategic support in complex regulatory cases concerning electricity and natural gas issues; analysis of markets for non-utility generator power in the western U.S. and Asia; evaluation of the cost-effectiveness of onsite power generation options; advising large commercial and industrial customers on energy management and cost-reduction options; analysis of the value of incentives and regulatory mechanisms in encouraging utility-sponsored demand-side management (DSM); and negotiating non-utility generator power sales contract terms with utilities.

Expert witness in more than 50 proceedings before regulatory commissions in the United States, including in California, Colorado, Arizona, Nevada, and Massachusetts. Testimony topics typically pertain to electricity and natural gas market structure, including issues pertaining to independent or merchant power; electricity resource planning; electricity and natural gas revenue allocation and rate design; payments to qualifying facilities; distributed generation; and demand response.

Energy Economist at Pacific Gas & Electric Company ("PG&E") (1981 - 1989) Responsible for analysis of utility and non-utility investment opportunities using PG&E's Strategic Analysis Model. Performed technical analysis supporting PG&E's Long Term Planning efforts. Performed Monte Carlo analysis of electric supply and demand uncertainty to quantify the value of resource flexibility. Developed DSM forecasting models used for long-term planning studies. Created an engineering-econometric modeling system to estimate impacts of DSM programs. Responsible for PG&E's initial efforts to quantify the benefits of DSM using production cost models.

Academic Staff at University of Wisconsin-Madison Solar Energy Laboratory (1980 - 1981) Developed simplified methods to analyze efficiency of passive solar energy systems. Performed computer simulation of passive solar energy systems as part of the Department of Energy's System Simulation and Economic Analysis working group.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 102

California Public Utilities Commission
Resolution E-4031
November 9, 2006

November 16, 2012

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ENERGY DIVISION **RESOLUTION E-4031**
November 9, 2006

R E S O L U T I O N

Resolution E-4031. Southern California Edison Company (SCE) requests the Commission's approval to establish the Peakers Generation Memorandum Account (PGMA) and to revise the Generation Sub-account of the Base Revenue Requirement Balancing Account (BRRBA).

The PGMA will record the revenue requirement (i.e., incremental O&M expenses, book depreciation, applicable taxes, and an authorized rate of return on rate base) as each peaking facility is completed and closed to plant-in-service. The revenue requirement recorded in the PGMA will be transferred to the Generation Sub-account of the BRRBA on a monthly basis.

By Advice Letter 2031-E Filed on August 24, 2006.

SUMMARY

This Resolution approves SCE's request to establish a Peakers Generation Memorandum Account (PGMA) and to revise the Generation Sub-account of the Base Revenue Requirement Balancing Account (BRRBA). This Resolution also authorizes SCE to record the revenue requirement as each peaking generation plant is completed and becomes used and useful. The revenue requirement will be recorded in the PGMA and will be transferred to the Generation Sub-account of the BRRBA on a monthly basis.

BACKGROUND

On August 15, 2006, in Rulemakings 05-12-013 and 06-02-013, an Assigned Commissioner's Ruling (ACR) "Addressing Electric Reliability Needs in Southern California For Summer 2007" directed Southern California Edison Company (SCE) to, among other thing, pursue the development and installation of up to 250 MW of black-start, dispatchable generation capacity within its service territory for summer 2007 operation. The ACR invited SCE to file an advice letter to establish a memorandum account in which it would record the acquisition and installation costs.

Assigned Commissioner's Ruling directed SCE to procure 250 MW of utility owned generation that can be online in time for summer 2007.

The ACR directed SCE to procure black-start, dispatchable generation capacity within its service territory for summer 2007 operation.

The ACR stated that it was taking these actions in response to the critical near-term needs in southern California that was identified by the California Independent System Operator (CAISO).

> The CAISO's assessment for the summer of 2006 indicated that it could handle a demand in excess of 48,000 MW, close to what demand was forecasted to be under extreme temperatures that materialize once every 10 years, with limited to no impact on firm load customers.[1] However, the CAISO reports, the peak demand during that heat wave was 51,000 MW, well above any of the scenarios it had assumed in its assessment. As the CAISO notes, that was over 12% higher than last year's record, 6% higher than the worst case scenario the CAISO analyzed in its assessment, and 38% higher than the peak demand of the crisis year 2001; it represents the demand forecasted not to appear until five years from now. Across the CAISO's service area, weighted average temperatures ranged between 106 and 110 degrees Fahrenheit on various days, something California and the West have not experienced in recent history; these temperatures were higher than anything recorded in the 30-year history of the temperature models used by the CAISO.[8/15/06 ACR]

ACR invited SCE to file an advice letter to establish a memorandum account.

The ACR noted that it did not appear possible for SCE to develop and for the Commission to consider proposals for ratemaking treatment of the costs of developing and installing the utility-owned generation prior to the time such generation would be installed. As such, the ACR invited SCE to file an advice

[1] Prepared Statement of Yakout Mansour, President and Chief Executive Officer of CAISO, before the California State Senate Committee Governmental Organizations, dated August 9, 2006. The statement is available at the CAISO's website.

letter to establish a memorandum account in which it would record the acquisition and installation costs of the generation facilities.

SCE filed Advice Letter 2031-E to establish the Peakers Generation Memorandum Account.

SCE filed Advice Letter 2031-E on August 24, 2006. The advice letter sought Commission permission to establish the Peakers Generation Memorandum Account (PGMA) and to revise the Generation Sub-account of the Base Revenue Requirement Balancing Account (BRRBA).

NOTICE

Notice of AL 2031-E was made by publication in the Commission's Daily Calendar. SCE states that a copy of the Advice Letter was mailed and distributed in accordance with Section III-G of General Order 96-A.

PROTESTS

Advice Letter 2031-E was not protested.

DISCUSSION

Energy Division has reviewed SCE's Advice Letter 2031-E and recommends approval as clarified. The clarifications are needed to ensure that the Commissions direction and SCE implementation are consistent with the intent of the ACR.

The advice letter filed by SCE exceeds the ACR's directive.

The ACR invited SCE to file an advice letter to establish a memorandum account to "record the acquisition and installation costs." SCE's advice letter, in addition to establishing a memorandum account, sought authority to record the revenue requirement (i.e., incremental O&M expenses, book depreciation, applicable taxes, and an authorized rate of return on rate base) arising from with the acquisition costs, installation costs, and other related costs associated with peaking generation units and non-ISO transmission facilities upgrades associated with interconnecting the peaker units. SCE proposes to calculate the revenue requirement as each peaking facility is completed and closed to plant-in-service.

SCE further proposes that the revenue requirement recorded in the memorandum account be transferred to the Generation Sub-account of the BRRBA on a monthly basis.

SCE's filing highlights the different purpose of its proposed memorandum account. SCE proposes to use the memorandum account to record the revenue requirement associated with the peaker plants. The ACR directive indicated that the memorandum account was to record the acquisition and installation costs. The ACR did not address revenue requirement for the peakers.

SCE does not require a memorandum account to record acquisition and installation costs.

SCE states that prior to the peaker plants going into service, SCE spends the cash to construct the project and those expenditures are accumulated and tracked in a "work order" and those expenditures are recorded as an asset (Construction-work-in-progress) on the general ledger. SCE also accrues allowance for funds used during construction (AFUDC) associated with the expenditures in the work order. As the peaker costs are tracked in a "work order", a mechanism already exists at SCE to record the acquisition and installation costs.

SCE proposes to record $57 to $71 million of revenue requirement to the PGMA

SCE estimates that, for up to 250 MW of resources (5 combustion turbines of approximately 45 MW each), the total costs associated with the development, installation and start-up will probably exceed $250 million. As noted above, these costs will be accrued and tracked in a "work order", not the PGMA.

Based on the estimated $250 million of capital expenditures to install 5 peaking units, SCE estimates that the annual revenue requirement will be approximately $40 to $50 million. SCE proposes to record the revenue requirement in the PGMA. Assuming that the units go in-service in August 2007, the revenue requirement recorded in the PGMA in 2007 will be approximately $17-$21 million (5 month) and another $40-$50 million in 2008, for a total of $57-$71 million. Beyond 2008, the annual revenue requirement for the peakers will be included in SCE's authorized 2009 GRC revenue requirement which is currently scheduled to be implemented on January 1, 2009.

SCE's advice letter filing seeks to neutralize the income statement impact once the peakers are in service.

Once the peaker plants are operational and transferred to plant-in-service, SCE starts recording depreciation, O&M, and tax expenses. Recording these expenses without a corresponding increase in revenues will result in SCE's recorded earnings to be negatively impacted. Allowing SCE to record the revenue requirement in a memorandum account without the monthly transfer to the BRRBA does not mitigate the earnings impact, as SCE's memorandum account balances cannot be recorded on the general ledger until the Commission has approved rate recovery through a balancing account. SCE's advice letter proposal to record the revenue requirement to the memorandum account with a monthly transfer to the Generation Sub-account of the BRRBA neutralizes the income statement impact. SCE is ensured that the addition of the power plants will not affect SCE's opportunity to earn its authorized rate of return.

SCE will track the revenue requirement for each unit separately.

Mitigating circumstances compel deviating from standard Commission procedure.

As described above in the ACR, unanticipated conditions occurring during the summer of 2006 have prompted the CAISO to identify critical near-term needs in southern California for summer 2007. Accordingly, the ACR directed SCE to, among other things, pursue new utility-owned peaker units with the characteristics described in the ACR that provide up to 250 MW of new generation and can be online in time for August 1, 2007. SCE would ordinarily be required to procure any such resources through a competitive solicitation, pursuant to D.04-12-048. As competitive IOU procurement processes are key elements of the Commission's procurement regime, the ACR directed SCE to promptly evaluate any offers for resources in its on-going New Generation Request for Offers (RFO) process that have the features described in the ACR and to submit any resulting contracts for Commission approval by November 15, 2006, to the extent agreements can be reached for appropriate resources. However, given the extremely limited timeframe to bring such units online, there would not be sufficient time for SCE to wait until the results of that process are known and only then initiate its development of any still-needed utility-owned generation. Nor is there sufficient time for SCE to initiate and conduct a separate RFO that would include consideration and evaluation of new utility-owned resources along with third party resources. In light of the foregoing mitigating circumstances, it is reasonable to permit SCE to proceed with the development of this limited amount of utility-owned resources outside of a competitive procurement process.

Additionally, allowing SCE to request authority to record revenue requirements associated with the peaker plants via an advice letter is not standard Commission practice. The advice letter process is an informal procedure. A revenue requirement request, should, under normal circumstances, be filed under an application process with its more formal procedures.

However, given that the peaker units were not forecasted in the 2006 GRC, begin accruing operational expenses by summer 2007, and that an application process may take a year or longer, there are sufficient mitigating circumstances for SCE's request.

Burden to show reasonableness of accrued costs will be on SCE.

SCE should be prepared to demonstrate that the accrued costs were reasonable. Accrued costs include all costs related to acquisition and installation of the peaker plants tracked through the "work order" system (estimated at $250 million), as well as the associated revenue requirement recorded to the memorandum account once the plants are in service (estimated at $57-$71 million). SCE should file an application no later than December 31, 2007 to demonstrate that the costs were reasonable.

The Preliminary Statement for the Peakers Generation Memorandum Account should be clarified.

CE should submit a substitute tariff sheet for the preliminary statement for the PGMA to clarify the purpose of the memorandum account. The currently stated purpose "to record the costs of acquisition and installation" is not correct and is misleading. SCE should properly state that the purpose of the PGMA is to record the revenue requirement associated with the peaker plants.

SCE's proposal to submit a monthly status report is welcomed.

In SCE's advice letter filing, SCE proposed to submit a monthly "Planning and Construction" Report to keep the Commission informed of the progress of the projects. That report will include information such as the status of the projects, the costs incurred from inception to date, and any issues or concerns regarding the projects so that the Commission can provide guidance as the project advances.

The Commission endorses SCE's proposal for a monthly status report. We request that the date of August 1, 2007 be identified as being the peaking generation on-line date with all corresponding progress measured to this date.

Effective date should be November 9, 2006.

SCE request for an effective date of August 15, 2006 is denied.

The Commission's standard practice is to authorize memorandum accounts to be effective only on or after the date on which the Commission approves them. Accordingly, we will authorize this memorandum account to be effective as of the date of today's decision. As SCE does not plan to record any amounts in this memorandum until the peaker plants are in service, there is no harm to SCE.

COMMENTS

Public Utilities Code section 311(g)(1) provides that resolutions generally must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day comment period for the draft of this resolution was neither waived nor reduced. Accordingly, this draft resolution was mailed to parties for comments, and placed on the Commission's agenda no earlier than 30 days from the date of mailing.

SCE provided comments on the draft resolution on October 26, 2006 to parties on service list for E-4031, R.04-04-003, and R. 06-02-013. No other party provided comments. No parties provided reply comments on the draft resolution.

In its comments, SCE requested clarifications confirming that SCE may develop up to 250 MW of new utility-owned generation as described in the ACR outside of a competitive solicitation process, as a limited exception to the requirements of D. 04-12-048.

Based in part on SCE's comments, the draft resolution is being modified. Modifications to the draft resolution have been incorporated throughout as reflected herein.

FINDINGS

1. Assigned Commissioner's Ruling (ACR) "Addressing Electric Reliability Needs in Southern California For Summer 2007" directed Southern California Edison Company (SCE) to pursue the development and installation of up to 250 MW of black-start, dispatchable generation capacity within its service territory for summer 2007 operation.
2. The ACR invited SCE to file an advice letter to establish a memorandum account in which SCE would record the acquisition and installation costs.
3. SCE filed Advice Letter 2031-E on August 24, 2006 to establish the Peakers eneration Memorandum Account (PGMA) and to revise the Generation Sub-account of the Base Revenue Requirement Balancing Account (BRRBA).
4. No protests were filed.
5. Advice Letter 2031-E, in addition to establishing a memorandum account, sought authority to record the revenue requirement (i.e., incremental O&M expenses, book depreciation, applicable taxes, and an authorized rate of return on rate base) arising from the acquisition cost, installation costs, and other related costs associated with peaking generation units.
6. SCE estimates total revenue requirement to be recorded in the PGMA of $57-$71 million, based on an estimated capital expenditures of $250 million to install 5 peaking units.
7. SCE proposes to calculate the revenue requirement as each peaking facility is completed and closed to plant-in-service.
8. SCE further proposes that the revenue requirement recorded in the PGMA be transferred to the Generation Sub-account of the BRRBA on a monthly basis.
9. The cost to be recorded in the PGMA is different from what the ACR directed. The ACR directed SCE to record "acquisition and installation costs" of the peaker plants. SCE filed its advice letter to record the revenue requirements associated with the peaker plants.
10. As SCE utilizes a "work order" to accumulate and track the costs associated with the peaker plants, SCE does not require a memorandum account for that purpose.

11. SCE states that once the plants are in service, SCE will begin recording depreciation, O&M, and tax expenses.
12. Recording these expenses without a corresponding increase in revenue will result in SCE' recorded earnings to be negatively impacted.
13. SCE's advice letter proposal to record the revenue requirement to the memorandum account with a monthly transfer to the Generation Sub-account of the BRRBA neutralizes the negative earnings effect caused by the peaker plants.
14. SCE will track the revenue requirement for each unit separately.
15. Allowing SCE to procure utility-owned generation outside of the competitive solicitation process and to request authority to record revenue requirements associated with the peaker plants via an advice letter is not standard Commission practice.
16. A revenue requirement request, should, under normal circumstances, be filed under an application.
17. Mitigating circumstances that require a limited exception from the competitive solicitation requirement of D.04-12-048 and standard Commission practice for requesting changes in authorized revenue requirements include: the unanticipated conditions arising in summer 2006 that prompted the CAISO to identify an urgent need for quick-start peaker units in southern California by summer 2007, the length of time for SCE to initiate and conduct a separate RFO for peaker units that would include new utility-owned resources and third party resources, the length of a formal application process associated with a revenue requirement request, the peaking units not being forecasted in the 2006 GRC, and the anticipated accrual of operational expenses by summer 2007.
18. SCE should be prepared to demonstrate that the acquisition and installation costs accrued in a "work order" and the associated revenue requirement recorded to the PGMA were reasonable.
19. SCE should submit a substitute sheet for the preliminary statement for the PGMA to clarify that the purpose of the memorandum account is to record the associated revenue requirement of the peaker plants, and not the acquisition and installation costs.
20. SCE's proposal to submit a monthly status report is welcomed.
21. SCE requests an effective date of August 15, 2006 for Advice Letter 2031-E.
22. The Commission's standard practice is to authorize memorandum accounts to be effective only on or after the date on which the Commission approves them.

THEREFORE IT IS ORDERED THAT:

1. The request of the Southern California Edison Company (SCE) to establish the Peakers Generation Memorandum Account (PGMA) and to revise the Generation Sub-account of the Base Revenue Requirement Balancing Account (BRRBA) as requested in Advice Letter AL 2031-E is approved.
2. SCE is authorized to record the revenue requirement (i.e. incremental O&M expenses, book depreciation, applicable taxes, and an authorized rate of return on rate base) arising from the acquisition costs, installation costs, and other related costs associated with peaking generation units and non-ISO transmission facilities' upgrades associated with interconnecting the peaker units.
3. SCE is authorized to record the revenue requirement to the PGMA as each peaker plant is completed and becomes used and useful.
4. SCE shall track the revenue requirement for each unit separately.
5. SCE is authorized to develop utility-owned peaker units, consistent with the requirements of the ACR and this Resolution, without using a competitive solicitation process to procure such units as required by D.04-12-048.
6. SCE shall file an application no later than December 31, 2007 to demonstrate the reasonableness of the accrued acquisition and installation costs tracked in a "work order" and the associated revenue requirement recorded to the PGMA.
7. SCE shall file a substitute preliminary statement for the PGMA to clarify the purpose of the PGMA.
8. SCE shall file a monthly "Planning and Construction" report and identify the date of August 1, 2007 as being the on-line date with all corresponding progresses measured to this date.
9. The effective date of Advice Letter 2031-E is November 9, 2006.

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on November 9, 2006; the following Commissioners voting favorably thereon:

____
STEVE LARSON
Executive Director

MICHAEL R. PEEVEY
PRESIDENT
GEOFFREY F. BROWN
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
Commissioners

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 103

California Public Utilities Commission
Decision D.10-05-008
May 6, 2010

November 16, 2012

ALJ/DUG/avs **Date of Issuance 5/7/2010**

Decision 10-05-008 May 6, 2010

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338-E) for Recovery of Peaker Costs.	Application 07-12-029 (Filed December 31, 2007)

DECISION GRANTING RECOVERY OF PEAKER COSTS TO SOUTHERN CALIFORNIA EDISON COMPANY

1. Summary

This decision authorizes Southern California Edison Company (Edison) to recover the reasonable capital and operating costs for four peaker units, which are owned and operated by Edison. The costs associated with these four peaker units were included in customer rates and subject to refund in Edison's Peakers Generation Memorandum Account which was authorized by Resolution E-4031. These costs are no longer subject to refund. This is the second and final phase of the proceeding. This proceeding is closed.

2. Background

On December 31, 2007, Southern California Edison Company (Edison) filed Application (A.) 07-12-029 for the recovery of the four peaker units' costs. Edison has built in its service territory four peaker units, 49 megawatt (MW) each, that provide additional capacity and collateral grid-reliability benefits. Edison filed Advice Letter 2031-E for interim treatment of the costs of the peakers, and Resolution E-4031, issued November 9, 2006, set forth the procedures for the interim tracking of the peaker installation and acquisition costs. Resolution E-4031 directed Edison to file an application to demonstrate the reasonableness of these costs and to address Edison's recovery of the associated revenue requirement for 2007-2008.

Edison filed this application seeking allocation of the resource adequacy capacity and the costs of the energy from the peaker units to all benefitting customers, and not just to its bundled customers, although the peakers are owned by Edison.

In phase 1, Decision (D.) 09-03-031 the Commission found it reasonable to adopt Edison's proposed method of allocation, to all benefiting customers, consistent with the Joint Parties' proposal described in D.06-07-029 (but excluding an auction).[1] This allocation authority will expire in 10 years from the date of the commercial operation for each unit, consistent with D.07-06-022, D.06-07-029, and D.08-09-012. We found that allocating the cost to all benefiting customers was a matter of equity and fairness; it would be unreasonable to arbitrarily limit the allocation according to D.06-07-029 when addressing a situation not contemplated when we adopted the general allocation policy.

3. Phase 2 of Proceeding

The June 9, 2009 Assigned Commissioner's Ruling and Scoping Memorandum (Scoping Memo) determined that "the scope of issues to be addressed in this proceeding are the reasonableness of the costs Edison incurred to acquire and install four peaker generation units, the costs to operate and maintain the peakers from August through November 2007, and appropriate authority to recover the resulting revenue requirement in customer rates."

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[1] D.06-07-029, at 14-18.

(Scoping Memo at 3.) On June 17, 2009, Edison served updated testimony for actual costs through December 2008. (Ex. SCE-2.)

The Scoping Memo also determined, and this decision affirms, that Edison bears the burden of proof to show that its requests are just and reasonable and the related ratemaking mechanisms are fair. (*Id.*) The record for this phase of the proceeding consists of all filed and served documents, including the prepared testimony served by Edison and the Division of Ratepayer Advocates (DRA), the only two active parties in this phase.

3.1. Costs to Acquire and Install the Units

Edison incurred a total cost for acquisition and installation for the four units of $260.121 million. (SCE-2 at 8.) DRA only addressed the first Scoping Memo question, whether the costs Edison incurred to acquire and install four peaker generation units was reasonable. In its prepared testimony, DRA's witness describes his analysis which included comparing Edison's actual costs to a proxy predicated on the California Energy Commission's "Comparative Costs of California Central Station Electricity Generation Technologies" a Final Staff Report dated December, 2007. (Ex. DRA-1 at 1, footnote 2.)[2] DRA found that Edison's cost (net of extra features) was approximately $1,067/ Kilowatt (kW) compared to the study's cost of $1,053/kW, which is very close, and that DRA also reviewed and considered additional features included in the Edison

[2] DRA's prepared testimony was timely served on September 11, 2009. There was no objection to the testimony and we therefore receive it into the record. Additionally, there was no objection to Edison's phase 2 prepared testimony and we therefore receive it into the record as well.

facilities, for example "Blackstart" capability.[3] In addition, DRA reviewed Edison's records and testimony, and discussed the need for the additional features which were netted out to derive an installed cost per kW to compare to the California Energy Commission's proxy.

Based on DRA's recommendation and our own review of Edison's prepared testimony, we find the $260.121 million in costs to acquire and install the four units to be reasonable.

3.2. Operating and Maintenance

Edison incurred $9.511 million from August 2007, when the four units became operational, through December 2008 for operating and maintenance costs. DRA provided no testimony on this issue. Based on our own review of Edison's prepared testimony, we find Edison made a sufficient showing to meet its burden of proof to demonstrate the $9.511 million was reasonable.

3.3. Authority to Recover Costs

Edison has met its burden of proof that the $260.121 million in costs to acquire and install the four units was reasonable, and that the $9.511 million in 2007 - 2008 operating and maintenance costs were reasonable. Additionally, in phase 1, D.09-03-031 the Commission found it reasonable to adopt Edison's proposed method of allocation, to all benefiting customers. Therefore, it is reasonable to allow Edison to recover these costs in rates.

The costs associated with these units, pending this reasonableness review, were included in customer rates and subject to refund in Edison's Peakers Generation Memorandum Account which was authorized by

[3] Blackstart is the ability to start or restore a power generator to operation without relying on energy sources external to the facility.

Resolution E-4031.[4] This memorandum account was to be recovered monthly through Edison's Base Revenue Requirement Balancing Account. (Resolution E-4031 at Ordering Paragraph 1.) No further ratemaking authority is required because the costs are already included in rates.

4. Comments on Proposed Decision

This is an uncontested matter in which the decision grants the relief requested. Accordingly, pursuant to Section 311(g)(2) of the Pub. Util. Code and Rule 14.6(c)(2) of the Commission's Rules of Practice and Procedure, the otherwise applicable 30-day period for public review and comment is waived.

5. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Douglas M. Long is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. Edison reasonably incurred $260.121 million to acquire and install four peaker units.

2. Edison reasonably incurred $9.511 million from August 2007 through December 2008 for operating and maintenance costs for the four peaker units.

3. Resolution E-4031 placed the costs of the four peaker units in rates for recovery in Edison's Peakers Generation Memorandum Account and Base Revenue Requirement Balancing Account.

Conclusions of Law

1. Edison may recover its (1) reasonable costs for acquiring and installing and (2) reasonable operating and maintenance costs for four peaker units.

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[4] Resolution E-4031, dated November 9, 2006 in Advice Letter 2031, E-filed on August 24, 2006.

2. Operating and maintenance costs after December 2008 are beyond the scope of this proceeding.

3. No additional ratemaking authority is required.

4. Application 07-12-029 should be closed.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company (Edison) is authorized to recover in rates $260.121 million in capital costs to acquire and install four electric generation peaker units. These costs, which were included in Edison's Peakers Generation Memorandum Account, are no longer subject to refund.

2. Southern California Edison Company (Edison) is authorized to recover $9.511 million incurred as operating and maintenance expenses from August 2007 through December 2008. These costs, which were included in Edison's Peakers Generation Memorandum Account, are no longer subject to refund.

3. Application 07-12-029 is closed.

This order is effective today.

Dated May 6, 2010, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
TIMOTHY ALAN SIMON
NANCY E. RYAN
Commissioners

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 104

Pacific Gas & Electric Response to
Independent Energy Producers Association
Data Request IEP_002-02
California Public Utilities Commission
Docket R.10-05-006
June 24, 2011

November 16, 2012

PACIFIC GAS AND ELECTRIC COMPANY
Long-Term Procurement Plan 2010 OIR-Track III
Rulemaking 10-05-006
Data Response

PG&E Data Request No.:	IEP_002-02		
PG&E File Name:	LTPP 2010 OIR TIII_DR_IEP_002-Q02		
Request Date:	June 8, 2011	Requester DR No.:	002
Date Sent:	June 24, 2011	Requesting Party:	Independent Energy Producers Association (IEP)
PG&E Witness:	Joe O'Flanagan	Requester:	Suzy Hong

QUESTION 2

For each gas-fired generating facility owned by PG&E, please provide all estimates of capital costs, annual fixed operating and maintenance costs, annual variable operating and maintenance costs, and annual capital additions that were prepared by or on behalf of PG&E prior to the facility's COD (in the case of a utility build project) or the date PG&E assumed ownership of the facility. For turnkey projects, please provide the initial purchase price proposed by the developer to PG&E, all estimates of the project purchase price prior to execution of the purchase agreement (either provided to PG&E by the seller or developed independently by or on behalf of PG&E), the actual purchase price specified in the purchase agreement, and the amount that was ratebased when PG&E took ownership of the project.

For all of these estimates, please provide the month and year in which the estimate was made and state whether the estimate is in real or nominal dollars. If the estimate is in real dollars, please state the year's dollars (e.g., "2004 dollars") in which the estimate is provided. Please provide all workpapers supporting these estimates, including any inflation assumptions used in developing these estimates.

ANSWER 2

Table 1 below shows forecasts of capital costs, fixed and variable Operations and Maintenance (O&M) Costs and Capital Additions for the Gateway Generation Station.[1]

[1] The Gateway Generation Station was formerly known as Contra Costa 8.

TABLE 1

Gateway (Originally Contra Costa 8) (thousands of nominal dollars)			
	Application	Decision	Dry Cooling Resolution
Capital Cost	309,988	295,000	370,542
Fixed O&M	7,920	7,442	7,442
Variable O&M	7,283	7,124	7,124
Capital Additions	0	0	0

The numbers shown are for the CPUC application, the decision approving a settlement in that application, and the advice letter reflecting the conversion of the facility to dry cooling.

Table 2 below shows forecasts of capital costs, fixed and variable O&M costs and capital additions for the Colusa Generation Station.

TABLE 2

Colusa Generation Station (thousands of nominal dollars)		
	Application Apr-06	Advice Letter Apr-10
Capital Cost	684,428	672,828
Fixed O&M	9,070	8,197
Variable O&M	10,253	9,077
Capital Additions	0	0

The capital cost in the advice letter excluded $11.6 million of incentive payments which PG&E can request recovery of by advice letter.

Table 3 below shows forecasts of capital costs, fixed and variable O&M costs and capital additions for the Humboldt Bay Generation Station.

TABLE 3

Humboldt Bay Generation Station (thousands of nominal dollars)		
	Application Apr-06	Advice Letter Apr-10
Capital Cost	250,016	238,652
Fixed O&M	4,350	3,886
Variable O&M	2,970	2,674
Capital Additions	0	0

The 2011 General Rate Case decision allows PG&E to request an increase in the capital cost target by up to $25 million by advice letter.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 105

California Public Utilities Commission
Decision D.04-03-037, Attachment A (excerpt)
March 16, 2004

November 16, 2012

ALJ/CAB/jva **Mailed 3/17/2004**

Decision 04-03-037 March 16, 2004

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of Southern California Edison Company (U 338-E) for Approval of a Power Purchase Agreement under PUHCA Section 32(k) Between the Utility and a Wholly-owned Subsidiary and for Authority to Recover the Costs of Such Power Purchase Agreement in Rates.	Application 03-07-032 (Filed July 21, 2003)

OPINION ADOPTING FEDERAL ENERGY REGULATORY COMMISSION'S CHANGES TO THE MOUNTAINVIEW POWER PURCHASE AGREEMENT APPROVED BY THIS COMMISSION IN DECISION 03-12-059

Summary

This decision approves the changes that the Federal Energy Regulatory Commission (FERC) ordered to the power purchase agreement (PPA) that our Decision (D.) 03-12-059 authorized Southern California Edison Company (Edison) to enter into with Mountainview Power Company, LLC (MVL) for electricity from the Mountainview Power Project (Mountainview). A copy of the FERC Order, 106 FERC ¶ 61, 183, is attached as Attachment A.

Background

On December 18, 2003, this Commission issued D.03-12-059 granting Edison's application to acquire MVL either as a wholly-owned subsidiary and to enter into a PPA with MVL for electricity from Mountainview, or as a utility-owned generation facility.

Conclusion of Law

The FERC required changes to the PPA approved by this Commission in D.03-12-059 do not create any detrimental rate impacts for Edison customers and we adopt and approve the FERC changes.

O R D E R

IT IS ORDERED that The Commission accepts the conditions required by the Federal Energy Regulatory Commission (FERC) as modifications to the Power Purchase Agreement we approved in Decision 03-12-059. A copy of FERC Order 106 FERC ¶ 61, 183 is attached as Attachment A.

This order is effective today.

Dated March 16, 2004, at San Francisco, California.

MICHAEL R. PEEVEY
President
CARL W. WOOD
GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners

I reserve the right to file a dissent.

/s/ LORETTA M. LYNCH
Commissioner

Docket No. ER04-316-000

ATTACHMENT A
Page 1

106 FERC ¶ 61, 183
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, and Joseph T. Kelliher.

Southern California Edison Company, On behalf of Mountainview Power Company, LLC — Docket No. ER04-316-000

ORDER CONDITIONALLY ACCEPTING PROPOSED RATE SCHEDULE AND REVISING AFFILIATE POLICY

(Issued February 25, 2004)

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.[1] Edison seeks to exercise an option to purchase the project by purchasing Mountainview from its current owner, Sequoia Generating LLC (Sequoia).[2] Edison claims that its purchase of

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[1] 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).

[2] 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.

ATTACHMENT A
Page 5

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 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 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).

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Page 6

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.[12] 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 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.[13] 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.

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.

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[12] 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.

[13] 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.

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Capital Costs

19. Edison has projected a total initial rate base for Mountainview of approximately $703 million which includes $84 million for AFUDC.[14] 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.[15] As an initial matter, we note 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 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.[16]

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

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[14] 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).

[15] The $624 million was developed using an original cost of $595 million plus a 5 percent contingency ($29 million).

[16] See Article VIII, Section 8.01 and Schedule 7.01 Original Sheet No. 44.

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Page 8

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 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. 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 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.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 106

Southern California Edison
Exhibit 2, Volume 9 (excerpt)
California Public Utilities Commission
Docket A.07-11-011
November 2007

November 16, 2012

Application No.:	
Exhibit No.:	SCE-02, Vol. 9 Ch. I-VII
Witnesses:	G. Butts I. Cuthbertson P. Nelson P. Phelan R. Pierce

SOUTHERN CALIFORNIA
EDISON®

An *EDISON INTERNATIONAL®* Company

(U 338-E)

2009 General Rate Case

Generation (Gas)
Volume 9 – Mountainview Operation And Maintenance (O&M) Expenses And Capital Expenditures
Chapters I – VII

Before the

Public Utilities Commission of the State of California

Rosemead, California
November 2007

SUMMARY

SCE-02, Volume 9
Mountainview O&M Expenses And Capital Expenditures

- Mountainview will transition to traditional Ratemaking, including continuation of the existing financial incentives for plant Reliability and Fuel Consumption performance.
- Mountainview Units 3&4 will provide 1050 MW of gas-fired generating capacity during 2009 through 2011
- Test Year 2009 O&M Expense forecast is $43 million.
- Capital Expenditure forecast for 2009 - 2011 is $19 million.
- Retired Mountainview Units 1&2 will be Decommissioned at a forecast cost of $11 million.
- Retired Solar 2 facilities will be Decommissioned at a forecast cost of $5 million.

SCE-02: Generation Gas
Volume 9 – Mountainview O&M and Capital

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UM 1182

SCE-02: Generation Gas
Volume 9 – Mountainview O&M and Capital

Table Of Contents (Continued)

SCE-02: Generation Gas
Volume 9 – Mountainview O&M and Capital

Table Of Contents (Continued)

SCE-02: Generation Gas
Volume 9 – Mountainview O&M and Capital

Table Of Contents (Continued)

SCE-02: Generation Gas
Volume 9 – Mountainview O&M and Capital

Table Of Contents (Continued)

To date, Mountainview has operated within the six percent dead band.

C. Description of Mountainview Power Plant

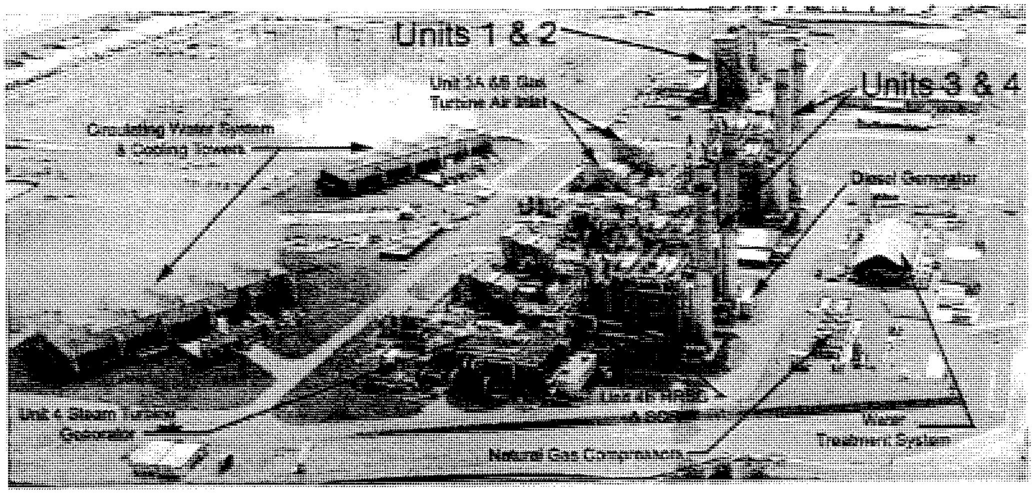
Mountainview uses state-of-the-art combined cycle plant technology to generate 1,050 MW of power, with extremely low air emissions and with very high fuel economy[14]. Mountainview Units 3 & 4 each has two combustion turbines and one steam turbine. Each combustion turbine discharges its hot exhaust gas into its respective Heat Recovery Steam Generator (HRSG). On each unit, steam from that unit's two HRSGs combines to power that unit's single steam turbine.

Figure I-1 shows that Mountainview Units 3 & 4 have the following pieces of major equipment:

- Water treatment system, which purifies reclaimed water supplied from a near-by municipal sewage plant, so that it can be used in the HRSGs and Cooling Towers;
- Inlet air filters for each combustion turbine;
- Evaporative inlet air coolers for power augmentation;
- Selective Catalytic Reduction (SCR) for the control of NOx emissions;
- Circulating water systems and cooling towers;
- Steam Turbine Generators;
- Natural Gas Compressors;
- A 1,500 kilowatt (kW) diesel generator to provide auxiliary power to portions of the plant in case of a power failure.

[14] The station's nominal maximum output is 1050 MW; however, actual maximum output varies above and below this figure depending on ambient weather, as is the case for other combined cycle power plants.

Figure I-1
Mountainview Generating Station



In 2006, its first year of commercial operation, Mountainview Units 3 & 4 generated 4,887,920 net Megawatthours (MWh). Table I-1 provides additional operating statistics for 2006.

Table I-1
Mountainview 2006 Operational History

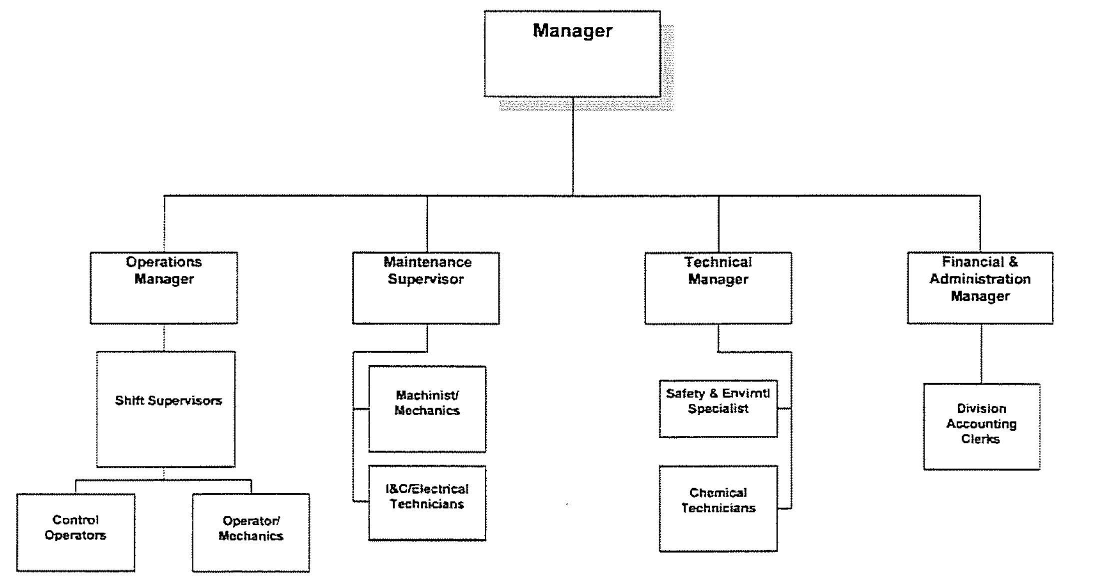
	Unit 3		Unit 4	
	CTG-3A	CTG-3B	CTG-4A	CTG-4B
Start Ups	265	280	278	274
Operating Hours	6,553	5,795	6,074	5,285
Net Use Factor	71.4%		67.9%	
Net Capacity Factor	56.5%		49.8%	

SCE's Test Year 2009 forecast assumes a moderate service duty increase over that experienced in 2006 and a significant reduction in the number of start-ups. The SCE Generation Operations Center forecast for 2007 included a forecast capacity factor of 70 percent for Mountainview.[15] Based on this capacity factor, SCE forecasts that during 2009 through 2011 each combustion turbine will average approximately 100 startups per year, with an average service run of 77 hours for each startup and a total run time of 7,700 hours per year.[16]

D. Organization of the Mountainview Generating Station

The Plant Manager leads Mountainview's 42 employees. The Plant Manager reports to the Vice President of the SCE Power Production Department (PPD). Figure I-2 contains the current Mountainview organization chart. As discussed in more detail in Chapter II, we forecast that plant staffing will increase to 49 employees by 2009 for various reasons.

Figure I-2
Mountainview Generating Station Organization Chart



The Operations Manager currently oversees 23 employees. Five Shift Supervisors report to the Operations Manager. In turn, the Control Operators (CO) and Operator/Mechanics (OMs) report to their respective Shift Supervisors. The COs and OMs work rotating 12 hour shifts, providing

[15] The SCE Generation Operations Center is responsible for dispatching SCE's generating resources.

[16] Capacity factor of a power plant is the ratio of the actual output of a power plant over a period of time and its output if it had operated a full capacity of that time period.

around-the-clock staffing. The COs remotely operate certain equipment, and monitor overall equipment status. The COs also raise and lower unit load, and start and stop the units as requested.

The COs provide functional direction to the OMs. The OMs operate the remaining plant equipment locally, and inspect equipment to discover any problems as early as possible. The OMs perform minor preventative maintenance such as filter replacements, equipment oil status checks and replenishment as necessary, and equipment vibration checks.

The Maintenance Supervisor and eight maintenance employees provide maintenance support for the station. They undertake most required preventative maintenance, repair maintenance, corrective maintenance, and support or oversee major repairs and capital projects.

Machinist/Mechanics duties include most routine maintenance of equipment, as well as most of the major maintenance functions of equipment dismantling, inspection, testing, reassembly and alignment. This includes work performed on pumps, fans, heat exchangers, and valves. Instrument & Control Electrical Technicians (ICE Techs) inspect, test, calibrate, repair and install recording and automatic control instruments such as flow-meters, pressure gages, thermometers, controllers, and regulators. The ICE Techs also perform preventative maintenance on electrical and air operated equipment. The Utilityman provides basic support functions such as parts delivery to the job site, general equipment and site cleaning, and trash pickup.

The Technical Manager and three employees provide engineering support, analyses of equipment failures, management of capital projects, and similar technical support to the station. The Safety & Environmental Specialist (SES) assures proper safety procedures are in place, and updates them as needed. The SES assures that employees perform required safety training, as scheduled. The SES has oversight of the Station's compliance with Federal, State and local air environmental regulations. The Chemical Technicians perform chemical analyses to ensure compliance with the plant water chemistry program and wastewater treatment standards. PPD's Water Chemistry Resources also provides support to Mountainview, as they do for other SCE power plants.

The Financial & Administration Manager and four employees provide day to day plant accounting, payroll, material orders, station warehouse management and general administrative support, such as annual budget preparation and personnel records management.

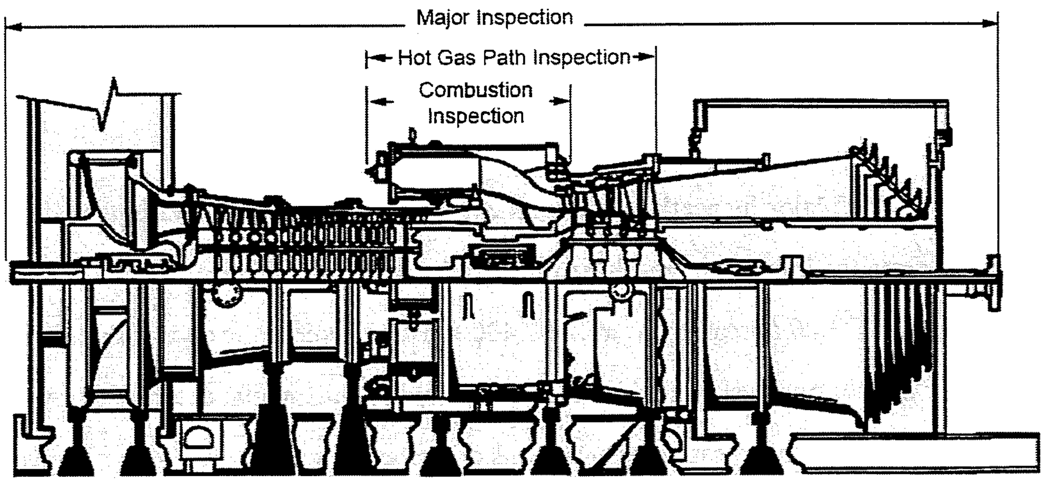
IBEW Local 47 union represents all employees, except the Plant Manager, his direct reports, the Shift Supervisors and the SES.

E. Overhaul Planning

For the next several years, SCE expects the maintenance recommendations of the combustion turbine generator and steam turbine generator manufacturer, GE, to drive the scheduling of overhauls. SCE also expects to perform maintenance activities on other equipment during these planned overhaul outages. In years without long overhaul outages, SCE still expects to undertake at least one short planned outage for various maintenance needs. Plant needs may require additional scheduled outages in any given year.

GE recommends three types of scheduled outages for the Mountainview turbine generators. These three types are: (1) Combustion Inspections, (2) Hot Gas Path Inspections (or Hot Gas Path Overhauls), and (3) Major Inspections (or Major Overhauls). Figure I-3 shows the areas of the turbine targeted during each of these outages. In addition, GE is likely to occasionally recommend additional inspections or repair outages in-between these three principal outage types. For example, in 2005, GE recommended SCE undertake an outage in 2006 to inspect the turbine first row compressor blades for signs of cracking, based on cracks recently found in other GE 7F units at other locations.

Figure I-3
Areas Of Turbine Targeted During Inspections



1. **Combustion Inspection**

GE recommends a Combustion Inspection every 12,000 operating hours, or 450 startups, whichever occurs first. Results of a Combustion Inspection can influence planning of subsequent overhauls. The Combustion Inspection is a relatively short (7 days) outage where the scope of work includes replacement of fuel nozzles, liners, flow sleeves, and transition pieces along with consumables, such as seals, nuts, bolts and gaskets. SCE visually inspects the inlet of the compressor section, first-stage turbine nozzles, and turbine exhaust area and performs a borescope inspection of the compressor section.

2. **Hot Gas Path Inspection Overhaul**

The Hot Gas Path Inspection Overhaul examines and repairs those parts exposed to high temperatures from the hot gases discharged from the combustion process. GE recommends these inspections every 24,000 operating hours, or 900 startups, whichever occurs first. Operating hours and startups used to determine scheduled inspections include adjustments determined by the on-site GE representative. These adjustments factor in previous inspections and operating conditions during the previous operating cycle. Based on operating assumptions described in Section I.C, SCE expects these inspections to occur on Units 3 & 4 in years 2009 and 2010, respectively.

The Hot Gas Path Inspection Overhaul includes the full scope of the Combustion Inspection. To perform the inspection, SCE removes the top of the turbine shell to provide access to the turbine rotor. In addition, the overhaul includes the replacement of first stage nozzles, buckets, and shrouds, and the inspection of the second stage nozzles, buckets, and shrouds. The second stage components are replaced if necessary, but this is not usually the case.

3. Major Inspection Overhaul

The Major Inspection Overhaul examines all the internal rotating and stationary components from the inlet of the machine through the exhaust. GE recommends a Major Inspection Overhauls every 48,000 operating hours, or 2,400 startups, whichever occurs first. Operating hours and startups used to determine scheduled inspections include adjustments, determined by the on-site GE representative. Based on operating assumptions described in section I.C, Major Inspection Overhauls are not forecast for Units 3 & 4 during the 2009 through 2011 timeframe.

V.

MOUNTAINVIEW CAPITAL INVESTMENT

A. Purpose

This chapter presents SCE's recorded investment for Mountainview as of December 31, 2006 and forecast through December 31, 2008. The Mountainview investment included in this filing is consistent with the authorized recovery from the PPA approved by both the FERC and the Commission. The Commission should approve inclusion of this investment in utility rate base to be recovered from SCE customers concurrent with termination of the PPA.

B. Summary of Mountainview Investment as of December 31, 2006

Table V-11 shows the Mountainview rate base as of December 31, 2006. The following sections discuss the elements making up the rate base.

Table V-11
Summary of Mountainview Rate Base As of December 31, 2006
(Systems Basis, Nominal $000)

1.	Plant In Service	707,391
2.	Inventories	
3.	Incremental Materials & Supplies	647
4.	Emission Credits	14,199
5.	Working Cash	--
6.	Accumulated Depreciation	(23,926)
7.	Accumulated Deferred Taxes	(77,550)
8.	Total Rate Base	620,761

1. Plant-in-Service

Mountainview Plant-In-Service investment consists of four categories – intangible plant, other production plant, general plant, and other plant items (*see* Table V-12, below). These categories are discussed in turn, below.

Table V-12
Mountainview Plant In Service As of December 31, 2006
(Systems Basis, Nominal $000)

1.	**Intangible Plant:**		
2.	301 Organizational Costs	2,797	
3.	303 Gas Pipeline/Transmission Line Rights	39,840	
4.	303 Option Payments & Legal Costs	11,362	
5.	Total Intangibles		53,998
6.			
7.	**Other Production Plant:**		
8.	340 Land & Land Rights	3,200	
9.	341 Structures & Improvements	33,107	
10.	342 Fuel Holders, Products & Accessories	6,560	
11.	343 Prime Movers	397,761	
12.	344 Generators	67,485	
13.	345 Accessory Electric Equipment	66,144	
14.	346 Misc Power Plant Equipment	105	
15.	Total Other Production		574,362
16.			
17.	**General Plant:**		
18.	391 Furniture & Equipment/Computers	297	
19.	397 Communication Equipment	1,030	
20.	Total General		1,327
21.			
22.	**Other Plant Items:**		
23.	Capitalized Interest/AFUDC	74,810	
24.	Preoperational Support Costs	2,771	
25.	General Plant Depr. Rate Diff.	123	
26.	Total Other Plant Related Items		77,704
27.			
28.	**Total Plant**		707,391

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 107

San Diego Gas & Electric
Advice Letter 1778-E, Attachment B (excerpt),
to the California Public Utilities Commission
June 28, 2006

November 16, 2012

STATE OF CALIFORNIA

ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298
(415) 703-1691

June 28, 2006

Advice Letter 1778-E

J. Steve Rahon, Director
Tariffs and Regulatory Accounts
San Diego Gas and Electric
8330 Century Park Court, CP32C
San Diego, CA 92123-1548

Subject: Revenue requirement update associated with the Palomar generating facility

Dear Mr. Rahon:

Advice Letter 1778-E is effective March 31, 2006 by Resolution E-3988. A copy of the advice filing and resolution are included herewith for your records.

Sincerely,

Sean H. Gallagher, Director
Energy Division

jjr

SDGE
A Sempra Energy utility

J. Steve Rahon
Director
Tariffs & Regulatory Accounts
8330 Century Park Court
San Diego, CA 92123-1548

Tel: 858.654.1773
Fax: 858.654.1788
srahon@semprautilities.com

February 28, 2006

ADVICE LETTER 1778-E
(U 902-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

SUBJECT: REVENUE REQUIREMENT UPDATE ASSOCIATED WITH THE PALOMAR GENERATING FACILITY

San Diego Gas and Electric Company (SDG&E) hereby submits for filing revisions to its electric tariffs, as shown in Attachment D.

PURPOSE

The purpose of this Advice Letter is to submit for California Public Utilities Commission (Commission or CPUC) approval the updated revenue requirement associated with the purchase of the Palomar Generation Facility (Palomar), including modifications to SDG&E's Non-fuel Generation Balancing Account (NGBA) and Energy Resource Recovery Account (ERRA). This Advice Letter is filed in compliance with Commission Decision (D.) 05-08-005.

BACKGROUND

On June 9, 2004, the Commission issued D.04-06-011, approving five proposals that SDG&E presented to meet its short-term and long-term grid reliability needs. One of the approved proposals was a Turnkey Acquisition Agreement (TAA) between SDG&E and Palomar Energy, LLC (Palomar Energy) (a subsidiary of Sempra Generation), dated January 29, 2004. Palomar is a 500 MW (base load)/555 MW (peaking load) combined cycle natural gas-fired generation plant located in Escondido, California. SDG&E will assume care, custody and control and risk of loss under the TAA upon closing, which SDG&E presently expects will occur on or about March 30, 2006. While D.04-06-011 approved the TAA, the Commission deferred SDG&E's cost recovery proposals related to Palomar.

On November 1, 2004 SDG&E filed Application (A.) 04-11-003, requesting approval for the cost recovery and ratemaking mechanisms necessary to allow SDG&E to recover its reasonable and prudent costs of acquiring, operating and owning Palomar. Specifically, the Palomar Application requested approval of: (1) a fixed monthly revenue requirement of $7,600,100, subject to update prior to going into effect on the first month of commercial operation of Palomar, (2) a variable O&M rate of $3.08 per MWh, subject to update, and (3) an overall cost recovery regulatory plan that recognizes that the fixed monthly revenue requirement and variable O&M rate will be reset in SDG&E's next General Rate Case (GRC) proceeding. The Commission issued D.05-08-005 on August 25, 2005 approving SDG&E's request with modifications.

Regarding the modifications, Ordering Paragraph (OP) 2 of D.05-08-005 directs that "When SDG&E files its update advice letter SDG&E will update in the advice letter (i) the fixed monthly revenue requirement to reflect the Return on Equity then in effect, (ii) the fixed monthly revenue requirement to reflect an 18.0% loader for non-union employees, and (iii) the fixed monthly revenue requirement to reflect a negative 3.5% net salvage rate for the steam generator." The Palomar update advice letter is required to be filed no later than 30 days prior to the expected date of commercial operation of the facility, which SDG&E presently expects will occur on or about March 30, 2006.

DISCUSSION

This filing represents the pre in-service date true-up advice letter, as described above and authorized in OP 3 of D.05-08-005. SDG&E will initiate operation of Palomar for its load requirements on or after March 30, 2006. Consequently, the updated fixed monthly revenue requirement of $7,482,300, as identified in Attachment A to this filing, reflects changes to the following revenue requirement inputs summarized below:

A. Purchase Price

In compliance with OP 3 of D.05-08-005, the Palomar purchase price is trued up to reflect adjustments due to various cost items identified in the TAA (Sections 2.6-2.9) for Palomar, including but not limited to delay rebates and performance shortfall rebates, performance bonuses, and change orders. Attachment B identifies the various adjustments to the Palomar purchase price, which result in a total increase of $9,961,000.

B. Additional Factors

Escalation factors used in the development of the fixed monthly revenue requirement and variable O&M non-fuel rate have been updated. The escalation factors are used to convert estimated 2004 expenses to 2006 and 2007 dollars. The escalation factors used were initially based on 2nd Quarter 2004 Global Insight Forecasts and are being updated to reflect the most current forecasts available, which are based on 3rd Quarter 2005 Global Insight Forecasts.

Update to Escalation Factors

	2006		2007	
	Old	**New**	**Old**	**New**
Fixed O&M Escalator	1.0606	1.0894	1.0912	1.1230
Variable O&M Escalator	1.0538	1.1106	1.0812	1.1341
Capital Escalator	1.0449	1.0634	NA	NA

Old - Escalation Factors based on 2nd Quarter 2004 Global Insight Forecasts.
New - Escalation Factors based on 3rd Quarter 2005 Global Insight Forecasts.

The updated 2006 and 2007 fixed O&M escalation factors result in a change to the average monthly fixed O&M costs included in the fixed monthly revenue requirement from $634,200 to $658,100 as identified in Attachment A. Also, the updated fixed O&M and capital escalation factors results in increases to the Material & Supplies, Commissioning & Mobilization, and Working Cash cost rate base items, as identified in Attachment B. In addition, the updated 2006 and 2007 variable O&M escalation factors identified above result in an average variable O&M non-fuel rate for the 2006-2007 period of $3.09 per MWh compared to the preliminary $3.08 per MWh rate identified in A.04-11-003. Finally, as explained in Attachment B to this filing the updated Palomar revenue requirement includes estimated costs of a raw water crosstie to supplement or replace recycled water production.

C. Cost of Capital

In accordance with OP 2 of D.05-08-005, the fixed monthly revenue requirement is being updated to reflect SDG&E's currently authorized cost-of-capital adopted in D.05-12-043, including the increase in return on equity (ROE) from 10.37% to 10.70%.

D. Non-Union Employees

In accordance with OP 2 of D.05-08-005, the fixed monthly revenue requirement is updated to reflect an 18.0% loader for non-union employees.

E. Net Salvage Rate

In accordance with OP 2 of D.05-08-005, the fixed monthly revenue requirement is updated to reflect a negative 3.5% net salvage rate for the steam generator.

F. In-Service Date Change

In SDG&E's original filing, the fixed monthly revenue requirement was based on an assumed plant in-service date of June 1, 2006. The expected in-service date of the plant is now on or shortly after March 30, 2006. For this reason, the revenue requirement calculation has been updated to reflect the new in-service date.

Regulatory Accounts

As shown in Attachment D to this filing, language has been added to SDG&E's NGBA to include recovery for approved Palomar non-fuel costs not being recovered by another component of SDG&E's rates. Pursuant to D.05-08-005, the authorized monthly Palomar revenue requirement to be recorded in the NGBA in 2006 for recovery in Schedule EECC rates is $6,892,300. This authorized revenue requirement consists of a fixed monthly revenue requirement component of $7,482,300 and an estimated variable monthly component of $853,800, less $1,443,800 in estimated monthly 2006 RMR revenues projected to recover Palomar costs. The variable component, which is trued-up in SDG&E's NGBA, currently equals the non-fuel rate of $3.09/MWh multiplied by the estimated 2006 Palomar generation output of 2,486.8 GWh, divided by 9 (months of operation in 2006). Fuel costs are recorded in SDG&E's ERRA. The ERRA includes wording that addresses the recording of fuel and fuel-related expenses of electric generation.

Electric Rate Adjustments

With the recent adoption of SDG&E's 2006 ERRA revenue requirement (D.06-02-018), SDG&E will file an advice letter to adjust commodity rates in the near future to reflect the recovery of 2006 commodity costs, both ERRA and NGBA costs. At that time, commodity rates contained in SDG&E's schedule Electric Energy Commodity Cost (EECC) will be adjusted to reflect recovery of 2006 commodity costs, including Palomar costs. Furthermore, Reliability Services (RS) rates were changed on January 1, 2006 (SDG&E Advice Letter 1740-E) to reflect SDG&E's 2006 RS Revenue Requirement, which included Palomar revenues. Consequently, electric rate adjustments are not necessary at this time.

Final Update

In its approval of the ratemaking for the Palomar Facility, the CPUC requires SDG&E to file adjusted project costs 30 days before SDG&E starts commercial operation of the facility. For every month in advance of the guaranteed closing date, SDG&E's customers save several million dollars in avoided RMR payments and lower energy costs, as discussed in Attachment

C. In addition, with the expectation of a mid-cycle outage at San Onofre Nuclear Generating Station (SONGS) Unit 3 at the end of April, effecting the closing of Palomar sooner rather than later increases the availability of reliable power for SDG&E customers. As such, SDG&E is in the unenviable position of weighing the benefits of filing final “hard and fast” costs to the customer benefits of an earlier closing date. This Advice Letter filing is being done at this time to maximize customer savings. In doing so, SDG&E has identified several cost items that, at this time, cannot be finalized. These include final net test gas cost, performance bonus, back-up cooling water supply pipeline, and any punchlist change orders. For punchlist change orders, a current estimate for the remaining cost items is provided. It is SDG&E’s belief that delaying closing in order to have final costs is unwarranted. Accordingly, SDG&E requests authorization to file a final update advice letter to finalize these costs consistent with Final Completion provisions of the TAA for the Palomar facility.

EFFECTIVE DATE

SDG&E respectfully requests that the Commission issue a resolution providing the authorizations requested at the Commission’s earliest convenience.

PROTEST

Anyone may protest this advice letter to the California Public Utilities Commission. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. The protest must be made in writing and received within 20 days of the date this advice letter was filed with the Commission. There is no restriction on who may file a protest. The address for mailing or delivering a protest to the Commission is:

CPUC Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Copies should also be sent via e-mail to the attention of both Jerry Royer (jjr@cpuc.ca.gov) and Honesto Gatchallian (jnj@cpuc.ca.gov) of the Energy Division. It is also requested that a copy of the protest be sent via electronic mail and facsimile to SDG&E on the same date it is mailed or delivered to the Commission (at the addresses shown below).

Attn: Monica Wiggins
Regulatory Tariff Manager
8330 Century Park Court, Room 32C
San Diego, CA 92123-1548
Facsimile No. (858) 654-1788
E-Mail: mwiggins@semprautilities.com

NOTICE

A copy of this filing has been served on the utilities and interested parties shown on the attached list, including parties in A.04-11-003 and R.01-10-024, by either providing them a copy electronically or by mailing them a copy hereof, properly stamped and addressed.

Address changes should be directed to Christina Sondrini by facsimile at (858) 654-1788 or by e-mail to csondrini@semprautilities.com.

J. STEVE RAHON
Director - Tariffs & Regulatory Accounts

(cc list enclosed)

Attachment B

SAN DIEGO GAS & ELECTRIC
PALOMAR RATE BASE
ADJUSTMENTS TO INITIAL RATE BASE

Line No		($000)
1	**Total Rate Base filed in Application 04-11-003**	**$484,343**
2		
3	**Base Purchase Price Adjustments**	
4	Change Orders	
5	Change Order 1 - SDG&E Office Trailer #1	$26
6	Change Order 2 - Deletion of Plant Paging System	($19)
7	Change Order 4 – Electric Revenue Meter Relocation	$105
8	Change Order 6 – SDG&E Office Trailer #2	$37
9	Change Order 9 – Accelerate Guarantee Acceptance Date to May 1, 2006	$3,754
10	Change Order 10 – Gas Compressor Upgrades	$542
11	Change Order 11 – Gas Meter System Compliance	$153
12	Change Order 12 – Deletion of Telecom System	($27)
13	Change Order 13 – Raw Water Emergency Supply - Phase I	$71
14	Change Order 14 – Raw Water Emergency Supply - Phase II	$61
15	Change Order 15 – Balance of Plant Spare Parts	$395
16	Change Order 16 - Increase in Emission Reduction Credits	$2,089
17	Change Order 17 – First fill and Start-up and Chemical Credit	($275)
18	Change Order 18 – Reimbursement of Cost, Chemical Fills	($21)
19	Change Order 20 - Force Majeure claim - Electrical curtailment	$152
20	Change Order 21 - Force Majeure claim - Water curtailment	$422
21	Change Order 22 - Temporary Raw Water Line (construction plus 2 months rent)	$115
22	Subtotal - Change Orders	$7,580
23		
24	Other Base Purchase Price Adjustments	
25	Interest During Construction Cost Adjustment (accrued cost from 12/01/03 through closing date)[1]	($6,443)
26	Start-up and Testing Cost Adjustment (natural gas, backfeed power & utility charges less power sales)[2]	$3,750
27	Property Taxes During Construction Cost Adjustment (accrued property taxes from 12/01/03 through closing date)[3]	($102)
28	Delay Rebates, Performance Shortfall Rebates & Performance Bonus Payments	$5,133
29	Sales Taxes	$31
30	Subtotal - Other Base Purchase Price Adjustments	$2,371
31		
32	Total Base Purchase Price Adjustments w/o Transfer Taxes	$9,950
33	Transfer Taxes on Total Base Purchase Price Adjustments	$11
34		
35	**Total Base Purchase Price Adjustments**	**$9,961**
36		
37	**Other Rate Base Adjustments**	
38	Raw Water Cross Tie[4]	$1,495
39	Material & Supplies Cost Adjustment[5]	$196
40	Commissioning & Mobilization Cost Adjustment[6]	$106
41	Working Cash Cost Adjustment[7]	$1
42	General Plant Cost Adjustment[8]	$19
43	**Total Other Rate Base Adjustments**	**$1,818**
44		
45	**Updated Total Rate Base**	**$496,122**

Note:
(1) Rate Base filed in Application 04-11-003 included an estimate for Interest During Construction costs of $38,680,000. The updated interest costs are $32,237,000, resulting in a cost reduction of $6,443,000.
(2) Rate Base filed in Application 04-11-003 included an estimate for Start-up and Testing costs of $9,371,000. The updated start-up and testing costs are $13,121,000, resulting in a cost increase of $3,750,000.
(3) Rate Base filed in Application 04-11-003 included an estimate for Property Taxes During Construction costs of $2,309,000. The updated property tax costs are $2,207,000, resulting in a cost reduction of $102,000.
(4) Estimated costs of a permanent raw water cross tie to provide an emergency back-up water source if sufficient recycled water is unavailable due to malfunction or maintenance of the City of Escondido Hale Avenue Resource Recovery Facility (HARRF).
(5) Material & Supplies costs increased by $196,000 from $11,069,000 to $11,265,000 due to the update of the 2006 capital cost escalation factor.
(6) Commissioning & Mobilization costs increased by $106,000 from $6,011,000 to $6,117,000 due to the update of the 2006 capital cost escalation factor.
(7) Working Cash costs increased by $1,000 from $2,308,000 to $2,309,000 due to the combination of updating the 2006 and 2007 O&M escalation factors and reflecting the new in-service date of April 1, 2006.
(8) General Plant costs increased by $19,000 from $1,082,000 to $1,101,000 due to the update of the 2006 capital cost escalation factor.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 108

San Diego Gas & Electric
Advice Letter 1796-E, Attachment B,
to the California Public Utilities Commission
May 30, 2006

November 16, 2012

J. Steve Rahon
Director
Tariffs & Regulatory Accounts
8330 Century Park Court
San Diego, CA 92123-1548

Tel: 858.654.1773
Fax: 858.654.1788
srahon@semprautilities.com

May 30, 2006

ADVICE LETTER 1796-E
(U 902-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

SUBJECT: FINAL REVENUE REQUIREMENT UPDATE ASSOCIATED WITH THE PALOMAR GENERATING FACILITY

PURPOSE

The purpose of this Advice Letter is to submit for California Public Utilities Commission (Commission) approval the final updated revenue requirement associated with the purchase of the Palomar Generation Facility (Palomar). This Advice Letter is filed in compliance with Commission Decision (D.) 05-08-005 and Resolution E-3988.

BACKGROUND

On November 1, 2004 SDG&E filed Application (A.) 04-11-003, requesting approval for the cost recovery and ratemaking mechanisms necessary to allow SDG&E to recover its reasonable and prudent costs of acquiring, operating and owning Palomar. The Commission issued D.05-08-005 on August 25, 2005 approving SDG&E's request with modifications. The Decision also required SDG&E to file an update advice letter no later than 30 days prior to the expected date of commercial operation of the facility, which occurred on March 31, 2006. Consequently, SDG&E filed Advice Letter 1778-E on February 28, 2006. Commission Resolution E-3988, issued on May 11, 2006, approved the updated revenue requirement presented in Advice Letter 1778-E. Furthermore, the Resolution granted SDG&E's request of providing a final update in order to present any final adjustments for Palomar.

This filing therefore represents the final update advice letter, as described above and authorized in Ordering Paragraph (OP) 2 of Resolution E-3988. SDG&E initiated operation of Palomar for its load requirements on March 31, 2006. Consequently, the final updated fixed monthly revenue requirement of $7,479,000, as identified in Attachment A to this filing, reflects final updates to the revenue requirement inputs summarized below. This monthly revenue requirement reflects a $3,300 decrease from the revenue requirement approved in Resolution E-3988.

Purchase Price
In compliance with OP 2 of Resolution E-3988, the Palomar purchase price is trued up to reflect final adjustments due to various cost items for Palomar, including interest during construction, start-up and testing, delay rebates and performance shortfall rebates, performance bonuses, and resulting changes to transfer taxes. Attachment B identifies the various adjustments to the Palomar purchase price, which result in a total decrease of $1,771,000 as compared to the purchase price of $496,122,000 approved by Resolution E-3988.

Variable O&M Rate
OP 2 of Resolution E-3988 authorizes SDG&E to update the variable O&M rate for Palomar. Updates to the purchase price, as described above, do not affect the variable O&M rate. In addition, the O&M estimates included in Advice Letter 1778-E and approved in Resolution E-3988 have not changed. Therefore, the variable O&M rate of $3.09 per MWh, approved in Resolution E-3988, remains unchanged.

Depreciation Rate
In compliance with OP 2 of D.05-08-005, the revenue requirement is modified to reflect the correct negative 3.5% net salvage rate for the Palomar steam generation unit. After discussions with the Commission's Energy Division, it was discovered that Advice Letter 1778-E included a negative 1% net salvage rate. The correction therefore results in a slightly higher depreciation rate than what was filed in Advice Letter 1778-E.

EFFECTIVE DATE

SDG&E believes this filing is subject to Energy Division disposition and therefore respectfully requests that the updated revenue requirement be approved effective March 31, 2006, the commercial operation date of Palomar.

PROTEST

Anyone may protest this advice letter to the California Public Utilities Commission. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. The protest must be made in writing and received within 20 days of the date this advice letter was filed with the Commission. There is no restriction on who may file a protest. The address for mailing or delivering a protest to the Commission is:

CPUC Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Copies should also be sent via e-mail to the attention of both Jerry Royer (jjr@cpuc.ca.gov) and Honesto Gatchallian (jnj@cpuc.ca.gov) of the Energy Division. It is also requested that a copy of the protest be sent via electronic mail and facsimile to SDG&E on the same date it is mailed or delivered to the Commission (at the addresses shown below).

Attn: Monica Wiggins
Regulatory Tariff Manager
8330 Century Park Court, Room 32C
San Diego, CA 92123-1548
Facsimile No. (858) 654-1788
E-Mail: mwiggins@semprautilities.com

NOTICE

A copy of this filing has been served on the utilities and interested parties shown on the attached list, including parties in A.04-11-003 and R.01-10-024, by either providing them a copy electronically or by mailing them a copy hereof, properly stamped and addressed.

Address changes should be directed to Christina Sondrini by facsimile at (858) 654-1788 or by e-mail to csondrini@semprautilities.com.

J. STEVE RAHON
Director - Tariffs & Regulatory Accounts

(cc list enclosed)

Attachment B

SAN DIEGO GAS & ELECTRIC
PALOMAR RATE BASE
ADJUSTMENTS TO INITIAL RATE BASE

	($000)
Total Rate Base filed in Advice Letter 1778-E and Approved in Resolution E-3988	**$496,122**
Base Purchase Price Adjustments	
Interest During Construction Cost Adjustment (accrued cost from 12/01/03 through closing date)[1]	$411
Start-up and Testing Cost Adjustment (natural gas, backfeed power & utility charges less power sales)[2]	($2,137)
Delay Rebates, Performance Shortfall Rebates & Performance Bonus Payments Adjustment[3]	($43)
Base Purchase Price Adjustments w/o Transfer Taxes	($1,769)
Transfer Taxes on Base Purchase Price Adjustment	($2)
Total Adjusted Base Purchase Price w/ Transfer Taxes	**($1,771)**
Updated Total Rate Base	**$494,351**

Note:

(1) Rate Base adopted in Resolution E-3988 included an estimate for Interest During Construction costs of $32,237,000. The updated costs are $32,648,000, resulting in a cost increase of $411,000.

(2) Rate Base adopted in Resolution E-3988 included an estimate for Start-up and Testing costs of $13,121,000. The updated costs which include final CAISO settlements are $10,984,000, resulting in a cost decrease of $2,137,000.

(3) Rate Base adopted in Resolution E-3988 included an estimate for Delay Rebates, Performance Shortfall Bonus Payments costs of $5,133,000. The updated costs are $5,090,000, resulting in a cost decrease of $43,000.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 109

San Diego Gas & Electric
Advice Letter 1621-E
to the California Public Utilities Commission
September 8, 2004

November 16, 2012

SDGE
A Sempra Energy utility

J. Steve Rahon
Director
Tariffs & Regulatory Accounts
8330 Century Park Court
San Diego, CA 92123-1548

Tel: 858.654.1773
Fax: 858.654.1788
srahon@semprautilities.com

September 8, 2004

ADVICE LETTER 1621-E
(U 902-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

SUBJECT: APPROVAL OF THE RAMCO CONTRACT AND ASSOCIATED COST RECOVERY/RATEMAKING PURSUANT TO D.04-06-011

PURPOSE

The purpose of this Advice Letter is to request California Public Utilities Commission (Commission) approval of: (1) the contract between Ramco Generating One (Ramco) and San Diego Gas & Electric Company (SDG&E) which memorializes, with certain modifications addressed herein, the Term Sheet conditions for SDG&E to acquire from Ramco a 46 MW combustion turbine (CT) and related equipment as approved by the Commission in Decision (D.) 04-06-011; (2) an exemption from Public Utilities Code (PUC) Section 851, as permitted by PUC Section 853, for Commission approval of the temporary transfer of a portion of SDG&E's Miramar property to Ramco for the purpose of siting its CT; (3) SDG&E's first year revenue requirement for ownership and operation of the Ramco CT; and (4) an annual update mechanism for SDG&E's first year revenue requirement for the Ramco CT that will be in place until SDG&E's next general rate case/cost of service (GRC/COS) proceeding. This Advice Letter is filed in compliance with, and as provided by, Ordering Paragraph #8 of D.04-06-011.

Portions of Attachments 1 and 3 contain confidential information and therefore are protected from disclosure under the provisions of PUC Section 583 and the Commission's General Order 66-C. The confidential (unredacted) portions of those Attachments are being submitted to the Commission only.

DISCUSSION

A. Introduction

On June 9, 2004, the Commission issued D.04-06-011, approving five proposals that SDG&E presented to meet its short-term and long-term grid reliability needs. One of the proposals was a Term Sheet between SDG&E and Ramco. In the Term Sheet Ramco offered, and SDG&E accepted, a turnkey proposal whereby Ramco would construct pursuant to SDG&E's specifications a 45 MW LM 6000 CT and related equipment. Ramco agreed to design, permit and construct the CT in Chula Vista, California. Under the Term Sheet, title to the CT will transfer to SDG&E when the CT is fully constructed and in operating condition. SDG&E's intent is to acquire title and initiate operation of the CT for its load requirements beginning June 2005.

On page 41 of D.04-06-011 the Commission found that the Ramco CT acquisition was supported by the record and therefore approved the turnkey approach. The Commission stated: "We approve the terms and conditions in the Term Sheet attached to Exhibit RFP-19 and we will approve it [the contract] when it is submitted to the Commission." In this Advice Letter SDG&E submits the SDG&E/Ramco turnkey contract (Turnkey Acquisition Agreement) for final approval.

In its motion requesting Commission approval of the Term Sheet SDG&E also requested Commission approval of certain cost recovery, ratemaking and revenue requirement proposals related to SDG&E's prospective ownership and operation of the Ramco CT. Ordering Paragraph 5 of D.04-06-011 states that SDG&E "is authorized to recover the costs of this generation-owned asset [Ramco]." However, the Commission found in D.04-06-011, on page 41, that: "[w]e do not approve the cost recovery, ratemaking, and revenue requirement proposals as presented by SDG&E at this time." (Emphasis added.) Because in this Advice Letter SDG&E is requesting final Commission approval of the Ramco/SDG&E turnkey contract, and SDG&E intends to begin ownership and operation of the Ramco CT in June 2005 (in less than one year), now is the appropriate time for the Commission to address "the upfront standards and criteria"[1] for SDG&E's recovery of its reasonable costs of owning and operating the Ramco CT. Consequently, in this Advice Letter SDG&E requests the Commission approve SDG&E's first year revenue requirement and an interim annual revenue requirement adjustment mechanism (until SDG&E's next GRC/COS) relative to ownership and operation of the Ramco CT.

As permitted by the Turnkey Acquisition Agreement, SDG&E requested that Ramco permit an additional site for its CT in order to mitigate the schedule risks associated with permitting only one site. The most appealing second site was determined to be certain SDG&E-owned real property in the Miramar area of San Diego, California. Therefore, Ramco pursued permitting two sites for its CT, one in Chula Vista and the other at Miramar. Under the Turnkey Acquisition Agreement SDG&E has the option to select which site will be the location of the Ramco CT.

In July 2004, RAMCO notified SDG&E that the City of Chula Vista could not process the permit for the Chula Vista site in a fashion that would allow RAMCO to meet its June 1, 2005 commercial operation deadline.[2] The present schedule for the Chula Vista site would result in commercial operation after November 1, 2005, thereby missing a critical time of reliability need for the CT. As such, SDG&E directed RAMCO to focus developmental activities at the Miramar site. Given this recent situation and RAMCO's obligation to permit both sites, SDG&E is assessing the marketability of the permit for the Chula Vista site and price reduction change order opportunities for reduced permitting work. The change in site from Chula Vista to Miramar results in a $750,000 contract price reduction. Further, building the Ramco CT at Miramar will result in a savings of approximately $2 million in transmission upgrades.

In order for Ramco to obtain the necessary financing for construction at the Miramar site, it will be necessary for Ramco to acquire a temporary real property interest in SDG&E's property. Normally such a transaction would require PUC Section 851 Commission review and approval. However, due to the anticipated transitory nature of Ramco's property interest in SDG&E's Miramar property, in this Advice Letter SDG&E requests the Commission exempt the land

[1] PUC Section 454.5(b)(7).
[2] This is further supported by the public comments of the city of Chula Vista where it threatened future delays (see: Application for Rehearing of D.04-06-011 or, in the Alternative, Request for Clarification of the City of Chula Vista, July 15, 2004, at pg. 8.).

transfer by SDG&E to Ramco from PUC Section 851 review and approval as permitted by PUC Section 853.

In an effort to expedite review of this Advice Letter and to minimize issues of concern, SDG&E provided a draft of this Advice Letter to The Utility Reform Network ("TURN") and solicited TURN's comments. SDG&E made various changes to its draft based on TURN's input and, as a result, TURN stated it would not protest this Advice Letter filing.

B. Specific Approvals Requested

1. The Contract Between Ramco and SDG&E.

After SDG&E submitted the Term Sheet between it and Ramco for approval by the Commission in its RFP Motion on October 7, 2003, SDG&E and Ramco continued in earnest to negotiate the necessary contractual documents to implement the intent of the parties as specified in the Term Sheet. These negotiations ultimately resulted in the "Turnkey Acquisition Agreement" between SDG&E and Ramco (with associated appendices and exhibits) that is Attachment 1 to this advice letter.[3] It is this contract that SDG&E requests the Commission to approve through this advice letter.

The Turnkey Acquisition Agreement is in substantial conformance with the Term Sheet although in the negotiations there were various adjustments made in pricing and contract scope. The most substantive of these changes are addressed in detail in Attachment 3 to this advice letter. They are summarized below. The final negotiated price for the Ramco CT increased by $658,000 to $31,458,000, representing a 2.1% increase in overall price as compared to the price in the Term Sheet.[4] The majority of this cost increase relates to an adjustment for tax consequences and the increased cost of the CT. There were also several material changes to commercial terms and conditions requested by Ramco that did not significantly increase risk to SDG&E or its customers.

Material Cost Changes

1) The price was increased by $675,000 based upon the further evaluation of tax consequences to each party resulting from the sale of the facilities as assets rather than through the transfer of stock (equity transaction).
2) The price was increased by $300,000 based upon the need to begin permitting a second site (the Miramar property) in order to ensure an in-service date of June 2005.
3) Final negotiations with GE resulted in a 3% net increase in price over initial estimates for the LM 6000 generator package.
4) The price was lowered by $300,000 to adjust for refinements made by GE in its latest version of the LM 6000 that reduced Ramco's facility completion costs.

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[3] A portion of the project, the substation, is addressed in a separate document, the "Turnkey Agreement for Engineering, Equipment and Construction for Turnkey Substation" between SDG&E and Ramco (with associated schedules and attachments). That Turnkey Agreement for Engineering, Equipment and Construction for Turnkey Substation is attached to the Turnkey Acquisition Agreement as Exhibit K thereto (although due to its length and associated attachments it is included with this Advice Letter as Attachment 2). Certain work required by that substation contract relates to electrical interconnection facilities (such as a step-up transformer) which costs are included in the revenue requirement addressed in this Advice Letter.

[4] Although, as set forth in Attachment 5 and in the Turnkey Acquisition Agreement, this price is subject to further adjustment. One such adjustment is an increase in Ramco interest costs (currently estimated at $642,000 which if added to the base purchase price would increase it to $32,100,000).

5) The price was reduced by $750,000 to reflect the savings in land cost by construction of the facility on the Miramar site.
6) The price was increased by $200,000 to compensate Ramco for additional services it provided in the negotiations with GE over the price and attributes of the LM 6000.
7) The performance guarantees for the CT evolved over the course of the negotiations and ultimately resulted in the contract guarantee for capacity increasing by 0.5 MW over that in the Term Sheet and an additional 0.5 MW increase in capacity output before capacity bonus payments are triggered.

<u>Material Changes to Commercial Terms</u>

1) The requirement that Ramco's debt/equity ratio be no greater than 80% debt to 20% equity was limited to the project cost exclusive of the cost of the LM 6000 generator package.
2) The performance bond requirements were reduced to $4.0 million.
3) SDG&E agreed to increase its share of pre-payments. The most significant change is SDG&E's agreement to make a secured downpayment to General Electric (GE) the LM 6000 generator package vendor. The negotiated down-payment saves SDG&E approximately $200,000 in interest over the payment schedule proposed by GE.
4) The cure period for Ramco to meet final completion, after having met minimum acceptance criteria, was extended from 3 months to 6 months.

2. An Exemption From Section 851 of the Miramar Land Transfer Pursuant to Section 853.

PUC Section 853(b) states, in pertinent part, that the Commission "may from time to time by order or rule, and subject to those terms and conditions as may be prescribed therein, exempt any public utility from this article if it finds that the application thereof with respect to the public utility is not necessary in the public interest." The article, Article 6 enacted by Stats. 1951, Ch. 764, requires in Section 851 that a utility must obtain a Commission order before encumbering the whole or any part of its property. Obtaining that order normally requires the utility to file an application. Processing the application normally takes a minimum of 4 months and not infrequently takes more than one year. Due to the unique circumstances surrounding the proposed temporary land transfer between SDG&E and Ramco pertaining to SDG&E's Miramar property, by this advice letter SDG&E requests the Commission exempt the transfer of that property from Section 851 analysis and review pursuant to PUC Section 853(b). Requiring Section 851 review in this instance is not necessary to promote or advance the public interest. Alternatively, should the Commission determine that an exemption under Section 853(b) is inappropriate in this case, by this advice letter SDG&E requests the Commission issue an order pursuant to Section 851 approving the land transfer.

SDG&E requested Ramco perform permitting work on an additional site to mitigate the schedule risks associated with permitting only the Chula Vista site. SDG&E believes it is imperative that all reasonable and prudent actions be taken in order to meet the Ramco CT June 2005 delivery date. The vagaries associated with the permitting processes for a generation facility can readily lead to delays. Given the time needed for engineering and construction, little delay in the permitting process can be tolerated. By requesting Ramco to permit an additional site (the Miramar site) in another local jurisdiction that can also serve as the location for this project, permitting risk was mitigated somewhat related to the on-time transfer of ownership. Protecting the delivery date of the facility is in the best interest of SDG&E's customers because the Ramco CT will support SDG&E's local grid reliability needs.

SDG&E's Miramar property was selected as the additional site because it has suitable usable area for the proposed facilities, it has readily available gas and electric transmission interconnections, and it is zoned to accommodate generation. Construction at the Miramar site will require Ramco to have a real property interest in that portion of the Miramar property needed for the construction of the project facilities in order to satisfy construction financing requirements.

This temporary land transfer is unique because even though Ramco's lending institutions may require a long-term real property interest, under the circumstances it will only be a short-term encumbrance. Locating the project at Miramar, SDG&E proposes to transfer the property to Ramco under the terms set forth in Attachment 4 to this Advice Letter. Assuming Ramco successfully constructs the CT on the Miramar site pursuant to the Turnkey Acquisition Agreement, Ramco's real property interest will only be in effect, and an encumbrance against SDG&E property will only exist, during the construction and testing period. Upon completion of its contractual requirements and successful testing of the CT and related facilities, ownership of the project will be transferred to SDG&E and Ramco's real property interest will merge out of existence. If Ramco at any time defaults under Turnkey Acquisition Agreement, SDG&E will have the right to step-in and foreclose on Ramco's real property interest (subject to the financing liens on the project that are permitted under the Turnkey Acquisition Agreement). Under such circumstances, Ramco's real property interest would terminate and SDG&E would complete the project itself, pay off the permitted liens, and to the extent SDG&E's expenditures at that time were less than the purchase price, pay the difference to Ramco. Therefore, absent unforeseen circumstances, Ramco's real property interest will only be in effect during the construction and testing of the CT and its related equipment or the period of time it takes SDG&E to step-in and assume control of the project itself after a default by Ramco. The transitory nature of Ramco's real property interest eliminates any possible impact it could have on SDG&E's performance of its duties to the public.

SDG&E will not transfer the site to Ramco until Ramco has secured all necessary permits for the site. Ramco does not actually need its real property interest in the site (and SDG&E will not grant one) until just before Ramco begins construction. Ramco cannot begin construction of the project until it has all necessary federal, state and local permits (including compliance with the California Environmental Quality Act). Therefore, it is a precondition to any transfer that the Miramar site be fully permitted by Ramco.

3. SDG&E's First Year Revenue Requirement for Ownership and Operation of the CT.

SDG&E requests Commission approval, effective as of the date the Ramco CT is put in service (scheduled to be June 1, 2005), of both the monthly fixed cost revenue requirement of $520,100 (subject to adjustment via advice letter filing as addressed below) and the variable operating and maintenance (O&M) non-fuel rate of $5.76 per MWhr (see: Attachment 5, pg. 12). The monthly fixed cost revenue requirement will be recorded in SDG&E's Non-Fuel Generation Balancing Account (NGBA) for recovery through SDG&E's commodity rates (Schedule EECC),[5] as will the monthly variable O&M non-fuel costs which will be calculated by multiplying the variable O&M non-fuel rate by the forecasted monthly generation output (MWhrs). The actual fuel costs of the Ramco CT will be recorded in SDG&E's Energy Resource Recovery Account (ERRA), and will also be recovered through SDG&E's commodity rates.

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[5] As previously noted, this revenue requirement assumes that SDG&E's Miramar site will be the location of the Ramco CT. If ultimately this does not prove to be the case, SDG&E will up-date its revenue requirement request to appropriately reflect the costs relative to the Chula Vista site.

In Attachment 5 SDG&E describes in detail how it arrives at the aforementioned monthly revenue requirement. In sum, the Ramco monthly revenue requirement consists of a return on the rate base for Ramco (SDG&E is authorized in OP 5 of D.04-06-011 to recover its Ramco investment at its authorized return on equity for distribution operations of 10.90%), depreciation, taxes, fixed O&M expenses, and franchise fees & uncollectibles (FF&U).

Ramco's rate base consists of the base purchase price for the facility (as adjusted), Miramar site preparation costs, general plant, materials and supplies, working cash, mobilization costs, transaction and legal costs, sales and transfer taxes, natural gas and backfeed power for start-up and testing, and accumulated depreciation and deferred taxes. The Turnkey Acquisition Agreement specifies a base purchase price for the Ramco CT and associated equipment at $31,458,000[6] that, after adjustment for estimated Ramco accrued interest costs of $642,000, is adjusted to $32,100,000. However, as also specified in the Turnkey Acquisition Agreement, this adjusted rate base is subject to further adjustments including, but not limited to, delay rebates and performance shortfall rebates, performance bonuses, change orders, the cost of spare parts, and a change in the site requiring a change in associated site costs. SDG&E will file an Advice Letter prior to the in-service date of the Ramco CT to true up the base purchase price for these adjustments.

As described in Attachment 6, reliability costs of the Ramco CT will be recovered through the Reliability Services (RS) rate component that all SDG&E customers pay as part of their distribution rate, with the revenues collected being used to offset the cost of the generation facility recovered in commodity rates. With that said, if in the future if the Commission adopts a policy for allocating costs of local reliability resources that differs from this approach, unless otherwise stated by the Commission SDG&E will allocate Ramco costs pursuant to that articulated policy.

4. The Annual Update Mechanism for SDG&E's First Year Revenue Requirement Pending the Next COS/GRC.

In Attachment 6 SDG&E specifies the regulatory/ratemaking framework for SDG&E's revenue requirement associated with the Ramco CT for which SDG&E requests Commission approval. This regulatory/ratemaking framework consists of three phases: an initial phase from the in-service date through the first full calendar year of operation (expected to be the year 2006), a second phase consisting of the additional years of operation until implementation of SDG&E's next GRC/COS decision (anticipated to occur in 2009), and the term of the next GRC/COS. The first phase revenue requirement for the Ramco CT would be determined as specified in the preceding discussion. The second phase would allow for annual attrition adjustments to the authorized first phase revenue requirement. As discussed in Attachment 6, the annual attrition adjustments would apply to O&M, capital, and financial element costs (such as any changes in the cost of capital). The third phase would begin upon issuance of a decision in a future GRC/COS that is subsequent to SDG&E's present COS proceeding, A.02-12-028.

EFFECTIVE DATE

This Advice Letter, and the authorization requested herein, is filed as required by, and pursuant to, Ordering Paragraphs 5 and 8 of D.04-06-011, the Commission's Opinion Approving the

[6] This is calculated by adding $30,608,000 for the plant assets to $1,600,000 for the substation equipment installed to support the CT, minus the $750,000 cost savings for siting the CT at SDG&E Miramar site.

Motion of SDG&E for Approval to Enter Into New Electric Resource Contracts Resulting from SDG&E's Grid Reliability Request for Proposal. SDG&E respectfully requests that the Commission issue a resolution providing the authorizations requested at the Commission's earliest convenience. Prompt authorization is appropriate as SDG&E expects to acquire and begin operation of the Ramco CT on June 1, 2005, and SDG&E must have assurance that it will recover its reasonable costs of ownership and operation well before that date.

PROTEST

Anyone may protest this advice letter to the California Public Utilities Commission. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. The protest must be made in writing and received within 20 days of the date this advice letter was filed with the Commission. There is no restriction on who may file a protest. The address for mailing or delivering a protest to the Commission is:

Energy Division—IMC Branch
California Public Utilities Commission
505 Van Ness Avenue, Room 4002
San Francisco, CA 94102

Copies should also be sent via e-mail to the attention of both Jerry Royer (jjr@cpuc.ca.gov) and Honesto Gatchallian (jnj@cpuc.ca.gov) of the Energy Division. It is also requested that a copy of the protest be sent via electronic mail and facsimile to SDG&E on the same date it is mailed or delivered to the Commission (at the addresses shown below).

Attn: Monica Wiggins
Regulatory Tariff Manager
8330 Century Park Court, Room 32C
San Diego, CA 92123-1548
Facsimile No. (858) 654-1788
E-Mail: mwiggins@semprautilities.com

NOTICE

In accordance with Section III.G of General Order No. 96-A, a redacted copy of this filing has been served on the utilities and interested parties shown on the attached list, including parties in R.01-10-024, by either providing them a copy electronically or by mailing them a copy hereof, properly stamped and addressed.

Address changes should be directed to Christina Sondrini by facsimile at (858) 654-1788 or by e-mail to csondrini@semprautilities.com.

J. STEVE RAHON
Director - Tariffs & Regulatory Accounts

(cc list enclosed)

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 110

San Diego Gas & Electric
Advice Letter 1711-E, Attachment B,
to the California Public Utilities Commission
September 25, 2007

November 16, 2012

STATE OF CALIFORNIA

ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

September 25, 2008

Advice Letter 1711-E

Ken Deremer, Director
Tariffs and Regulatory Accounts
San Diego Gas and Electric
8330 Century Park Court, CP32C
San Diego, CA 92123-1548

Subject: Revenue Requirement Update Associated with the RAMCO Generating Facility

Dear Mr. Deremer:

Advice Letter 1711-E is effective November 18, 2005.

Sincerely,

Kenneth Lewis, Acting Director
Energy Division

J. Steve Rahon
Director
Tariffs & Regulatory Accounts
8330 Century Park Court
San Diego, CA 92123-1548

Tel: 858.654.1773
Fax: 858.654.1788
srahon@semprautilities.com

July 26, 2005

ADVICE LETTER 1711-E
(U 902-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

SUBJECT: REVENUE REQUIREMENT UPDATE ASSOCIATED WITH THE RAMCO GENERATING FACILITY

San Diego Gas and Electric Company (SDG&E) hereby submits for filing revisions to its electric tariffs, as shown in Attachment C.

PURPOSE

The purpose of this Advice Letter is to submit for California Public Utilities Commission (Commission) approval the updated revenue requirement associated with the purchase of a generation facility constructed by Ramco Generating One (Ramco), including modifications to SDG&E's Non-fuel Generation Balancing Account (NGBA) and Energy Resource Recovery Account (ERRA). This Advice Letter is filed in compliance with Resolution E-3896.

BACKGROUND

On June 9, 2004, the Commission issued Decision (D.) 04-06-011, approving five proposals that SDG&E presented to meet its short-term and long-term grid reliability needs. One of the proposals was a Term Sheet between SDG&E and Ramco. In the Term Sheet Ramco offered, and SDG&E accepted, a turnkey proposal whereby Ramco would construct pursuant to SDG&E's specifications a 46 MW combustion turbine (CT) and related equipment. SDG&E filed Advice Letter 1621-E on September 8, 2004, submitting a modified Turnkey Acquisition Agreement (TAA) between SDG&E and Ramco, along with proposing the regulatory framework for recovery of Ramco costs for the generation facility to be built at SDG&E's Miramar complex. Resolution E-3896, adopted January 27, 2005 approved SDG&E's TAA with Ramco. The Resolution approved SDG&E's initial revenue requirement from the in-service date through 2006 for the ownership and operation of the facility, as well as an annual update mechanism that will be in place from 2007 until the implementation of SDG&E's next cost-of-service proceeding. In addition, the Resolution: (1) required SDG&E to file an Advice Letter prior to the commercial operation date (COD) of Ramco to true-up the base purchase price and other items for numerous adjustments affecting the "adjusted rate base", update the escalation factors used in the development of the fixed revenue requirement and variable O&M non-fuel rate, as well as to incorporate the currently applicable ROE of 10.37% into the fixed revenue requirement calculation, (2) required SDG&E to include in the Advice Letter " detailed supporting documentation showing that the base purchase price adjustments are consistent with the provisions of the Purchase Agreement approved in this resolution" (p. 8), and (3) rejected SDG&E's proposal to file a second Advice Letter after the Ramco COD for a true-up of all appropriate costs, but did state that " SDG&E should address the need for a post in-service date true-up advice letter when it files the pre in-service date true-up advice letter." (p. 11)

DISCUSSION

This filing represents the pre in-service date true-up advice letter, as described above. SDG&E will acquire title and initiate operation of the Ramco CT for its load requirements on or shortly after July 26, 2005. Consequently, the updated fixed monthly revenue requirement of $505,500, as identified in Attachment A to this filing, reflects changes to the following revenue requirement inputs summarized below:

A. Purchase Price

Advice Letter 1621-E states that the Ramco purchase price will be trued up in this filing to reflect adjustments due to various cost items identified in the TAA for Ramco. As stated in Resolution E-3896, the TAA specifies that the Ramco rate base is subject to " adjustments including, but not limited to, delay rebates and performance shortfall rebates, performance bonuses, change orders, the cost of spare parts, and a change in the site requiring a change in associated site costs." (Resolution E-3896, p. 7) Attachment B identifies the various adjustments to the Ramco purchase price, which result in a total increase of $897,700.

B. Escalation Factors

Attachment 5 of Advice Letter 1621-E states that the escalation factors used in the development of the fixed monthly revenue requirement and variable O&M non-fuel rate will be updated in this filing (Section VI, p. 10). The escalation factors are used to convert estimated 2003 expenses to 2005 and 2006 dollars. The escalation factors used were initially based on 2nd Quarter 2003 Global Insight Forecasts and are being updated to reflect the most current forecasts available, which are based on 1st Quarter 2005 Global Insight Forecasts.

Update to Escalation Factors

	2005		2006	
	Old	**New**	**Old**	**New**
Fixed O&M Escalator	1.0387	1.0934	1.0590	1.1062
Variable O&M Escalator	1.0503	1.0927	1.0761	1.1143
Capital Escalator	1.0425	1.0828	NA	NA

Old - Escalation Factors based on 2nd Quarter 2003 Global Insight Forecasts.
New - Escalation Factors based on 1st Quarter 2005 Global Insight Forecasts.

The updated 2005 and 2006 fixed O&M escalation factors result in a change to the average monthly fixed O&M costs included in the fixed monthly revenue requirement from $22,600 to $23,800, as identified in Attachment A. Also, the updated 2005 capital escalation factor results in increases to the Material & Supplies and Commissioning & Mobilization cost rate base items, as identified in Attachment B. Finally, the updated 2005 and 2006 variable O&M escalation factors identified above result in an average variable O&M non-fuel rate for the 2005-2006 period of $5.93 per MWh compared to the preliminary $5.76 per MWh rate identified in Advice Letter 1621-E.

C. Cost of Capital

In accordance with Ordering Paragraph 3 of Resolution E-3896, the fixed monthly revenue requirement is being updated to reflect SDG&E's currently authorized cost-of-capital adopted in Advice Letter 1630-E/1479-G, including the reduction in return on equity (ROE) from 10.90% to 10.37%. The update to the cost-of-capital used to develop the fixed monthly revenue requirement is also consistent with D.04-06-011, allowing SDG&E to recover costs through its adopted ROE until further modified by the Commission (Conclusion of Law 6), which occurred in Advice Letter 1630-E/1479-G, effective January 1, 2005.

SDG&E Authorized Rate of Return (ROR) Calculation

Capital Structure	Weighting	Cost	ROR
Debt	45.25%	5.90%	2.67%
Preferred Stock	5.75%	7.45%	0.43%
Common Equity	49.00%	10.37%	5.08%
Total	100.00%		8.18%

D. Start-up and Testing

Attachment 5 of Advice Letter 1621-E states that the fixed monthly revenue requirement includes $350,000 in estimated natural gas and electric backfeed costs minus the value of the energy generated during start-up and testing of the plant. This estimate was based on forecasted average costs and energy prices for April, May and June of 2005. In this filing the net start-up and testing costs are being updated to reflect actual natural gas costs and electric backfeed costs incurred during start-up and testing minus the value of the energy generated based on hourly California Independent System Operator (ISO) imbalance energy prices through July 22, 2005. The updated start-up and testing cost is $64,800 reflecting a $285,200 decrease, as identified in Attachment B.

E. In-Service Date Change

In SDG&E's original Ramco advice letter filing (1621-E), the fixed monthly revenue requirement was based on an assumed plant in-service date of June 1, 2005. The expected in-service date of the plant is now on or shortly after July 26, 2005. For this reason, the revenue requirement calculation has been updated to reflect the new in-service date.

NGBA

As shown in Attachment C to this filing, language has been added to SDG&E's NGBA to include recovery for approved Ramco non-fuel costs not being recovered by another component of SDG&E's rates. Pursuant to D.04-06-011, the authorized monthly Ramco revenue requirement to be recorded in the NGBA for recovery in Schedule EECC rates is $508,100. This authorized revenue requirement consists of a fixed cost monthly revenue requirement component of $505,500 and an estimated variable monthly component of $20,100, less $17,500 in estimated monthly 2005 RMR revenues projected to recover Ramco costs. The variable component, which is trued-up in SDG&E's yearly NGBA filing, currently equals the non-fuel rate of $5.93/MWh multiplied by the estimated 2005 Ramco generation output of 16,925 MWh (see Exhibit RFP-30C of A.01-10-024) divided by 5 (months of operation in 2005). Fuel costs are recorded in SDG&E's ERRA.

Final Update

Ramco certified the facility complete June 21, 2005. Outstanding disputes between Ramco and its subcontractors prevented Ramco from promptly closing. Resolution of most disputes has now allowed sufficient funds to facilitate closing. One dispute remains between Ramco and a subcontractor that has been taken into account by the holdback of 150% of the disputed amount. Upon resolution, SDG&E shall pay Ramco and/or the subcontractor as appropriate.

Additionally, SDG&E and Ramco have a dispute related to the payment of sales/use tax. Both parties have agreed to resolve this issue by arbitration per the provisions of the contract. Ramco believes it is due approximately $1.3 million from SDG&E to pay for use taxes while SDG&E believes it owes Ramco $4 thousand as sales tax. The issue goes to the heart of the transaction. SDG&E contends that the transaction, as represented to Ramco and described in the term sheet and contract, was for the sale of assets. Ramco contends that the transaction was that of an Engineering, Procurement, and Construction (EPC) contract where tax is owed on all parts making up the facility. Therefore, upon conclusion of the binding arbitration to resolve this dispute, SDG&E requests the opportunity to submit a second update advice letter filing to update its revenue requirement to incorporate expenses for litigation of this matter and payment to Ramco, if any.

EFFECTIVE DATE

SDG&E respectfully requests that the Commission issue a resolution providing the authorizations requested at the Commission's earliest convenience.

PROTEST

Anyone may protest this advice letter to the California Public Utilities Commission. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. The protest must be made in writing and received within 20 days of the date this advice letter was filed with the Commission. There is no restriction on who may file a protest. The address for mailing or delivering a protest to the Commission is:

CPUC Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Copies should also be sent via e-mail to the attention of both Jerry Royer (jjr@cpuc.ca.gov) and Honesto Gatchallian (jnj@cpuc.ca.gov) of the Energy Division. It is also requested that a copy of the protest be sent via electronic mail and facsimile to SDG&E on the same date it is mailed or delivered to the Commission (at the addresses shown below).

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Regulatory Tariff Manager
8330 Century Park Court, Room 32C
San Diego, CA 92123-1548
Facsimile No. (858) 654-1788
E-Mail: mwiggins@semprautilities.com

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Address changes should be directed to Christina Sondrini by facsimile at (858) 654-1788 or by e-mail to csondrini@semprautilities.com.

J. STEVE RAHON
Director - Tariffs & Regulatory Accounts

(cc list enclosed)

Attachment B

SAN DIEGO GAS & ELECTRIC
RAMCO RATE BASE
ADJUSTMENTS TO INITIAL RATE BASE

Line No		($000)
1	**Total Rate Base filed in Advice Letter 1621-E**	**$34,008.5**
2		
3	**Base Purchase Price Adjustments**	
4	Change Order 1 & 1A:	
5	Reduce Gas Compressor Size	($56.0)
6	Delete 4160V System, Change to 480V	($30.4)
7	Delete Power Control Module	($87.0)
8	Delete Oily Water Separator System and Tank	($95.0)
9	Delete GE UPS Battery	($2.0)
10	Add Redundant Generator Protection	$15.6
11	Soil and Subsurface Conditions	$111.0
12	Longer Connection for gas/water/sewer	$184.9
13	Dual site engineering	$100.0
14	Alt site~ FAA legal review & plume analysis & TAA Amendment legal costs	$110.7
15	Add emergency spill containment underground tank	$14.8
16	Add Control Room to Maintenance Building	$45.0
17	GE Late payment interest 50% of $148,287	$74.1
18	10% O/H and Profit on RAMCO Change Orders	$64.1
19		
20	Change Order 2: Construction Trailer and Furniture	$4.4
21	Change Order 3: Duct bank repair	$3.4
22	Change Order 4: Spare parts	$58.8
23	Change Order 5: Roadbed Upgrade	$30.3
24	Change Order 6: Cementitious Earth Excavation	$81.3
25	Change Order 7 – Comex Box (spare parts storage container)	$3.8
26	**Subtotal - Change Order Costs**	**$631.7**
27		
28	Construction Loan Interest[1]	($20.3)
29	Delay Rebates ($20,000 a day from June 16-20)	($50.0)
30	Performance Guarantees: Heat Rate and Capacity Bonuses	$330.8
31	Sales Tax	$4.6
32	Total Base Purchase Price Adjustments w/o Transfer Taxes	$896.7
33	Transfer Taxes on Purchase Price Adjustments	$1.0
34	**Total: Base Purchase Price Adjustments w Transfer Taxes and Sales Taxes**	**$897.7**
35		
36	**Other Rate Base Adjustments**	
37	Start-up and Testing Costs Adjustment[2]	($285.2)
38	Working Cash Adjustment[3]	($18.6)
39	Material & Supplies Cost Adjustment[4]	$21.6
40	Commissioning & Mobilization Cost Adjustment[5]	$10.9
41	**Total Other Rate Base Adjustments**	**($271.3)**
42		
43	**Updated Total Rate Base**	**$34,634.9**

Note:
(1) Rate Base filed in Advice Letter 1621-E included an estimate for construction loan interest of $642,000. The updated interest costs are $621,700, resulting in a $20,300 interest cost reduction.
(2) Rate Base filed in Advice Letter 1621-E included an estimate for natural gas and backfeed power costs for start-up and testing of $350,000. Based on actual data the updated start-up and testing costs are $64,800, resulting in a $285,200 decrease.
(3) Working Cash decreased by $18,600 from $76,700 to $58,100 due to the combination of updating the 2005 and 2006 O&M escalation factors and reflecting the new in-service date.
(4) Material & Supplies increased by $21,600 from $557,700 to $579,300 due to the update of the 2005 capital escalation factor.
(5) Mobilization & Commissioning Costs increased by $10,900 from $281,500 to $292,400 due to the update of the 2005 capital escalation factor.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 111

San Diego Gas & Electric
Advice Letter 2099-E
to the California Public Utilities Commission
July 30, 2009

November 16, 2012

STATE OF CALIFORNIA

ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

March 22, 2010

Advice Letter 2099-E

Ronald van der Leeden, Director
Rates, Revenues and Tariffs
San Diego Gas and Electric
8330 Century Park Court, CP32C
San Diego, CA 92123-1548

Subject: Revenue Requirement Update Associated with the Miramar Energy Facility II

Dear Mr. van der Leeden:

Advice Letter 2099-E is effective January 1, 2010.

Sincerely,

Julie A. Fitch, Director
Energy Division

Ron van der Leeden
Rates, Revenues & Tariffs
8330 Century Park Court
San Diego, CA 92123-1548

Tel: 213-244-2009
Fax: 858.654.1788
RvanderLeeden@semprautilities.com

July 30, 2009

ADVICE LETTER 2099-E
(U 902-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

SUBJECT: REVENUE REQUIREMENT UPDATE ASSOCIATED WITH THE MIRAMAR ENERGY FACILITY II

PURPOSE

The purpose of this Advice Letter is to submit for California Public Utilities Commission (Commission) approval the updated revenue requirement associated with the completion of the Miramar Energy Facility II (MEF II), including modifications to SDG&E's Non-fuel Generation Balancing Account (NGBA) as shown in Attachment A. This Advice Letter is filed in compliance with Commission Decision (D.) 09-01-008.

BACKGROUND

On January 30, 2009, the Commission issued D.09-01-008, approving SDG&E's application for the MEF II project including an Engineering, Procurement, and Construction contract with Wellhead Services, Inc. and a contract with General Electric for the supply of a simple cycle gas-fired combustion turbine with a capacity of approximately 46.5 megawatts to provide peaking energy and capacity for SDG&E's service territory. This facility is complete and in the testing phases. It is owned and operated by SDG&E. As such, D.09-01-008 authorizes SDG&E to recover in rates the cost of constructing and operating MEF II consistent with the approved construction-related risk and reward incentive mechanism described in detail below.

The MEF II Application projected the total cost of the facility at $56.5 million. The Commission acknowledged SDG&E's need for additional generation to service its bundled customers and approved MEF II as a reasonable option to meet this need. An advice letter that provides an update of the final construction costs and associated revenue requirements is required to be filed with the Commission when MEF II is complete.

DISCUSSION

This filing represents a pre in-service date true-up advice letter. SDG&E will initiate operation of MEF II for its load requirements on or after August 1, 2009. Consequently, SDG&E has updated its current total cost projection for MEF II and the associated revenue requirement, provided as Attachment B to this filing. This revenue requirement reflects changes to the following revenue requirement inputs filed in the application as summarized below:

Capital Construction Costs

Total project costs are currently projected to be $53.8 million, or $2.7 million lower than the original filing. SDG&E submits Attachment C as confidential information per Section 583 of the Public Utilities Code and/or General Order 66-C. Attachment C breaks these costs down by the major categories of equipment, engineering/procurement/construction, generation interconnection, AFUDC, and other SDG&E costs that include items such as labor, start-up fuel, and materials/supplies. In each of these categories, there remain non-fixed costs as work continues to ready the facility for commercial operation starting August 1, 2009. Even after this commercial date, costs will accrue due to yet to be undertaken/completed training, purchases, and minor work items. Minor work items are those tasks needed to reach final completion. SDG&E will include information that identifies final cost by category which will describe variances from its original application and the reasons therefore in SDG&E's NGBA update advice letter filed in November 2009 for rates effective January 1, 2010. SDG&E has not burdened this filing because there are no notable variances at this point as small cost savings were realized across most of the categories.

Construction-Related Risk/Reward Mechanism

D.09-01-008 approved SDG&E's proposed construction risk/reward mechanism in which: (1) shareholders take no construction risk (and have no reward opportunities) for construction costs within 5% of the $56.5 million project cost estimate (the "deadband"), (2) shareholders take 10% of the construction risk/reward for the band that is 5% over (or under) to 15% over (or under) the estimated project cost, and (3) cost overruns in excess of 15% of the estimated project cost are subject to recovery through a regulatory review process (and shareholders have no reward opportunities for savings resulting from actual costs being greater than 15% below the estimated project cost).

As stated previously, currently, the total estimated costs for constructing MEF II is $53.8 million (4.8% below the approved projection of $56.5 million) which falls within the deadband in the approved mechanism above.

SDG&E intends to update the results of this mechanism with its final cost and revenue requirement update submitted in the NGBA update advice letter in November 2009 for rates effective January 1, 2010.

Regulatory Accounts

Language has been added to SDG&E's NGBA to include recovery for MEF II non-fuel costs not being recovered by another component of SDG&E's rates. Pursuant to D.09-01-008, the authorized MEF II non-fuel related revenue requirement is to be recorded in the NGBA and collected through rates from its bundled customers[1]. Fuel costs are recorded in SDG&E's ERRA. The ERRA currently includes wording that addresses the recording of fuel and fuel-related expenses of electric generation and therefore does not need to be updated as part of this advice filing.

[1] D.09-01-008 OP 2.

Rate Making Treatment

Upon the initiation of operations at MEF II, SDG&E will record the monthly revenue requirement filed herein to the NGBA for recovery from bundled service customers. However, SDG&E does not intend to adjust its retail electric rates for this additional revenue requirement at this time. Once all of the final costs are accumulated, SDG&E will update this cost projection and associated revenue requirement in the NGBA update advice letter filed in November, for rates effective January 1, 2010. At that time, commodity rates contained in SDG&E's schedule Electric Energy Commodity Cost (EECC) will be adjusted to reflect recovery of these commodity costs, along with other approved NGBA related changes.

EFFECTIVE DATE

SDG&E believes that this filing is subject to Energy Division disposition and should be classified as Tier 3 (effective after Commission approval) pursuant to GO 96-B. SDG&E respectfully requests that the Commission issue a resolution providing the authorizations requested at the Commission's earliest convenience.

PROTEST

Anyone may protest this Advice Letter to the California Public Utilities Commission. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. The protest must be made in writing and must be received within 20 days of the date this Advice Letter was filed with the Commission. There is no restriction on who may file a protest. The address for mailing or delivering a protest to the Commission is:

CPUC Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Copies of the protest should also be sent via e-mail to the attention of both Honesto Gatchalian (jnj@cpuc.ca.gov) and Maria Salinas (mas@cpuc.ca.gov) of the Energy Division. A copy of the protest should also be sent via both e-mail and facsimile to the address shown below on the same date it is mailed or delivered to the Commission.

Attn: Megan Caulson
Regulatory Tariff Manager
8330 Century Park Court, Room 32C
San Diego, CA 92123-1548
Facsimile No. (858) 654-1788
E-Mail: mcaulson@semprautilities.com

NOTICE

A copy of this filing has been served on the utilities and interested parties shown on the attached list, including parties in A.08-06-017, by either providing them a copy electronically or by mailing them a copy hereof, properly stamped and addressed.

Address changes should be directed to SDG&E Tariffs by facsimile at (858) 654-1788 or by e-mail at SDG&ETariffs@semprautilities.com.

RON VAN DER LEEDEN
Director - Tariffs & Regulatory Accounts

(cc list enclosed)

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 112

San Diego Gas & Electric
Advice Letter 2126-E
to the California Public Utilities Commission
November 16, 2009

November 16, 2012

STATE OF CALIFORNIA ARNOLD SCHWARZENEGGER, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

December 17, 2009 **Advice Letter 2126-E**

Ronald van der Leeden, Director
Rates, Revenues and Tariffs
San Diego Gas and Electric
8330 Century Park Court, CP32C
San Diego, CA 92123-1548

Subject: Annual Non-Fuel Generation Balancing Account Update

Dear Mr. van der Leeden:

Advice Letter 2126-E is effective December 16, 2009.

Sincerely,

Julie A. Fitch, Director
Energy Division

Ron van der Leeden
Rates, Revenues & Tariffs
8330 Century Park Court
San Diego, CA 92123-1548

Tel: 213-244-2009
Fax: 858.654.1788
RvanderLeeden@semprautilities.com

November 16, 2009

ADVICE LETTER 2126-E
(U 902-M)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

SUBJECT: ANNUAL NON-FUEL GENERATION BALANCING ACCOUNT UPDATE

PURPOSE

The purpose of this Advice Letter is to request California Public Utilities Commission (Commission) approval of SDG&E's 2010 Non-Fuel Generation Balancing Account (NGBA) revenue requirement, reflecting updates to the San Onofre Nuclear Generating Station (SONGS) and SDG&E's Generation Plants (Miramar Combustion Turbine (CT) facility, Miramar Energy Facility II (MEF II) and Palomar Energy Center). Additionally, this advice letter updates SDG&E's NGBA tariff for SONGS refueling revenue requirements in accordance with Southern California Edison's AL 2336-E approved by the Commission on June 26, 2009.

DISCUSSION

The NGBA applies to SDG&E's bundled service customers and provides recovery of approved electric generation non-fuel costs not being recovered by another component of SDG&E's electric commodity rates. Currently, SDG&E has ownership interest in SONGS, the Miramar CT facility, MEF II and the Palomar Energy Center facility, of which the non-fuel revenue requirement for each is reflected in the NGBA. The generation non-fuel revenue requirement adjustments presented in this advice letter have received prior Commission authorization, and are consolidated to produce an NGBA revenue requirement effective January 1, 2010.[1]

As part of this advice letter, SDG&E proposes to adjust electric commodity rates to reflect the updated NGBA revenue requirement effective January 1, 2010. The NGBA change will be included in the advice letter consolidating all Commission-authorized changes in SDG&E's revenue requirements, and related changes to its rates, filed at least three days prior to the January 1, 2010 effective date of such rates. A summary of the NGBA revenue requirement for 2010 and a summary of present and proposed rates are both included herein as Attachments B, C, D and E (confidential) respectively.

The following adjustments to SDG&E's NGBA, resulting in a $36.4 million increase to the 2010 NGBA revenue requirement, are therefore effective January 1, 2010:

[1] D. 06-11-026 in SONGS Steam Generator Replacement Proceeding A.06-04-018, D.08-07-046 in SDG&E's 2008 General Rate Case Proceeding A.06-12-009 and D.09-03-025 in Southern California Edison's 2009 General Rate Case Preceding A.07-11-011.

SAN ONOFRE NUCLEAR GENERATING STATION (SONGS)

The 2010 SONGS revenue requirement includes $96.3 million for operations & maintenance (O&M) costs, $23.2 million for capital-related costs and $13.8 million for refueling outage amounts as approved in the Southern California Edison's AL 2336-E[2]. The amounts include a 4.25% post-test year ratemaking increase from the 2009 revenue requirement. Furthermore, the 2010 SONGS revenue requirement includes $1.3 million representing SDG&E's ownership share of the removal and disposal costs of the original steam generators related to the Steam Generator Replacement Program (SGRP) as approved in Decision (D.) 06-11-026. As such, the total 2010 SONGS non-fuel revenue requirement is $134.6 million.

MIRAMAR CT & PALOMAR

The 2010 Miramar CT and Palomar revenue requirement is $117.4 million, a $3.9 million increase over the 2009 revenue requirement due to attrition in the SDG&E generation revenue requirement as approved in SDG&E most recent GRC, D.08-07-046.

MIRAMAR ENERGY FACILITY II (MEF II)

Background

On January 30, 2009, the Commission issued D.09-01-008, approving SDG&E's application for the MEF II project including an Engineering, Procurement, and Construction contract with Wellhead Services, Inc. and a contract with General Electric for the supply of a simple cycle gas-fired combustion turbine with a capacity of approximately 46.5 megawatts to provide peaking energy and capacity for SDG&E's service territory. This facility is complete and operational. It is owned and operated by SDG&E. As such, D.09-01-008 authorizes SDG&E to recover in rates the cost of constructing and operating MEF II consistent with the approved construction-related risk and reward incentive mechanism described in detail below.

The MEF II Application projected the total cost of the facility at $56.5 million. The Commission acknowledged SDG&E's need for additional generation to service its bundled customers and approved MEF II as a reasonable option to meet this need. This advice letter provides an update of the final construction costs and associated revenue requirements as required to be filed with the Commission when MEF II is complete.

Discussion

The MEF II was ready for commercial operation August 1, 2009, but not recognized by the CAISO until August 8, 2009 as they awaited confirmation of air quality test results. In Advice Letter 2099-E, in compliance with Commission D.09-01-008, SDG&E requested approval for the updated 2009 revenue requirement associated with MEF II's completion based on its most current total cost projection. SDG&E did not adjust its retail electric rates at that time but requested that once all of the final costs were accumulated, SDG&E would update its cost projection and associated revenue requirement in the NGBA update advice letter for inclusion in rates January 1, 2010. MEF II's final cost is $51.8 million and requires a 2010 revenue

[2] Southern California Edison Application 07-11-011 / Decision 09-03-025.

requirement of $8.9 million[3] (excluding Franchise Fees & Uncollectibles). Attachments D and E provides details of the 2010-2013 revenue requirements and MEF II total costs along with explanations for variances between the original filed and final plant costs. This revenue requirement reflects changes to the following revenue requirement inputs filed in the application as summarized further below.

Capital Construction Costs

Total project costs are $51.8 million, or $4.7 million lower than the original filing. SDG&E submits Attachment E as confidential information per Section 583 of the Public Utilities Code and/or General Order 66-C. Attachment E breaks these costs down by the major categories of equipment, engineering/procurement/construction, generation interconnection, AFUDC, and other SDG&E costs that include items such as labor, start-up fuel, Owner's engineer, and materials/supplies. A comparison is provided between costs filed in the original Application and final cost along with a variance explanation.

Construction-Related Risk/Reward Mechanism

D.09-01-008 approved SDG&E's proposed construction risk/reward mechanism in which: (1) shareholders take no construction risk (and have no reward opportunities) for construction costs within 5% of the $56.5 million project cost estimate (the "deadband"), (2) shareholders take 10% of the construction risk/reward for the band that is 5% over (or under) to 15% over (or under) the estimated project cost, and (3) cost overruns in excess of 15% of the estimated project cost are subject to recovery through a regulatory review process (and shareholders have no reward opportunities for savings resulting from actual costs being greater than 15% below the estimated project cost).

The total cost for constructing MEF II is $51.8 million (8.3% below the approved projection of $56.5 million) which falls within the benefit sharing portion of the approved mechanism. As enumerated in Attachment E, SDG&E customers saved $4.5 million and SDG&E shareholders are eligible for a $184,699 reward.

AMORTIZATION OF DECEMBER 31, 2009 BALANCES

The projected NGBA balance as of December 31, 2009 is a $17.3 million undercollection and will be amortized over the next 12 months beginning January 1, 2010. The projected amount includes the balance of the SONGS O&M Balancing Account (SONGSBA), which is transferred annually to the NGBA.

This filing will not create any deviations from SDG&E's tariffs, cause withdrawal of service from any present customers, or impose any more restrictive conditions.

[3] Revenue Requirement including Franchise Fees & Uncollectibles (FF&U) is $9.2 million ($8.9 million plus $.322 million of FF&U).

PROTEST

Anyone may protest this Advice Letter to the California Public Utilities Commission. The protest must state the grounds upon which it is based, including such items as financial and service impact, and should be submitted expeditiously. The protest must be made in writing and must be received within 20 days of the date this Advice Letter was filed with the Commission. There is no restriction on who may file a protest. The address for mailing or delivering a protest to the Commission is:

CPUC Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Copies of the protest should also be sent via e-mail to the attention of both Honesto Gatchalian (jnj@cpuc.ca.gov) and Maria Salinas (mas@cpuc.ca.gov) of the Energy Division. A copy of the protest should also be sent via both e-mail and facsimile to the address shown below on the same date it is mailed or delivered to the Commission.

Attn: Megan Caulson
Regulatory Tariff Manager
8330 Century Park Court, Room 32C
San Diego, CA 92123-1548
Facsimile No. (858) 654-1748
E-mail: mcaulson@semprautilities.com

EFFECTIVE DATE

SDG&E believes this filing is subject to Energy Division disposition and should be classified as Tier 2 (effective after staff approval) pursuant to GO 96-B. SDG&E respectfully requests that this filing be approved effective December 16, 2009, 30 days from the date filed.

NOTICE

A copy of this filing has been served on the utilities and interested parties shown on the attached list by either providing them a copy electronically or by mailing them a copy hereof, properly stamped and addressed.

Address changes should be directed to SDG&E Tariffs by facsimile at (858) 654-1748 or by e-mail at SDG&ETariffs@semprautilities.com.

RON VAN DER LEEDEN
Director – Rates, Revenues & Tariffs

(cc list enclosed)

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 113

Northwest and Intermountain Power Producers Coalition
Data Requests to PacifiCorp, Portland General Electric,
and Idaho Power Company
January 20, 2012

November 16, 2012

RICHARDSON & O'LEARY, PLLC
ATTORNEYS AT LAW
Tel: 208-938-7900 Fax: 208-938-7904
P.O. Box 7218 Boise, ID 83707 - 515 N. 27th St. Boise, ID 83702

January 20, 2012

Via Electronic Mail

MARY WIENCKE
NATALIE HOCKEN
PACIFICORP
825 NE MULTNOMAH ST, STE 1800
PORTLAND OR 97232-2149
mary.wiencke@pacificorp.com
natalie.hocken@pacificorp.com
oregondockets@pacificorp.com

Re: UM 1182 – Northwest and Intermountain Power Producers Coalition's Revised Second Set of Data Requests to PacifiCorp

Please see the data request set forth below with regard to the above-referenced docket. Please provide responses electronically only, and in the original electronic format, if possible. Please use the definitions set forth in NIPPC's Data Request sent December 5, 2011. Please also assume that these are ongoing requests, and include requests for information that becomes available during these proceedings.

Please provide responses to the following persons:

Gregory M. Adams
Richardson & O'Leary PLLC
515 N. 27th Street
P.O. Box 7218
Boise, Idaho 83702
Telephone: (208) 938-2236
Fax: (208) 938-7904
greg@richardsonandoleary.com

William A. Monsen
MRW & Associates, LLC
1814 Franklin Street, Suite 720
Oakland, CA 94612
Telephone: (510) 834-1999
Fax: (510) 834-0918
wam@mrwassoc.com

DATA REQUESTS

2.1 Please provide the following documents for the plants owned by your utility listed in Attachment 1 which were placed in service in and after 2006:

a. Please provide the initial application or document containing cost projections for such plant (not necessarily including work papers) submitted to OPUC or other regulators announcing that your utility is going to construct or acquire a generating plant. Such a document may include, but is not limited to, a Certificate of Public Convenience and Necessity filing, an RFP benchmark bid, or an RFP waiver application.

b. The Commission order allowing the plant to be entered into rate base.

2.2 Please provide electronic copies of all FERC Form 1s that your utility filed from 1990 to the present.

Thank you for your prompt attention to this request.

Sincerely,

/s/ *Gregory M. Adams*

Gregory M. Adams
RICHARDSON AND O'LEARY PLLC
Attorney for the
Northwest and Intermountain Power Producers Coalition

ATTACHMENT I

LIST OF GENERATING PLANTS

PacifiCorp-owned Natural Gas Plants
Chehalis
Currant Creek
Gadsby 1-6
Hermiston 1 and 2
Lake Side
Little Mountain
James River Cogen

PacifiCorp-owned Wind Resources
Foote Creek I
Leaning Juniper
Goodnoe Hills East Wind
Marengo
Glenrock Wind I and III
Marengo II
Rolling Hills Wind
Seven Mile Hill Wind I and II
High Plains
McFadden Ridge 1
Dunlap 1

PGE-owned Natural Gas Plants
Port Westward
Beaver
Coyote Springs

PGE-owned Wind Plant
Biglow Canyon

Idaho Power-owned Natural Gas Plants
Bennett Mountain
Danskin

RICHARDSON & O'LEARY, PLLC
ATTORNEYS AT LAW
Tel: 208-938-7900 Fax: 208-938-7904
P.O. Box 7218 Boise, ID 83707 - 515 N. 27th St. Boise, ID 83702

January 20, 2012

Via Electronic Mail

Patrick Hager
Denise Saunders
PORTLAND GENERAL ELECTRIC
121 SW SALMON ST - 1WTC0702
PORTLAND OR 97204
pge.opuc.filings@pgn.com

Re: UM 1182 – Northwest and Intermountain Power Producers Coalition's Revised First Set of Data Requests to Portland General Electric Company

Please see the data request set forth below with regard to the above-referenced docket. Please provide responses electronically only, and in the original electronic format, if possible. Please use the definitions set forth in NIPPC's First Data Request sent December 5, 2011. Please also assume that these are ongoing requests, and include requests for information that becomes available during these proceedings.

Please provide responses to the following persons:

Gregory M. Adams
Richardson & O'Leary PLLC
515 N. 27th Street
P.O. Box 7218
Boise, Idaho 83702
Telephone: (208) 938-2236
Fax: (208) 938-7904
greg@richardsonandoleary.com

William A. Monsen
MRW & Associates, LLC
1814 Franklin Street, Suite 720
Oakland, CA 94612
Telephone: (510) 834-1999
Fax: (510) 834-0918
wam@mrwassoc.com

DATA REQUESTS

1.1 Please provide the following documents for the plants owned by your utility listed in Attachment 1 which were placed in service in and after 2006:

a. Please provide the initial application or document containing cost projections for such plant (not necessarily including work papers) submitted to OPUC or other regulators announcing that your utility is going to construct or acquire a generating plant. Such a document may include, but is not limited to, a Certificate of Public Convenience and Necessity filing, an RFP benchmark bid, or an RFP waiver application.

b. The Commission order allowing the plant to be entered into rate base.

1.2 Please provide electronic copies of all FERC Form 1s that your utility filed from 1990 to the present.

Thank you for your prompt attention to this request.

Sincerely,

/s/ *Gregory M. Adams*

Gregory M. Adams
RICHARDSON AND O'LEARY PLLC
Attorney for the
Northwest and Intermountain Power Producers Coalition

ATTACHMENT I

LIST OF GENERATING PLANTS

PacifiCorp-owned Natural Gas Plants
Chehalis
Currant Creek
Gadsby 1-6
Hermiston 1 and 2
Lake Side
Little Mountain
James River Cogen

PacifiCorp-owned Wind Resources
Foote Creek I
Leaning Juniper
Goodnoe Hills East Wind
Marengo
Glenrock Wind I and III
Marengo II
Rolling Hills Wind
Seven Mile Hill Wind I and II
High Plains
McFadden Ridge 1
Dunlap 1

PGE-owned Natural Gas Plants
Port Westward
Beaver
Coyote Springs

PGE-owned Wind Plant
Biglow Canyon

Idaho Power-owned Natural Gas Plants
Bennett Mountain
Danskin

RICHARDSON & O'LEARY, PLLC
ATTORNEYS AT LAW
Tel: 208-938-7900 Fax: 208-938-7904
P.O. Box 7218 Boise, ID 83707 - 515 N. 27th St. Boise, ID 83702

January 20, 2012

Via Electronic Mail

Lisa Rackner
MCDOWELL RACKNER & GIBSON PC
419 SW 11TH AVE., SUITE 400
PORTLAND OR 97205
lisa@mcd-law.com

Lisa Nordstrom
Christa Bearry
Idaho Power Company
PO BOX 70
BOISE ID 83707-0070
lnordstrom@idahopower.com
cbearry@idahopower.com

Re: UM 1182 – Northwest and Intermountain Power Producers Coalition's Revised First Set of Data Requests to Idaho Power Company

Please see the data request set forth below with regard to the above-referenced docket. Please provide responses electronically only, and in the original electronic format, if possible. Please use the definitions set forth in NIPPC's Data Request sent December 5, 2011. Please also assume that these are ongoing requests, and include requests for information that becomes available during these proceedings.

Please provide responses to the following persons:

Gregory M. Adams
Richardson & O'Leary PLLC
515 N. 27th Street
P.O. Box 7218
Boise, Idaho 83702
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Telephone: (510) 834-1999
Fax: (510) 834-0918
wam@mrwassoc.com

DATA REQUESTS

1.1 Please provide the following documents for the plants owned by your utility listed in Attachment 1 which were placed in service in and after 2006:

a. Please provide the initial application or document containing cost projections for such plant (not necessarily including work papers) submitted to OPUC or other regulators announcing that your utility is going to construct or acquire a generating plant. Such a document may include, but is not limited to, a Certificate of Public Convenience and Necessity filing, an RFP benchmark bid, or an RFP waiver application.

b. The Commission order allowing the plant to be entered into rate base.

1.2 Please provide electronic copies of all FERC Form 1s that your utility filed from 1990 to the present.

Thank you for your prompt attention to this request.

Sincerely,

/s/ *Gregory M. Adams*

Gregory M. Adams
RICHARDSON AND O'LEARY PLLC
Attorney for the
Northwest and Intermountain Power Producers Coalition

ATTACHMENT I

LIST OF GENERATING PLANTS

PacifiCorp-owned Natural Gas Plants
Chehalis
Currant Creek
Gadsby 1-6
Hermiston 1 and 2
Lake Side
Little Mountain
James River Cogen

PacifiCorp-owned Wind Resources
Foote Creek I
Leaning Juniper
Goodnoe Hills East Wind
Marengo
Glenrock Wind I and III
Marengo II
Rolling Hills Wind
Seven Mile Hill Wind I and II
High Plains
McFadden Ridge 1
Dunlap 1

PGE-owned Natural Gas Plants
Port Westward
Beaver
Coyote Springs

PGE-owned Wind Plant
Biglow Canyon

Idaho Power-owned Natural Gas Plants
Bennett Mountain
Danskin

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
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Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 114

UE-217, Exhibit PPL/801

Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-3

November 16, 2012

Northwest and Intermountain Power Producers Coalition Exhibit 114 contains confidential material and has been redacted

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
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Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 115

Confidential Cost Information for the Dunlap I Wind Project, filed in Wyoming Public Service Commission Docket 2000-xx-EA-09, July 24, 2009

Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-5

November 16, 2012

Northwest and Intermountain Power Producers Coalition Exhibit 115 contains confidential material and has been redacted

BEFORE THE

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In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
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Northwest and Intermountain Power Producers Coalition Exhibit 116

Direct Testimony of William J. Fehram (excerpt)
Idaho Public Utilities Commission
Docket PAC-E-07-05, June 2007

Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-2

November 16, 2012

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-07-05**
MOUNTAIN POWER FOR	)	
APPROVAL OF CHANGES TO ITS	)	**Direct Testimony of William J. Fehrman**
ELECTRIC SERVICE SCHEDULES	)	
	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-07-05

June 2007

Q. Please state your name, business address and position with the Company (also referred to as Rocky Mountain Power).

A. My name is William J. Fehrman. My business address is 1407 West North Temple, Suite 320, Salt Lake City, Utah. My position is President of PacifiCorp Energy.

Qualifications

Q. Please describe your education and business experience.

A. I have a Bachelor of Science degree in Civil Engineering from the University of Nebraska at Lincoln and a Masters in Business Administration from Regis University in Denver, Colorado. During my career, I have served as an engineer for coal-fired and nuclear power plants, a nuclear projects manager, an assistant station manager, senior manager for operations, maintenance and environmental, station manager of the Gerald Gentleman station (a two unit plant with 1,365 megawatts of capacity), vice president of fossil energy, vice president of energy supply and president and chief executive officer for Nebraska Public Power District. I was appointed president of PacifiCorp Energy in February 2006 with responsibilities for PacifiCorp's electric generation, commercial and energy trading, and coal-mining operations.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the reason for and prudence of major supply-side resource additions and the known and measurable increases to generation related operation and maintenance (O&M) expenses included in the test year through the end of December 31, 2007. I will discuss how these

Q. What investment related to the Marengo project is included in the revenue requirement?

A. The Company has included $258.5 million for the Marengo project in this application. The Marengo project is expected to be operational by August 2007. The O&M cost associated with the Marengo resource is approximately $2.2 million. This is due to the wind turbine-generator maintenance agreement, permitting obligations, local levy tax and land royalties and easements.

As discussed in Company witness Mark T. Widmer's testimony, the Company's net power cost calculation reflects the inclusion of Marengo for the same number of months that the investment is included in the revenue requirement. Company witness Steven R. McDougal's testimony describes the revenue requirement calculations associated with the inclusion of this resource.

Goodnoe Hills

Q. Please describe the size and location of the Goodnoe Hills resource.

A. The Goodnoe Hills resource is a wind resource located near Goldendale, Washington. Exhibit No. 20 shows a map of the plant location. PacifiCorp owns the assets, all output, all environmental attributes and 94 MW of interconnection rights with the BPA. Ongoing operations, warranty, and general maintenance services will be performed by the wind turbine supplier (REpower System AG) for the first two years and then by enXco Service Corporation for the following eight years. The Goodnoe Hills wind project consists of a 94 MW wind energy generation facility utilizing 47 REpower System AG 2.0 MW (model MM92) 60 hertz wind turbine generators. The turbines have 80 meter tubular towers and a

92.5 meter rotor diameter. The project includes above-ground and underground electric cable, fiber optic communication cable, turbine access roads, permanent meteorological towers, a supervisory control and data acquisition system, a collector substation and one operation and maintenance building.

Q. How will energy generated by Goodnoe Hills be delivered?

A. The energy generated by the projects will be delivered to a 34.5/230 kilovolt substation which connects to the Rock Creek substation built by the BPA. The energy is then delivered to BPA's transmission system for transmission across BPA's system for delivery into PacifiCorp's system.

Q. Please describe the benefits of this resource to Idaho ratepayers.

A. Idaho ratepayers benefit from this resource as it represents a renewable resource that can economically meet a commercial operation date during 2007. The 2003 and subsequent IRPs specify that that renewable resources (using wind resources as a proxy) be steadily added to the system with the target of reaching 1,400 megawatts or more of renewable resources prior to 2015. Goodnoe Hills represents such a resource.

Q. How else will the Goodnoe Hills resource benefit Idaho ratepayers?

A. The Goodnoe Hills resource further benefits Idaho ratepayers by providing the Company with a zero incremental cost fuel source (thus reducing commodity risk exposure), a multi-shafted generation resource (thus diversifying the impact of individual generator failures), and further valuable ownership and operational experience with utility scale wind projects. The Goodnoe Hills project utilizes REpower wind turbines, thus giving PacifiCorp valuable experience with this particular manufacturer. The combination of the turbine supplier and operational expertise held by the project developer enabled the Company to negotiate a long-term operation and maintenance agreement for the entire project. This benefited ratepayers as it is an economical way to operate a project that is located outside of PacifiCorp's service territory. Further, as a result of long-term planning and the reasonable expectation that a federal renewable portfolio standard will be established, PacifiCorp is expecting to have a robust need for renewable resources in the coming years. PacifiCorp currently has a number of power purchase agreements from wind projects in its portfolio and it is important that the Company diversify to include owned renewable resources. Goodnoe Hills will provide the Company with further experience in owning wind resources.

Q. How did the Company make the decision to move forward with the Goodnoe Hills project?

A. The Company was provided with a detailed overview of the project, the contract support and counterparty guarantees for executing upon the project, a comparison against the risks associated with an alternative bidder, the risks associated with the project, the need for the project as established by the IRP, the financial assessment of the project, the fueling strategy, and the justification of the project due to the results of RFP 2003-A. Upon review of this information, the Company determined that it would proceed with acquisition of the project.

Q. What investment related to the Goodnoe Hills project is included in the revenue requirement?

A. The Company has included $151.9 million for the Goodnoe Hills project in this application with a projected in-service date of November 15, 2007. The O&M cost associated with the Goodnoe Hills resource is approximately $0.2 million. This is due to the wind turbine-generator maintenance agreement, permitting obligations, local levy tax and land royalties and easements. These expenses will be reduced by funds made available by BPA (via the conservation and renewable resource credit program) and by grant monies supplied via the Energy Trust of Oregon, Inc.

As discussed in Company witness Mark T. Widmer's testimony, the Company's net power cost calculation reflects the inclusion of Goodnoe Hills for the same number of months that the investment is included in the revenue requirement. Company witness Steven R. McDougal's testimony describes the revenue requirement calculations associated with the inclusion of this resource.

Geothermal

Blundell Bottoming Cycle

Q. Please describe the size and location of the Blundell Bottoming Cycle resource.

A. The Blundell Bottoming Cycle resource is a separate facility at the Blundell plant, located near Milford, Utah. Exhibit No. 21 shows a map of the plant location. The bottoming cycle generates a nominal 11 MW of electrical energy using latent heat in the geothermal brine.

Q. Please provide additional detail about the Blundell Bottoming Cycle resource.

A. The Blundell Plant, which was developed and constructed in the 1980's, utilizes a

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Northwest and Intermountain Power Producers Coalition Exhibit 117

UE 200, Exhibit PPL/200

Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-2

November 16, 2012

PPL/200
Tallman Testimony

Case UE-
Exhibit PPL/200
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Mark R. Tallman

RENEWABLE RESOURCES

April 2008

Q. Please state your name, business address and present position with PacifiCorp, dba Pacific Power & Light Company (the Company).

A. My name is Mark R. Tallman. My business address is 825 NE Multnomah, Suite 2000, Portland, Oregon 97232. My present position is Vice President of Renewable Resource Acquisition.

Qualifications

Q. Briefly describe your education and business experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from Oregon State University and a Masters of Business Administration from City University. I am also a Registered Professional Engineer in the states of Oregon and Washington. I have been the Vice President of Renewable Resource Acquisition since December 2007. Prior to that, I was Managing Director of Renewable Resource Acquisition from April 2006 to December 2007. I have worked at the Company for more than 22 years in a variety of positions of increasing responsibility, including the commercial and trading organization; the Company's engineering organization; the retail distribution organization; and five years as a District Manager.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to demonstrate the prudence of multiple renewable resources that the Company is seeking cost recovery for in this proceeding. These renewable resources are the: Leaning Juniper 1; Marengo; Goodnoe Hills; Marengo II; Seven Mile Hill; Glenrock; and Rolling Hills wind cost associated with the Marengo resource that is associated with this application is $4.9 million on a total company basis. This is due to the wind turbine-generator maintenance agreement, permitting obligations, local levy tax and land and easement payments.

The Marengo plant was placed in service August 4, 2007. Mr. Dalley's testimony describes the revenue requirement calculations associated with the inclusion of this resource.

Q. What was the result of the PVRR(d) method of analysis that was presented to Company executives with respect to the Marengo resource?

A. The response to this question is included in confidential Exhibit PPL/202.

Goodnoe Hills

Q. Please describe the size and location of the Goodnoe Hills resource.

A. The Goodnoe Hills resource is a wind resource located near Goldendale, Washington. Exhibit PPL/201 shows a map of the plant location. PacifiCorp owns the assets, all output and 94 MW of interconnection rights with the BPA. Ongoing operations, warranty, and general maintenance services will be performed by the wind turbine supplier (REpower System AG) for the first two years and then by enXco Service Corporation for the following eight years. The Goodnoe Hills wind project consists of a 94 MW wind energy generation facility utilizing forty-seven REpower System AG 2.0 MW (model MM92) sixty hertz wind turbine generators. The turbines have a 92.5 meter rotor diameter and eighty meter tubular towers. The project includes above-ground and underground electric cable; fiber optic communication cable, turbine access roads; permanent meteorological towers; a supervisory control and data acquisition system; a collector substation and one operation and maintenance building.

Q. How is energy generated by Goodnoe Hills delivered to PacifiCorp's system?

A. The energy generated by the project will be delivered to a 34.5/230 kilovolt substation which connects to the Rock Creek substation built by BPA. The energy is then delivered to BPA's transmission system for transmission across BPA's system for delivery into the Company's system.

Q. Please describe the benefits of this resource to Oregon customers.

A. The Goodnoe Hills resource benefits Oregon customers in several ways. It is a cost-effective addition to the Company's portfolio that is consistent with the preferred portfolios resulting from PacifiCorp's last three IRP cycles. Goodnoe Hills will also provide the Company and its customers with a long-term resource to comply with requirements of Oregon's RPS. In addition, the Goodnoe Hills resource provides our customers with a zero incremental cost fuel source (thus reducing commodity risk exposure), a multi-shafted generation resource (thus diversifying the impact of individual generator failures), and further valuable ownership and operational experience with utility scale wind projects. The Goodnoe Hills project utilizes REpower wind turbines, thus giving PacifiCorp valuable experience with this particular manufacturer who is establishing a sales and maintenance operation in Oregon. The combination of the turbine supplier and operational expertise held by the project developer enabled the Company to negotiate a long-term operation and maintenance agreement for the entire project. This benefited customers as it is an economical way to operate a project that is located outside of PacifiCorp's historical service territory. Further, as a result of long-term planning and the reasonable expectation that additional state and/or federal renewable portfolio standards will be established, PacifiCorp is expecting to have a robust need for renewable resources in the coming years. PacifiCorp currently has a number of power purchase agreements and service agreements for wind projects in its portfolio and it is important that the Company diversify to include owned renewable resources. Goodnoe Hills will provide the Company with further experience in owning wind resources and enable the evolution of those activities in other locations.

Q. How did the Company make the decision to move forward with the Goodnoe Hills project?

A. Company executives were provided with a detailed overview of the project; the contract support and counterparty guarantees for executing upon the project; the risks associated with the project; the need for the project as established by the IRP; the financial assessment of the project; and the justification of the project. Upon review of this information, the Company determined that it would proceed with acquisition of the project.

Q. What investment related to the Goodnoe Hills project is included in the revenue requirement?

A. The Company has forecasted $196.6 million, total company, for the Goodnoe Hills project. The O&M cost associated with the Goodnoe Hills resource is forecasted at $3.2 million total company. This is due to the wind turbine-generator maintenance agreement, permitting obligations, local levy tax and land

and easement payments.

The Goodnoe Hills project is expected to be operational by June 2008. Mr. Dalley's testimony describes the revenue requirement calculations associated with the inclusion of this resource.

Q. What was the result of the PRVV(d) method of analysis that was presented to Company executives with respect to the Goodnoe Hills resource?

A. The response to this question is included in confidential Exhibit PPL/202.

Marengo II

Q. Please describe the size and location of the Marengo II resource.

A. The Marengo II project is a 70.2 MW wind energy generation facility, consisting of 39 Vestas 1.8 MW wind turbine generators located near the Marengo wind project outside of Dayton, Washington. Exhibit PPL/201 shows a map of the plant location. PacifiCorp owns the assets, all output and all interconnection rights. The Vestas turbines located at the Marengo II site have 67 meter tubular towers and an 80 meter rotor diameter. The project includes above-ground and underground electric cable; fiber optic communication cable; turbine access roads; a permanent meteorological tower; one collector substation; a transmission line extension; and one supervisory control and data acquisition system. Ongoing operations, warranty and general maintenance services will initially be performed by Vestas American Wind Technology, Inc. for a period of four years.

Q. How will energy generated by Marengo II be delivered?

A. The electrical energy generated by the Marengo II wind project will be delivered to the project substation and stepped up from 34.5kV to 230kV and delivered into

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Northwest and Intermountain Power Producers Coalition Exhibit 118

Direct Testimony of Mark R. Tallman (excerpt)
Utah Public Service Commission
Docket 04-035-30, May 2004

Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-4

November 16, 2012

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of	)	Docket No. 04-035-_______
PACIFICORP for a Certificate of	)	
Convenience and Necessity Authorizing	)	DIRECT TESTIMONY OF
Acquisition of the Lake Side	)	MARK R. TALLMAN
Power Project	)	

May 2004

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is Mark R. Tallman, my business address is 825 N.E. Multnomah, Suite 600, Portland, Oregon 97232, and my present position is Managing Director of Trading & Origination for the Commercial & Trading Department. My position is part of PacifiCorp's regulated merchant function.

Q. How long have you been the Managing Director of Trading & Origination at PacifiCorp?

A. I have been the Managing Director of Trading & Origination since September 12, 2003. Prior to that date, I worked in the Origination Department, first as an Originator (beginning March 1995), then as the Manager of Origination (beginning January 1999), and finally as the Director of Origination (beginning September 2000).

Q. What did you do before working in the wholesale side of PacifiCorp's business?

A. I served in a variety of different roles in PacifiCorp's engineering organization and retail distribution organization, including five years as a District Manager. I have worked at PacifiCorp for more than 18 years.

Q. Please describe your educational history.

A. I have a Bachelor of Science degree in Electrical Engineering from Oregon State University and a Masters of Business Administration from City University. I am also a Registered Professional Engineer in the states of Oregon and Washington.

Q. Have you previously appeared in any proceedings before the Utah Public Utility Commission?

A. Yes. I testified in Docket No. 03-035-29 (the certificate proceeding for the Currant Creek project) and Docket No. 03-035-14 (the large QF generic avoided cost proceeding) and filed testimony in Docket No. 03-2035-02 (the recent general rate case).

Summary of Testimony

Q. What is the purpose of your testimony?

A. PacifiCorp issued a Request for Proposal (RFP 2003A) on June 6, 2003. RFP 2003A solicited offers for 995 megawatts (MW) of supply-side resources in three bid categories ("SuperPeak", "Peaker", and "Baseload"). The purpose of my testimony is to describe how the two finalist bids received in the "Baseload" bid category compared against one another and the benchmark resource (expansion of the Currant Creek Project).

Q. How is the "Baseload" bid category referred to in your testimony?

A. I refer to the "Baseload" bid category as the "2007" category. This is because one of the criteria for submitting a bid(s) in this category was the requirement to have a resource available by the summer of 2007.

Q. Would you please summarize your testimony in this proceeding?

A. I provide an overview of the RFP 2003A process, the bids received for the 2007 bid category, and the role of Navigant Consulting Inc. (Navigant). I describe the resource that was selected and compare it with the other finalist and the benchmark resource. I also describe an alternative resource that was not selected.

Finally, I describe the analysis performed by the Company in choosing the Lake Side Power Project to fulfill the solicited needs for the 2007 resource category.

Need for RFP 2003A

Q. What determined the need to issue RFP 2003A?

A. On January 24, 2003, PacifiCorp formally published its most recent version of its Integrated Resource Plan (IRP). As described in the testimony of Ms. Melissa Seymour, the IRP set forth an action plan consisting of twenty-eight recommended actions to implement the plan. Action item number 2 called for additional supply-side resources to be added to PacifiCorp's East portion of the system in fiscal year 2008 (April 2007 – March 2008).

Q. What do you mean by the "East" portion of PacifiCorp's system?"

A. The East portion of PacifiCorp's system includes all of the Company's operations in Utah, Wyoming, and Idaho.

Q. What did action item number 2 consist of?

A. IRP action item number 2 consisted of "approximately 570 MW of base load resource in the East of the system by April 2007." Based on action item number 2, the Company established the 2007 bid category in RFP 2003A.

Q. Why is it important that the 2007 bid category resource not be delayed beyond the summer of 2007?

A. As Ms. Seymour testifies, the Company has a material need for additional resources in fiscal year 2008. Since the East portion of PacifiCorp's system typically reaches peak load during the summer, it is critical that the new resource be available by that time (summer of 2007).

Q. Please describe the proposed site for bid number 213 and bid number 493.

A. Both bidders submitted proposals that would utilize the same site for the location of the prospective resource. This site is located at Geneva Steel and is in proximity to end-use loads and PacifiCorp's 345 kV and 138 kV transmission system. Geneva Steel is currently bankrupt and is in the process of selling off its assets. Both bidders have proposed to obtain the necessary land, emission reduction credits (ERCs), and water rights from Geneva Steel in order to effectuate development of the proposed resource. It is PacifiCorp's understanding that the bankruptcy trustee for Geneva Steel retained the right to sell these necessary development components to either bidder, pending the Company's decision for the 2007 bid category.

Q. Which bid has the Company chosen?

A. The Company has chosen Summit Power, the bidder for bid number 493.

Summit Power and the Lake Side Power Project

Q. Please describe who Summit Power is and the nature of the transaction that will take place between the Company and them.

A. Summit Power, via Summit Vineyard, LLC (Summit), submitted the bid to develop, construct, and transfer, upon completion, ownership of a 534 MW (summer rated) power plant to PacifiCorp. The name of the project is the Lake Side Power Project. Summit will develop the Lake Side Power Project on the Geneva Steel site and enter into an EPC contract with Siemens Power to construct the resource. Summit and Siemens Power have worked extensively together on a variety of CCCT projects and have delivered these new resources on time and per agreement. Siemens Power will guarantee their work under the EPC. In addition, subject to satisfactory terms, PacifiCorp intends to enter into a long-term service agreement for the Lake Side Power Project.

Q. Please describe the expected payment to Summit and the expected total project cost.

A. PacifiCorp expects to make a total of $274.6 million in staged payments to Summit with the total expected project cost being $330 million. The majority of the difference between the two amounts takes into account sales tax, allowance for funds used during construction and a potential alternative gas source connection. Title will transfer to PacifiCorp as materials are brought to the project site in line with the negotiated milestones and progress payment schedule.

Q. How will fuel be supplied to the project?

A. It is planned that the primary natural gas connection will be to the Kern River gas pipeline (Kern Pipeline), an interstate pipeline that is capable of delivering up to 2,000,000 MMBtu/day. The Lake Side Power Project is expected to use up to 90,000 MMBtu/day of natural gas. PacifiCorp will procure the natural gas to fuel the Lake Side Power Project. An alternative connection possibility is to the Questar Gas Company local distribution system (Questar LDC). This alternative would require that gas compression be installed as well as an upgraded lateral from the Geneva Steel site. In evaluating the economics associated with the Lake Side Power Project, the Company included $8.5 million associated with a potential Questar LDC[1] interconnection. The prudence of this alternative connection will be reviewed in line with construction progress of the lateral to the Kern Pipeline and in light of the then current natural gas market. At present, it does not appear that a secondary connection to Questar LDC will provide commercial advantage. This means that there is $8.5 million included in the $330 million expected project cost that may not be necessary. The cost of a lateral to the Kern Pipeline is also included in the Lake Side Power Project economics.

Q. What type of generation equipment will the Lake Side Power Project have?

A. Summit will utilize new Siemens Westinghouse 501F machines. These combustion turbines will be connected to two heat recovery steam generators and a steam turbine. Approximately 470 MW will be produced by the CCCT portion of the design, 45 MW from the ability to duct fire, and 19 MW via steam augmentation. The Lake Side Power Project is expected to produce 534 MW on a nominally rated basis during summer temperature conditions.

Q. Why does the Company believe that Summit, with the Lake Side Power Project, will result in the resource being available by the Summer of 2007?

A. Summit's relationship with Siemens Power is a proven one. The combination of their strong track record and the fact that Siemens Power, a large credit-worthy entity, has substantial strength and capabilities should give customers comfort that the Company is taking prudent actions in order to meet our load service obligation.

[1] The Questar Gas Company provides regulated gas service and is an affiliate of Questar Pipeline.

Q. When would construction on the Lake Side Power Project begin and when is it anticipated to be completed by?

A. It is anticipated that construction would begin following completion of this certificate process and the projected resource availability date is by no later than the Summer of 2007.

Role of Direct and/or Inferred Debt in the 2007 Category Decision

Q. Did direct and/or inferred debt impact the economic analysis involved in making the 2007 bid category decision?

A. Yes.

Q. What do you mean by inferred debt?

A. I am informed that ratings agencies (such as Standard & Poors) infer debt associated with long-term power supply agreements, including both PPA and TSA agreements, and take this inferred debt information into consideration when issuing credit ratings.

Q. What do you mean by direct debt?

A. I am informed that PPA and TSA agreements may result in debt being directly applied to the Company's balance sheet, or to the consolidation of the selling entity, or an individual asset of the selling entity, onto the books of the purchasing entity.

Q. How was the debt issue handled in the bid analysis?

A. In its analysis, the Company applied a cost associated with inferred and/or direct debt based on: (a) the difference between after-tax return on equity (ROE) and after-tax weighted average cost of capital (WACC), multiplied by (b) the

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Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 119

UE 210, Exhibit PPL/503

Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-3

November 16, 2012

Northwest and Intermountain Power Producers Coalition Exhibit 119 contains confidential material and has been redacted

BEFORE THE

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Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 120

Confidential Cost Information for the Seven Mile Hill Wind Energy Development Project filed in Wyoming Public Service Commission Docket 20000-285-EA-07
August 31, 2007

Provided by PacifiCorp in response to
Northwest and Intermountain Power Producers Coalition
Data Request 2.1, Attachment 2.1-5

November 16, 2012

Northwest and Intermountain Power Producers Coalition Exhibit 120 contains confidential material and has been redacted

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Northwest and Intermountain Power Producers Coalition Exhibit 121

Wyoming Section 109 Permit Application for the Dunlap Energy Project (excerpt), June 15, 2009, filed in Wyoming Public Service Commission Docket 20000-xx-EA-09, July 24, 2009

Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-4

November 16, 2012

NIPPC/121
Monsen/1

Wyoming Industrial Development Information and Siting Act

Section 109 Permit Application
Dunlap Wind Energy Project

Prepared for PacifiCorp Energy

PACIFICORP ENERGY
A DIVISION OF PACIFICORP

Prepared by CH2M Hill

CH2MHILL

UM 1182

June 15, 2009

Final Report

Wyoming Industrial Development Information and Siting Act

Section 109 Permit Application Dunlap Energy Project

Prepared for

Pacificorp Energy

June 15, 2009

Prepared By:

CH2MHILL

9193 South Jamaica Street
Englewood, CO 80112

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Appendices

1.0 Purpose, Need, and Benefit

1.1 Purpose

Recent national and regional forecasts project an increase in consumption of electrical energy continuing into the future. The purpose of the proposed Dunlap Wind Energy Project (Project) is to meet this increased consumption by development of new generation facilities, particularly renewable facilities, as substantiated by the following sources:

- The Energy Policy Act of 2005 (P.L. 109-58), Section 211, states "It is the sense of the Congress that the Secretary of the Interior should, before the end of the 10-year period beginning on the date of enactment of this Act, seek to have approved nonhydropower renewable energy projects located on the public lands with a generation capacity of at least 10,000 megawatts of electricity." The Act encourages the development of renewable energy resources, including wind energy, as part of an overall strategy to develop a diverse portfolio of domestic energy supplies for the future.
- Presidential Executive Order (E.O.) 13212 (Bush, 2001): "Actions to Expedite Energy-Related Projects" established a policy that federal agencies should take appropriate actions, to the extent consistent with applicable law, to expedite projects to increase the production, transmission, or conservation of energy.
- The National Energy Policy Development Group (NEPDG, 2001) recommended to the President, as part of the National Energy Policy, that the Departments of the Interior, Energy, Agriculture, and Defense work together to increase renewable energy production.
- To address increased interest in wind energy development and to implement the NEPDG recommendation to increase renewable energy production, the Bureau of Land Management (BLM) established a wind energy development program. This program, which included the amendment of multiple land use plans, supported the Congressional direction provided in the Energy Policy Act of 2005 regarding renewable energy development on public lands, the directives of E.O. 13212, and the recommendations of the NEPDG.
- On March 11, 2009, Secretary of the Interior Ken Salazar signed Order No. 3285 - Renewable Energy Development by the U.S. Department of the Interior (DOI) (U.S. Secretary of the Interior, 2009), which establishes the development of renewable energy as a priority for the DOI. Encouraging the production, development, and delivery of renewable energy is now one of the DOI's highest priorities. Although the Project would not involve any DOI lands, Order No. 3285 presents one facet of the federal government's energy policy and demonstrates the Administration's desire to support renewable energy projects such as wind facilities.

- The Energy Information Administration (EIA), a statistical agency of the U.S. Department of Energy (DOE), predicts in the Annual Energy Outlook 2009 (March 2009) that total electricity demand will grow by 0.5 percent per year from 2006 through 2030, with total renewable generation growing by 3.3 percent per year from 2006 to 2030 (DOE/EIA, 2009). This rapid growth reflects the impacts of the renewable fuel standard in the Energy Independence and Security Act of 2007 (EISA, 2007) and strong growth in the use of renewables for electricity generation spurred by renewable portfolio standard (RPS) programs at the State level (DOE/EIA, 2009).
- The Western Electricity Coordinating Council (WECC), which forecasts electricity demand in the western United States, states in the *10-Year Coordinated Plan Summary 2006-2015* (July 2006) that peak demand and annual energy requirements in the Rocky Mountain Power Pool Area, which includes Wyoming, are projected to grow at annual compound rates of 2.4 percent and 2.2 percent, respectively, from 2006 through 2015 (WECC, 2006).
- In 2004, the Western Governors' Association set a goal of developing 30,000 megawatts (MW) of clean energy by 2015 from traditional and renewable energy sources (Policy Resolution 04-13, June 2004). This goal was reaffirmed in 2006 by Policy Resolution 06-10, *Clean and Diversified Energy for the West* (Western Governors' Association, 2006).

1.2 Need

On a periodic basis, PacifiCorp undertakes a comprehensive Integrated Resource Plan (IRP) process. The IRP is developed with considerable public involvement from customer interest groups, regulatory staff, regulators, and other stakeholders. Each of these entities is asked to participate actively and provide input and guidance as PacifiCorp considers a number of issues related to long-term resource planning. The IRP planning horizon is typically 20 years, and an action plan identifies steps that will be taken to secure resources for the first 10 years of that horizon. During the IRP process, all material planning assumptions are updated (e.g., load/resource forecasts and a prudent planning margin), and any resource deficiency is identified. The IRP process then models a number of potential new resource portfolios with the ultimate conclusion being the selection of a preferred portfolio, which is expected to result in the least cost on a risk-adjusted basis. The current IRP identifies renewable energy as a necessary component of PacifCorp's generation mix.

PacifiCorp is pursuing the acquisition and development of renewable resources with the intent of reaching the levels established in the 2008 IRP preferred portfolio (PacifiCorp, 2009). Specifically, this level is 1,400 MW of cost-effective renewable generation by 2018. PacifiCorp will work toward meeting these goals by successfully adding at least 226.5 MW of Wyoming wind resources to its portfolio in 2009; this includes construction of PacifiCorp's High Plains and McFadden Ridge I facilities near McFadden, Wyoming as well as purchasing 100 percent of the output associated with the Three Buttes, LLC wind facility near Glenrock, Wyoming.

Moreover, in connection with MidAmerican Energy Holdings Company's (MEHC) acquisition of PacifiCorp, approved by the Wyoming Public Service Commission (PSC) in

Because of the relatively short timeframe of the construction workforce and limited operations workforce, the Project will place very minimal demands on water, sewer, roads, electrical lines, and other local infrastructure. In addition, there would be little measurable increase in non-basic employment, as these jobs are generated from ongoing employment of the existing base of construction workers and would be maintained through the continued employment of both local and nonlocal construction workers. Therefore, construction and operation of the Project would not significantly affect the various public and nonpublic facilities and services described above from the immigration of workers for non-basic employment opportunities.

1.4.4 State of Wyoming Land Trust Lease Revenue Payments

The Project anticipates locating facilities on lands owned by the State of Wyoming. A Special Use Lease issued from the Board of Land Commissioners was received in June 2009. The issued Special Use Lease includes structured payments for the use of the State land. Fees typically include an annual fee per acre, an installation fee based on capacity, and an operating fee based on energy generated by facilities on State lands. For example, if 6 1.5-MW turbines were located on one section (640 acres) of State land, payments over the projected 35-year operational lease term of the project are estimated to produce over $2 million in added revenue for the State land trust. After the wind energy generation facility is operational, the land will serve a dual purpose and allow for the continued use of conventional livestock grazing and ranching activities.

1.4.5 Tax Effects

Tax effects are another important consideration and benefit of the Project. The benefits would occur based primarily on the *ad valorem* taxes that would be collected over the life of the Project. In conjunction with associated ancillary activities, state and local tax revenues would be generated during construction and operation of the proposed facility. Although some of these tax revenues will be distributed on a local level, the state controls such distribution.

Carbon County

Carbon County is a leader in installed wind capability (MW) within the State of Wyoming. In the late 1990s and early 2000s, six smaller wind energy projects comprising 194 wind turbine generators (WTGs) with a total installed capability of 143.14 MW were constructed in the county. These six operational wind farms have been paying *ad valorem* taxes to the county over a period of 10 years. **Table 1-3** provides the 2008 *ad valorem* taxes paid by the six wind farms to Carbon County.

A review of Table 1-3 shows Carbon County received $524,078 in *ad valorem* tax revenues from the six operational wind farms in 2008. It is very important to note that Table 1-3 does not include the tax revenues associated with the approximately $234,000,000 capital cost of the projects constructed at Seven-Mile Hill in 2008. Therefore, 2009 *ad valorem* tax revenues will markedly increase in Carbon County.

TABLE 1-3
2008 Tax Year Wind Farm Units in Carbon County, Installed MW, Assessed Value and Total Taxes Paid

Company	Tax District	Number of Towers	MW Capacity	2008 Assessed Value	Mill Levy Rate	Total Amount of Taxes Paid
Eugene Water and Electric Board	203	69	41.40	$983,400	58.057	$57,093
Foote Creek II, LLC	203	3	1.80	$97,555	58.057	$5,664
Foote Creek III, LLC	203	33	24.75	$2,135,550	58.057	$123,984
Foote Creek IV, LLC	203	28	16.80	$1,453,037	58.057	$84,359
Platte River Power Authority	202	11	8.39	$159,924	60.057	$9,605
Rock River I	203	50	50.00	$4,191,969	58.057	$243,373
Total		**194**	**143.14**	**$9,021,435**	**--**	**$524,078**

Source: Wyoming Department of Revenue, 2009.

Ad Valorem Taxes

It is estimated that *ad valorem* property taxes of approximately $1,273,000 as a result of the first phase of the Project would be payable to Carbon County (see **Table 1-4**). This would be the estimate for increased taxes during the first full year of operation. These taxes levied against the property would account for 2.2 percent of all *ad valorem* taxes levied in Carbon County in 2008.

TABLE 1-4
Dunlap Wind Project - Ad Valorem Property Tax Estimate

Estimation of Assessed Value					Applicable Tax Rates		
Capital Investment[1]	**Market to Book Ratio[2]**	**Estimated Market Value**	**Assessment Ratio[3]**	**Estimated Assessed Value**	**Tax District**	**2008 Tax Rate[4]**	**Estimated Property Tax**
A	B	C	D	E	D	G	H
		a x b		c x d			e x g
$259,278,000	71.1%	$184,268,875	11.5%	$21,190,921	202	60.06	$1,273,000

[1] Level of capital investment reflected in project's executive summary.

[2] Ratio of the assessed value of the company's existing Wyoming property to its net book value.

[3] Statutory assessment ratio applicable to industrial operating property.

[4] 2008 mill levy for the listed taxing district.

Sales, Use, and Lodging Taxes

Local tax revenues would also accrue from the sale of goods and services to nonlocal workers. These purchases would be mostly for meals, recreation and entertainment, gasoline and automotive service, and lodging. It is possible that tax revenues totaling almost $100,000 over the construction period would accrue to the local communities combined.

Lodging tax revenues could accrue to the counties where construction workers temporarily reside, and estimates are included in the local tax revenues reported above. However, it should be noted that: (1) the actual distribution of construction workers is not known at this time, and (2) the duration of their stays is not known and lodging taxes are levied only on sleeping accommodations for guests staying less than 30 days.

1.4.6 Environmental Benefits

The environmental benefits of the Project are substantial. Wind power is a renewable and nonpolluting electrical generation source. The Project will result in a reduction of PacifiCorp's overall electrical generation pollutant emissions on a per-megawatt basis as compared to other nonrenewable alternatives. In addition, unlike most other electrical generation sources, WTGs do not consume water nor require additional fuel sources. The construction and operation of the Project is a low-impact, exceptionally low water use, and non-extractive source of electrical generation. The complete development of Phase I of the Dunlap Project would result in permanent disturbance to only approximately one percent of the lands within the defined Project area.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 122

Idaho Power Company's Response to
Request No. 20 of Staff's First Production Request,
Idaho Public Utilities Commission
Docket IPC-E-09-03, April 14, 2009

November 16, 2012

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE LANGLEY GULCH POWER PLANT.	))))))))	CASE NO. IPC-E-09-03 IDAHO POWER COMPANY'S RESPONSE TO THE COMMISSION STAFF'S FIRST PRODUCTION REQUEST TO IDAHO POWER COMPANY

COMES NOW, Idaho Power Company ("Idaho Power" or "the Company"), and in response to the First Production Request of the Commission Staff to Idaho Power Company dated March 25, 2009, herewith submits the following information:

REQUEST NO. 20: Does Idaho Power believe that by not allowing bids to be submitted for turnkey or build-and-transfer proposals, but allowing a self-build proposal to be submitted by its own Benchmark Resource development team, that it excluded potential projects from being bid that could have been superior to the self-build proposal? Please explain.

RESPONSE TO REQUEST NO. 20: No, and Idaho Power supports its belief that a turn-key or build and transfer proposal would not have resulted in a superior proposal on several grounds.

First, as noted in Response to Staff's Request No. 19, the only means by which the project owner can be confident the plant is designed and constructed in a manner to assure it is capable of being operated and maintained in a cost-effective and reasonable manner is by including in the contract with the developer detailed engineering and construction specifications. Prior to the issuance of the RFP, Company representatives inspected several combined cycle plants and interviewed the operational personnel. Among the plants visited was a combined cycle plant built in Utah pursuant to a build and transfer arrangement. In the unanimous opinion of all team members who visited this plant, it evidenced numerous design defects that undermined the efficient and economical operation and maintenance of the plant, delayed the planned commercial operation date, as well as caused significant project cost overruns. The lessons learned from these plant visits was when dealing with a facility of the complexity and magnitude of a combined cycle plant, a utility should not be required to operate the plant unless the utility participates integrally in the design and construction of the plant. Absent the opportunity to develop complete and thorough design and construction specifications, this level of participation is not possible in the context of a build and transfer arrangement.

Second, even if a utility is afforded the opportunity to develop detailed design and construction specifications incident to a build and transfer arrangement, the absence of a direct contractual relationship between the utility, the design engineer, and construction contractor prevents the utility from exercising its contractual rights to directly influence the design and construction of the facility while it is being designed and constructed.

Third, the developer in a build and transfer arrangement has contractual warranty responsibility for a finite term after commencement of commercial operation of the facility, while the utility's operation and maintenance responsibilities extend through the life of the plant. This creates a greater incentive on the part of the utility to assure quality of engineering and construction than exists for the developer. In the case of Idaho Power's Bennett Mountain Plant, the failure of the developer to fulfill its contractual obligations during construction contributed to the creation of a latent defect that manifested itself after commercial operation and leading to a prolonged outage and direct repair expense in excess of $14 million. Although Idaho Power considered the developer's position to be commercially unreasonable and legally untenable, the developer of the Bennett Mountain plant disavowed any contractual obligation to reimburse Idaho Power for the repair expense.

Further, incident to a build and transfer arrangement, the developer charges a substantial development fee. Such a fee is incremental to the underlying costs of designing and constructing the plant and results ultimately in a more expensive project for the utility's customers.

Finally, nothing precluded any project from being bid, the proposal just needed to be structured as a PPA or a TA with the developer pricing the cost of owning, operating, and maintaining the project in their proposal.

The response to this Request was prepared by Karl Bokenkamp, General Manager Power Supply Operations and Planning, and Vern Porter, General Manager Power Production, in consultation with Barton L. Kline, Lead Counsel, Idaho Power Company.

REQUEST NO. 60: Please discuss the status of Idaho Power's plans to upgrade the Borah-West transmission path. Was an upgraded Borah-West transmission path assumed to be available in the evaluation of RFP bids? Were transmission cost estimates for projects east of the Treasure Valley area less in the 2012 Baseload RPF than in previous thermal RFPs due to an assumed upgraded Borah-West transmission path?

RESPONSE TO REQUEST NO. 60: Idaho Power placed the Borah West transmission path upgrade in-service on July 24, 2007. The upgraded path would have been included in any transmission analysis of RFP projects located near Borah or further east. No bids were received proposing projects near or east of Borah.

The response to this Request was prepared by Dave Angell, Manager, Delivery Planning, Idaho Power Company, in consultation with Barton L. Kline, Lead Counsel, Idaho Power Company.

DATED at Boise, Idaho, this 14th day of April 2009.

BARTON L. KLINE
Attorney for Idaho Power Company

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 123

Portland General Electric
Form 1 filing to the
Federal Energy Regulatory Commission
for the year 2011, pages 402-403

November 16, 2012

THIS FILING IS		
Item 1: ☐ An Initial (Original) Submission	OR	☒ Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)

Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)

Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Portland General Electric Company	**End of** 2011/Q4

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Portland General Electric Company	02 Year/Period of Report End of 2011/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 121 SW Salmon Street, Portland, Oregon, 97204	
05 Name of Contact Person Kirk M. Stevens	06 Title of Contact Person Controller & Asst. Treasurer
07 Address of Contact Person *(Street, City, State, Zip Code)* 121 SW Salmon Street, Portland, Oregon 97204	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(503) 464-7121	(1) ☐ An Original (2) ☒ A Resubmission	05/30/2012

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Maria M. Pope	Maria M. Pope	05/30/2012
02 Title SVP, CFO and Treasurer		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/30/2012	End of 2011/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	Not Applicable
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	Not Applicable
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	None
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	None
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	None
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2011/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	None
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Sales of Electricity by Rate Schedules	304	
44	Sales for Resale	310-311	
45	Electric Operation and Maintenance Expenses	320-323	
46	Purchased Power	326-327	
47	Transmission of Electricity for Others	328-330	
48	Transmission of Electricity by ISO/RTOs	331	Not Applicable
49	Transmission of Electricity by Others	332	
50	Miscellaneous General Expenses-Electric	335	
51	Depreciation and Amortization of Electric Plant	336-337	
52	Regulatory Commission Expenses	350-351	
53	Research, Development and Demonstration Activities	352-353	
54	Distribution of Salaries and Wages	354-355	
55	Common Utility Plant and Expenses	356	None
56	Amounts included in ISO/RTO Settlement Statements	397	
57	Purchase and Sale of Ancillary Services	398	
58	Monthly Transmission System Peak Load	400	
59	Monthly ISO/RTO Transmission System Peak Load	400a	Not Applicable
60	Electric Energy Account	401	
61	Monthly Peaks and Output	401	
62	Steam Electric Generating Plant Statistics	402-403	
63	Hydroelectric Generating Plant Statistics	406-407	
64	Pumped Storage Generating Plant Statistics	408-409	None
65	Generating Plant Statistics Pages	410-411	
66	Transmission Line Statistics Pages	422-423	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/30/2012	End of 2011/Q4

NIPPC/123
Monsen/5

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Boardman* (b)	Plant Name: *Boardman* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional
3	Year Originally Constructed	1980	1980
4	Year Last Unit was Installed	1980	1980
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	642.20	417.43
6	Net Peak Demand on Plant - MW (60 minutes)	598	0
7	Plant Hours Connected to Load	6208	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	575	0
10	When Limited by Condenser Water	575	0
11	Average Number of Employees	112	0
12	Net Generation, Exclusive of Plant Use - KWh	3305796000	2191433000
13	Cost of Plant: Land and Land Rights	1274078	832853
14	Structures and Improvements	153132849	101073073
15	Equipment Costs	533895764	346266930
16	Asset Retirement Costs	33978545	25189268
17	Total Cost	722281236	473362124
18	Cost per KW of Installed Capacity (line 17/5) Including	1124.6983	1133.9916
19	Production Expenses: Oper, Supv, & Engr	5378605	2799461
20	Fuel	63468760	41507187
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	2386700	2209294
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	7176916	4662468
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	5723519	279135
30	Maintenance of Structures	369601	285020
31	Maintenance of Boiler (or reactor) Plant	7725	5773
32	Maintenance of Electric Plant	10443437	10244782
33	Maintenance of Misc Steam (or Nuclear) Plant	4573460	2485078
34	Total Production Expenses	99528723	64478198
35	Expenses per Net KWh	0.0301	0.0294

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels				
38	Quantity (Units) of Fuel Burned	1985277	12725	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8517	138600	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	30.156	137.366	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	31.186	122.320	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.831	21.013	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.019	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10229.700	0.000	0.000	0.000	0.000	0.000

UM 1182

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	05/30/2012	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: (b)			Plant Name: *Colstrip* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear				Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			311.20		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			1933569000		
13	Cost of Plant: Land and Land Rights	0			3327908		
14	Structures and Improvements	0			114941832		
15	Equipment Costs	0			322016279		
16	Asset Retirement Costs	0			-285471		
17	Total Cost	0			440000548		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			1413.8835		
19	Production Expenses: Oper, Supv, & Engr	0			1223236		
20	Fuel	0			27807849		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			1450780		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			1429672		
27	Rents	0			31254		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			2825008		
30	Maintenance of Structures	0			664756		
31	Maintenance of Boiler (or reactor) Plant	0			5198215		
32	Maintenance of Electric Plant	0			805834		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			-124940		
34	Total Production Expenses	0			41311664		
35	Expenses per Net KWh	0.0000			0.0214		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [ ] An Original (2) [X] A Resubmission	05/30/2012	End of 2011/Q4

NIPPC/123
Monsen/7

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Beaver* (d)	Plant Name: *Port Westward* (e)	Plant Name: *Coyote Springs* (f)	Line No.
Gas & Steam Turbine	Gas & Steam Turbine	Gas & Steam Turbine	1
Outdoor	Outdoor	Outdoor	2
1974	2007	1995	3
2001	2007	1995	4
610.70	483.30	266.40	5
515	429	272	6
371	3373	2628	7
0	0	0	8
533	418	270	9
0	0	0	10
53	22	28	11
56399000	1391213000	690844000	12
0	0	0	13
30234068	40816455	10789145	14
171705780	218238534	186779776	15
42315	226391	112544	16
201982163	259281380	197681465	17
330.7388	536.4812	742.0475	18
1475874	2266465	2458518	19
7418924	123588927	67087088	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
2992211	1547903	545366	26
179310	33929	68369	27
0	0	0	28
545991	25017	28125	29
35545	7170	0	30
0	0	0	31
3698679	4474685	6708836	32
64898	41508	30505	33
16411432	131985604	76926807	34
0.2910	0.0949	0.1114	35

(d)			(e)			(f)			Line No.
Gas	Oil		Gas	Oil		Gas	Oil		36
Mcf's	Barrels		Mcf's	Barrels		Mcf's	Barrels		37
565785	32	0	9878346	0	0	5445302	158	0	38
1011000	138600	0	1011000	138600	0	1011000	138600	0	39
3.880	0.000	0.000	3.793	0.000	0.000	3.486	0.000	0.000	40
13.107	99.321	0.000	12.511	0.000	0.000	12.320	0.196	0.000	41
12.963	17.083	0.000	12.373	0.000	0.000	12.184	0.034	0.000	42
0.131	0.000	0.000	0.089	0.000	0.000	0.097	0.000	0.000	43
10144.000	0.000	0.000	7179.500	0.000	0.000	7969.800	0.000	0.000	44

UM 1182

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 124

PacifiCorp
Form 1 filing to the
Federal Energy Regulatory Commission
for the year 2008, page 337

November 16, 2012

THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 2/29/2009)
Form 1-F Approved
OMB No. 1902-0029
(Expires 2/28/2009)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 2/28/2009)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
PacifiCorp	**End of** 2008/Q4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	03/31/2009	End of 2008/Q4

NIPPC/124
Monsen/2

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Important Changes During the Year	108-109	
7	Comparative Balance Sheet	110-113	
8	Statement of Income for the Year	114-117	
9	Statement of Retained Earnings for the Year	118-119	
10	Statement of Cash Flows	120-121	
11	Notes to Financial Statements	122-123	
12	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
13	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
14	Nuclear Fuel Materials	202-203	N/A
15	Electric Plant in Service	204-207	
16	Electric Plant Leased to Others	213	N/A
17	Electric Plant Held for Future Use	214	
18	Construction Work in Progress-Electric	216	
19	Accumulated Provision for Depreciation of Electric Utility Plant	219	
20	Investment of Subsidiary Companies	224-225	
21	Materials and Supplies	227	
22	Allowances	228-229	
23	Extraordinary Property Losses	230	N/A
24	Unrecovered Plant and Regulatory Study Costs	230	
25	Transmission Service and Generation Interconnection Study Costs	231	
26	Other Regulatory Assets	232	
27	Miscellaneous Deferred Debits	233	
28	Accumulated Deferred Income Taxes	234	
29	Capital Stock	250-251	
30	Other Paid-in Capital	253	
31	Capital Stock Expense	254	
32	Long-Term Debt	256-257	
33	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
34	Taxes Accrued, Prepaid and Charged During the Year	262-263	
35	Accumulated Deferred Investment Tax Credits	266-267	
36	Other Deferred Credits	269	

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	N/A
38	Accumulated Deferred Income Taxes-Other Property	274-275	
39	Accumulated Deferred Income Taxes-Other	276-277	
40	Other Regulatory Liabilities	278	
41	Electric Operating Revenues	300-301	
42	Sales of Electricity by Rate Schedules	304	
43	Sales for Resale	310-311	
44	Electric Operation and Maintenance Expenses	320-323	
45	Purchased Power	326-327	
46	Transmission of Electricity for Others	328-330	
47	Transmission of Electricity by ISO/RTOs	331	N/A
48	Transmission of Electricity by Others	332	
49	Miscellaneous General Expenses-Electric	335	
50	Depreciation and Amortization of Electric Plant	336-337	
51	Regulatory Commission Expenses	350-351	
52	Research, Development and Demonstration Activities	352-353	
53	Distribution of Salaries and Wages	354-355	
54	Common Utility Plant and Expenses	356	N/A
55	Amounts included in ISO/RTO Settlement Statements	397	N/A
56	Purchase and Sale of Ancillary Services	398	
57	Monthly Transmission System Peak Load	400	
58	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
59	Electric Energy Account	401	
60	Monthly Peaks and Output	401	
61	Steam Electric Generating Plant Statistics	402-403	
62	Hydroelectric Generating Plant Statistics	406-407	
63	Pumped Storage Generating Plant Statistics	408-409	N/A
64	Generating Plant Statistics Pages	410-411	
65	Transmission Line Statistics Pages	422-423	
66	Transmission Lines Added During the Year	424-425	

NIPPC/124
Monsen/4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Eastside Mobile Gener.						
13	344.00 UT	840	20.00		5.00		
14							
15	SOLAR GENERATING						
16	Utah Solar						
17	344.00 UT	36	15.00		8.84	SQ	3.00
18							
19	Oregon Solar						
20	344.00 OR	56	15.00		5.73	SQ	4.00
21							
22	Wyoming Solar						
23	344.00 WY	61	15.00		8.98	SQ	3.00
24							
25	WIND GENERATION						
26	Foote Creek						
27	341.00 WY	110			3.84		
28	343.00 WY	32,339	26.09	-0.95	3.92		17.59
29	344.00 WY	1,636	26.42	-0.82	3.84		17.92
30	345.00 WY	2,891	26.46	-0.82	3.84		17.96
31							
32	Leaning Juniper I						
33	341.00 OR	4,911	25.47	-0.52	3.96		24.97
34	343.00 OR	153,407	24.82	-0.71	4.08		24.32
35	344.00 OR	5,140			3.96		
36	345.00 OR	8,399			3.96		
37	346.00 OR	80	25.47	-0.52	3.96		24.97
38							
39	Marengo I & II						
40	341.00 WA	10,189	24.87	-1.00	4.06		24.87
41	343.00 WA	324,805	24.87	-1.00	4.06		24.87
42	344.00 WA	9,221	24.87	-1.00	4.06		24.87
43	345.00 WA	18,802	24.87	-1.00	4.06		24.87
44	346.00 WA	337	24.87	-1.00	4.06		24.87
45							
46							
47							
48							
49							
50							

UM 1182

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 125

Portland General Electric Response to Northwest and Intermountain Power Producers Coalition Data Request 2.4 (renamed DR 010), Attachment B

November 16, 2012

Northwest and Intermountain Power Producers Coalition Exhibit 125 contains confidential material and has been redacted

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 126

Idaho Power Company's Response to Northwest and Intermountain Power Producers Coalition Data Requests 2.4(a), 2.4(b), and 2.4(d)

November 16, 2012

Northwest and Intermountain Power Producers Coalition Exhibit 126 contains confidential material and has been redacted

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 127

Direct Testimony of Mark R. Tallman (excerpt)
Idaho Public Utilities Commission
Docket PAC-E-10-07
May 28, 2010

November 16, 2012

RECEIVED
2010 MAY 28 PM 12: 05
IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	**)**	
APPLICATION OF ROCKY	**)**	**CASE NO. PAC-E-10-07**
MOUNTAIN POWER FOR	**)**	
APPROVAL OF CHANGES TO ITS	**)**	**Direct Testimony of Mark R. Tallman**
ELECTRIC SERVICE SCHEDULES	**)**	
AND A PRICE INCREASE OF $27.7	**)**	
MILLION, OR APPROXIMATELY	**)**	
13.7 PERCENT	**)**	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-10-07

May 2010

Q. Please state your name, business address and present position with Rocky Mountain Power ("Company").

A. My name is Mark R. Tallman. My business address is 825 NE Multnomah, Suite 2000, Portland, Oregon 97232. My present position is Vice President of Renewable Resource Acquisition.

Qualifications

Q. Please describe your educational and professional background.

A. I have a Bachelor of Science Degree in Electrical Engineering from Oregon State University and a Masters of Business Administration from City University of Seattle. I am also a Registered Professional Engineer in the states of Oregon and Washington. I have been the Vice President of Renewable Resource Acquisition since December 2007. Prior to that, I was Managing Director of Renewable Resource Acquisition from April 2006 to December 2007. I have worked at the Company for more than 24 years in a variety of positions of increasing responsibility, including the commercial and trading organization; the Company's engineering organization; the retail distribution organization; and five years as a District Manager.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to demonstrate the prudence of the Seven Mile Hill, Glenrock, Rolling Hills, Seven Mile Hill II, Glenrock III, High Plains and McFadden Ridge I wind-powered generation resources (collectively the "Wind Resources" and individually a "Wind Resource"). The Company is also adding the Dunlap I wind-powered generation resource that is addressed in the testimony of Mr. Stefan A. Bird.

Q. Please summarize your testimony.

A. I start by describing the Company's integrated resource plan ("IRP") and how it is utilized to identify and quantify the need and timing of new supply-side resources. I also provide an overview of the relevant MidAmerican Energy Holdings Company ("MEHC") transaction commitments related to acquisition of renewable resources. Finally, I provide a description of the Wind Resources, the decision-making process leading to their acquisition and a description of updated information for each Wind Resource.

Q. What were the commercial operation dates for each Wind Resource?

A. Each Wind Resource is in service. As shown in the table below, the commercial operation date ("COD") varies by Wind Resource.

<u>Wind Resource COD</u>

Wind Resource	COD
Seven Mile Hill	December 31, 2008
Glenrock	December 31, 2008
Rolling Hills	January 17, 2009
Seven Mile Hill II	December 31, 2008
Glenrock III	January 17, 2009
High Plains	September 13, 2009
McFadden Ridge I	September 29, 2009

Q. Please summarize each Wind Resource.

A. The table below summarizes each Wind Resource, its location and its associated investment.

Wind Resource Summary

Wind Resource	MW	Location	Investment	COD
Seven Mile Hill	99.0	Medicine Bow, WY	$206,070,352	12/31/2008
Glenrock	99.0	Glenrock, WY	$217,015,087	12/31/2008
Rolling Hills	99.0	Glenrock, WY	$200,234,936	1/17/2009
Seven Mile Hill II	19.5	Medicine Bow, WY	$41,304,822	12/31/2008
Glenrock III	39.0	Glenrock, WY	$86,840,843	1/17/2009
High Plains	99.0	McFadden, WY	$232,518,676	9/13/2009
McFadden Ridge I	28.5	McFadden, WY	$56,511,031	9/29/2009

Integrated Resource Plan

Q. Please briefly describe the IRP process.

A. The IRP is a strategic planning tool that presents a framework for resource acquisitions to ensure the Company continues to provide reliable, low-cost service with manageable and reasonable risk to customers. The IRP builds on the Company's prior resource planning efforts and reflects significant advancements in portfolio modeling and risk analysis.

Q. What is the main purpose of the IRP?

A. The mandate for an IRP is to ensure that the Company has, on a long-term basis, an adequate and reliable electricity supply at the lowest reasonable cost and to ensure that such supply is provided or fulfilled in a timely and planned manner consistent with the long-term public interest. The IRP serves as a strategic roadmap to assist the Company in determining and implementing its long-term resource strategy. In doing so, the IRP accounts for state specific IRP requirements, expected customer resource needs, the current planning environment, corporate business goals and certain commitments made by the Company as part of MEHC's acquisition of PacifiCorp, including the acquisition of renewable resources.

Q. Has the Company obtained a Certificate of Public Convenience and Necessity ("CPCN") for each Wind Resource?

A. Yes. The Company obtained a CPCN for each Wind Resource from the Wyoming Public Service Commission. Because each Wind Resource is in Wyoming, application for a like certificate in Idaho was not required.

Update for Most Recent Capacity Factor Projections

Q. In completing the construction process, did the Company obtain third-party technical studies updating the capacity factor estimates for each Wind Resource?

A. Confidential Exhibit Nos. 27, 28, 29, 30 and 31 are the final build design energy projections for the Seven Mile Hill, Glenrock, Rolling Hills, Seven Mile Hill II and Glenrock III resources, respectively. A final build design energy projection has yet to be completed for the High Plains and McFadden Ridge I resources.

Q. Please summarize the final build design energy projections for these resources.

A. The table below provides a summary of the final build design energy projection estimate ("FBDE") for each Wind Resource as well as the projection at the time the decision was made to acquire the resource. The summary shows estimated annual capacity factor ("CF") at the probability fifty (P50) level and megawatt-hours ("MWh"). Because actual CF is dependent on the weather and other factors, a P50 estimate means that the actual production in any given year can be expected to be higher or lower over the life of the resource.

Wind Resource FBDE

Resource	Acquisition Decision (CF)	Acquisition Decision (MWh)	Updated w/FBDE (CF)	Updated w/FBDE (MWh)
Seven Mile Hill	41.3%	358,170	40.3%	349,948
Glenrock	38.6%	334,755	37.4%	324,348
Rolling Hills	31.0%	268,844	33.8%	293,127
Seven Mile Hill II	39.3%	67,132	40.3%	68,840
Glenrock III	31.0%	105,908	36.4%	124,357
Total MWh		**1,134,810**		**1,160,170**
Average CF	**36.2%**		**37.6%**	
High Plains	35.7%	309,605		n/a
McFadden Ridge I	34.5%	86,133		n/a
Total MWh		**1,530,547**		**1,555,907**
Average CF	**35.9%**		**36.9%**	

Q. **Is it unusual for capacity factor estimates to vary over time as the construction of wind-powered generation facilities progress?**

A. No. As more information is acquired, it is not unusual for capacity factor estimates to be updated.

Q. **Why were the estimated capacity factors of these resources updated?**

A. The update in estimated capacity factor reflects normal changes that resulted in the final construction design of the resources, as well as additional information on wind climatology for the sites.

Q. **Is the average capacity factor of the Wind Resources in line with the average capacity factor for the Company's Wyoming power purchase contracts with wind-powered generation resources?**

A. Yes. The average capacity factor for the Company's Wyoming power purchase contracts with wind-powered generation resources is approximately 32.0 percent.

Q. Is the average capacity factor predicted for the Wind Resources in line with the proxy capacity factor assumed for Wyoming wind resources in the Company's IRP?

A. Yes. The Company's 2007 IRP and 2008 IRP used a 35 percent[4] capacity factor to model proxy wind projects for building the Company's portfolio of renewable energy resources. In reality, some renewable resources will have capacity factors above 35 percent and others will be lower than 35 percent.

Q. Does the Company currently have wind resources or contracts with wind resources in its portfolio with capacity factors below 35 percent?

A. Yes, excluding any of the Wind Resources, the Company currently has 21 such resources with projected annual capacity factors below 35 percent. These resources are located inside and outside of Wyoming. *See* Confidential Exhibit No. 32.

Q. Does the net power cost study in this case include the FBDE?

A. Yes. The Company believes the most recent capacity factor projection is appropriate to use for setting rates and, as such, the Company included the FBDE updates in the net power cost study sponsored by Company witness Dr. Hui Shu in this case.

Q. Has the Company included the value of PTCs and RECs in its filing?

A. Yes. The value of PTCs, RECs or other known tax-related benefits and burdens for each Wind Resource are included in the Company's filing.

---

[4] 35% is in line with the proxy wind assumptions used in the 2004 IRP.

Q. Did the Company acquire the Wind Resources for the purpose of complying with renewable portfolio standards in Oregon, Washington, California or to meet the requirements of carbon reduction legislation in Utah?

A. No, each Wind Resource was acquired on the basis of its economics, other quantitative factors and qualitative factors.

Conclusion

Q. What are the overall benefits of Wind Resources to Idaho customers?

A. Customers benefit from the Wind Resources because they represent cost effective renewable resources. The 2004, 2007 and 2008 IRPs specify that cost effective renewable resources (using wind-powered generation resources as a proxy) should be steadily added to the system. The Wind Resources benefit customers as their acquisitions were both cost effective and consistent with the Company's robust long-term planning efforts through the IRP process. Customers further benefit from these renewable resources because they provide a zero incremental cost fuel source, thus reducing exposure to potentially volatile commodity and/or fuel risks.

Q. Are there other benefits the Commission should consider?

A. Yes. The Wind Resources are multi-shafted generation resources that diversify the impact of individual generator failures and provide the Company with continued ownership and operational experience with utility-scale wind projects. Each Wind Resource utilizes G.E. wind turbines, thus complementing the Company's operating experience with other G.E. based projects, spare optimization and procurement of O&M services.

Q. Was each Wind Resource acquired consistent with the Company's then-current IRP and does it represent the least cost/risk option available for the long-term benefit of customers?

A. Yes

Q. Was each Wind Resource prudently acquired, in the public interest and is each Wind Resource used and useful?

A. Yes

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 128

UE 200, Exhibit PPL/203

November 16, 2012

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

August 22, 2008

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

Attn: Vikie Bailey-Goggins, Administrator
Regulatory and Technical Support

Re: Docket No. UE 200
PacifiCorp's 2009 Renewable Adjustment Clause
Rebuttal Testimony and Exhibits

PacifiCorp dba Pacific Power submits for filing an original and five (5) copies of PacifiCorp's Rebuttal Testimony and Exhibits of Andrea L. Kelly, Mark R. Tallman, R. Bryce Dalley and Judith Ridenour in the above-referenced proceeding. The confidential exhibits to the testimony of Mark R. Tallman are provided in separate envelopes and sealed pursuant to the Protective Order in this proceeding. Also enclosed are three (3) CDs containing the electronic workpapers for Mark R. Tallman, R. Bryce Dalley and Judith Ridenour.

The Company has waived confidential protection of the annual capacity factors and the ACC analysis results for the Glenrock and Rolling Hills resources that are cited in Mark Tallman's Rebuttal Testimony PPL/203. Although these data are confidential and subject to protection under the Protective Order in this proceeding, for ease of reference the Company is waiving confidentiality of these items.

Please direct informal correspondence and questions regarding this filing to Joelle Steward, Regulatory Manager, at (503) 813-5542.

Very truly yours,

Andrea L. Kelly /JS

Andrea L. Kelly
Vice President, Regulation

Enclosures

cc: UE 199 Service List

CERTIFICATE OF SERVICE

I hereby certify that on this 22nd day of August, 2008, I caused to be served, via E-Mail and Overnight Delivery (to those parties who have not waived paper service), a true and correct copy of the foregoing document on the following named person(s) at his or her last-known address(es) indicated below.

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Ariel Son

Ariel Son
Coordinator, Administrative Services

Case UE-200
Exhibit PPL/203
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of Mark R. Tallman

August 2008

Q. Are you the same Mark R. Tallman who provided direct testimony in this proceeding?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to (1) provide updated capacity factor information based upon final build design projections for the Company's wind resources now under construction; (2) demonstrate that the Rolling Hills resource was acquired through prudent decision-making, is cost effective and is in the best interest of customers; (3) rebut Staff's and ICNU's arguments to the contrary, based on the allegation that PacifiCorp violated the Commission's competitive bidding guidelines; (4) rebut Staff's proposed Operation and Maintenance (O&M) disallowances for wind plant operating costs; and (5) explain why the next highest alternative cost for compliance (ACC) analysis method is preferable to Staff's recommendation and why Staff's concerns are unfounded.

Update for Most Recent Capacity Factor Projections

Q. Staff has proposed to increase the capacity factor of two wind resources, Rolling Hills and Glenrock. As a part of the construction process, has the Company recently received third-party technical studies updating the capacity factor estimates for these resources based upon the final build design?

A. Yes. Confidential Exhibits PPL/204 and PPL/205 are the final build design energy projections for Rolling Hills and Glenrock. Based upon final project alternative cost for compliance. Based upon the capacity factors used for project approval, the ACC for the Rolling Hills resource is $4.53 per MWh on a nominal-levelized basis.

Q. Do Staff or ICNU dispute that the $4.53/MWh nominal-levelized ACC for Rolling Hills represents a reasonable amount for renewable portfolio standards (RPS) compliance?

A. No. Neither Staff nor ICNU dispute that $4.53 per MWh nominal levelized is a reasonable level. In fact, at $4.53 per MWh nominal levelized, the ACC for Rolling Hills is below the implied $6.37 per MWh nominal-levelized ACC for the Goodnoe Hills resource. The Goodnoe Hills resource includes an Energy Trust of Oregon, Inc. (Energy Trust) grant that Staff helped negotiate[5]. No party has challenged the prudence of the Goodnoe Hills resource on any basis, including the fact that it is projected to have a capacity factor of approximately 32.4 percent or was acquired outside of a Commission-approved RFP.

Q. How do the overall resource economics for Rolling Hills change using the most recent projected capacity factor of 33.8 percent?

A. Using an estimate of 33.8 percent yields a projected resource cost as shown in Confidential Exhibit PPL/207 on a real-levelized basis. The nominal levelized ACC is negative $2.91 per MWh which can be compared to the nominal-levelized ACC of positive $4.53/MWh using the initially conservative estimate of 31 percent. The result is a beneficial movement of $7.44 per MWh on a nominal-

[5] In fact, Staff originally helped negotiate two separate Energy Trust grants for two 56 MW wind projects (Goodnoe Hills West and Goodnoe Hills East) that were in close proximity to one another, would have been constructed at the same time by a single contractor and would have shared a single collector substation and single transformer.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

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In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 129

Rocky Mountain Power Quarterly Compliance Filing
Public Service Commission of Utah Docket 03-035-14
January 31, 2007

November 16, 2012

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

201 South Main, Suite 2300
Salt Lake City, Utah 84111

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

January 31, 2007

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84111

Attn: Julie P. Orchard
Commission Secretary

Re: **Case No. 03-035-14 – Quarterly Compliance Filing – Avoided Cost Input Changes**

As part of the Public Service Commission of Utah's (the "Commission") Orders dated October 31, 2005 and February 2, 2006 in Case No. 03-035-14, the company was required to keep a record of any changes, including data inputs, made to the Proxy and GRID models used in calculating avoided costs. The Orders further require that the company notify the Commission and Division of Public Utilities of updates made to the models used in the approved Proxy and Partial Displacement Differential Revenue Requirement (PDDRR) avoided cost methodologies.

This filing reports changes since the company's last compliance filing dated October 30, 2006, Case No. 03-035-14.

PacifiCorp (dba Rocky Mountain Power) hereby respectfully submits an original and five (5) copies of this compliance filing to address this requirement. An electronic copy of this filing will be provided to mlivingston@utah.gov. Additional detail is provided below:

1. GRID Model Release

The current GRID model is Release 6.1. This is unchanged from the October 2006 filing.

2. GRID Model Data Updates

A number of data updates and modeling assumption updates have occurred in the GRID model. **Appendix A** provides a summary of the updates that have occurred since the company's October 2006 filing.

3. Proxy / Partial Displacement Differential Revenue Requirement (PDDRR) Avoided Cost Methodology

In the Commission's Order, dated December 21, 2006 (Case No. 05-035-47, page 26), the Commission suggested that the company modify the November Draft 2012 Request for Proposal (RFP) for Base Load Resources to solicit bids to contract for power up to 1,700 MW through 2014. Avoided cost modeling has been revised to be consistent with the Commission's suggestion; therefore IRP resources have been replaced with RFP resources. The resource benchmarks that equate to the 1,700 MW are:-

(1) IPP 3 - 340 MW (June 1, 2012),
(2) expansion of Blundell Geothermal – 50 MW (June 1, 2012),
(3) front office transactions - 208 MW (June 1, 2012),
(4) Hunter 4 - 575 MW (June 1, 2013), and
(5) Jim Bridger 5 - 527 MW (June 1, 2013).

The Proxy / Partial Displacement Differential Revenue Requirement (PDDRR) avoided cost methodology, requires that a resource be identified as the "proxy" resource to be displaced. For this purpose, the company has updated the Proxy / Partial Displacement Differential Revenue Requirement (PDDRR) spreadsheet to reflect a 340 MW coal-fired resource located in Utah as the "proxy" resource (IPP 3).

4. Proxy Wind Resource

The company's most recently acquired wind resource is Marengo Wind, a 140.5 MW 35% capacity factor wind resource located near Dayton, Washington and scheduled to be on-line before July 2007. The company proposes to update the avoided cost "proxy" wind resource from Wolverine Creek to Marengo Wind. **Appendix B** provides updated wind resource pricing, based on Marengo Wind.

Quarterly Compliance Filing
Docket No. 03-035-14
January 31, 2007

5. Impact to Avoided Cost Prices ($/MWh)

Provided as **Appendix C** is a $/MWh impact study of the above mentioned updates, together with a comparison to the October 2006 filing. The updates reflect an increase of approximately $7.01/MWh on a 20-year nominal levelized basis. Please note that avoided costs presented in **Appendix C** were calculated assuming a 164 MW 100% capacity factor QF resource, which reflects resources previously dispatched. Avoided costs for smaller QF resources would be higher than those shown in **Appendix C**. For projects greater than 164 MW, avoided cost prices would be based on the next RFP deferrable resource.

It is respectfully requested that all formal correspondence and requests regarding this compliance filing be addressed to:

By E-Mail (preferred) : datarequest@pacificorp.com

By Fax : (503) 813-6060

By Regular Mail : Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232

Informal inquiries may be made to Laren Hale at (503) 813-6054 or Mark Widmer at (503) 813-5541.

Very truly yours,

Jeffrey K. Larsen
Vice President, Regulation

Enclosure

cc: Service List (Case No. 03-035-14)

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

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Northwest and Intermountain Power Producers Coalition Exhibit 130

Rebuttal Testimony for Phase II of
Charles E. Peterson, Exhibit 3.2R, Public Service
Commission of Utah Docket 09-035-15
September 15, 2010

November 16, 2012

PacifiCorp

Comparison of Actual Annual Wind Capacity Factors with Expected Wind Capacity Factors
2004-2009

				Actual Annual Capacity Factors						
Wind Plant	**Year of Construction**	**Nameplate Capacity (MW)**	**Expected Capacity Factor**	2004	2005	2006	2007	2008	2009	Average
				(Megawatt Hours)/**(Capacity Factor--Percent)**						
Foote Creek	1999	32.62		103,892	104,394	106,038	95,139	106,930	86,324	100,453
				36.26%	**36.53%**	**37.11%**	**33.29%**	**37.32%**	**30.21%**	**35.13%**
Glenrock	2008	99.00							253,875	253,875
			37.4%						**29.27%**	**29.27%**
Glenrock III	2009	39.00							84,675	84,675
			36.4%						**nmf**	**nmf**
Rolling Hills	2009	99.00							207,820	207,820
			33.8%						**nmf**	**nmf**
Goodnoe Hills	2008	94.00						147,308	237,374	237,374
			33.0%					**nmf**	**28.83%**	**28.83%**
Leaning Juniper 1	2006	100.50				57,993	289,452	312,614	258,767	286,944
			31.2%			**nmf**	**32.88%**	**35.41%**	**29.39%**	**32.57%**
Marengo	2007	140.40					160,636	400,245	316,552	358,399
							nmf	**32.45%**	**25.74%**	**29.12%**
Marengo II	2008	70.20						78,457	158,279	158,279
			30.5%					**nmf**	**25.74%**	**25.74%**
Seven Mile Hill	2008	99.00							303,510	303,510
			41.0%						**35.00%**	**35.00%**
Seven Mile Hill II	2008	19.50							62,229	62,229
			40.3%						**36.43%**	**36.43%**
High Plains	2009	99.00							72,695	72,695
			35.3%						**nmf**	**nmf**
McFadden Ridge I	2009	28.50							20,558	20,558
			34.5%						**nmf**	**nmf**

nmf -- not a meaningful figure, partial year data

Sources: PacifiCorp FERC Form-1, 2004-2009, p. 410.
Expected Capacity Factors from unsourced spreadsheet in possession of Division.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

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NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
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Northwest and Intermountain Power Producers Coalition Exhibit 131

Direct Testimony of Mark Widmer
Public Service Commission of Utah
Docket 99-035-10
September 20, 1999

November 16, 2012

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is Mark Widmer, my business address is 825 N.E. Multnomah, Suite 600, Portland, Oregon 97232, and my present position is Principal System Planner.

Qualifications

Q. Briefly describe your education and business experience.

A. I received an undergraduate degree in Business Administration from Oregon State University. I have worked for PacifiCorp since 1980 and have held various positions in the power supply and regulatory areas. I was promoted to my present position in 1998.

Q. Please describe your current duties.

A. I am responsible for the coordination and preparation of net power cost and related analyses used in retail price filings. In addition, I represent the Company on power resource and other various issues with intervenor and regulatory groups associated with the six state regulatory commissions to whose jurisdiction we are subject.

Summary of Testimony

Q. Will you please summarize your testimony?

A. I will provide information on how input data is normalized in the Company's production cost model and will present the results of the production cost model study for the 12-month period ending December 31, 1998. I will also discuss the Wyoming Wind Project.

Determination of Net Power Cost

Q. Please explain how net power costs are calculated.

A. Table 1 is a schedule of the Company's major sources of energy supply by major source of supply, expressed in average megawatts, owned and contracted for by the Company to meet system load requirements, for the 12-month test period ended December 31, 1998. The total shown on line 13, represents the total normalized usage of resources during the test period to serve system load. The total system load is represented by lines 13 through 15. Line 14 consists of wholesales sales made to neighboring utilities within the Pacific Northwest, the Pacific Southwest, and the Desert Southwest as calculated from the production cost model study. Line 15 represents the Company's System Load.

Q. Please describe Exhibit UP&L__.1 (MTW-1), Table 2.

A. Table 2 shows the major sources of peak generation capability for the Company's winter and summer peak loads and the Company's normalized energy load for the twelve month test period ended December 31, 1998.

Q. How are the results of the production cost study used in this rate proceeding?

A. The resulting purchased power expense, fuel and wheeling expenses, and wholesale sales revenues are included in Jeffrey K. Larsen's Exhibit UP&L __.1 (JKL-1).

Wyoming Wind Project

Q. Please describe the Wyoming Wind Project.

A. The Wyoming Wind Project consists of 69 wind turbines for a total capacity of 41.4 MW and an annual projected output of 154 GWH at a 42.6% capacity factor. The Wyoming Wind Project, located at Foote Creek Rim in southeastern Wyoming, has been developed by ToyoWest Wyoming, LLC and will be operated and maintained by SeaWest Wyoming LLC. Two utilities, PacifiCorp and Eugene Water & Electric

Board (EWEB) own the Wyoming Wind Project's generating facilities. In addition to the two owners, BPA has signed a Power Purchase Agreement to purchase 15 MW of the Project's output. Initial synchronization to the grid and delivery of energy occurred in October, 1998 and commercial operation started April, 1999.

Q. Why is PacifiCorp participating in the Wyoming Wind Project?

A. PacifiCorp's decision to participate in the project is based on a Company commitment to the development of cost-effective renewable resource alternatives. For a number of years, PacifiCorp has included in its Strategic Goals specific references to the development of environmental resource alternatives and the diversification of resources.

Q. What are the benefits of the project?

A. Participation in the project not only furthers the Company's efforts to meet its Environmental Strategic Goal and the Company's RAMPP action plans; it will also provide valuable operational experience and knowledge that will allow the Company to develop and use renewable technologies more effectively in the future. There is a definite need for the Company to gain knowledge with renewable technologies and that knowledge can only be gained through actual hands-on experience with various technologies. Sharing the wind project's costs among several utilities allows PacifiCorp to minimize the risks involved with newer technologies.

The experience being gained from the Wyoming Wind Project will allow PacifiCorp to develop ways of integrating this type of resource into the system, and will reveal how these plants affect the system use of other resources for load following and how they affect the local transmission and distribution systems.

Q. What do you recommend regarding the Wyoming Wind Project?

A. The Wyoming Wind Project is a prudently acquired resource which is used and useful. Therefore, I recommend that the acquisition costs of the Wyoming wind resources be included in rate base and allowed to earn the allowed rate of return. The operating expenses of these resources should be included in establishing the Company's revenue requirement.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

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In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
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Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 132

UE-210, Exhibit PPL/406 (excerpt)

Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-3

November 16, 2012

Northwest and Intermountain Power Producers Coalition Exhibit 132 contains confidential material and has been redacted

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

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	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 133

UE-217, Exhibit PPL/902

Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 2.1, Attachment 2.1-3

November 16, 2012

Northwest and Intermountain Power Producers Coalition Exhibit 133 contains confidential material and has been redacted

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

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In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power Producers Coalition Exhibit 200

Direct Testimony of Camden Collins

Introduction and Background

Q: What is your name and address?

A: Camden Collins, 275 S. Arroyo Pky #401, Pasadena, California, 91105.

Q: Please describe your professional background.

A: I have attached NIPPC/201, which includes a description of my education and qualifications. From 1989 to 1992, I worked on an unfair competition case brought by generators against Pacific Gas & Electric Company, with the scope of discovery including all generators in that service franchise from 1982 to 1989. From 1992 to 1997, I worked at the California Public Utilities Commission (CPUC), and was from 1992 to 1995 assigned to all wholesale power contract and transmission issues on behalf of ratepayers, and represented the CPUC in bankruptcy proceedings. From 1997 to 2000, I worked at Bechtel Enterprises and my duties involved working with wholesale generation outside of California. I had a very small legal role in the debt restructuring of the Boston Generating assets between 2003 and 2006. I graduated with a bachelor's of science in electrical engineering and computer science from the University of California, Berkeley, in 1985. I graduated with a juris doctor from the University of San Francisco in 1988. I graduated with a master's in business administration from the University of Pennsylvania, Wharton School of Business, in 2004.

Q. On whose behalf are you testifying?

A. I am submitting testimony on behalf of the Northwest and Intermountain Power Producers Coalition (NIPPC).

Q: What is the scope of your testimony?

A: My direct testimony will address the topic of financial performance risks in independent power producers (IPP's) and utility transactions. Item 11 of the ALJ's Ruling of May 30, 2012, was adopted by Commission Order No. 12-324, and described this topic as the potentially higher "financial performance risk of an IPP" relative to a utility. My testimony is directed at this line of inquiry and relies on my experience with special purpose entities (SPE's) established by IPP's, and the relationship between the loans obtained by IPP's or SPE's, and power purchase agreements (PPA's) with rate regulated electric utilities. It does not cover credit issues pertinent to other forms of wholesale power procurement, organized exchanges, or credit contagion.

Credit Determinations

Q: In your experience, do prudent power purchase agreements with IPP's protect ratepayers from financial performance risks of IPP's experienced during project development and construction?

A: Yes. Of the bankruptcy cases I monitored or participated in between 1992 and 1997, only one I can recall involved a pre-operational project, and that project had a solar technology problem.

Q: For projects that achieved a commercial operational date (COD), did the CPUC ever advocate in bankruptcy for a return of funds previously paid for metered and delivered energy under a PPA?

A: To the best of my recollection, not while I was employed between 1992 and 1997. Between 1992 and 1995 I was working on contract administration of over 500 PPAs that ultimately attained on-line operational status, a cumulative capacity of over 8,000MW. The number of cases in bankruptcy in any year posing any exposure to utility rates was less than one half of one percent, and most PPAs had been signed without credit requirements of any kind. That risk would be even smaller if one were to use MW weightings instead of number of projects. In none of these bankruptcy or financial distress cases I was involved in for post COD projects did the generator seek to terminate the PPA. The purpose of monitoring and participating in these cases was to curb adverse changes to a PPA by a bankruptcy judge, and in no case did that actually occur.

Q: Are you aware of less formal instances of potential project financial distress in which the utility sought a return of funds previously paid?

A: Yes, on two occasions. In the first instance, the utility had advanced payment to the project prior to generation, metering, and delivery of the energy, and by today's standards the PPA term would probably not be considered prudent to have entered into. In the second instance, the financial distress never manifested, but the potential was a consequence of a dispute between the Division of Ratepayer Advocates and Southern California Edison about how to interpret a calculation provision in a PPA. For the customary payment arrangement in a PPA, the generator is paid after delivery is received, and it is the utility to whom credit is extended by the generator, not vice-versa. Prudent utilities tend to be cautious about avoiding negligent overpayments to an SPE, and true pre-payment issues rare.

Q: What is credit?

A: The loan or loans the IPP or SPE obtains to fund its business.

Q: What is credit quality?

A: The more common term I have heard is credit worthiness, which has to do with the initial issuance of the credit extended by a lender, and its terms and conditions. If the business gets a loan, it is said to be credit worthy: the loan is the evidence of that worthiness. If the business cannot get a loan, it is not credit worthy. Sometimes people use credit worthiness and credit rating interchangeably, but this is imprecise. Sometimes people use credit quality to refer to an aggregated bundle of all of an entity's loans or lines of credit, at one point in time or over time, but this is also imprecise. It is difficult to imagine fairly scoring competitors without stronger definitions of the attribute of interest to the buyer.

Q: Have you ever known of an SPE debt issuance for a project that took place in advance of that entity signing a PPA?

A: No.

Q: Have you ever known of an SPE debt issuance for a project that had a credit rating in advance of that entity signing a PPA?

A: No.

Q: Why not?

A: The vast majority of my experience involves SPE financing of individual power projects. Although such projects are from time to time financed through alternative means, or live through some portion of their development that combines the SPE with another type of capital, the projects I have dealt with were mostly SPE's that had passed their commercial operation tests. In other words, creditors typically had no recourse for payment beyond the income streams and assets specified in the loan to the SPE. In order to obtain that loan, the lender uses among other things a pro forma of project financial statements. While lenders can provide some indication of credit worthiness and rates based on various estimated scenarios, to my knowledge no lender makes a commitment to a loan or can obtain a rating for a loan structure when the PPA terms are still being negotiated. The actual credit lags the formation and commitment of commercial terms creating project revenue, and opinions that precede it are a form of speculation, inextricably connected with the negotiating process. Without the PPA terms, one would be at a loss to know the most basic items to a credit evaluation, like the amount of free cash flow in excess of debt service requirements (the debt coverage ratio).

Q: Can you generalize about the causes of financial distress experienced by an individual project, in other words, a financial distress that is not widespread among all projects similarly situated?

A: No. Project failures, however they initiate, are highly idiosyncratic. It would not be correct to say that access to capital, which will always be more limited than a regulated utility's, is the cause of a project's inability to correct a management, operations, or fuel supply problem. It may be true that the failure to correct such problems diminishes income and financial distress ensues as a consequence. But that does not render the SPE's loan or credit the cause of the distress. One simply cannot say that because "enough" money ultimately can fix most kinds of power generation problems, the absence of "enough" at one point in time transforms those problems and renders them caused by limitations in the SPE's credit. During the years I was involved, the most common source of project financial distress was the failure of newer technologies or fuels to perform as expected when the debt was issued. This era of wider experimentation at high volumes appears to be over, and much smaller experimentation is more common now.

Q: Is SPE financing imprudent in its lack of flexibility?

A: No. Many utilities buy IPP assets in this form outside their service territories, and do not consider the form of financing used an unacceptable risk when holding these assets outside the regulated utility entity.

Q: Is it possible to unbundle the credit determinations made by creditors?

A: I don't believe so. Credit is extended upon an examination that, in the broadest terms, indicates it is likely the loan will be repaid. The classic qualitative description of the examination is that it evaluates all the facts and circumstances of: (1) the character of the business, (2) the collateral or other resources to which the lender has recourse, and (3) the capacity of the business to fulfill its objectives. Many people substitute the character of management for item (1), but it remains the case that other aspects of business character are present and thus assumed supportive. It is not the case, in my experience, that one can increment or decrement the equity in a power project, and unbundle the amount of key numerical terms: interest rate, debt reserve, and debt coverage ratio. Power project financing is laborious. It is not made easy to shop around for credit. The only exception to this "bundling" I have experienced involved the state of California's infrastructure bonds, available for municipal projects, conditioned on a legal ability of the municipality to raise the rates charged for service. In such a situation, the local governmental power to raise revenue was stated to be the basis of and directly related to the coverage ratio required and interest rate. No competitive provision of credit was involved: this was a provider of last resort.

Q: In your experience, do creditors have the capacity to take over operating IPP's and keep them operating?

A: Yes. They can and do. In a complex, multi-creditor situations there are coordinating agreements that set out when and how this takes place.

Q: Have you read the following comments of Investor Owned Utilities filed March 19, 2012 in this proceeding?

> **"There are two primary aspects of counterparty risk, both of which have significant impacts on a utility and its customers. The first is the risk that the counterparty will become unwilling or <u>unable</u> to perform some or all of the provisions of a specific contract <u>due to</u> a change in circumstance that adversely impacts the economics of**

the transaction.

The second primary aspect of counterparty exposure is financial risk – the risk that a counterparty will no longer be able to fulfill many or all of its contract obligations due to insolvency or a material deterioration of the organization's financial condition. Footnote 6: It is common that an IPP will form a Limited Liability Corporation (LLC) and place the assets underlying a PPA in the LLC. By doing so, the IPP/parent company is protected should the LLC fail." [emphasis added.]

A: Yes. This does not make sense to me, given the IPP's and SPE's I have dealt with. I know of no way to divorce the "economics of the transaction" from the pro forma used at the point credit is issued, upon which the SPE's "financial condition," as monitored by its creditors, will depend for the term of the loan and PPA. There are many established methods for addressing fuel cost variation in gas fired generation procurement. Therefore, my answer assumes that the "economics" intended by the authors are not a veiled reference to gas price variation. Utilities are in complete control through the RFP of specifying acceptable gas procurement practices for the competitor, practices it would be committing to use for its own competitive offer (e.g., 100% fixed price for the term of operation, or any lesser percentage and duration).

Generally, the NERC reliability requirements of the transmission system ensure that an excess of supply over demand (various forms of generation reserve) are maintained at ratepayer expense. Consequently, when it comes to a threat of contract breach or abrogation motivated by prevailing wholesale prices, in my experience the temptation is more persistent and of longer duration for the buyer than the seller. Exceptions to this general observation do occur, but in situations not present in the Pacific Northwest. Unlike other energy price contexts (e.g., oil and gas), sellers in a traditional PPA with a vertically integrated utility do not prematurely exit long-term contracts for momentary, upward short-run wholesale price excursions in any significant amount (i.e., greater than 1%), in large part because spare capacity is mandated. It is hard to imagine an IPP management willing to risk the project's equity investment in bankruptcy for the magnitude of firm, long-term opportunities it might elsewhere obtain, net of damages owed.

There is something perhaps unintentionally awkward about finding fault with the limited nature of a generator's liability (as indicated by the footnote quoted above) from the perspective of entities with a <u>government</u> guarantee of sole and exclusive access to new retail revenue. If one honestly wanted to obtain a mortgage pre-approval at a good rate, it would help not to declare the house is going to sit in a war torn or otherwise hostile country. By raising credit quality as a concern, but not proposing any RFP terms that level the playing field for the regulatory compact's relative financial security, utilities can inadvertently drive up the cost of IPP's signaling to IPP creditors how hostile the franchise is to them.

Q: Have you reviewed discovery responses from the utilities in this proceeding regarding how they already treat credit in Oregon RFPs?

A: Yes, the only utility to provide a detailed response thus far is Portland General Electric Company, which spoke to the topic in PGE's Responses 2.1 and 2.2 to NIPPC Data Request No. 007 and 008. I have included these responses as NIPPC/202. The Response to Request 2.2 implies that for the 2007 price scores only an investment grade credit of the bidder is acceptable, and anything lower would be scored lower. This form of scoring has several disadvantageous features. First, it relies on a credit rating agency review that has hindsight deficiencies, conflicts of interest, and lags, and is currently undergoing reform. Additionally, the credit rating takes into account attributes like experience or track record of the bidder's management, which are better handled through bid eligibility requirements or separate quantified scoring. Second, it does not translate grades of ratings into impacts on the score. Therefore, it is lacking in transparency and fails to communicate to bidders what the buyer truly wants to buy. Third, it does not have a sufficient nexus to the credit of the entity that will hold the asset. Fourth, it disregards the value associated with credit differentials. In other words, what is it worth in price received to have triple A credit instead of triple B? Why, given the accrual of experience with IPP's, would one presume a utility needed to have and should pay for investment grade credit from suppliers? Fifth, it has no nexus to the credit of the supplier over time. For example, a bidder with an investment grade rating could win, transfer the asset to an SPE and hold the asset at the lowest possible grade, beating another bidder that sat in between highest and lowest grades. For all these reasons, PGE's bid scoring method does not meaningfully address financial performance risk.

Q: Does that conclude your direct testimony?

A: Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	)
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Northwest and Intermountain Power

Producers Coalition Exhibit 201

Witness Qualifications of Camden Collins

WITNESS QUALIFICATION

NAME; Camden Collins

EMPLOYER: None

TITLE: None

ADDRESS: 275 S. Arroyo Pky #401, Pasadena, California, 91105

EDUCATION: University of California, B.S. in Electrical Engineering & Computer Science, electronics emphasis; University of San Francisco, J.D.; University of Pennsylvania, Wharton School of Business, Executive M.B.A., finance emphasis.

EXPERIENCE:

Starting in 1986, I began doing legal work in the area of unfair competition while still in law school. In 1989, while employed at a private law firm I was assigned to assist with discovery of the cause of project failure of all independent power projects within the client Pacific Gas & Electric Company's (PG&E's) territory since 1982, in an unfair competition case. In 1992, I became employed by the California Public Utilities Commission (CPUC) as a staff counsel, and was assigned to their Division of Ratepayer Advocates (DRA). In that capacity, from early 1992 to mid-1994, I was also assigned to all wholesale power and transmission matters, including contract administration for any independent generator holding a power purchase agreement with a rate regulated utility. I was instrumental in writing an unusual number of comfort letters for utilities, defining reasonable contract practices subject to rate recovery. During those years and in coordination with the CPUC's federal litigation attorneys, I represented the CPUS in bankruptcy cases involving qualifying facilities (QFs) under the Public Utility Regulatory Policies Act of 1978. From 1995 through 1996, I reviewed all federal filings on energy matters as the Legal Advisor to the CPUS's President. In 1997 I was appointed to the non-market participant position on the California Independent System Operator's Board, where I served on the Executive and Finance Committees until July 2000.

While employed at Bechtel Enterprises from 1997 through 1999, I was involved with a variety of wholesale generators across the United States and outside of California, and one small generating company with operations in Brazil and Venezuela. Bechtel Enterprises at that time held assets in various operating companies, including U.S. Generating companies. I attended meetings wherein Bechtel Enterprises received detailed pitch books from investment banking firms seeking the company's business, and summarizing transaction history of independent generators across the country. These meetings provided a unique opportunity to learn a great deal about structured financing and special purposes entities at the hands of the creditors. I worked on the syndication of a $300 million credit facility for a small international generation company, jointly owned with PacifiCorp. I was CEO of this company when the debt was assumed by a successor pursuant to a sale of the company. I was from time to time involved in the creation and sale of both domestic generating assets and operating companies that held generating assets outside of

California. I was briefly asked to investigate two QF biomass projects in Florida that a joint venture of Bechtel Enterprises and Pacific Gas & Electric has ownership in, selling output to Florida Power & Light. This bankruptcy involved private placement bonds under Section 144A of the U.S. Securities Act of 1933. I was asked to provide advice regarding reporting protocols for an energy trading business in the U.K.

I had a small role in providing legal advice to the equity participant in the restructuring of debt for assets of Boston Generating, LLC between 2003 and 2006. My spouse was the sole equity during ths work out.

I have not previously testified as an expert witness in any forum.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

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In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
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Northwest and Intermountain Power

Producers Coalition Exhibit 202

Portland General Electric Company Response to NIPPC's

Data Requests 2.1 and 2.2

October 22, 2012

TO: Gregory M. Adams
Northwest and Intermountain Power Producers Coalition

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1182
PGE Response to NIPPC Second Set Data Request No. 007
(Renumbered from 2.1)
Dated October 5, 2012

Request:

Please describe all ways in which credit risk and counter-party risk were accounted for in bid evaluation in your last power solicitation. For credit risk, please include the percentage of price and non-price scoring criteria allocated to credit risk in scoring bids to establish the short list.

Response:

In PGE's 2007 Renewable RFP, credit risk was accounted for in the scoring criteria. Credit risk refers to the risk associated with the counterparty's financial strength. We did not have a separate criterion entitled "counter party risk". Counterparty risk refers to the risk associated with the counterparty's failure to execute the transaction and/or its non-performance of its obligations. Credit risk scoring accounted for a potential 55 points out of a total of 1,000 points. PGE's approach was to look specifically at the creditworthiness ("credit evaluation") of a bidder based on their ratings from the main ratings agencies (S&P, Moody's, Fitch, or DBRS) and the finance-ability of the project ("development viability").

A limited measure of counter-party risk, experience of project team, was accounted for in our 2007 Renewable RFP scoring under the category 'Development Viability'. Development Viability accounted for a potential of 65 points out of a total of 1,000 points, of which we allocated 15 points (maximum points) to Experience of Project Team. The scoring for Development Viability does not capture the risk that the counter-party will be unable to fulfill its obligations due to insolvency or a material deterioration of its financial condition or other changed circumstances. In addition, Development Viability included other non-counterparty, non-credit risk factors.

October 22, 2012

TO: Gregory M. Adams
Northwest and Intermountain Power Producers Coalition

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1182
PGE Response to NIPPC Second Set Data Request No. 008
(Renumbered from 2.2)
Dated October 5, 2012

Request:

Please describe how PPA pricing and collateral/surety requirements were affected by the counter-party's credit risk in PPA(s) resulting from the last power solicitation where an independent bidder was the successful bidder. Please include a copy of the executed PPA.

Response:

Ostensibly each bid price reflects all of the bidder's anticipated costs, including the bidder's cost of credit risk, for example, the cost of obtaining and maintaining performance assurance in the form of a letter of credit. Typically, during scoring and negotiations, the bid price is not adjusted for credit risk. As indicated in PGE's 2007 RFP (and reflected in the template agreements attached to the RFP), collateral/surety requirements are affected by the counter-party's credit risk.

Counterparty credit risk could affect collateral/surety requirements in the PPA in any one or more of the following ways:

- Using a credit rating threshold matrix to reduce unsecured credit thresholds as credit ratings deteriorate.
- Reserving margining rights if exposure to counterparty goes beyond contractual unsecured credit threshold.

- Providing for the loss of unsecured credit line in the event of a material adverse change or credit event upon merger affecting the seller or the company issuing the parental guarantee under the PPA.
- Reserving the right to suspend performance from credit deterioration until the occurrence of early termination.

Price vs. Credit Risk

In 2007 price scores accounted for a total of 60% of the total 1000 point scale. In contrast, credit scores accounted for 5% of the total score respectively.
PGE dealt with credit risks with 2 filters:

- Threshold: Is the counter-party investment grade or can it provide surety from a third party who is?
- Scoring: From the pool of those counter-parties who have met that threshold, who is a better credit risk?

PGE's PPAs with Yamhill Solar LLC and Bellevue Solar, LLC require PGE to provide each seller with notice prior to disclosing confidential information under either agreement to third parties. Accordingly, PGE expects to provide the Yamhill Solar, LLC PPA and Bellevue Solar, LLC PPAs by October 26, 2012.