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January 14, 2013

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 Reply Testimony and Exhibits

Dear Filing Center:

Enclosed please find the Northwest and Intermountain Power Producers Coalition's reply 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:

- Reply Testimony and Exhibits of William Monsen: NIPPC/300 - NIPPC/330
- Reply Testimony and Exhibits of Camden Collins: NIPPC/400 - NIPPC/401
- Reply Testimony and Exhibits of Allen Kasper: NIPPC/500 – NIPPC/504

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.

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 300 Witness Reply Testimony of William A. Monsen

REDACTED VERSION

January 14, 2012

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Table of Exhibits

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. Did you present opening testimony in this proceeding?

A. Yes, I provided opening testimony on behalf of the Northwest and Intermountain Power Producers Coalition (NIPPC).

Q. What is the purpose of your reply testimony?

A. My reply testimony responds to the opening testimony submitted by Public Utility Commission (Commission) staff (Staff), as well as testimonies submitted by PacifiCorp, Portland General Electric (PGE), and Idaho Power Company (IPC) (collectively, "the utilities").

Following this brief introduction, my testimony is organized as follows:

1. Section II responds to issues raised in opening testimony that are fundamental to this proceeding, such as the need for bid adders and the ability to assess bid adders during bid evaluation.

2. Section III responds to high-level issues raised in Staff's opening testimony.

3. Section IV responds to opening testimony comments specific to the cost over-runs adder.

4. Section V responds to opening testimony comments specific to the heat rate adder.

5. Section VI responds to opening testimony comments specific to the capacity factor adder.

II. <u>Response to Fundamental Issues Raised by Staff and Utilities</u>

Q. What is the purpose of this section of your testimony?

A. This section addresses issues that are fundamental to this proceeding and that were questioned in the Staff and utility testimonies: (1) the need for changes to the Request for Proposals (RFP) bid evaluation process, (2) whether construction cost over-runs and performance deficiencies at utility-owned generation (UOG) projects have been passed on to Oregon ratepayers, and (3) whether regulatory oversight shields ratepayers from this risk.

A. Need for Changes to the RFP Bid Evaluation Process

Q. Do you agree with other parties' testimony that quantitative bid adders may not be needed?[1]

A. No. I believe there is a strong need for bid adders and that quantitative adders are preferable to qualitative guidelines.

[1] Staff/100, Procter/6.

Utility cost-of-service bids are based on projected plant performance and costs, whereas bids from Independent Power Producers (IPPs) usually represent the proposed performance and costs that ratepayers would bear (as well as the penalties the IPPs would face for failure to meet their proposed commitments). UOG bids therefore present ratepayers with a different risk profile than IPP bids.

Quantitative bid adders are a mechanism that can be used to level the playing field between UOG and IPP bids. Bid adders for UOG bids account for the *risk* of cost over-runs and performance deficiencies that are likely to increase ratepayer costs over the project lifetime above the costs estimated by the utilities in their bids. These bid adders should allow the independent evaluator (IE) to determine whether a low-risk IPP bid provides greater value to ratepayers than a slightly lower-priced, but higher-risk UOG bid. Qualitative guidelines do not provide sufficient specificity to help the IE make this determination.

Q. What support do you have for your assumption that the playing field between UOG and IPP bids is not currently level?

A. As discussed in my opening testimony, the Commission has already found that the utility procurement process favors the development of UOG projects over entering into power purchase agreements (PPAs) on account of the utilities' bidding incentives. As the Commission noted in Order 11-001:[2]

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

> 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, What do you conclude from this?

A. The Commission has already determined that there is a bias in favor of UOG projects and has re-opened UM 1182 not to reevaluate whether this bias exists, but rather to quantify it.[3] For that reason, the Commission should give no weight to the claims by other parties that there is a need to establish the bias in favor of UOG projects.

B. UOG Construction Cost Over-Runs and Performance Deficiencies Have Been Passed on to Oregon Ratepayers

Q. IPC witness M. Mark Stokes notes that cost over-runs are only passed on to ratepayers if the Commission determines that the investment was prudently incurred.[4] Is this point relevant to the issues in this proceeding?

A. No. This proceeding is addressing the ability of utilities and the IE to accurately estimate ratepayer costs associated with UOG projects during bid evaluation. The fact that a cost over-run is reasonable ignores the fact that there is, in fact, a cost over-run relative to that

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[3] Order No. 11-001, Docket UM 1276, January 3, 2011, at 5-6, "Although we accept this premise [that a bias exists in the utility resource procurement process that favors utility-owned resources over PPAs], we share the concern raised by NWEC, CUB, ICNU, and others that, even after this lengthy proceeding, we know little about the scope and impact of this bias. We have identified its existence, but are not able to quantify its significance…Because of these unresolved questions, we decline to adopt any of the recommended proposals to address the preference of a utility to build new resources rather than buy power from third parties…We do, however, take action to address the concerns raised about the self- build bias. … we reopen Docket UM 1182 to further examine issues related to our competitive bidding guidelines."

[4] Idaho Power/100, Stokes/5.

assumed during bid evaluation and that if the bid evaluation had accounted for that cost over-run then there might have been a lower-cost resource selected.

Q. Can you demonstrate that Oregon ratepayers have paid for reasonable construction cost over-runs relative to those proposed in UOG proposals?

A. Yes. In my opening testimony I presented evidence from data provided by the Oregon utilities that PacifiCorp's Goodnoe Hills wind plant's final construction cost was 29% higher than the original estimate.[5] In addition, I presented evidence that IPC incurred $14 million in additional capital expenditures for its $60 million Bennett Mountain Plant as a result of a latent construction defect,[6] representing a 23% cost increase.[7] I additionally present evidence later in this testimony regarding significant construction costs incurred at two PacifiCorp plants after the plants' in-service dates.[8]

Q. Can you demonstrate that Oregon ratepayers have paid for reasonable changes in performance relative to those proposed in UOG proposals?

A, Yes. I can point to three examples. First, consider PGE's Biglow Phase 2 wind plant, which experienced unanticipated performance deficiencies that resulted in an increase in net variable power costs of $1.1 million and a reduction in production tax credits of

[5] NIPPC/100, Monsen/17.
[6] NIPPC/100, Monsen/19.
[7] 23% = ($14 million + $60 million)/$60 million – 1.
[8] PacifiCorp response to NIPPC Data Request 6.4, presented in NIPPC Exhibit 301; PacifiCorp response to NIPPC Data Request 6.4, Attachment 6.4-1, presented in NIPPC Exhibit 302; and PacifiCorp response to NIPPC Data Request 6.4-2, presented in NIPPC Exhibit 303.

$400,000.[9] The Commission allowed PGE to require ratepayers to bear the costs of these reduced benefits and credits.[10] Second, as I discussed in my opening testimony, Oregon utilities have experienced significant heat rate degradations at their gas-fired plants,[11] but they propose to ignore the bulk of the historically seen heat rate degradation (all of which was apparently deemed reasonable by regulators) in future RFPs.[12] Third, and perhaps most striking, PacifiCorp's UOG wind plants have systematically underperformed compared to the utility's projected capacity factors.[13] This underperformance was generally deemed reasonable by regulators even though it resulted in direct cost increases to Oregon ratepayers who must pay more per unit of electricity and renewable energy credits than projected when the utility proposed to move forward with construction.

Q. Do these examples constitute a comprehensive list of cost over-runs and performance deficiencies that Oregon ratepayers have had to pay for?

A. This is unlikely. These examples, most of which are discussed in more detail below, were culled primarily from publicly available data. I had hoped to develop a comprehensive list of cost over-runs and under-performance based on the utilities' recent experience with UOG projects and have been trying since December 2011 to obtain data from the utilities on the expected and actual costs and performance characteristics of these projects in order to develop this list. The utilities objected to my initial data request, claiming that it

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[9] Staff Report regarding PGE – UM 1471 RAC deferral, March 2, 2010, provided as Appendix A of Order No. 10-116, Docket UM 1471, April 1, 2010, at 2.
[10] Order No. 10-116, Docket UM 1471, April 1, 2010, at 2.
[11] NIPPC/100, Monsen/27-28.
[12] PAC/100, Kusters/16-17; Idaho Power/100, Stokes/12; and PGE/100, Outama-Bettis-Mody-Hager/19.
[13] NIPPC/100, Monsen 30-32.

was overly burdensome. In response, I scaled back my request considerably, yet I still had difficulty obtaining responsive data from the utilities, and responses to that initial request and subsequent follow-up requests have yielded only spotty information on expected and actual costs and performance characteristics. As a result, I have not been able to develop a comprehensive list of cost over-runs and performance deficiencies borne by Oregon ratepayers. However, the numerous examples found in the limited data available to me show that Oregon ratepayers have repeatedly had to bear the costs resulting from higher-than-expected construction costs and performance deficiencies at the utilities' generation projects.

C. Does Regulatory Oversight Shield Ratepayers from the Risk of Cost Over-Runs?

Q. The utilities claim that regulatory oversight is sufficient to shield ratepayers from the risk of cost over-runs and under-performance relative to the utilities' proposals.[14] Do you agree?

A. No. Regulatory oversight is not structured to shield ratepayers from the risk of reasonable but unanticipated cost increases. As explained in OPUC Order No. 11-432:[15]

> To determine whether a particular cost was prudently incurred and recoverable in rates under ORS 757.210, "the Commission examines the objective reasonableness of a company's actions measured at the time the company acted[.]" Prudence is not a post hoc analysis that focuses on the outcome of the utility's decision, but instead examines what the utility knew, or should have known, at the time the utility incurred the costs.

[14] PAC/100, Kusters/10-11; Idaho Power/100, Stokes/5 and Stokes/12-13; and PGE/100, Outama-Bettis-Mody-Hager/23.
[15] Order No. 11-432, Docket UE 228, November 2, 2011, at 4.

In other words, as long as a utility's actions were reasonable given what was known at the time of the cost incurrence, the cost is considered prudently-incurred and recoverable in rates. For example, according to this Order, the Commission might determine that cost increases that result from an unanticipated spike in material and labor costs, reasonable change orders during the course of construction, and less-than-expected generation resulting from unexpectedly lower wind speeds are reasonable and recoverable in rates.

Q. Does NIPPC contend that reasonable cost increases should not be recoverable in rates?

A. No. NIPPC is not objecting to cost-of-service ratemaking. Instead, NIPPC's position is that the potential for ratepayer costs for UOG projects to increase above the amount anticipated in the UOG bid must be considered as part of the bid evaluation. If these costs are not considered in bid evaluation, a UOG project that is selected instead of an IPP project because the UOG project appears to be slightly less expensive in bid evaluation may end up costing ratepayers significantly more than the IPP project would have cost as a result of reasonably-incurred cost increases and performance degradation.

Q. Do you have specific evidence that Commission oversight does not shield ratepayers from these risks of higher-than-expected costs for UOG projects?

A. Yes. For example, I presented evidence in my opening testimony that IPC's plants have experienced heat rate degradation, including, for the Danskin plant, heat rates during the plant's first seven years of operations that are [redacted] than the average lifetime heat rate that was anticipated for the plant.[16] However, when asked in discovery for examples of cost disallowances resulting from prudence reviews related to heat rate degradation at IPC's plants, the utility was unable to provide a single example.[17] Similarly, PGE was unable to provide evidence of any disallowance related to heat rate degradation at its plants,[18] even though, as discussed in my opening testimony, [redacted].[19]

Q. Do you believe that the Commission has the information to hold the utilities to the construction cost and performance assumptions used in their RFPs?

A. I am not certain that the Commission has the information to perform an after-the-fact comparison of actual costs and performance to utility assumptions in RFPs. Thus, it is not clear that the Commission could hold utilities to their bids even if the Commission wished to do so.

Q. Why do you say that?

A. Two examples show the challenges that the Commission would face. First, IPC reports that it has not retained the files associated with the 2005 Peaking RFP in the ordinary course of business.[20] Unless the Commission had a complete duplicate set of the utilities' RFP-related documents, it would be very difficult for the Commission to know what the

[16] NIPPC/100, Monsen/27-28.
[17] Idaho Power Company response to NIPPC Data Request 3.5(b), presented in NIPPC Exhibit 304.
[18] Portland General Electric response to NIPPC Data Request No. 033, presented in NIPPC Exhibit 305.
[19] NIPPC/100, Monsen/28.
[20] Idaho Power Company response to Staff Data Request 2, presented in NIPPC Exhibit 306.

utilities assumed during bid evaluation because there might not be any record of the utility's original cost and performance projections for the plant.

Second, PGE stated in discovery that it changed the configuration of the Biglow Canyon Wind Project after the RFP and that the costs bid into the RFP are therefore not comparable to the actual construction costs.[21] Such changes would hamper the ability of the Commission to hold the utilities to the original RFP assumptions.

III. <u>Response to Staff's Testimony</u>

Q. What testimony are you responding to in this section?

A. I am responding to the opening testimony of Staff witness Dr. Robert Procter, which addressed three documents provided by NIPPC in this proceeding prior to submittal of my opening testimony: (1) "Technical Approach to Developing Bid Adders for Utility-Owned Generation Proposals," provided as Attachment 1 to Phase 2 Comments, submitted on March 19, 2012, (2) a whitepaper titled "Leveling the Bidding Field: Some Initial Steps Toward Fairly Comparing Proposals for Utility-Owned Generation and Independent Power Projects," provided to parties on November 16, 2011, and (3) testimony that I submitted in a California procurement case, which is referred to in the whitepaper and was provided upon request of other parties. (I refer to these three documents collectively as the Documents).

[21] Portland General Electric response to NIPPC Data Request No. 034, presented in NIPPC Exhibit 307; and Portland General Electric response to NIPPC Data Request No. 035, presented in NIPPC Exhibit 308.

Q. What is the relationship between the Documents and your opening testimony?

A. The Documents should not be confused with my testimony in this proceeding. My testimony in this proceeding builds off of analyses I had developed previously, but I have updated and refined those analyses and have added additional analysis that is based on the Oregon IOUs' power plants. While some of these updates, refinements, and additions are reflected in the Whitepaper and the Technical Approach mentioned above, my opening testimony in this proceeding reflects still additional effort based on subsequent discovery and further analysis. I believe that my testimony addresses many of the concerns raised by Dr. Procter about the Documents.

Q. Are Dr. Procter's critiques of the Documents relevant to your opening testimony in this proceeding?

A. Some of Dr. Procter's critiques are relevant to my opening testimony in this proceeding but others are not.

Q. How do you propose to respond to Dr. Procter's critiques?

A. In this section of testimony I will address Dr. Procter's high-level concerns that are relevant to my opening testimony. In the sections below, I will address Dr. Procter's critiques that are specific to individual bid adders and will identify those concerns that are not relevant to my opening testimony.

Q. What is your response to Dr. Procter's concern that the Documents do not include an examination of how the current bid evaluation guidelines address the defined risks?[22]

A. Dr. Procter is correct that the Documents do not include an assessment of the manner in which risks are addressed in the current bid evaluation process. The Commission has already explicitly found that "the IE's evaluation of the comparative risks and advantages of utility benchmark resources has not met [the Commission's] expectations."[23] Therefore, consistent with the Commission's guidance, NIPPC has instead focused on means of improving the way in which the utilities' and the IE's bid evaluations account for the risk differentials between proposed UOG and IPP projects.

Q. What is your response to Dr. Procter's concern that the Documents do not evaluate whether bias exists in the evaluation method towards the Benchmark Resource bid or IPP bids, but instead make implicit assumptions of bias towards the Benchmark Resource bid?[24]

A. As described above, the Commission has already found that there exists inherent structural bias towards utility-owned generation. In Order No. 11-001, which defined the scope of this proceeding, the Commission clearly stated that it "believe[s] further improvements [in the bid evaluation process] are needed to fully address utility self-build

[22] Staff/100, Procter/10.
[23] Order No. 11-001, Docket UM 1276, January 3, 2011, at 6.
[24] Staff/100, Procter/11.

bias."[25] Even Dr. Procter agrees that "utility regulation itself results in an inherent bias towards the Benchmark Resource bid at the expense of the IPP bid."[26] Therefore, additional examination of whether a bias exists is unnecessary.

Q. What is your response to Dr. Procter's concern that NIPPC implicitly assumes that cost over-runs from the construction of Benchmark Resource bid are totally placed on ratepayers whereas the IPP bid completely insulates ratepayers against all construction cost over-runs?[27]

A. NIPPC's recommendation is based on the assumption of cost-of-service ratemaking for UOG plants and on typical PPA structures for IPPs. From that assumption, it follows that UOG projects put greater risk onto ratepayers than IPPs because of ratepayer risk protections in PPAs. For example, the Top of the Wind PPA that PacifiCorp signed with Duke Energy [redacted] as described in the IE report for PacifiCorp's 2008R-1 RFP:[28]

[redacted]

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[25] Order No. 11-001, Docket UM 1276, January 3, 2011, at 6.
[26] Staff/100, Procter/4-5.
[27] Staff/100, Procter/11.
[28] PacifiCorp Supplemental Response to NIPPC Data Request 6.10, Supplemental Response, Confidential Attachment, "Report of the Independent Evaluator on Negotiations in PacifiCorp's 2008R-1 Request for Proposals for Renewable Electric Resources," presented to the Public Utility Commission of Oregon by Boston Pacific Company, Inc., September 18, 2009 ("Boston Pacific Company 2008 R-1 Negotiations Report"), at 8, presented in NIPPC Confidential Exhibit 309.

[redacted]

This type of risk mitigation is obviously understood within the industry to be common in PPAs.[29]

Q. Is your proposal flexible enough to deal with other forms of cost-recovery for UOG projects?

A. Yes. Under my proposal, if a utility agrees, for example, to cap construction costs, the cost over-run bid adder would not apply.

Q. Please describe Dr. Procter's concern with the use of averages as the basis for the bid adder.[30]

A. Dr. Procter agreed that NIPPC's method of calculating capital cost over-runs or under-runs was "reasonable with respect to calculating a weighted average expected value;"[31] however, he stated that using the average difference in construction cost as the bid adjustment adder "does not calculate that proposed adder consistent with either the variance or the standard deviation of capital cost."[32] Dr. Procter suggested that in order to account for associated risk, NIPPC could "calculate the variance or the standard deviation for its sample."[33]

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[29] I provide greater discussion at the start of each of the sections below in support of my belief that cost over-runs and performance shortfalls from UOG projects are usually borne by ratepayers, whereas PPAs usually insulate ratepayers from many of these cost over-runs.
[30] Staff/100, Procter/12.
[31] Staff/100, Procter/12.
[32] Staff/100, Procter/12.
[33] Staff/100, Procter/12.

Q. What is your response to Dr. Procter's suggestion?

A. I find that, given the available data, following Dr. Procter's suggestion to incorporate the standard deviation or variance into the bid adder would not produce a meaningful answer. The standard deviation and the variance (calculated as the standard deviation squared) provide information on the distribution of values around the mean; they do not change the fact that the mean remains the expected value. Additionally, in order to calculate a meaningful standard deviation or variance, the sample must be random.[34] As discussed below, the data used in our analysis do not meet the criteria of a random sample.

Q. Assuming, as Dr. Procter does,[35] that the data used in NIPPC's analyses are samples collected from a larger population, what can you learn by calculating the variance or the standard deviation?

A. Calculating the variance or standard deviation of a *sample* provides an estimate of the *population* variance or standard deviation, that is, the deviation of data in the population from the true population mean.[36] While the variance and standard deviation can be useful tools for estimating the variation of data in a given population, these statistics do not influence the expected value; nor do they tell us anything about how the adder will vary from one group of plants to another. In some circumstances, they can be used to calculate a confidence interval, which would give us information about how the bid adder might

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[34] Stone, Charles J, A Course in Probability and Statistics, 1996, San Francisco: Duxbury Press, at 99-100.
[35] Staff/100, Procter/12.
[36] StatSoft, Inc, "Statistics Glossary" in Electronic Statistics Textbook, 2012, Tulsa, OK: Statsoft, available from http://www.statsoft.com/textbook/statistics-glossary/.

differ among different groups of plants from the same population. However, those circumstances are not present in our case.

Q. Why is it not meaningful to calculate a confidence interval for the data from the California plants that you used to estimate the capital cost adder?

A. In order to calculate a meaningful confidence interval, or even a meaningful standard deviation, the sample must be random.[37] For a sample to be random, it must meet the following criteria: 1) every unit of the population must have an equal chance of being selected for the sample, and 2) the selection of the units must be independent, such that the selection of one unit in the population does not influence the selection of another unit.[38] Our sample data does not to meet the first criterion, since all UOG plants that were constructed in California over the past decade are included in the sample, and all other UOG plants, including all of the Oregon UOG plants, are excluded.

Furthermore, even if the sample were random, additional difficulties remain. For example, we would also need to consider whether the sample data should be weighted and, if so, how? These concerns are non-trivial, and simply calculating a confidence interval without addressing them would not produce a meaningful result.

[37] Schluter, Dolph, and Michael Whitlock, The Analysis of Biological Data, 2009, Greenwood Village, CO: Roberts & Company Publishers, at 7.
[38] Schluter, Dolph, and Michael Whitlock, The Analysis of Biological Data, 2009, Greenwood Village, CO: Roberts & Company Publishers, at 7.

Q. Are these concerns relevant to your heat rate and capacity factor adder analyses as well?

A. Yes. The datasets used in those analyses are not random samples as they represent all data points meeting the specified criteria. In addition, those datasets may not be normally distributed, which adds significant complications to the statistical analysis for small samples like those used in our analysis.

Q. Has Dr. Procter provided any guidance on how to implement his suggestion in the face of these concerns?

A. No. Dr. Procter simply suggests calculating a standard deviation or variance without providing any additional guidance[39] beyond noting that "more complex methods of measuring risk" [40] would need to be used for data that are not normally distributed. He does not suggest what more complex methods might be used. Nor does he indicate how a standard deviation or variance would be used in calculating the bid adder.

Q. Do you have any suggestions for how to respond to Dr. Procter's concern that your bid adders were not calculated using "a conventional definition of risk"?[41]

A. Dr. Procter defines risk as the "variation of outcomes around the expected outcome of some choice."[42] This is precisely what my proposed bid adders represent. For example, I calculated the capital cost bid adder by comparing actual construction costs with expected

[39] Staff/100, Procter/12.
[40] Staff/100, Procter/4.
[41] Staff/100, Procter/5.
[42] Staff/100, Procter/4.

construction costs. The 7% bid adder represents the deviation from the expected outcome (as do my other proposed bid adders). The methodology that I used is a straightforward way of assessing the risk of cost over-runs and performance shortfalls that avoids unnecessarily complex statistical analyses.

IV. Cost Over-Runs

Q. What is the purpose of this section of your testimony?

A. This section addresses various contentions raised by the utilities and Staff regarding the cost over-runs bid adder.

A. Need for Bid Adder

Q. Do you have evidence that cost over-runs affect the Oregon utilities' UOG plants?

A. Yes. As described above, I presented evidence in my opening testimony of cost over-runs of 29% at PacifiCorp's Goodnoe Hills plant and cost over-runs of 23% at IPC's Bennett Mountain plant.[43]

Q. Does IPC agree that there was a cost over-run at its Bennett Mountain plant?

A. No. IPC claims that there were no cost over-runs for the plant.[44]

[43] NIPPC/100, Monsen/17 and Monsen/19.
[44] Idaho Power Company response to Staff Data Request 4, presented in NIPPC Exhibit 310.

Q. Please explain why you claim that there was a cost over-run at the Bennett Mountain plant.

A. IPC's statement applies only to the costs incurred prior to the plant's commercial operation date. As discussed above, IPC incurred significant costs repairing a latent construction defect after IPC's Bennett Mountain plant came online. When the costs of repairing a latent construction defect are added in, the resulting construction costs are 23% higher than originally expected. In assessing cost over-runs, the full construction costs must be assessed, whether these costs were incurred prior to or following the start of commercial operations. This is necessary since, under typical cost-of-service ratemaking, ratepayers are fully at risk for reasonable construction cost over-runs for UOG projects, regardless of when the costs are incurred.

Q. Do you have evidence that PPAs shield ratepayers from the costs associated with cost over-runs in IPP plants.

A. Yes. It is my understanding that a typical PPA structure does not allow an IPP to pass through costs that exceed the agreed-upon price. This understanding is confirmed by the IE Reports from Oregon RFPs. For example, in one report, the IE stated [redacted]

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[45] PacifiCorp response to NIPPC Data Request 5.2, Confidential Attachment, "The Oregon Independent Evaluator's Final Closing Report on PacifiCorp's 2009R Renewables RFP," presented to the Oregon Public Utility Commission

[redacted]

Q. Do you agree with the utilities' contentions that engineering, procurement, and construction (EPC) contracts shield ratepayers from cost over-runs from UOG projects?

A. No. In opening testimony PacifiCorp witness Kusters admitted that contingency cost adders must be used to account for the risk of cost over-runs on EPC contracts.[47] In discovery, PacifiCorp reported that contingency reserves of 5-6.2% were added to the fixed EPC price in recent RFPs.[48] PacifiCorp reported no such contingency cost adders in its evaluation of PPAs.[49] The limitations of EPC contract guarantees are discussed further in the reply testimony of NIPPC witness Allen Kasper, NIPPC/500.

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by Boston Pacific Company, Inc., November 5, 2009, at 22 ("Boston Pacific Company 2009R"), presented in NIPPC Confidential Exhibit 311.

[46] Boston Pacific Company 2009R, at 23, presented in NIPPC Confidential Exhibit 311.

[47] PAC/100, Kusters/20.

[48] PacifiCorp response to NIPPC Data Request 4.14(a), presented in NIPPC Exhibit 312.

[49] PacifiCorp response to NIPPC Data Request 5.1(c), presented in NIPPC Exhibit 313.

Q. Does PacifiCorp's contingency cost adder account sufficiently for the risk of cost over-runs?

A. No. First of all, PacifiCorp's adder is *ad hoc* and not currently required by the Commission. Only PacifiCorp has stated that it has ever used such an adder, and it is not at all clear that PacifiCorp would continue to use this adder in future RFPs. Indeed, PGE has stated that its newest UOG plants have been built below cost and has proposed that no adder be assigned to UOG projects.[50]

Additionally, while I certainly agree that applying a contingency cost adder to UOG projects is worthwhile and should be required of all the utilities, PacifiCorp's methodology is flawed in at least two ways: (1) it is too limited given that it overlooks cost over-runs that spill into the first five years of operation and (2) it is not large enough to account even for the full risk of cost over-runs during the initial construction period. [redacted]

[50] PGE/100, Outama–Bettis-Mody-Hager/23-24.
[51] Boston Pacific Company 2009R, at 23, presented in NIPPC Confidential Exhibit 311.

Q. Doesn't PacifiCorp also claim to use another form of risk adder in its bid evaluation?

A. Yes. PacifiCorp has used a second risk adder.[52] This adder adjusts bids only for the risk of indexing capital costs to inflation during the bid evaluation process.[53]

Q. Does PacifiCorp's risk adder account sufficiently for the risk of cost over-runs?

A. No. It does not at all account for the risk of capital cost over-runs during construction and during the first five years of operations.

Q. Why are over-runs during the first five years of operations relevant?

A. As discussed in my opening testimony,[54] the cost of a plant initially put in ratebase can be misleading because a utility may choose to incur construction costs for a period after the online date of the plant. For example, IPC made $16 million in capital expenditures in the year following Bennett Mountain's in-service year and then spent an additional $7 million purchasing capital spare turbine blades and vanes for the plant in 2009,[55] four years after the plant's in-service year.[56] IPC also spent about $3 million in installation charges and capital spare parts for Danskin Units 2 and 3 in the two years following the units' in-service year.[57] Similarly, PacifiCorp made a $6.2 million increase to the rate

[52] PAC/100, Kusters 20.
[53] PacifiCorp response to NIPPC Data Request 4.13, presented in NIPPC Exhibit 314; and PacifiCorp Response to NIPPC Data Request 4.13, Confidential Attachment 4.13-1, presented in NIPPC Confidential Exhibit 315.
[54] NIPPC/100, Monsen/19-20.
[55] The purchase of capital spare parts should be considered part of the construction cost unless specifically identified as a planned capital expenditure in the project bid.
[56] Idaho Power Company response to NIPPC Data Request 4.1(a), Attachment 1, presented in NIPPC Exhibit 316.
[57] Idaho Power Company response to NIPPC Data Request 4.4, presented in NIPPC Exhibit 317.

base for Seven Mile Hill in the year following the plant's in-service year, with the "majority of these costs relate[d] to project construction close out costs and other construction cost adjustments."[58] PacifiCorp also identified \$3.1 million in construction close out costs and construction costs adjustments for the Gadsby Peakers during the two years following the plant's in-service year, as well as a \$5.9 million expenditure to purchase a spare turbine engine.[59] It should be noted that the costs of all these purchases were passed on to ratepayers in whole.[60]

Q. Were these cost over-runs reflected in the FERC Form 1 data that you used to develop your bid adder for construction cost over-runs incurred during the first five years of commercial operations?

A. Only in part. The FERC Form 1 data show the difference in Cost of Plant from year to year. Given that I had no data indicating otherwise, I conservatively assumed that, aside from depreciation, the year-to-year changes in Cost of Plant reflected only expenditures. However, I have since learned from recent discovery responses that, in some cases, significant retirements occurred during the first five years of operations. For example, the \$16 million capital expenditure for Bennett Mountain mentioned above was offset in that same year by a \$15.2 million retirement.[61] As a result, the FERC Form 1 data indicate a

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[58] PacifiCorp response to NIPPC Data Request 6.4, presented in NIPPC Exhibit 301; and PacifiCorp response to NIPPC Data Request 6.4, Attachment 6.4-2, presented in NIPPC Exhibit 303.
[59] PacifiCorp response to NIPPC Data Request 6.4, presented in NIPPC Exhibit 301; and PacifiCorp response to NIPPC Data Request 6.4, Attachment 6.4-1, presented in NIPPC Exhibit 302.
[60] Idaho Power Company response to NIPPC Data Request 4.4, presented in NIPPC Exhibit 317; and PacifiCorp response to NIPPC Data Request 6.4, presented in NIPPC Exhibit 301.
[61] Idaho Power Company response to NIPPC Data Request 4.1(a), Attachment 1, presented in NIPPC Exhibit 316.

net increase in Cost of Plant of just $800,000.[62] The remaining $15.2 million increase was not incorporated into the bid adder calculation because the expenditure was not apparent from the FERC Form 1 data.

Q. What conclusion can you reach from this new information?

A. The utilities' discovery responses confirm that the FERC Form 1 "Cost of Plant" data that I used to develop the 5.7% annual adder for cost over-runs during the first five years of operations is an appropriate data source.[63] However, they also demonstrate that this adder is likely conservative because change in Cost of Plant on the FERC Form 1 may not represent all of their construction costs after a plant comes online.

B. Responses to Staff Comments

Q. What are Dr. Procter's key responses to your capital cost adder proposals in the Documents?

A. Dr. Procter makes the following points:

1. The data set is extremely small and does not include plants from the Oregon utilities or plants from states other than California.[64]

2. Separate adders should be developed for combined cycle plants and for single cycle plants.[65]

[62] $800,000 = $16 million - $15.2 million.
[63] IPC Response to NIPPC Data Request 4.4 (b), presented in NIPPC Exhibit 317; and PacifiCorp response to NIPPC Data Request 6.4 (c), presented in NIPPC Exhibit 301.
[64] Staff/100, Procter/11.
[65] Staff/100, Procter/12.

3. NIPPC does not provide construction cost over-run data for other types of resources, such as renewable plants.[66]

I respond to each of these concerns below.

Q. What is your response to Dr. Procter's first point regarding the size and scope of the data set?

A. I agree with Dr. Procter that a larger data set would be preferable. I had hoped to have a full set of data regarding the Oregon utilities' UOG plants that I could include in my opening testimony and repeatedly requested the relevant information from the utilities. However, as described above and in my opening testimony,[67] the utilities have been highly resistant to providing data on their plants' expected and actual construction costs.

Q. What is your response to Dr. Procter's second point regarding the technology-specific bid adders?

A. Dr. Procter's proposal is reasonable. I originally had decided not to provide technology-specific adders because developing two adders further reduces the size of each data set used to develop the adders. However, given Dr. Procter's proposal, I have used the same dataset of California UOG plants that I used in my opening testimony to develop adders for risk from cost over-runs for simple cycle and combined cycle plants, both through the plants' commercial operation date (COD) and during the first five years of operations.

[66] Staff/100, Procter/13.
[67] NIPPC/100, Monsen/14-15.

The results, and the number of data points included in each analysis, are shown in Table 1.

Table 1: Cost Over-Runs Bid Adders by Technology

(number of data points shown in parentheses)

	Through COD	During First Five Years of Operations (annual value)
Simple Cycle	20.9% (6)	8.5% (6)
Combined Cycle	6.2% (4)	5.2% (3[68])
All Plants	7.0% (11[69])	5.7% (9)

Q. What is your response to Dr. Procter's third point regarding developing cost adders for renewable plants?

A. I agree with Dr. Procter that it would have been preferable to have a separate analysis for other types of resources. I tried to obtain the necessary data for an analysis of the construction costs for renewable plants from the utilities; however, as discussed previously, the utilities refused to provide most of the data needed for the analysis.

Q. From the data you did receive, did you find significant cost over-runs for renewable plants?

A. Yes. The data I obtained reveal that PacifiCorp's Goodnoe Hills and Seven Mile Hills plants both experienced significant construction cost over-runs through COD,[70] demonstrating that cost over-runs are not an issue limited to gas-fired plants. However,

[68] Consistent data on capital expenditures at the Mountainview combined cycle power plant during the plant's first five years of operations was not available, so this plant was excluded from this element of the analysis.
[69] Includes a plant using reciprocating engine technology, which is not included in either the simple cycle or the combined cycle adder.
[70] NIPPC/100, Monsen/17.

lacking a full dataset for renewable projects, I was unable to develop a renewable-specific adder for cost over-runs through COD.

Q. Do you have a recommendation for an adder for renewable projects?

A. Yes. I recommend that the Commission apply the 7.0% adder, which reflects the full data set of California UOG plants, to renewable projects unless the Oregon utilities provide data demonstrating that a different adder is more relevant to their renewable plants.

V. Heat Rate Degradation

Q. What is the purpose of this section of your testimony?

A. This section addresses various claims raised by the utilities and Staff regarding the heat rate degradation bid adder.

A. Need for Bid Adder

Q. Do you have evidence that the Oregon utilities' UOG plants suffer from heat rate degradation?

A. Yes. As demonstrated in my opening testimony, an examination of reported heat rates from the Oregon utilities' gas-fired plants shows a deviation from the minimum reported heat rate (which was the baseline heat rate for the derivation of my proposed heat rate adder) of 10.4%.[71] In addition, confidential data revealed deviations from expected heat rates during the first five-to-seven years of operations of [redacted] for the Port Westward plant

[71] NIPPC/100, Monsen/28.

and [redacted] for the Danskin plant.[72] Furthermore, data recently provided by PacifiCorp show that the average heat rate during the first ten years of operations for the Gadsby peaker units was 11.9% higher than the expected heat rate used in the evaluation of these units.[73]

Q. Do you have evidence that PPAs shield ratepayers from the costs associated with heat rate degradation in IPP plants?

A. Yes. In her opening testimony, PacifiCorp witness Kusters describes guaranteed heat rate terms that are common in tolling service agreements (TSA), which is a form of PPA.[74] Ms. Kusters explains that the guaranteed heat rate under a TSA is a contractual concept and that regardless of the heat rate at which the plant ultimately operates, customers are ensured that the price paid for energy will not be impacted.[75] Additionally, Idaho Power's witness stated in his opening testimony that IPP projects generally offer a guaranteed heat rate.[76]

Q. What do you conclude?

A. Because UOG and IPP projects expose ratepayers to different levels of risk, a heat rate adder for UOG projects is justified.

[72] NIPPC/100, Monsen/28.
[73] PacifiCorp response to NIPPC Data Request 6.6(d), presented in NIPPC Exhibit 318.
[74] PAC/100, Kusters/14-15.
[75] PAC/100, Kusters/15.
[76] Idaho Power/100, Stokes/ 13.

B. Manufacturer Degradation Factors Are Not Adequate Proxies For the Risk of Heat Rate Degradation

Q. The utilities claim that their use of Original Equipment Manufacturer (OEM) heat rate degradation factors in their UOG proposals accounts for the risk of heat rate degradation.[77] Do you agree?

A. OEM degradation factors do not appear to adequately reflect the heat rate degradation seen historically in gas-fired generation. As demonstrated in my opening testimony, heat rate degradation can be expected to be on the order of 8.0%-10.4%.[78] According to information provided by PacifiCorp in discovery,[79] OEM degradation factors average around [redacted]. OEM degradation factors therefore cover just a small fraction of the level of heat rate degradation seen in existing power plants. That said, to the extent that a UOG bid already reflects some sort of degradation factor, the applicable bid adder should be adjusted by the amount of heat rate degradation reflected in the bid.

C. PacifiCorp's Argument That Higher Heat Rates May Reflect Operational Differences, Not Degradation, is Unsupported

Q. PacifiCorp claims that higher heat rates may reflect operational differences, such as operations at reduced load, rather than performance degradation.[80] Do you agree?

A. I agree that the way a plant is operated can affect the plant's heat rate. However, PacifiCorp has presented no evidence that operational differences contribute a significant

[77] PAC/100, Kusters/11-12; Idaho Power/100, Stokes/12; and PGE/100, Outama-Bettis-Mody-Hager/16-17.
[78] NIPPC/100, Monsen/27-28.
[79] PacifiCorp response to NIPPC Data Request 3.4, Confidential Attachment 3.4-1, Lakeside I, Lakeside II, and Currant Creek Heat Rate Degradation Information, presented in NIPPC Confidential Exhibit 319.
[80] PAC/100, Kusters/14.

amount towards the observed increases in heat rate in their own plants. NIPPC asked PacifiCorp in discovery for an estimate of the proportion of the increase in heat rate that is associated with each of the factors that PacifiCorp alleges contribute to increases in heat rate:[81] (1) operations at reduced load, (2) variations in ambient conditions, (3) the effects of startups and shutdowns, and (4) other factors. PacifiCorp was unable to provide any estimate of the impacts, stating, "The Company has not prepared the requested analysis and…does not categorize the portions of time the heat rate is attributable to these factors."[82] Absent such evidence, the Commission should give no weight to PacifiCorp's claim that operational differences, rather than performance degradation, are a cause for heat rate increases.

Q. Do you have other concerns with PacifiCorp's assertion about operating below full load resulting in higher heat rates?

A. Yes. While PacifiCorp notes that operations at reduced load can arise from the need to provide ancillary services, it is also the case that operations at reduced load can be a consequence of performance degradation that has resulted in a higher heat rate. This is because a plant whose heat rate has increased due to performance degradation will have a higher marginal cost than it would have absent the degradation. As a result, the higher heat rate makes it more costly to operate the degraded plant, resulting in that plant potentially having lower run hours or running as a marginal resource at part load.

[81] PAC/100, Kusters/14.
[82] PacifiCorp response to NIPPC Data Request 4.7(a), presented in NIPPC Exhibit 320.

Q. Was PacifiCorp able to provide any quantitative evidence to support its claim regarding heat rate degradation due to provision of ancillary services?

A. No. In response to NIPPC's request, PacifiCorp was unable to provide any estimate of the proportion of load reductions at gas-fired plants that, on average, are due to the need to provide ancillary services versus for market reasons or other reasons.[83]

Q. What do you conclude?

A. To the extent that operations at reduced load are the result of heat rate degradation, the heat rate increase that results from the partial-load operations should be considered a cost of performance degradation.

Q. Do you agree with PacifiCorp that customers are not affected if reported heat rates are higher than full load heat rates?[84]

A. No. PacifiCorp's statement is much too broad. While there may be specific situations in which customers are not affected by increases in heat rate (e.g., when a heat rate increases solely from the need to provide reserves), customers are hurt by the higher operating costs resulting from heat rate increases that arise from performance degradation, which is a significant cause of heat rate increase.[85]

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[83] PacifiCorp response to NIPPC Data Request 4.7(b), presented in NIPPC Exhibit 320.
[84] PAC/100, Kusters/14.
[85] See, for example, Portland General Electric response to NIPPC Data Request No. 017, "The 'new and clean' heat rate is an 'out-of-the-box' heat rate. Non-recoverable performance degradation effectively begins with testing of the unit. Therefore, the heat rate realized in the first year of commercial operation (during which non-recoverable degradation continues) will exceed the 'new and clean' heat rate," presented in NIPPC Exhibit 321.

Q. To the extent that higher heat rates may reflect operational differences that arise from the need to provide reserves, rather than performance degradation, how does this affect your proposed bid adder?

A. PacifiCorp accounts in the shortlist phase of bid evaluation for the costs and benefits of providing reserves,[86] which either UOG projects or IPP projects can provide.[87] Therefore, there is no need to adjust my recommended bid adder to account for carrying reserves.

Q. Do you agree with PacifiCorp that a bidder offering a guaranteed heat rate would embed a risk premium into the price of the TSA in the form of a heat rate margin to address degradation? [88]

A. I agree with PacifiCorp that offering a guaranteed heat rate in a TSA creates a risk for an IPP and that embedding a risk premium into the price of the TSA in the form of a heat rate margin is one way the IPP may address this risk.

Q. How does this risk mitigation by the IPP relate to a heat rate adder for UOG projects?

A. Unlike IPPs, UOG projects may not provide ratepayers with a guaranteed heat rate. The heat rate adder serves as a proxy for the potential costs ratepayers would incur because of the lack of a heat rate guarantee. Without the adder, an IPP bid with a guaranteed heat rate would be compared to the UOG bid without any adjustment for the UOG bid not

[86] PAC/100, Kusters/16.
[87] PacifiCorp response to NIPPC Data Request 4.9, presented in NIPPC Exhibit 322.
[88] PAC/100, Kusters/15-16.

providing the heat rate guarantee. If the IPP bid includes a risk premium to account for its heat rate guarantee, the IPP bid will appear more expensive than a comparable UOG bid because the risk of heat rate degradation is accounted for in the IPP bid, while the ratepayer risk from heat rate degradation in the UOG bid is partially or wholly unaccounted for.[89] This is precisely why there is a need for a bid adder: to accurately quantify the relevant costs in an RFP's bid evaluation comparing an IPP bid with a specified heat rate and performance guarantees to a UOG bid with no guaranteed heat rate.

D. Response to Staff Comments

Q. What are Dr. Procter's key responses to your heat rate adder proposals?

A. Dr. Procter's responses focus on a heat rate adder proposal put forth in the Documents. As noted above, I refined the heat rate adder proposal over the course of developing my opening testimony in this proceeding, thereby resolving some of Dr. Procter's concerns. For example, Dr. Procter's discussion of whether plants in de-regulated markets should be omitted from the dataset[90] is no longer relevant—in my opening testimony, I included plants from all markets.

It is also worth noting that my testimony in this docket has accounted for critiques made by other Staff personnel through the workshop process and has incorporated additional material obtained from the Oregon utilities.

[89] Of course, if a UOG bid has a guaranteed heat rate, then it should not have a heat rate adder assigned to it.
[90] Staff/100, Procter/18.

Dr. Procter also raises the following issues:

- Concerns over the vintages and types of plants in the dataset;[91]
- Whether it would be appropriate to remove plants with high heat rates from the dataset;[92] and
- Whether it is appropriate to weight observations by energy output.[93]

I address each of these concerns below.

Q. What is your response to Dr. Procter's concerns regarding the vintages and types of plants in the dataset?

A. While the dataset used in my analysis does have limitations regarding plant vintage and type, my examination of heat rate data from the Oregon utilities' gas-fired plants shows that the results from the broader dataset are not atypical of the performance of the Oregon utilities' plants. Using the dataset of plants located throughout the US, I found that a heat rate adder of 8.0% was needed.[94] When I examined heat rate degradation for plants owned by the utilities (i.e., Currant Creek, Lake Side, Gadsby, Chehalis, West Valley, Port Westward, Danskin, and Bennett Mountain), I found an appropriate heat rate adder for those plants would be 10.4%.[95] This result is particularly striking given that the Oregon utilities' UOG plants are all relatively new plants, which would be expected to have <u>less</u> degradation than the nationwide sample, which consists of data from older utility-owned plants. Thus, the heat rate adder based on the nationwide dataset is a

[91] Staff/100, Procter/15-16.
[92] Staff/100, Procter/16-17.
[93] Staff/100, Procter/16-17.
[94] NIPPC/100, Monsen/27.
[95] NIPPC/100, Monsen/27-28.

conservative estimate relative to the history of plants in Oregon. That said, if the Commission is concerned about the relevance of the nationwide dataset, a heat rate adder of 10.4% based on the Oregon utilities' UOG plants could be used instead.

Q. What is your response to Dr. Procter's discussion of removing the highest heat rate plants from the dataset before calculating the adder?

A. The heat rate adder proposal in my opening testimony excludes plants with heat rates below 7,000 Btu/kWh because it would be physically unrealistic for plants of this vintage to have such low heat rates.[96] Dr. Procter recommended removing plants with heat rates greater than 8,000 Btu/kWh.[97] Such an adjustment is unreasonable. Plants with heat rates above 8,000 Btu/kWh are certainly physically realistic. Indeed, most of the plants in the dataset are combustion turbines, whose starting heat rates are above this level. For this reason, the Commission should not adopt this proposal by Dr. Procter.

Q. What is your response to Dr. Procter's discussion of weighting observations by plant output?

A. I agree with Dr. Procter that a performance weighting is better than an un-weighted average in linking the observed heat rate degradation with the resulting costs borne by ratepayers. I addressed this in my opening testimony by weighting heat rate degradation by plant capacity factor to develop my proposed heat rate adder. An alternative approach would be to weight heat rate degradation by energy production to derive the weighted-

[96] NIPPC/100, Monsen/26.
[97] Staff/100, Procter/17-18.

average adder. This approach would result in a bid adder of 5.5% based on the nationwide dataset or a bid adder of 8.9% based on the Oregon utilities' UOG plants.

VI. Wind Capacity Factors

Q. What is the purpose of this section of your testimony?

A. This section addresses various contentions raised by the utilities and Staff regarding the wind capacity factor bid adder.

A. Need for Bid Adder

Q. Do you have evidence that the Oregon utilities' UOG wind plants have experienced lower than anticipated capacity factors?

A. Yes. As demonstrated in my opening testimony, on average, PacifiCorp has overestimated the capacity factors of its UOG wind plants by [redacted].[98]

Q. Do you have evidence that PPAs shield ratepayers from the costs associated with capacity factor overestimates in IPP plants?

A. Yes. This is inherent in the structure of PPAs. As the Accion Group explained in its IE report for PGE's 2008 renewables RFP:[99]

> PPAs implicitly assume capacity factor risk as the development costs are independent of the projected capacity factor. Therefore, if the capacity factor over time is higher than that assumed in the PPA, the developer's profit is

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98 NIPPC/100, Monsen/31-33.

99 Portland General Electric response to NIPPC Data Request No. 012, Supplement 1, Attachment B, "Final Report of the Independent Evaluator Regarding Portland General Electric Company's Request for Proposals for Renewable Energy Resources," submitted to the Public Utility Commission of Oregon by Accion Group, January 9, 2009 (Accion Group 2009 Report), at 15, presented in NIPPC Exhibit 323.

> commensurately higher. However, a lower than expected capacity factor can substantially impact the returns to the developer.

In other words, the PPA structure places the risk of error in estimating capacity factor with the developer. Ratepayers pay for the delivered energy from an IPP at an agreed-upon price, regardless of the amount of energy production. Lower-than-expected production reduces the developer's returns; it does not affect the price that ratepayers pay for power.

B. PGE's Assumption That Wind Forecast Error Has Been Fixed is Unsupported and Overly Optimistic

Q. What is your response to PGE's argument that wind forecasting has improved and that the capacity factor over-estimates observed in existing wind projects should not be anticipated from future projects?[100]

A. As discussed below, I find this argument to be unsupported because evidence indicates that forecasting error does not fully explain the UOG capacity factor over-estimates and that incentives for over-estimating performance may be a more significant factor than wind forecasting technology in determining the magnitude of the over-estimate. Furthermore, prior improvements in forecasting technology have not yielded corresponding improvements in capacity factor estimates for UOG projects. I therefore do not anticipate that more recent forecasting improvements will be sufficient on their own to solve the problem of UOG capacity factor overestimation.

[100] PGE/100, Outama-Bettis-Mody-Hager/26.

Q. Have you seen capacity factor forecasting errors for IPPs that are similar to those seen for UOG wind projects?

A. No. NIPPC requested data from each of the utilities on the expected and actual capacity factors of their wind PPAs. PacifiCorp refused to provide these data;[101] however, NIPPC did obtain data on PacifiCorp's Top of the World wind PPA through an Independent Evaluator report provided as part of a separate discovery request,[102] and NIPPC obtained performance data from IPC for its PPA with the Elkhorn Valley project[103] and from PGE for its PPAs with the PaTu[104] and Klondike II wind projects.[105,106] Using the same methodology I used to estimate the capacity factor for PacifiCorp's UOG plants, I calculated that these IPP plants had an average capacity factor [redacted], compared with an [redacted] calculated for PacifiCorp's UOG plants.

Q. What does this difference in forecast error imply?

A. This implies that wind forecasting error may not be just a result of forecasting technology, but also one of incentives.

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[101] PacifiCorp response to NIPPC Data Request 3.7, presented in NIPPC Exhibit 324.
[102] "Revised 2008R-1 Final Shortlist, Updated July 6, 2009 with Independent Expert Capacity Factor Review and Pre-Gateway Coal Coal Backdown Study," PacifiCorp, provided in Exhibit 2 to the Boston Pacific Company 2008R-1 Negotiations Report, presented in NIPPC Confidential Exhibit 309. Note, the document cited provided only the expected capacity factor for the wind project. I obtained the actual capacity factor from PacifiCorp's FERC Form 1 filing.
[103] Idaho Power Company confidential response to NIPPC Data Request 2.7, presented in NIPPC Confidential Exhibit 325.
[104] Portland General Electric response to NIPPC Data Request No. 013, Confidential Attachment 013-A, presented in NIPPC Confidential Exhibit 326.
[105] Portland General Electric response to NIPPC Data Request No. 013, 1st Supplemental Response, Confidential Attachment 013-D, presented in NIPPC Confidential Exhibit 327.
[106] Portland General Electric reported that there was no expected capacity value associated with the Vansycle PPA, so this PPA was not included in the analysis. Portland General Electric response to NIPPC Data Request No. 013, Confidential Attachment 013-A, presented in NIPPC Confidential Exhibit 326.

Q. How would incentives explain the difference between UOG and PPA capacity factor errors?

A. Utilities have the incentive to over-estimate plant performance for their UOG bids because doing so makes their bids more competitive without imposing on them any costs (since ratepayers, not shareholders, would bear the cost of the underperformance). IPPs have the incentive to accurately predict performance because the IPPs would bear the cost of underperformance. These incentives are consistent with the [redacted]

Q. Could plant age account for the difference between the UOG and PPA capacity factor errors?

A. This is unlikely. Nine of PacifiCorp's 12 UOG wind plants came into service in 2008 and 2009, and the set of UOG plants as a whole has a capacity-weighted in-service date of January 2007.[107] In contrast, two of the four IPP plants selling pursuant to PPAs came into service prior to 2008, and the set of PPA plants as a whole has a capacity-weighted in-service date of August 2006, which is earlier than for PacifiCorp's UOG projects. If PGE's assertions that wind forecasting technology has improved in recent years (thereby reducing errors in capacity factor forecasts) were correct, I would expect the older PPAs to have larger forecasting errors than the more recent UOG plants. However, the data

[107] Each in-service year is weighted by the plant capacity and the number of data points available for the plant in order to accurately reflect the weighting of the plant within the calculated capacity factor adder.

shows [redacted], with the older PPAs having [redacted] forecast error than the newer UOG plants. This result holds true even when considering only the two oldest PPA plants: the Klondike II and Elkhorn Valley wind PPAs, with in-service dates in 2005 and 2007, have had an average capacity factor [redacted] average capacity factor over-estimate for the much newer UOG plants.

Q. Could the difference between the UOG and PPA capacity factor errors be accounted for by differences in timing of the available data?

A. No. Table 2 below shows the capacity-weighted capacity factor over-estimate for the PPA plants and for the UOG plants by year. [redacted]

Table 2: Capacity Factors for UOG and IPP Projects by Year

	2006	2007	2008	2009	2010	2011
IPP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
UOG						

Q. What does PGE claim regarding improvements in forecasting technology?

A. PGE provides a presentation from GL Garrad Hassan to support its claim that an improved assessment methodology has reduced underperformance expectations to 0%.[108] The GL Garrad Hassan presentation shows a number of incremental forecasting improvements over the years, not one change that resolved the forecasting error entirely.[109]

Q. Why do you claim that prior improvements in forecasting technology have not yielded corresponding improvements in capacity factor estimates for UOG projects?

A. The GL Garrad Hassan presentation used by PGE to support its contention shows that the change in forecasting technology that resulted in the greatest magnitude of improvement occurred around 2006, with less significant changes occurring in more recent years.[110] Yet, PacifiCorp wind projects constructed subsequent to 2006 are still showing large underperformance errors. Even if you remove from the analysis the three oldest plants (i.e., the PacifiCorp plants that come online in 1999, 2006, and 2007) and retain only the plants built from 2008 through 2010, there remains a [redacted] underperformance error. This is particularly striking given that actual data are available for these plants for only three years, 2009-2011, and 2011 appears to have been a high wind year with unusually low

[108] PGE/100, Outama – Bettis – Mody – Hager/26.
[109] Portland General Electric response to NIPPC Data Request No. 027, Attachment 027-A, "Actual vs. Predicted Performance – Validating pre construction energy estimates," GL Garrad Hassan, September 2012 ("GL Garrad Hassan Presentation"), at 8, presented in NIPPC Exhibit 328. (Note: a black-and-white version of the entire presentation is included in PGE Exhibit 102. A color version of the cited slide is provided in NIPPC Exhibit 328 for greater clarity.)
[110] GL Garrad Hassan Presentation, at 8, presented in NIPPC Exhibit 328.

capacity factor error for nearly all the UOG and PPA plants reviewed. The overestimate in capacity factors for these recently constructed plants were [redacted] in 2009 (for plants coming online in 2008 only) and [redacted] in 2010. These errors may be lower than they would have been absent the forecasting improvements, but clearly the forecasting improvements were insufficient to substantially reduce the capacity factor over-estimates.

C. Capacity Factor Risk is Not as High for IPP Projects as For UOG Projects

Q. What is your response to arguments by PacifiCorp and PGE that receiving more wind power from wind PPAs than anticipated could be costly to ratepayers?[111]

A. I believe this argument to be disingenuous. The utilities' RFP evaluations are based on the premise that there is a need for high capacity factor renewable energy projects that will produce the most energy and renewable energy credits (RECs) for the least cost.[112] Obtaining slightly more renewable power than anticipated at the least-cost price should have little or no adverse impacts on ratepayers.

Furthermore, the confidential data on IPP wind forecast error discussed above show that, even given a circumstance where extra renewable power is not needed, the risk of retail rate increases due to higher than anticipated IPP wind generation is much lower than the risk of retail rate increases due to lower than anticipated UOG wind generation because, as discussed above, [redacted].

[111] PAC/100, Kuster/9; and PGE/100, Outama-Bettis-Mody-Hager/28.
[112] Accion Group 2009 Report, at 10, presented in NIPPC Exhibit 323; and Boston Pacific Company 2009R, at 15, presented in NIPPC Confidential Exhibit 311.

This is not surprising given the incentives for IOUs to overestimate capacity factors, and the incentives for IPPs to forecast as accurately as possible.

Notably, neither PacifiCorp nor PGE presented evidence that ratepayers have had to bear costs on account of IPP wind forecasting underestimates. They appear to have posed this hypothetical argument as a red herring to try to divert attention from the widely established and well-documented real risk of cost over-runs from UOG wind forecasting over-estimates.

Q. What indications do you have that the incremental risk to ratepayers from capacity factor overestimates in UOG wind projects is well-known?

A. [redacted]

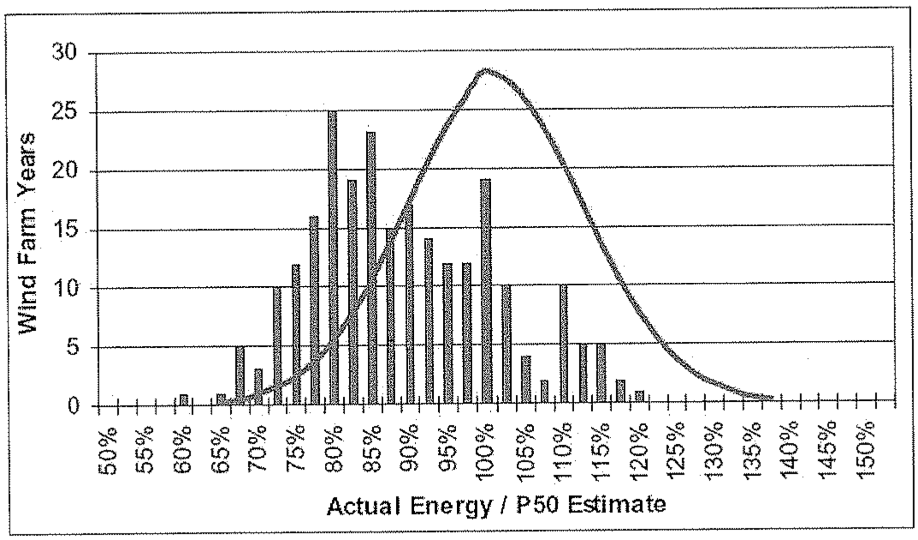
The Accion Group described this risk differential in their IE report for PGE's 2008 renewables RFP, stating, "the ownership option [of a bid for a wind project with both ownership and PPA options] comes with significant capacity factor risk for the ratepayer which would be borne by the counterparty in a PPA structure."[113] The IE report cites a study showing that actual production from wind farms that had recently been placed in

[113] Accion Group 2009 Report, at 3, presented in NIPPC Exhibit 323.

service in the U.S. had produced about 11% less energy than expected (Figure 1). This is similar to the [redacted] overestimate that I calculated for PacifiCorp's UOG wind plants.[114]

Figure 1: Actual versus Expected Energy Production at U.S. Wind Farms

Reproduced from Accion Group's IE Report for PGE's 2008 Renewable RFP



Average: about 11% below P50

The Accion Group IE report further notes that two capacity factor estimates for the ownership bid that were completed within three months of each other varied by more than 5%, which affected the projected levelized cost of the project by about $20 per MWh.[115] The IE noted that this variation "reflects the risk that lower energy production from the facility could dramatically lower the value the ownership option would provide."[116]

[114] NIPPC/100, Monsen/32.
[115] Accion Group 2009 Report, at 3, presented in NIPPC Exhibit 323.
[116] Accion Group 2009 Report, at 3, presented in NIPPC Exhibit 323.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[117] PacifiCorp response to NIPPC Data Request 6.10, Confidential Attachment, "The Oregon Independent Evaluator's Final Closing Report on PacifiCorp's 2008R-1 Renewables RFP," presented to the Oregon Public Utility Commission by Boston Pacific Company, Inc., May 15, 2009 ("Boston Pacific Company 2008R-1"), at 23, presented in NIPPC Confidential Exhibit 329.
[118] Boston Pacific Company 2008R-1, at 23, presented in NIPPC Confidential Exhibit 329.
[119] Boston Pacific Company 2009R, at 21, presented in NIPPC Confidential Exhibit 311.
[120] Boston Pacific Company 2009R, at 22, presented in NIPPC Confidential Exhibit 311.

[redacted] Given the observed trends for UOG wind projects to underperform their estimates, this created the risk that a UOG project that bid below-cost using a capacity factor over-estimate could be selected in place of a IPP project with a higher fixed price bid but a more realistically estimated capacity factor.

[redacted] The Accion Group said that they would expect PGE to "fully document the benefits and value of the ownership option, beyond what is reflected in the RFP evaluation model, and establish that the value offered by the ownership option outweighs the risk of energy production implicit in the ownership option."[121] They further recommended that a "risk adjustment should be assessed to the ownership option" to account for this capacity factor risk.[122] [redacted] This approach would partially protect ratepayers from cost over-runs by providing penalties for outages, but it would not protect ratepayers from weaker than anticipated wind. It would also not correct the selection bias that favors UOG projects. A bid adder (or "risk adjustment," in the Accion Group's nomenclature) is needed to correct for this bias.

[121] Accion Group 2009 Report, at 4, presented in NIPPC Exhibit 323.
[122] Accion Group 2009 Report, at 15, presented in NIPPC Exhibit 323.
[123] Boston Pacific Company2009R, at 23, presented in NIPPC Confidential Exhibit 311.

Q. Was a "risk adjustment" used, as suggested by Accion Group in its IE report?

A. No. Apparently, the Accion Group had no risk adder developed that it could assign to the UOG wind projects.

Q. Did the Commission find the IE reports needed improvement?

A. Yes. In Order No. 11-001, the Commission found shortcomings with the IE reports to date, when it stated:

> Guideline 10(d) requires the IE to evaluate the unique risks and advantages of utility benchmark resources, including consideration of the regulatory treatment if construction costs and plant performance should differ from expected levels. In practice, the IE's evaluation of the comparative risks and advantages of utility benchmark resources has not met our expectations. When the benchmark has been a natural gas resource, the evaluation has primarily focused on the terms of the engineering, procurement, and construction (EPC) contract. When the benchmark has been a wind resource, the evaluation has tended to focus on the value of the site location after the plant's useful life. We want a more comprehensive accounting and comparison of all of the relevant risks, including consideration of construction risks, operation and performance risks, and environmental regulatory risks. We also want more in-depth analysis of all of these risks. We invite comment on the analytic framework and methodologies that should be used to evaluate and compare resource ownership to purchasing power from an independent power producer.[124]

If the Commission adopts bid adders, the problem identified in the order will be addressed, and the Commission would not be left with unquantifiable recommendations for "risk adjustments."

---

[124] Order No. 11-001, Docket UM 1276, January 3, 2011, at 6.

D. Capacity Factor Expert

Q. What is your response to PacifiCorp's recommendation that a capacity factor expert be employed to evaluate all resource alternatives on the initial shortlist?[125]

A. I think this is a good suggestion that should be applied to all utility RFPs. However, employing a capacity factor expert would not eliminate the need for a capacity factor bid adder for two reasons:

1. The recommendation would be applied only after development of the shortlist. A bid adder is still needed to ensure that the appropriate projects make it to the short list.

2. The capacity factor expert would ensure that the expected capacity factors used in the bid evaluation are reasonable. The capacity factor expert would in no way address the differential risk to ratepayers from UOG versus IPP capacity factor error. A bid adder is needed to address this risk.

[redacted]

[125] PAC/100, Kusters/10.

[redacted]

Q. Given these limitations, what benefit do you see to utilizing a capacity factor expert to review the capacity factors submitted in wind RFP bids?

A. The expert report provided by PacifiCorp in discovery demonstrates the value of utilizing a capacity factor expert. [redacted]

[126] PacifiCorp response to NIPPC Data Request 5.2, Confidential Attachment 5.2, "Independent Engineer's Review of Four Wyoming Energy Assessment Reports," prepared by GEC, November 3, 2009 ("GEC Report"), at 1, presented in NIPPC Confidential Exhibit 330.
[127] GEC Report, at 3, presented in NIPPC Confidential Exhibit 330.
[128] GEC Report, at 5, presented in NIPPC Confidential Exhibit 330.
[129] [redacted] GEC Report, at 15, presented in NIPPC Confidential Exhibit 330.

VII. Conclusion

Q. Does this conclude your reply testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

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Northwest and Intermountain Power Producers Coalition Exhibit 301

PacifiCorp Response to Northwest and Intermountain Power Producers Coalition Data Request 6.4

January 14, 2013

NIPPC Data Request 6.4

The following questions concern the changes in Cost of Plant recorded in the FERC Form 1 filings for the Gadsby Peakers from 2002-2004 and for Seven Mile Hill from 2008-2009.

(a) Please provide workpapers supporting the changes in Cost of Plant.

(b) Please identify the capital expenditures that contributed to the increases to the Cost of Plant and specify the reason for these expenditures. Smaller expenditures may be grouped together by project, but please separately identify and provide the reason for any expenditures greater than $500,000.

(c) Please provide regulatory filings (such as from a rate case application or a stand-alone application) requesting cost recovery of the capital expenditures identified in part (b) above and the Commission orders ruling on these applications.

(d) For each capital expenditure identified in part (b) above, please specify what fraction of the Oregon share of the cost increase was passed onto Oregon ratepayers. If less than 100% of the Oregon share was passed on to Oregon ratepayers, please provide the Commission order denying full ratepayer recovery or, if unavailable, other documentation demonstrating that Oregon ratepayers were not charged their full share of the cost recovery and explaining the reason for the reduced cost recovery.

Response to NIPPC Data Request 6.4

The Company objects to this request because, with respect to the Gadsby Peakers, it is not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company provides the following response:

(a) Please refer to Attachments NIPPC 6.4 -1 and NIPPC 6.4 -2.

(b) Please refer to the Company's response to subpart (a) above.

(c) Seven Mile Hill: As per Attachment NIPPC 6.4 -2, the majority of these costs relate to project construction close out costs and other construction cost adjustments. The Seven Mile Hill project was included in PacifiCorp's renewable adjustment clause proceeding (Oregon Docket UE 200). Please refer to the Company's response to NIPPC Data Request 2.1; specifically Attachment NIPPC 2.1 -1, which provides a link to the order in that docket.

Gadsby Peakers: As per Attachment NIPPC 6.4 -1, $3.1 million of these costs relate to project construction close out costs and other construction cost adjustments and $5.9 million of these costs relate to the purchase of a spare turbine engine. The

UM-1182 / PacifiCorp
December 28, 2012
NIPPC Data Request 6.4

Gadsby Peakers were included in PacifiCorp's general rate case proceeding (Oregon Docket UE 170). Please refer to the Company's response to NIPPC Data Request 3.3, which provides a link to the order in that docket. The spare turbine engine project was included in the base period in that docket.

(d) Oregon's portion of the cost increase has been passed on to Oregon customers.

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Northwest and Intermountain Power Producers Coalition Exhibit 302

2003 – 2004 EPIS Activity for Gadsby Peakers

Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 6.4, Attachment 6.4-1

January 14, 2013

OR UM 1182
NIOPPC 6.4-1

2003 - 2004 EPIS Activity for Gadsby Gas Peakers (Locations 000264-000267)

Sum of Amount posted				Transaction Type			
Project Definition	Project Description	WBS Element	WBS Description	Addition	Retirement	Transfer	Grand Total
SGAD/2002/C/100	Gadsby Gas Turbine Peakers	SGAD/2002/C/100	Gadsby Gas Turbine Peakers	48,499			48,499
		SGAD/2002/C/100/BLDGS	Gadsby Gas Turbine Buildings	429,834			429,834
		SGAD/2002/C/100/COMM	Gadsby Gas Turbine Communication Upgrade	31,452			31,452
		SGAD/2002/C/100/ENG	Gadsby Gas Turbine Peakers - Engineering	(377,510)			(377,510)
		SGAD/2002/C/100/GE	Gadsby Gas Turbine Peakers-EPC CONTRACT	433,037			433,037
		SGAD/2002/C/100/GENBRK	Gadsby U1 & U2 Generator Breakers	192,682			192,682
		SGAD/2002/C/100/GSU	Gadsby & WV Gas Turbine Spare GSU	527,619			527,619
		SGAD/2002/C/100/H20	Gadsby Gas Turbine Peakers-H20 TREATMENT	218,393			218,393
		SGAD/2002/C/100/INVNTRY	GT Spare Parts transfer to Inventory	(414,817)			(414,817)
		SGAD/2002/C/100/LANDSCAP	Gadsby Gas Turbine Peakers - Landscaping	562,123			562,123
		SGAD/2002/C/100/MISC	Gadsby Gas Turbine Peakers - Misc.	1,251,014			1,251,014
		SGAD/2002/C/100/PI	Gadsby Gas Turbine PI installation	4,920			4,920
		SGAD/2002/C/100/TRAINING	Gadsby Gas Turbine Training	179,244			179,244
SGAD/2002/C/100 Total				3,086,490			3,086,490
SGAD/2004/C/017	GAS TURBINE SPARE ENGINE	SGAD/2004/C/017/PURCHASE	PURCHASE GAS TURBINE SPARE ENGINE	5,875,681			5,875,681
SGAD/2004/C/017 Total				5,875,681			5,875,681
SGAD/2004/C/021	GADSBY Gas Turbine CEM DAHS	SGAD/2004/C/021	CEM DAHS for Units 4,5 & 6	16,029			16,029
		SGAD/2004/C/021/CEMPC	Purchase and Install DAHS	9,108			9,108
SGAD/2004/C/021 Total				25,138			25,138
SGAD/2005/C/002	GADSBY: TOOLS AND TEST EQUIPMENT	SGAD/2005/C/002/U0HUMID	Gas Turbine Humidity Sensors	5,407			5,407
SGAD/2005/C/002 Total				5,407			5,407
Retirements/Transfers					(5,148)	(37,310)	(42,458)
Retirements/Transfers Total					(5,148)	(37,310)	(42,458)
Grand Total				8,992,716	(5,148)	(37,310)	8,950,258

The "cost of plant" balance at 12/31/2002 for the Gadsby Gas Peakers per FERC Form 1 was $70,276,509. The balance at 12/31/2004 was $79,226,767, a change of $8,950,258. Approximately $3.1 million relates to project construction close out costs and other construction cost adjustments (ref : SGAD/2002/C/100.) And additional $5.9 million was spent to purchase a spare turbine engine. This project provides a replacement engine in the event of an unscheduled failure in order to maintain high plant availability.

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Northwest and Intermountain Power Producers Coalition Exhibit 303

2009 EPIS Activity for Seven Mile

Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 6.4, Attachment 6.4-2

January 14, 2013

2009 EPIS Activity for Seven Mile (Locations 506100-506120)

Sum of Amount				Ttype	
Project Definition	Project Description	WBS Element	WBS Description	Addition	Grand Total
WGEN/2009/C/011	W-1730 Underground Improvements	WGEN/2009/C/011/MAT	W-1730 Underground Improvements - MAT	159,259	159,259
WGEN/2009/C/011 Total				$159,259	$159,259
WSMH/2007/C/001	Seven Mile Hill Wind Plant (99 MW)	WSMH/2007/C/001/BALANCE	Balance of Plant	43,958	43,958
		WSMH/2007/C/001/MISC	Miscellaneous Costs	(44,844)	(44,844)
		WSMH/2007/C/001/MISCCNTR	Miscellaneous Contracts	72,418	72,418
		WSMH/2007/C/001/PER_ACT	Activities	162	162
		WSMH/2007/C/001/PER_CON	Consultants	(163)	(163)
		WSMH/2007/C/001/TURBINES	Purchase Turbines and Commissioning	7,329,305	7,329,305
WSMH/2007/C/001 Total				$7,400,836	$7,400,836
WSMH/2007/C/002	Seven Mile Hill Network WBS (99 MW)	WSMH/2007/C/002/CNSTSVCS	Construction Services	10,724	10,724
		WSMH/2007/C/002/CNTRS	Contracts	(10,090,795)	(10,090,795)
		WSMH/2007/C/002/COLLSTA	Rocky Mountain Power DAF	144,830	144,830
		WSMH/2007/C/002/DEVLPSVS	Development Services	348	348
		WSMH/2007/C/002/DOCMGNT	Document Management	748	748
		WSMH/2007/C/002/ENVIRO	Enviromental/Cultural	6,997	6,997
		WSMH/2007/C/002/FEDERAL	Federal Permitting	4,655	4,655
		WSMH/2007/C/002/FNLZLAY	Finalize Layout	978	978
		WSMH/2007/C/002/IT	IT	610	610
		WSMH/2007/C/002/ITCONST	IT	112,997	112,997
		WSMH/2007/C/002/ITEQUIP	IT Eqiupment & Services	248	248
		WSMH/2007/C/002/LAND	Land	7,966	7,966
		WSMH/2007/C/002/MILEPMT	BOP Milestones/ Payments	4,422,704	4,422,704
		WSMH/2007/C/002/MILPMTS	LGIA Milestones//Payments	452,248	452,248
		WSMH/2007/C/002/O&M	O&M	8,699	8,699
		WSMH/2007/C/002/O&MADMIN	O&M Administration	59,529	59,529
		WSMH/2007/C/002/O&MGEN	O&M General	75,363	75,363
		WSMH/2007/C/002/O&MNT	Operations & Maintenance	12,346	12,346
		WSMH/2007/C/002/OPRPLAN	O&M Operations Plan	3,088	3,088
		WSMH/2007/C/002/PAYMENTS	Turbine Milestone s/Payments	3,365,750	3,365,750
		WSMH/2007/C/002/PROJMGMT	Project Management	136,285	136,285
		WSMH/2007/C/002/SCTRYSYS	Security System	8,200	8,200
		WSMH/2007/C/002/STATE	State Permitting	100	100
		WSMH/2007/C/002/WINDSUB	Rocky Mountain Power NUF	0	0
WSMH/2007/C/002 Total				($1,255,382)	($1,255,382)
WSMH/2008/C/003	Seven Mile Hill II Wind Plant (19.5 MW)	WSMH/2008/C/003/CONTRACT	Contracts	(142,428)	(142,428)
		WSMH/2008/C/003/DESIGN	Design	42,911	42,911
		WSMH/2008/C/003/LAND	Land/Permits/Environmental	13,093	13,093
WSMH/2008/C/003 Total				($86,424)	($86,424)
Grand Total				$6,218,288	$6,218,288

The combined "cost of plant" balance at 12/31/2008 for Seven Mile Hill and Seven Mile Hill II per FERC From 1 was $234,295, 725. The balance at 12/31/2009 was $240,514,014, a change of $6,218,289. The majority of these costs releated to project construction close out costs and other construction cost adjustme nts as shown in the schedule above.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

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In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
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Northwest and Intermountain Power Producers Coalition Exhibit 304

Idaho Power Company
Response to Northwest and Intermountain Power Producers Coalition Data Request 3.5

January 14, 2013

NIPPC'S DATA REQUEST NO. 3.5:

Reference Idaho Power/100, Stokes/12, stating, "As with any expenditure, increased expenses to operate a gas-fired plant due to heat rate degradation will likely be subjected to a prudence review."

a. Please describe the mechanisms in place at the Oregon PUC to compare annual average heat rates for utility-owned projects to the expected heat rates used in the RFP evaluation for such projects.

b. Please provide all examples in the last ten years of prudence reviews at the Oregon PUC related to increased expenses to operate an IPC gas-fired plant due to heat rate degradation. Please provide appropriate docket references and links to applicable testimony and Commission orders.

IDAHO POWER COMPANY'S RESPONSE TO NIPPC'S DATA REQUEST NO. 3.5:

a. The Company's rate cases and Annual Power Cost Adjustment filings are the "mechanisms" that allow the Commission to compare annual average heat rates. During those proceedings, parties can challenge the fuel consumption and claim that the heat rate was too high if the Company was imprudently operating its plant.

b. The requested documents related to the prudence reviews are publicly available in the below dockets via the following links:

¥ UE 167, Order No. 05-871:
http://apps.puc.state.or.us/edockets/docket.asp?DocketID=11628

¥ UE 213, Order No. 10-064:
http://apps.puc.state.or.us/edockets/docket.asp?DocketID=15728

¥ UE 233, case pending:
http://apps.puc.state.or.us/edockets/docket.asp?DocketID=16942

¥ UE 203, Order No. 09-186:
http://apps.puc.state.or.us/edockets/docket.asp?DocketID=15136

¥ UE 195, Order No. 09-373:
http://apps.puc.state.or.us/edockets/docket.asp?DocketID=14296

¥ UE 214, Order No. 10-191:
http://apps.puc.state.or.us/edockets/docket.asp?DocketID=15860

¥ UE 222, Order No. 11-178:
http://apps.puc.state.or.us/edockets/docket.asp?DocketID=16482

¥ UE 242, Order No. 12-176:
http://apps.puc.state.or.us/edockets/docket.asp?DocketID=17078

¥ UE 257, case pending:
http://apps.puc.state.or.us/edockets/docket.asp?DocketID=17970

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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In the Matter of	)
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Northwest and Intermountain Power Producers Coalition Exhibit 305

Portland General Electric
Response to Northwest and Intermountain Power Producers Coalition Data Request No. 033
(Renumbered from 4.6)

January 14, 2013

December 28, 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 Fourth Set Data Requests No. 033
(Renumbered from 4.6)
Dated December 14, 2012

Request:

Please provide all examples in the last ten years of prudence reviews at the Oregon PUC related to increased expenses to operate a gas-fired plant owned by PGE due to heat rate degradation. Please provide appropriate docket references and links to applicable testimony and Commission orders.

Response:

PGE objects to this data request on the grounds that it asks PGE to collect material that is in the public domain and already accessible. PGE further objects that the scope of the request is vague and ambiguous given that the term "prudence reviews" is not defined and the subject of such "prudence reviews" is similarly not clearly defined. Without waiving the above objections, PGE responds as follows:

The following table provides references to PGE General Rate Case (GRC), Resource Valuation Mechanism (RVM) and Annual Update Tariff (AUT) filings since 2002.

Filing	Source
UE 115 – 2002 GRC	http://apps.puc.state.or.us/edockets/docket.asp?DocketID=8350
UE 139 – 2003 RVM	http://apps.puc.state.or.us/edockets/docket.asp?DocketID=10005
UE 149 – 2004 RVM	http://apps.puc.state.or.us/edockets/docket.asp?DocketID=10566
UE 161 – 2005 RVM	http://apps.puc.state.or.us/edockets/docket.asp?DocketID=11237
UE 172 – 2006 RVM	http://apps.puc.state.or.us/edockets/docket.asp?DocketID=12427
UE 180 – 2007 GRC	http://apps.puc.state.or.us/edockets/docket.asp?DocketID=13199
UE 192 – 2008 AUT	http://apps.puc.state.or.us/edockets/docket.asp?DocketID=14013
UE 197 – 2009 GRC	http://apps.puc.state.or.us/edockets/docket.asp?DocketID=14729
UE 208 – 2010 AUT	http://apps.puc.state.or.us/edockets/docket.asp?DocketID=15438
UE 215 – 2011 GRC	http://apps.puc.state.or.us/edockets/docket.asp?DocketID=16048
UE 228 – 2012 AUT	http://apps.puc.state.or.us/edockets/docket.asp?DocketID=16706

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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NORTHWEST AND INTERMOUNTAIN	)
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Northwest and Intermountain Power Producers Coalition Exhibit 306

Idaho Power Company
Response to Staff Data Request 2

January 14, 2013

January 2, 2013

Subject: Docket No. UM 1182
Idaho Power Company's Responses to Staff's Data Requests 2-6 to Idaho Power Company

STAFF'S DATA REQUEST NO. 2:

Please provide the following information for each Request for Proposal (RFP) issued since 2005.

- **a. The RFP;**
- **b. Scoring criteria;**
- **c. List of bids received, including size, bid price, IPP versus utility;**
- **d. Initial short list using same identifiers as in 1(c);**
- **e. Final short list using same identifiers as in 1(c); and**
- **f. Final selection**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 2:

In response to this request, Idaho Power Company ("Idaho Power" or "Company") is providing the following information:

2005: Peaking RFP – Per its Document Retention Policy, Idaho Power has not retained the files associated with this RFP in the ordinary course of business.

2006: Geothermal RFP – Please see Attachments 1, 2, and 3.

2008: Geothermal RFP – Please see Attachments 4, 5, and 6.

Mona RFP – Please see Attachments 7 and 8.

2012 Baseload RFP – Please see Attachments 9 and 10.

2009: Eastside RFP – Please see Attachments 11, 12, and 13.

Wind RFP 2012 – Please see Attachments 14, 15, 16, and 17.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

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In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
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Petition for an Investigation Regarding	)
Competitive Bidding	)
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Northwest and Intermountain Power Producers Coalition Exhibit 307

Portland General Electric
Response to Response to Northwest and Intermountain
Power Producers Coalition Data Request No. 034
(Renumbered from 4.7)

January 14, 2013

December 28, 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 Fourth Set Data Requests No. 034
(Renumbered from 4.7)
Dated December 14, 2012

Request:

For each phase of the Biglow Canyon Wind Farm, please provide (1) the rated capacity, (2) the expected capacity factor, or if unavailable projected monthly output, for the wind project used in the initial project RFP bid, (3) the expected capacity factor, or if unavailable projected monthly output, for the wind project used in the final project RFP bid, and (4) the actual capacity factor, or if unavailable actual monthly output, in each year of the project's operations. Please provide supporting documentation with your response.

Response:

(1) The Biglow Canyon nameplate capacities per construction phase are as follows: Phase 1 = 125 MW; Phase II = 150 MW; Phase III = 175 MW. However, some of the Phase 3 turbines were connected to the Transformer Bank #2. So, the rated capacities for the plant will be reported per Transformer Bank: (TB) #1 = 125.4 MW; TB #2 = 149.5 MW from 09-2009 thru 07-2010, 163.3 MW from 08-2010 to present; TB #3 = 161 MW.

(2) The expected capacity factor used in the initial 'as bid' project RFP bid was 31%.

(3) The expected capacity factor used in the final 'as bid' project RFP bid was 31%.

(4) The bid into our RFP that became PGE's Biglow Canyon project was a PPA bid with a nameplate rating of 299 MW. During negotiations the bidder proposed that the project

be changed from a PPA to utility ownership. Ultimately, PGE agreed to utility ownership of the project, which allowed the project to be constructed in phases which better met our capacity needs. As a result, the project as constructed is not comparable to the project as bid. Please see Attachment 034-A for Biglow Canyon's actual annual capacity factors. Attachment 034-A is confidential and subject to Protective Order No. 11-506. As stated above, the data is collected and reported by transformer bank which does not exactly correspond to project phases.

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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	)
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Northwest and Intermountain Power Producers Coalition Exhibit 308

Portland General Electric
Response to Response to Northwest and Intermountain Power Producers Coalition Data Request No. 035
(Renumbered from 4.8)

January 14, 2013

December 28, 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 Fourth Set Data Requests No. 035
(Renumbered from 4.8)
Dated December 14, 2012

Request:

As a follow-up to PGE Response to NIPPC Data Request no. 025a, please provide the cost estimate used in the Biglow Canyon project's initial RFP bid when the project was bid as one project.

Response:

As stated in PGE's response to NIPPC Data Request No. 034 (renumbered from 4.7), the project as bid was a PPA with a capacity of 299 MWs to be constructed in one phase. As such, it is not comparable to the as built project. With that objection, the initial Adjusted Real Levelized cost as bid was $45.20 / MWH in 2003$. Bidders were allowed to refresh their initial bids. Orion's updated bid of $46.86 / MWh was used to develop the short list.

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BEFORE THE

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Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 309

"Report of the Independent Evaluator on Negotiations in PacifiCorp's 2008R-1 Request for Proposals for Renewable Electric Resources" presented to the Public Utility Commission of Oregon by Boston Pacific Company Inc.
September 18, 2009

Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 6.10, 1st Supplemental Response, Confidential Attachment

January 14, 2013

Northwest and Intermountain Power Producers Coalition Exhibit 309 contains confidential material and has been redacted

BEFORE THE

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Northwest and Intermountain Power Producers Coalition Exhibit 310

Idaho Power Company
Response to Staff Data Request 4

January 14, 2013

STAFF'S DATA REQUEST NO. 4:

On pg. 5, lines 21-26, and pg. 6, lines 1-2 of Opening Testimony, addresses the use of EPC contracts as a risk management tool. Please provide additional detail regarding the following:

- **a.** **Circumstances when an EPC did (not) include fixed price terms (note: testimony indicates that it is not uncommon for them to be included in EPC contract).**
- **b.** **Circumstances when an EPC did (not) include damages for cost overruns and discuss and explain the use of caps on cost overruns covered by such provisions (note: testimony indicates that almost all contracts include them).**
- **c.** **Identify the total amount of cost over-runs or under-runs, by project, for each project selected in the last ten years that has been acquired through a competitive solicitation, RFP process. If any amount of the cost over-run was excluded from the rate base, identify them separately and do include them in your reply.**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 4:

a. Bennett Mountain and Danskin 1 both had fixed price terms with the Engineer Procure Construct ("EPC") contracts. Langley Gulch had fixed price terms for the EPC contract with the exception of the engineered equipment portion of the contract, referred to in the contract as Engineered Equipment Target Price, where Idaho Power and the EPC Contractor shared the cost risk on the engineered equipment. The Engineered Equipment Target Price established an estimated price on the engineered equipment, any savings or costs, below or above the estimated price was equally shared between the parties. In exchange for sharing a portion of the risk on this equipment, the EPC Contractor lowered their project fee on that portion.

b. None of the contracts had a cost over-run clause for damages or caps associated with them. (Please see Idaho Power's response to Staff's Data Request No. 4.a)

c. There were no cost over-runs or under-runs for the Bennett Mountain or Danskin 1 projects. Langley Gulch was built for approximately $26 million less then the Company's commitment estimate.

BEFORE THE

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Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 311

"The Oregon Independent Evaluator's Final Closing Report on PacifiCorp's 2009R Renewables RFP"
Presented to the Oregon Public Utility Commission by
Boston Pacific Company, Inc.
November 5, 2009

Provided by PacifiCorp in response to
Northwest and Intermountain Power Producers Coalition
Data Request 5.2, Confidential Attachment 5.2

January 14, 2013

Northwest and Intermountain Power Producers Coalition Exhibit 311 contains confidential material and has been redacted

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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Northwest and Intermountain Power Producers Coalition Exhibit 312

PacifiCorp Response to Northwest and Intermountain Power Producers Coalition Data Request 4.14

January 14, 2013

UM-1182 / PacifiCorp
December 11, 2012
NIPPC Data Request 4.14

NIPPC Data Request 4.14

Reference PacifiCorp/100, Kusters/20 stating, "For third party proposals or the utility cost-based benchmark resource, contingency reserves are applied to the proposal price consistent with industry practices."

(a) Please describe with specificity how contingency reserves are applied for third-party proposals and for utility cost-based benchmark resources.

(b) Please clarify whether contingency reserves are included in the benchmark resource bid price that is compared to third-party bids.

Response to NIPPC Data Request 4.14

(a) For the most recent 2016 Resource request for proposals (RFP), a contingency reserve amount of 5 percent was applied to either an asset purchase and sale agreement (APSA) or an engineer-procure-construct (EPC) at the Currant Creek plant site or an APSA at a bidder's site. This percentage was applied to the fixed EPC price. This excluded owner's direct costs and startup/fuel and testing, transmission interconnection-directly assigned costs and network upgrades, capital surcharge, capitalized property taxes and allowance for funds used during construction (AFUDC). In the latest 2016 Resource RFP, there was no utility cost-based benchmark; therefore, EPC bidders could bid on the construction of a resource located at Currant Creek as part of the overall Resource RFP in lieu of a standalone utility benchmark.

In prior resource RFPs, for the utility cost-based benchmark based on a resource constructed at the Lake Side plant site (Lake Side 2), the benchmark capital cost included a contingency amount based on the fixed EPC cost amount; this contingency amount was approximately 5.3 percent of the total project cost (or approximately 6.2 percent of the fixed EPC cost).

Project specific capitalized property taxes and AFUDC were determined based on the individual project cash flows as proposed.

(b) As noted in the Company's response to subpart (a) above, contingency reserves are included in both the benchmark resource and third party EPC and APSA bids.

BEFORE THE

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Northwest and Intermountain Power Producers Coalition Exhibit 313

PacifiCorp Response to Northwest and Intermountain Power Producers Coalition Data Request 5.1

January 14, 2013

UM-1182 / PacifiCorp
December 13, 2012
NIPPC Data Request 5.1

NIPPC Data Request 5.1

Reference PacifiCorp/100, Kusters/20-21, stating that PacifiCorp has utilized a contingency cost for potential cost overruns or other unforeseen items in RFPs for bids that do not have fixed prices. For each RFP in the past ten years:

(a) Please provide and explain the basis for the percentage value of the contingency used as compared to overall bid cost in evaluating the utility benchmark bid;
(b) Please provide and explain the basis for the percentage value of the contingency used as compared to overall bid cost in evaluating any Build-Own-Transfer bids;
(c) Please provide and explain the basis for the percentage value of the contingency used as compared to overall bid cost in evaluating in evaluating PPA bids.

Response to NIPPC Data Request 5.1

The Company objects to this request because it is unduly burdensome and overbroad. Without waiving this objection, the Company responds as follows:

(a) The percentage values used for contingency in the most recent request for proposals (RFP) (All Source RFP – Resource 2016) and the RFP that resulted in the Lake Side 2 resource (2009 All Source RFP) were provided with the Company's response to NIPPC Data Request 4.14 subpart (a). The basis for the contingency amount to be included in a major construction project depends on a number of factors which include identified risks, length of the construction period, complexity of the project, unforeseen and unpredictable conditions (such as weather and soil conditions), uncertainties within the defined project scope, terms and conditions of the underlying engineer-procure-construct (EPC) contract and experience.

For the most recent RFP (All Source RFP – Resource 2016), there was no utility benchmark; for consistency a uniform contingency level was applied to all Build-Own-Transfer/EPC proposals.

(b) Please refer to the Company's response to (a) above.

(c) No contingency is included in the evaluation of power purchase agreement (PPA) bids.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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Northwest and Intermountain Power Producers Coalition Exhibit 314

PacifiCorp Response to Northwest and Intermountain Power Producers Coalition Data Request 4.13

January 14, 2013

UM-1182 / PacifiCorp
December 11, 2012
NIPPC Data Request 4.13

NIPPC Data Request 4.13

Reference PacifiCorp/100, Kusters/20 stating, "For a bid with any portion that is not provided as a fixed price, the Company applied an incremental risk adder that was calculated for each bid and the Company benchmark."

(a) Please explain how this risk adder was calculated and provide an example demonstrating this calculation.
Please explain why this bid adder was appropriate for bids that do not contain a fixed price, but PacifiCorp opposes bid adders for UOG projects or self-builds that would be passed onto ratepayers on a cost-of-service basis.

Response to NIPPC Data Request 4.13

(a) Please refer to Confidential Attachment 4.13 -1 for an explanation of the method of factor calculation, and Confidential Attachment 4.13 -2 for an example demonstrating the calculation.

(b) If appropriate under specific request for proposals (RFP), the Company does not oppose using indexed risk premiums for the construction of new resources in tolling services agreements (TSA), power purchase agreements (PPA), utility-owned generation (UOG) projects or self-builds that contain indexed risk with regard to construction materials. As explained in the direct testimony of Stacey J. Kusters, the Company found this necessary in the 2009 All Source RFP, because of the engineer-procure-construct (EPC) market was significantly more volatile than it is today. The Company objects to the characterization of the Company's position as generally opposing bid adders for UOG projects or self-builds that would be passed onto ratepayers on a cost-of-service basis. The Company has not made this general statement.

Information in Confidential Attachment NIPPC 4.13 -1 and Confidential Attachment NIPPC 4.13 -2 is designated as confidential under the protective order in this docket and may only be disclosed to qualified persons as defined in Order No. 11-506.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 315

PacifiCorp's Methodology for Adjusting Capital Indexing Risk

Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 4.13, Confidential Attachment 4.13-1

January 14, 2013

Northwest and Intermountain Power Producers Coalition Exhibit 315 contains confidential material and has been redacted

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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Northwest and Intermountain Power Producers Coalition Exhibit 316

Bennett Mountain and Danskin Capital Expenditures and Fixed O&M Costs

Provided by Idaho Power Company in response to Northwest and Intermountain Power Producers Coalition Data Request 4.1, Attachment 1

January 14, 2013

Attachment 1 - Response to NIPPC 's DR 4.1(a)

4.1 a - Capital Expenditures

Bennett Mountain

Year	Capital Expenditures	
2005	53,054,712	**(1)**
2006	15,965,511	**(2)**
2007	-901,570	
2008	364,043	
2009	7,421,536	
2010	938,177	

Danskin units 2 & 3

Year	Capital Expenditures	
2001	47,300,697	**(1)**
2002	2,499,192	
2003	1,035,371	
2004	773,812	
2005	28,074	
2006	576,947	

Danskin unit 1 combined with units 2 & 3

Year	Capital Expenditures	
2008	59,014,951	**(1)**
2009	395,592	
2010	-14,606	
2011	258,103	

Notes:

(1) The initial year of each plant has the original charges for the plant, and only represents expenditures from the time that the plant was placed in-service and the end of the year.

(2) The capital expenditure for 2006 is offset by a retirement of $15.2 million.

Attachment 1 - Response to NIPPC 's DR 4.1(a)

4.1 a - "Fixed" O&M Costs

Bennett Mountain

	2005 (2)	2006	2007	2008	2009	2010
Labor	$258,703	$294,412	$318,279	$330,899	$407,818	$412,605
Materials and Supplie	$118,089	$72,065	$118,786	$74,462	$77,175	$52,371
Total	$376,792	$366,477	$437,065	$405,361	$484,993	$464,976

Danskin units 2 & 3

	2001 (3)	2002	2003	2004	2005	2006
Labor	$137,314	$278,949	$315,342	$365,037	$441,577	$495,808
Materials and Supplie	$94,009	$140,860	$104,297	$95,525	$119,288	$153,062
Total	$231,322	$419,809	$419,639	$460,562	$560,865	$648,870

Danskin unit 1 combined with units 2 & 3

	2008 (4)	2009	2010	2011
Labor	$655,830	$840,379	$849,414	$824,384
Materials and Supplie	$192,029	$306,054	$401,942	$203,482
Total	$847,859	$1,146,433	$1,251,357	$1,027,866

Notes:

(1) IPC does not have "short-lived materials" or "long-lived materials" categories in its accounting. This line represents materials and supplies expenses that are deemed to be a current expense rather than materials and supplies that have the ability to be capitalized. Materials and supplies that have the ability to be capitalized are included in capital work orders, and will be included in the response to item 4.4 a and b.

(2) Bennett Mountain was placed in-service on March 31, 2005. Therefore, 2005 expenses represent a nine-month period.

(3) Danskin units 2 & 3 were placed in-service on September 30, 2001. Therefore, 2001 expenses represent a three-month period.

(4) Danskin Units 1, 2 and 3 are operated as a single power plant. As such, the Company's accounting records does not accommodate the ability to identify the operation costs of each individual unit. Danskin unit 1 was placed in-service on March 31, 2008. Therefore, 2008 expenses represent three months of expense for Danskin units 2 & 3 only, and nine months of expenses for all three units combined.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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Northwest and Intermountain Power Producers Coalition Exhibit 317

Idaho Power Company Response to Northwest and Intermountain Power Producers Coalition Data Request 4.4

January 14, 2013

<u>NIPPC'S DATA REQUEST NO. 4.4</u>:

The following questions concern the changes in Cost of Plant recorded in the FERC Form 1 filings for the Danskin plant from 2001-2003 and for Bennett Mountain from 2008-2009.

a. Please provide workpapers supporting the changes in Cost of Plant.

b. Please identify the capital expenditures that contributed to the increases to the Cost of Plant and specify the reason for these expenditures. Smaller expenditures may be grouped together by project, but please separately identify and provide the reason for any expenditures greater than $500,000.

c. Please provide regulatory filings (such as from a rate case application or a stand-alone application) requesting cost recovery of the capital expenditures identified in part (b) above and the Commission orders ruling on these applications.

d. For each capital expenditure identified in part (b) above, please specify what fraction of the Oregon share of the cost increase was passed onto Oregon ratepayers. If less than 100% of the Oregon share was passed on to Oregon ratepayers, please provide the Commission order denying full ratepayer recovery or, if unavailable, other documentation demonstrating that Oregon ratepayers were not charged their full share of the cost recovery and explaining the reason for the reduced cost recovery.

<u>IDAHO POWER COMPANY'S RESPONSE TO NIPPC'S DATA REQUEST NO. 4.4</u>:

a. Changes in Cost of Plant

Bennett Mountain

Year	Beginning Balance	Additions	Retirements	Ending Balance
2008	53,283,918	364,043	(121,838)	53,526,124
2009	53,526,124	7,421,536	-	60,947,659

Danskin

Year	Beginning Balance	Additions	Retirements	Ending Balance
2001	-	47,300,697	-	47,300,697
2002	47,300,697	2,499,192	-	49,799,889
2003	49,799,889	1,035,371	-	50,835,261

b. Expenditures Greater than $500,000

Bennett Mountain

Year	Project	Description	Expenditures
2008			
	No projects greater than $500,000		
	All others	Various	364,043
Total 2008			364,043
2009			
	Turbine Blades and Vanes	Purchase capital spare turbine blades and vanes.	7,411,126
	All others	Various	10,409
Total 2009			7,421,536

Expenditures Greater than $500,000

Danskin

Year	Project	Description	Expenditures
2001			
	Install Gas-Fired Peaking Turbine	Original installation of Danskin units 2 & 3	46,966,020
	All others	Various	334,678
Total 2001			47,300,697
2002			
	Install Gas-Fired Peaking Turbine	Final charges on installation of Danskin units 2 & 3	1,093,258
	Capital Spare Parts	Purchase of capital spare parts	948,156
	All others	Various	457,778
Total 2002			2,499,192
2003			
	Capital Spare Parts	Purchase of capital spare parts	956,167
	All others	Various	79,205
Total 2003			1,035,371

c. The Company requested recovery associated with Danskin and/or Bennett Mountain plant investment in the following dockets:

Docket No.	Order No.
UE 167	05-871
UE 213	10-064
UE 233	12-055

The requested documents are publicly available on the Public Utility Commission of Oregon website.

d. For each of the dockets listed in part c above, the Company was not denied rate recovery associated with the plant investment listed in part b. It should be noted that test year plant amounts calculated for general rate filings are adjusted according to the Oregon approved forecast test year methodology and do not necessarily reflect exact amounts included in the Company's FERC Form 1 filings.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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Northwest and Intermountain Power Producers Coalition Exhibit 318

PacifiCorp Response to Northwest and Intermountain Power Producers Coalition Data Request 6.6

January 14, 2013

UM-1182 / PacifiCorp
December 28, 2012
NIPPC Data Request 6.6

NIPPC Data Request 6.6

Please respond to the following questions with respect to Units 4, 5, and 6 of the Gadsby Plant:

(a) Please provide the date that PacifiCorp's management provided final approval for the project development.

(b) Please provide (non-redacted versions of) all documents used as part of the project approval process, including documents provided to executive officers and members of the Board of Directors as part of the project approval process.

(c) Please provide the (non-redacted) Oregon Commission order allowing the utility to enter the units into rate base.

(d) Please provide the average first-year heat rate(s) used by PacifiCorp for purposes of bid evaluation and project approval. Please provide supporting documentation with your response.

(e) Please specify any assumptions made by PacifiCorp for purposes of bid evaluation and project approval regarding changes to the average heat rate over time, such as from plant degradation, an increase in the number of unit starts, or other operational or age-related factors.

(f) Please specify the expected average heat rates for each year that were used for purposes of bid evaluation and project approval. Please include heat rates that were outputs of Strategist modeling or other modeling. Please provide supporting documentation with your response.

(g) Please provide the actual average heat rate for each year of operations. Please provide supporting documentation with your response.

Response to NIPPC Data Request 6.6

The Company objects to this request because it is not reasonably calculated to lead to the discovery of admissible evidence. The Gadsby Plant is not relevant because it was not acquired through a competitive bid solicitation process. Notwithstanding the objection, the Company responds as follows:

(a) The project was approved by the PacifiCorp Board on September 1, 2001 and was reaffirmed on October 12, 2001. Final approval to proceed was given on October 25, 2001.

(b) Please refer to Confidential Attachment NIPPC 6.6 for copies of the Gadsby Gas Turbine Peakers recommendation papers to the ScottishPower and PacifiCorp boards.

UM-1182 / PacifiCorp
December 28, 2012
NIPPC Data Request 6.6

Information in Confidential Attachment NIPPC 6.6 is designated as confidential under the protective order in this docket and may only be disclosed to qualified persons as defined in Order No. 11-506.

(c) Please refer to the Company's response to NIPPC Data Request 3.3.

(d) There was no bid evaluation for Gadsby 4, 5 and 6 as these peaking combustion turbines were not procured under a resource RFP process. The net total plant heat rate used for evaluation purposes was 10,224 Btus/kWh on a higher heating value basis at 59 degrees Fahrenheit.

(e) There was no bid evaluation for Gadsby 4, 5 and 6 as these peaking combustion turbines were not procured under a resource request for proposals (RFP) process. The net full load heat rate value of 10,224 Btu/kWh was considered to be the long term value which included any heat rate degradation impacts over the expected 25 year study period. Unit starts does not influence degradation for the LM6000 aero-derivative combustion turbine.

(f) Please refer to the Company's response to subpart (e) above.

(g) Please refer to the Company's response to NIPPC 3.4.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 319

Lakeside I, Lakeside II, and Currant Creek Heat Rate Degradation Information

Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 3.4, Confidential Attachment 3.4-1

January 14, 2013

Northwest and Intermountain Power Producers Coalition Exhibit 319 contains confidential material and has been redacted

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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Northwest and Intermountain Power Producers Coalition Exhibit 320

PacifiCorp Response to Northwest and Intermountain Power Producers Coalition Data Request 4.7

January 14, 2013

UM-1182 / PacifiCorp
December 11, 2012
NIPPC Data Request 4.7

NIPPC Data Request 4.7

Reference PacifiCorp/100, Kusters/14 stating, "There are a number of factors that contribute to reported heat rate values being higher than the full load heat rates, including operation at reduced load, variations in ambient conditions and the effects of startups and shut downs. Many natural gas-fired facilities regularly operate at reduced load, which is less efficient, in order to hold reserves for system reliability and to integrate intermittent generation resources."

(a) Please provide an estimate of the proportion of heat rate increase that, on average, is due to (1) operation at reduced load, (2) variations in ambient conditions, (3) the effects of startups and shut downs, and (4) other factors. Please provide analyses or studies in support of your response.

(b) Please provide an estimate of the proportion of load reductions at gas-fired plants (i.e., operations at less than full load) that, on average, is due to the need to hold reserves for system reliability or to integrate intermittent generation resources (versus for market reasons or other reasons). Please provide analyses or studies in support of your response.

Response to NIPPC Data Request 4.7

(a) The Company has not prepared the requested analysis and objects to this request because it is unduly burdensome. Without waiving its objection, the Company responds as follows: In general at any given time, a generation resource has an output and an associated heat rate. The heat rate is a function of output, ambient conditions, equipment operating conditions, etc. The Company does not categorize the portions of time the heat rate is attributable to these factors.

(b) The Company has not prepared the requested analysis and objects to this request because it is unduly burdensome. Without waiving its objection, the Company responds as follows: The Company has an obligation to meet both reserve and integration requirements and operates its resources accordingly. The Company does not, however, have a historical data set that indicates the portions of back-downs at each resource due to reserve requirements, market factors, etc.

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Northwest and Intermountain Power Producers Coalition Exhibit 321

Portland General Electric Response to Northwest and Intermountain Power Producers Coalition Data Request No. 017
(Renumbered from 3.2)

January 14, 2013

December 11, 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 Third Set Data Requests No. 017
(Renumbered from 3.2)
Dated November 27, 2012

Request:

Reference PGE/100, Outama - Bettis - Mody – Hager/16, discussing heat rate degradation. Do the witnesses believe that the "new and clean" heat rate is the lowest average heat rate that a generator would have over its lifetime? If not, please explain why not.

Response:

The "new and clean" heat rate is an "out-of-the-box" heat rate. Non-recoverable performance degradation effectively begins with testing of the unit. Therefore, the heat rate realized in the first year of commercial operation (during which non-recoverable degradation continues) will exceed the "new and clean" heat rate.

However, if the power plant undergoes a major upgrade or overhaul and regularly scheduled maintenance during its projected lifetime, it is possible that the plant heat rate could improve to a level lower than the original heat rate. See PGE's response to NIPPC Data Request No. 021 (renumbered from 3.6).

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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In the Matter of	)
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Competitive Bidding	)
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Northwest and Intermountain Power Producers Coalition Exhibit 322

PacifiCorp Response to Northwest and Intermountain Power Producers Coalition Data Request 4.9

January 14, 2013

UM-1182 / PacifiCorp
December 11, 2012
NIPPC Data Request 4.9

NIPPC Data Request 4.9

Reference PacifiCorp/100, Kusters/14-15, discussing Tolling Services Agreements (TSAs) and UOG projects. Please respond to the following questions:

(a) Does PacifiCorp have the right to request part-load operation for a plant operating under a TSA? If your response is anything except for an unqualified "no," please describe PacifiCorp's rights to request part-load operation.
(b) Do PacifiCorp's TSAs allow PacifiCorp to require the counterparty to operate at a part-load to integrate renewables or provide reserves? If so, please provide an example of such an agreement.
(c) If PacifiCorp has no executed TSAs, please state so and explain the basis for PacifiCorp's understanding of the typical terms of TSAs.

Response to NIPPC Data Request 4.9

(a) Yes, provided that the Tolling Services Agreement (TSA) is structured to allow for part-load operation. Currently, PacifiCorp has a TSA with a counterparty where PacifiCorp has full dispatch of the resource owned by a third party, which includes part load operation.

(b) No. PacifiCorp does not require under the TSA that the counterparty be required to operate at part load in order to allow for the integration of renewables or provide reserves. However, provided that the terms of the TSA allow for part load operation, and the operational characteristics meet the Company's balancing and reserve requirement needs, PacifiCorp may dispatch a TSA to integrate renewables.

(c) PacifiCorp has executed multiple TSAs.

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	)
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Petition for an Investigation Regarding	)
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Northwest and Intermountain Power Producers Coalition Exhibit 323

"Final Report of the Independent Evaluator Regarding Portland General Electric Company's Request for Proposals for Renewable Energy" submitted to the Public Utility Commission of Oregon by Accion Group
January 9, 2009

Provided by Portland General Electric in response to Northwest and Intermountain Power Producers Coalition Data Request No. 012, Supplement 1, Attachment B

January 14, 2013

Report of

Accion Group

to

STATE OF OREGON
PUBLIC UTILITY COMMISSION OF OREGON

FINAL REPORT OF THE INDEPENDENT EVALUATOR

REGARDING PORTLAND GENERAL ELECTRIC COMPANY'S REQUEST FOR PROPOSALS FOR RENEWABLE ENERGY RESOURCES

January 9, 2009

Submitted by:

ACCION GROUP, INC.
The Carriage House
244 North Main Street
Concord, New Hampshire 03301

advisors@acciongroup.com

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Accion Group

FINAL REPORT OF ACCION GROUP, INC.
INDEPENDENT EVALUATOR REGARDING
PORTLAND GENERAL ELECTRIC COMPANY'S
REQUEST FOR PROPOSALS FOR RENEWABLE ENERGY RESOURCES

EXECUTIVE SUMMARY

Accion Group, Inc. (Accion or IE) served as the Independent Evaluator for the Portland General Electric (Company or PGE) 2008 Renewables Request for Proposals (RFP). Accion worked closely with PGE and the Staff of the Oregon Public Utility Commission (Commission Staff) throughout the RFP. In addition, Accion created and operated the website used for all communications about the RFP from the first release of draft RFP documents, through the selection of the Final Short-list. With the website we had access to all RFP-related materials, reviewed all exchanges of information with bidders after bids were received, and captured all evaluation materials for possible review by the Oregon Public Utility Commission (Commission).

This, our final report, reviews the action taken by PGE in the selections of the Final Short-list. Our earlier report[1] reviewed the RFP process through the selection of the Initial Short-list.[2]

The Commission Order 06-446 provides guidelines for competitive bidding. The 2008 PGE Renewable RFP was designed to satisfy those guidelines in order to ensure a fair bidding process. The IE was engaged to evaluate the RFP process, the evaluation process, and adherence to the guidelines. During the RFP process several key issues and action items were identified by the IE, principally due to the uniqueness of preparing a RFP and evaluation methodology to accommodate a wide range of renewable resource bids. PGE's decision to forego bid fees was appropriate, though it was clear from the start that the decision would result in the receipt of bids that would cover a wide range of technology maturities making the evaluation methodology uniquely challenging. Also, from the outset we accepted that the evaluation modeling would likely need refinement after bids were received and specific supply characteristics were identified. The IE tested the evaluation model before bids were received by evaluating a set of "mock bids." The mock bids establish a baseline for the evaluation model and permitted us to confidently stress-test the model when adjustments were necessitated by unique bids.

Our access to PGE personnel was unfettered and we found PGE exceptionally responsive to suggestions and recommendations. PGE was consistently cooperative and responsive to our inquiries. We received full access to the Commission Staff, who we found to be fully engaged and knowledgeable in all aspects of the procurement process. The willingness of the Commission Staff and PGE personnel to discuss issues assisted greatly in crafting the RFP to maximize the opportunity for participation by prospective bidders. We found that PGE personnel made a sincere effort to address each potential shortcoming we identified while maintaining

[1] IE Supplemental Report on Draft RFP, April 15, 2008 (IE Supplemental Report). The report is available on the Portland General RFP Website (www.portlandgeneralrfp.com) in the IE Documents Sub-folder on the Documents Page.

[2] The IE Final Report was originally scheduled for release on December 4, 2008. The report was delayed to permit a full review to remove from the public version of the report all confidential information provided by bidders. This is necessary to respect the express commitments to bidders, and to avoid providing competitive information, such as price proposals, among competitive providers.

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compliance with the competitive bidding guidelines. As issues arose, we believe PGE succeeded in identifying the best available alternatives for meeting the Oregon Renewable Portfolio Standards (RPS), in terms of cost and risk.

In summary, we observed that:

- Bidders were advised of the RFP and invited to bid.
- The process was open and fair, permitting all bidders access to the same information at the same time.
- Prospective bidders were provided with draft RFP documents and the opportunity to request or recommend changes to those documents.
- The final RFP documents provided clear and complete product definitions that were not questioned by any prospective bidder. The RFP permitted submission of unique proposals.
- During the refinement of the RFP documents, PGE personnel and the Commission Staff demonstrated flexibility in order to provide a fair and comprehensive bidding opportunity to a wide range of alternative generation types.
- The RFP documents were thorough, accurate, and complete, providing bidders with all necessary information.
- The RFP documents provided adequate disclosure of the evaluation process that would be employed, and no prospective bidder questioned the evaluation process prior to the submission of bids.
- The RFP process treated all bidders in the same way.
- The RFP evaluation process and modeling treated all bidders fairly.
- Between the Initial Short-list and Final Short-listing of bids, PGE personnel sought additional information from bidders through the website. This ensured that a complete understanding of each bid was available before the Final Short-list was established.
- We reviewed the security used by PGE at their offices and provided a secure website for the exchange of information with bidders. We believe PGE took all necessary and appropriate steps to secure bid information and to prevent unauthorized disclosure of RFP-related information.
- Even with the potential diversity of technologies, we found the RFP documents to be free of bias towards any form of renewable generation.
- Some bidders contacted the IE because they disagreed with PGE's decision to release their bids. However, no bidders claimed that the RFP documents or process was flawed.
- Credit requirements were clearly defined.
- All bids were evaluated using the same standards, evaluation models, and methodology. The evaluation model was perfected to accommodate the types of generation bid into the RFP. All modeling adjustments were reviewed by the IE before being made and we found each adjustment to be appropriate.
- PGE personnel took appropriate measures to prevent un-monitored contact between any bidder and the PGE evaluation team, up until the point when the Final Short-list was finalized.
- We believe PGE conducted a fair RFP and that PGE acted appropriately when releasing certain bids.
- Transmission availability was a significant issue for a number of bids. We reviewed PGE's transmission assessment and found it to be appropriate.

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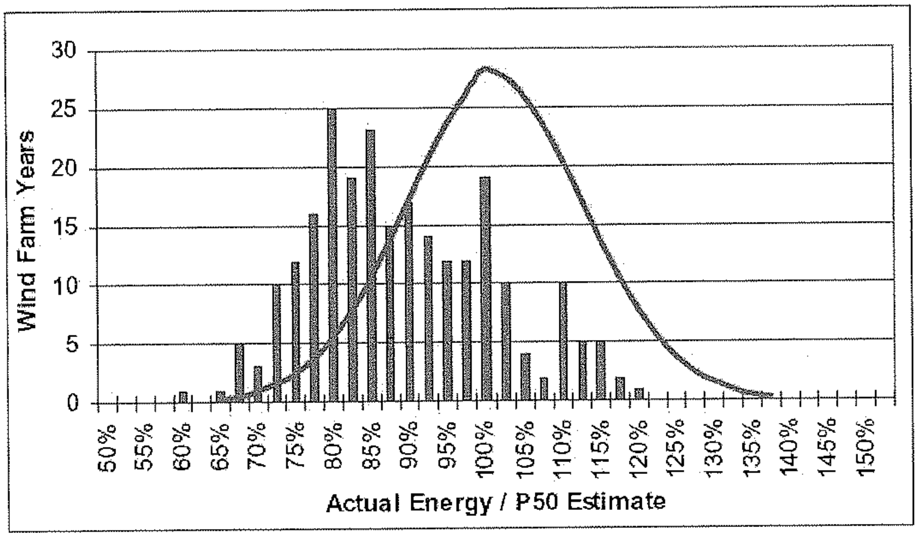
- We fully concur with the selected Final Short-list.

In the Conclusions and Recommendations section we present our views on ways to improve the RFP evaluation process. In this summary we offer one recommendation we believe is the most significant. The Final Short-list contains an ownership and PPA option for one wind project. Using the RFP evaluation model the ownership bid is ranked higher than the PPA bid in PGE's analysis. While the IE agrees with the analysis, he also recognizes that additional factors should be considered before making the final selection between the two options. First, the evaluation model reviews the life cycle cost of the project but does not assess all externalities unique to the site or the project which could raise the value of the ownership bid to customers. Second, the ownership option comes with significant capacity factor risk for the ratepayer which would be borne by the counterparty in a PPA structure. During the development of the project, two studies were completed within three months of each other. These studies resulted in capacity factor estimates that varied by more than 5%, which affected the projected levelized cost of the project by approximately $20/MWh. An ownership option would bear the full impact of this production shortfall, whereas a PPA option would effectively shield customers from most of the cost because the energy price would be fixed. The first study had a lower capacity factor and was for a partial year. We recognize that the additional data used in the second study makes it more reliable than the first study, but without more information we recommend additional review of wind history. Chart 1[3] graphically presents a study documenting actual energy versus predicted energy production from wind farms placed in service in the United States in the recent past. This variation reflects the risk that lower energy production from the facility could dramatically lower the value the ownership option would provide.

Chart 1



Average: about 11% below P50
2006 presentation: 13% below P50

PGE may identify benefits from the project that are beyond those identified in the RFP evaluation model, and it should be incumbent upon the Company to identify and quantify those benefits. At a minimum, we would

[3] Source: http://www1.eere.energy.gov/windandhydro/pdfs/20-2030_poore.pdf

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expect PGE to require an updated analysis of the project with a new wind study and a salvage value that reflects the potential for re-powering the site at the end of its economic life. Also, if PGE pursues the ownership option, we encourage PGE to explore structuring the acquisition to appropriately mitigate the risk that the project may not perform as projected. For example, PGE could structure the agreement with an initial purchase price that is lower than the bid value, and provide for a performance payment based on actual production during some number of initial years in operation. An arrangement of that sort would, in our opinion, more appropriately share the risk between the developer and PGE's customers. We would expect PGE to fully document the benefits and value of the ownership option, beyond what is reflected in the RFP evaluation model, and establish that the value offered by the ownership option outweighs the risk of energy production implicit in the ownership option. In summary, the IE believes PGE must make a stronger case for the ownership option either through a contractual arrangement that reduces the assumed risk or by quantifying additional benefits the ownership option would bring beyond what was considered in the RFP.

In IE Confidential Attachment 1 we provide a summary of bids received before the final short-list review was undertaken.

In this report we discuss our findings in greater detail.

I. RFP PROCESS

PGE submitted a draft RFP for all resources consistent with the most recently filed IRP. When the Commission declined to acknowledge the IRP in March 2008, PGE adjusted the RFP to only consider renewable resources. PGE issued the Renewable RFP on April 17, 2008. Prior to receipt of the bids, the IE completed a review of the evaluation methodology to be employed as well as performed a mock bid process to identify any limitations of the process and quantify the impact of key components on the rankings. Thirty-eight bids for 2,970 MW were received on the website and in hardcopy by the IE on June 4, 2008. Each bid was opened and summarized by the IE before being released to PGE.

The initial evaluation was concluded on September 10, 2008. The IE performed full scoring on 4 bids of various technologies and compared its scoring to PGE's scoring and reviewed in detail all of PGE's scoring at that time. After resolving differences, approximately 360.2 MW of nameplate capacity (Six bids) were released from the RFP, and 2127.8 MW, based on nameplate rating, (twenty bids) were invited to continue as part of the Initial Short-list. A summary table of the shortlist and explanations of bids released is included in IE Confidential Attachment 1, entitled "Initial Short-list and Released Bids." Further detailed analysis and scoring updates in the areas of credit, transmission, integration costs, and energy valuation were concluded on November 18, 2008, with the identification of the Final Short-list. The Final Short-list consisted of nine bids (787 MW of nameplate rating, with the ability to provide 255 MWa of energy). The release of six bids due to credit, transmission, and economic factors was concluded when the Final Short-list was established. A summary table of the Final Short-list and released bids is included in IE Confidential Attachment 2. A summary of all bids is provided in IE Confidential Attachment 3.

This RFP was particularly challenging because PGE's most recent IRP was not acknowledged by the Commission and because of the complexity of fairly evaluating renewable bids across a spectrum of various technologies. Upon selection of an evaluation process, a mock bidding process was used by the IE to stress test the evaluation

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In the Final Short-list, wind was the obvious leader followed by solar. One geothermal bid was received, but the bidder withdrew the bid before the Final Short-list evaluation was commenced. All biomass bids were eliminated for transmission and credit reasons or because the bidder withdrew the proposal. [7]

One wave power proposal was received, and one presentation for innovative solar-friendly home building design. The latter was eliminated because it was not consistent with the RFP goals of providing energy to the PGE system. Due to the novelty of the wave power proposal, PGE invested considerable effort to evaluate this project, in an attempt to fully appreciate the likely cost and to include the proposal on the Final Sort-list. After considerable time and effort, we encouraged PGE to release the wave power proposal because the technology was unproven, and the transmission and cost challenges were significant barriers to completing an agreement within the terms of the RFP.

Other areas given close attention were:

- **Ranking of Ownership Options vs. PPA** – Assuming an ownership bid is assigned to PGE upon completion of construction, a PPA wind project in the same location as a PGE-owned wind project would score almost at parity. Accion believes this to be acceptable as the scoring balances the risk-avoidance benefits of a PPA and some of the experience benefits of PGE. PGE and the IE recognized that regardless of the ranking, PGE would be required to provide additional substantial validation of the value offered by an ownership option over a PPA option because of the implicit risks of ownership that could not be captured in the scoring template.

- **Capacity Scoring** – One of the primary differences in value that the renewable technologies bring is the capacity value. Accion pushed PGE hard in this area to appropriately account for this difference in the scoring. PGE agreed to assign 60 points in non-price for capacity value as well as 20 points for intermittency. Projects with high capacity factors and dispatchability will score higher in these areas because of the capacity value the projects bring to PGE. We feel this appropriation is fair and does not unduly burden projects with significant output variability.

- **Locational Impacts on Bids** – PGE explicitly prefers projects inside Oregon and inside their service territory and this is reflected in the non-price scoring. However, the penalties for being outside the service territory are not too punitive to make a good project outside the territory score poorly in the evaluation. The total benefit a project could get from being inside the service territory is around 30 points (or approximately $1.75/MWh levelized).

- **PGE Experience vs. PPA Risk Avoidance** – PPA projects can provide some risk mitigation in terms of guaranteeing mechanical or actual availability. This was captured with 30 points in the non-price scoring. Ownership cases were obviously not eligible for these points. However, ownership projects could provide lower costs of capital, and would have high credit scores and low risk in areas that require experience. The price trade-offs were appropriately calculated in PGE's price scoring models, and the non-price scoring allocations were appropriate for reflecting the values provided in these areas.

[7] The bidder withdrew after signing a contract with a different buyer, and not due to any issues arising from the PGE RFP process or evaluation process.

- **Capacity Value**
  While quality of energy addresses the hourly swings in output, a capacity scoring component was necessary to account for the fact that some renewable resources do not have an energy profile that is coincident with peak load periods. In July of 2008, Bonneville Power Authority (BPA) and the Northwest Power and Conservation Council released their revised assessment of wind generator statistical capacity value from 15% to 5% of the nameplate. The study established that many renewable resources will require simple cycle combustion turbine back up for a majority of their nameplate capacity. The level of capacity back up required differs across renewable technologies. Initially, PGE did not reflect differences for capacity values across technologies, but in order to be consistent with actual resource planning guidelines of backing renewable resources with firm capacity, the IE and the PGE scoring team developed a table that adequately reflected the different capacity requirements without being punitive to certain technologies.

Risk Assessment

Renewable resources require unique risk assessment. PGE, the Commission Staff and the IE invested considerable effort in establishing appropriate risk components to be applied to bids. It was necessary to balance the encouragement of renewable resources with the potential unintended consequence of hidden costs to customers. We believe PGE successfully set risk components that fairly assigned costs, while at the same time avoiding inappropriate weighting. A review of risk components follows.

- **Weather Risk**
  The inherent weather risks that renewable technologies are forced to accept make diversity in location and technology important. In addition to the consideration of the effects of weather in the capacity scoring and quality of energy scoring, projects with similar energy profiles to existing PGE resources did not score as well as projects with different profiles. Among wind bids, locational diversity credit was awarded to projects that have different wind profiles by virtue of their physical distance from PGE's Biglow Canyon project.

- **Fuel Risk**
  Biomass projects are subject to significant fuel price and availability risks. PGE's method for alleviating this risk was to require all biomass bidders to provide firm fuel pricing for all bids. The IE believes that this adequately protects the ratepayer without significantly impacting the value of biomass bids. This also assisted in the comparison of bids with fuel costs (biomass) and without fuel costs (all other renewable), because there is no risk to be quantified if all fuel bids are fixed price.

- **Developmental risks**
  Ownership often can provide customers significant value over the long-term, but because of its implicit risk, ownership options must be evaluated not just from a total cost perspective but also from a risk perspective. For comparison to PPA options, development risk must be identified and mitigated for the ratepayer. The only ownership bid remaining on the Final Short-list is a turnkey project without development risk, so further consideration of this risk is not warranted.

- **Energy Production Risk**
  PPAs implicitly assume capacity factor risk as the development costs are independent of the projected capacity factor. Therefore, if the capacity factor over time is higher than that assumed in the PPA, the developer's profit is commensurately higher. However, a lower than expected capacity factor can substantially impact the returns to the developer. In an ownership option, these risks and benefits are reversed. A historical survey shows that average actual production is typically 11% below the projected P50 (see Chart 1). While the trend is getting better over time, we feel the risks are still weighted toward over-estimating capacity factors. In a PPA arrangement the developer is assuming this risk. In an ownership case, customers would assume this risk.

  This remains an outstanding issue as one of the Final Short-list bids has both ownership and PPA options. Specifically, the project had two wind studies performed with a 5% range of capacity factor estimates which affected the levelized cost of power by ~$20/MWh. The evaluation was performed based on the newer and more complete of the two studies, which also had the much higher capacity factor estimate. The earlier wind study was for a partial year as the developer attempted to refine the project. We know from experience that this is a normal evolution with a wind project, and refinement of the estimates would be unimportant with a PPA. Accordingly, the evaluation model did not require refinement of the wind study. We understand PGE will require additional wind studies if the acquisition option is pursued.

  The IE notified PGE that we believe this to be a substantial risk to the customers if the ownership option were to be selected before additional analysis is performed and other externalities are considered. The IE recommends that 1) additional independent wind studies be performed with the existing wind data before the decision is made between the ownership and PPA option and 2) that a risk adjustment should be assessed to the ownership option that takes into account the results of the additional wind study. While the IE recognizes that PGE should not be expected to guarantee the capacity factor of a wind ownership project if such project offers value over a PPA option, the negotiations with the bidder should attempt to reconcile the differences in the risk profiles between the two options. As discussed above, PGE will consider values other than those included in the evaluation model for this RFP when negotiating the terms of an acquisition contract. We expect the Company will establish a production risk assessment matrix for use when determining the value to PGE customers if PGE acquires the project, instead of entering into a PPA.
  We believe the risk assumed should be justified by additional value provided to the customers. PGE noted that additional factors not considered in the RFP evaluation, including the option for repowering the asset at the end of its economic life, could add significant value to the ownership option. However, until additional analysis and support for the ownership option is provided by PGE, the IE recommends the PPA option for contracting.

- **Operating Cost Risks**
  The only revenue mechanism in each PPA bid was energy payment, and bidders did not require pass-through of changes to their operating costs. Accordingly, these PPAs effectively shield customers from

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both variable and fixed operating cost risks. We found projected operating costs of the Final Short-list for the PPA proposals to be appropriate.

As discussed earlier, we recognize an ownership bid, as opposed to a PPA proposal, has the added concern of requiring assumption of this risk by taxpayers. Since the ownership evaluations used conservative estimates for operating costs, the IE did not recommend a separate risk adjustment for this component. Instead, we suggested PGE recognize the added risk associated with an ownership bid as part of the negotiation process and before contracting would be completed. PGE committed to document the value of ownership as opposed to a PPA, and we expect the projections for ongoing operating cost will be given full review as part of the documentation.

- **Availability Risk**
  In the non-price scoring PPA options were eligible for availability guarantee credit if the bidder was willing to assume availability risk. However, few bidders provided guarantees beyond manufacturer's mechanical availability guarantees, and when they provided a guarantee, their method of compensation for failure to meet those requirements was generally limited. Therefore, since the total risk the bidders were willing to assume was small, the credit in the non-price scoring was also small.

PGE Market Price Forecast Impact on Evaluation

A market price forecast reflecting accurate hourly shape and annual charges was developed by PGE for evaluating the renewable resource bids. The important aspects of developing market prices for use in an RFP bid evaluation are 1) that the annual price differences are reflective of appropriate escalation of costs across time and 2) that the hourly shapes accurately reflect the dispatch of resources in the system. Appropriate market price forecasts will result in the most cost effective technologies being selected in the RFP evaluation.

The significant factors of the market price forecast employed by PGE are discussed below.

- **Capacity cost**
  Inaccurate construction cost forecasts may affect the resource mix and thus not only the annual market prices but also the hourly market price shapes. The IE reviewed PGE's forecasts of technology specific construction costs to ensure that recent significant escalations in commodities were reflected in their costs. We believe PGE's capital cost expectations are in line with other market forecasts.

- **Aurora build out of resources**
  AuroraXMP is the production cost model that PGE utilizes to generate an expansion plan. The logic AuroraXMP uses is a cost-recovery algorithm that is typical in the industry. PGE's use of the software is consistent with standard practice and the expansion plan it developed as part of developing the hourly market price is reasonable.

- **Fuel price forecast**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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Northwest and Intermountain Power Producers Coalition Exhibit 324

PacifiCorp Response to Northwest and Intermountain Power Producers Coalition Data Request 3.7

January 14, 2013

UM-1182 / PacifiCorp
October 22, 2012
NIPPC Data Request 3.7

NIPPC Data Request 3.7

For each PPA that the utility has for wind power, please provide (1) plant rated capacity, (2) the expected capacity factor, or if unavailable projected monthly output, for the wind project supplied by the project and relied upon by the utility contemporaneous to execution of the PPA, and (3) the actual capacity factor, or if unavailable actual monthly output, in each year of the project's operations. Please provide supporting documentation with your response.

Response to NIPPC Data Request 3.7

The Company objects to this request because it is not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

Please refer to Attachment NIPPC 3.7, which provides the annual capacity and generation output, as reported annually to the Federal Energy Regulatory Commission (FERC), as part of PacifiCorp's annual FERC Form 1 filing.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 325

Idaho Power Company Response to Northwest and Intermountain Power Producers Coalition Data Request 2.7

January 14, 2013

Northwest and Intermountain Power Producers Coalition Exhibit 325 contains confidential material and has been redacted

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 326

Vansycle and PaTu Wind Capacity Factor Values

Provided by Portland General Electric in response to Northwest and Intermountain Power Producers Coalition Data Request 13, Confidential Attachment 013-A

January 14, 2013

Northwest and Intermountain Power Producers Coalition Exhibit 326 contains confidential material and has been redacted

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 327

Klondike II Monthly Wind Capacity Factor Values

Provided by Portland General Electric in response to Northwest and Intermountain Power Producers Coalition Data Request 13, 1st Supplemental Response, Confidential Attachment 013-D

January 14, 2013

Northwest and Intermountain Power Producers Coalition Exhibit 327 contains confidential material and has been redacted

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PUBLIC UTILITY COMMISSION OF OREGON

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Northwest and Intermountain Power Producers Coalition Exhibit 328

"Actual vs. Predicted performance –Validating pre construction energy estimates*"* by GL Garrad Hassan September 2012

Provided by Portland General Electric in response to Northwest and Intermountain Power Producers Coalition Data Request No. 027, Attachment 027-A

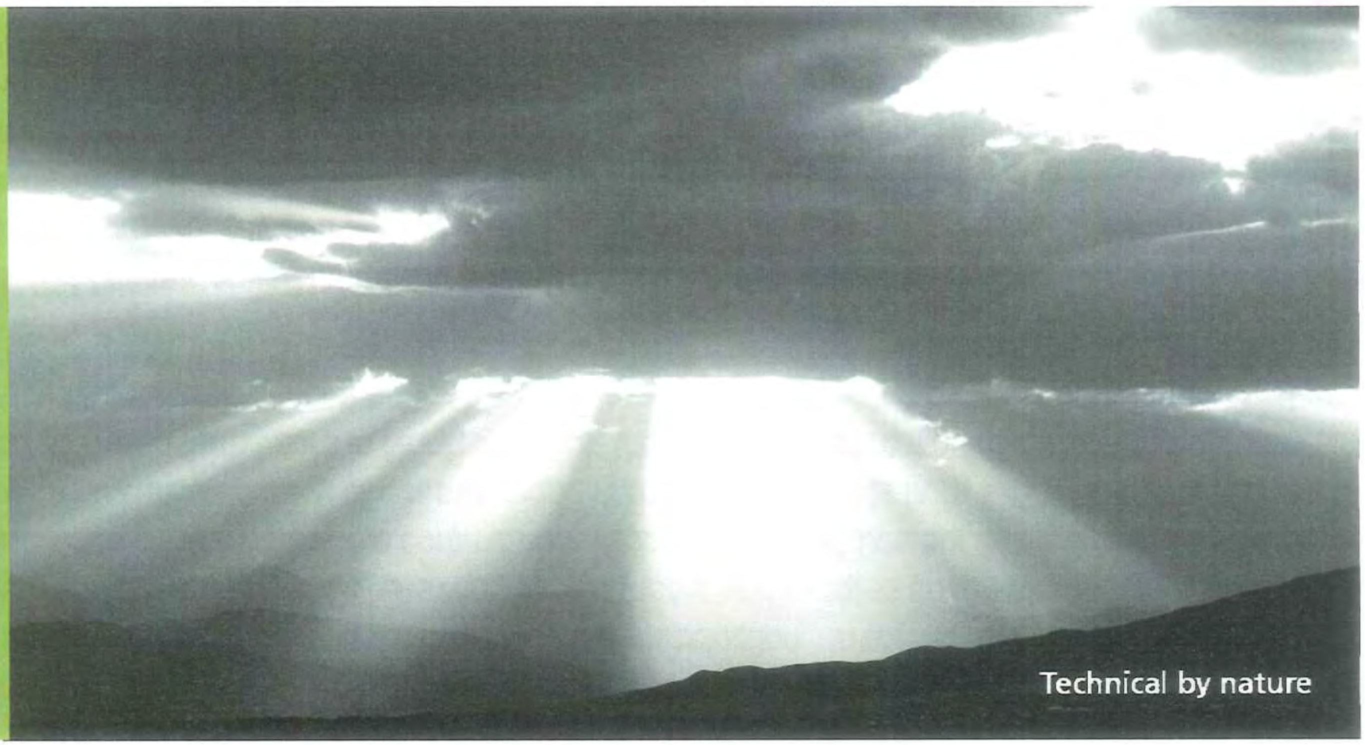
January 14, 2013

Renewable energy consultants

GL Garrad Hassan

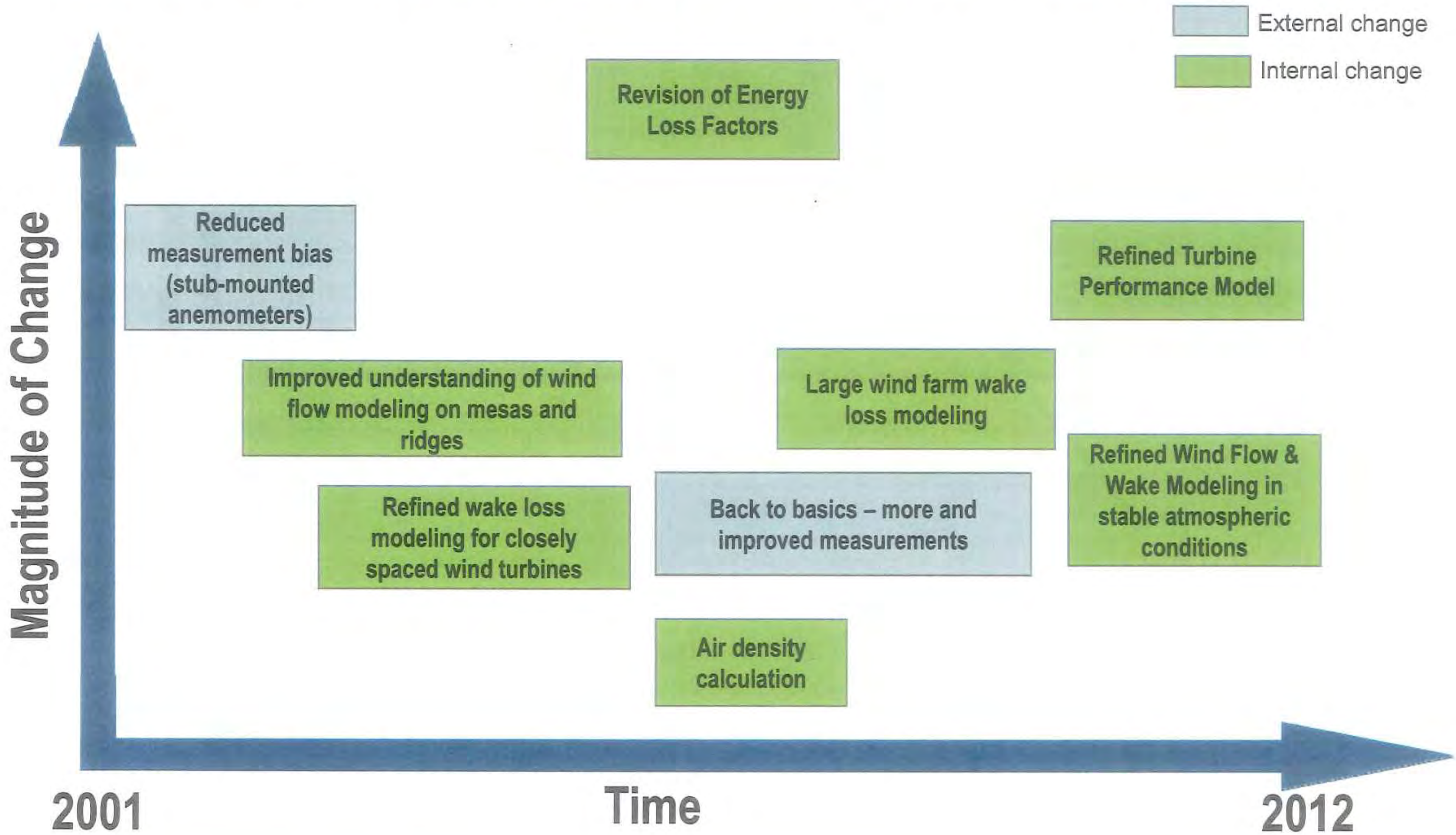
Actual vs. Predicted performance – Validating pre construction energy estimates

September 2012



www.gl-garradhassan.com

Evolution of GL GH Energy Production Assessments



GL Garrad Hassan

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Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 329

"The Oregon Independent Evaluator's Final Closing Report on PacifiCorp's 2008R-1 Renewables RFP" presented to the Oregon Public Utility Commission by Boston Pacific Company, Inc.
May 15, 2009

Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 6.10, Confidential Attachment

January 14, 2013

Northwest and Intermountain Power Producers Coalition Exhibit 329 contains confidential material and has been redacted

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Northwest and Intermountain Power Producers Coalition REDACTED Exhibit 330

"Independent Engineer's Review of Four Wyoming Energy Assessment Reports" prepared by GEC
November 3, 2009

Provided by PacifiCorp in response to Northwest and Intermountain Power Producers Coalition Data Request 5.2, Confidential Attachment 5.2

January 14, 2013

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Northwest and Intermountain Power Producers
Coalition Exhibit 400
Reply Testimony of Camden Collins

January 14, 2013

I. INTRODUCTION

Q: What is your name and address?

A: Camden Collins, 275 S. Arroyo Pky #401, Pasadena, California, 91105.

Q. Did you provide opening testimony in this proceeding?

A. Yes, I provided opening testimony on behalf of the Northwest and Intermountain Power Producers Coalition (NIPPC).

Q. What is the purpose of your reply testimony?

A. I will respond to the direct testimony on the topic of counter party risk and credit filed on behalf of PacifiCorp, Idaho Power Company (Idaho Power), and Portland General Electric Company (PGE), collectively the "utilities." In the next section (Section II), I will address the current scoring of credit in Oregon requests for proposals (RFPs) as implemented or proposed by the utilities. In Section III, I will respond to concerns regarding the ability of a power purchase agreement (PPA) to protect against costs that utilities allege might become those of its customers. Finally in Section IV, I will provide my policy recommendations in response to the utilities' proposals regarding credit and counter party risk.

Q. Could you summarize your conclusions and recommendation in this reply?

A. It is my opinion that the utilities have overstated the problem of "counter party risk," much of which is mitigated by the excess supply that exists in the market in the event of an inability to perform, and the remainder of which can be and is effectively dealt with in power purchase agreement (PPA) terms. With regard to "credit risk," it is my opinion that the utilities are not currently conducting fair RFPs, and are instead penalizing independent power producers (IPPs) for the inability of IPPs and their special purpose entities (SPEs) to provide excessive credit assurances *prior to execution of a financeable PPA.* In my opinion, the credit for either an IPP owned or a utility-owned power plant derives from the government authorized revenue stream supplied from the ratepayers. As currently structured, the Oregon RFPs penalize IPP bidders unfairly. I recommend that the Public Utility Commission of Oregon (OPUC or Commission) instruct the utilities to stop using credit in scoring bids. I also suggest that if the Commission wants to level the playing field on the credit issue, further modifications to the request for proposal (RFP) process could be implemented.

II. SCORING AND CREDIT ASSESSMENTS

Q. What have the utilities proposed with regard to credit assessments?

A. I understand the utilities' proposals to be implementation of a lower score or bid elimination for IPP bidders who are deemed to lack "creditworthiness" at the time of RFP bid submission or the time for establishing the short list in an RFP. For bidders who fail to meet some test or assessment of credit, they may be excluded altogether from the process, or there may be an option in the RFP for such bidders to provide a letter of credit or a commitment letter to remain in the RFP process. The credit assessment may rely on a rating by a ratings agency, or some other non-transparent, proprietary evaluation. It appears that this is how the utilities have conducted past RFPs and propose to do so in the future.

Q: Have utilities made feasible proposals for using credit scores or assessments in the bidding process?

A: No. Because the credit (i.e., loans) that will support the development, construction and operation of a new power plant have not yet issued at the time of bidding, the use of credit assessments (or scores by Moody's or Standard & Poor's, when available), has no nexus whatsoever to any financial performance risk of an IPP under the forms of PPA's customary in general, or which I have reviewed in particular for this docket. The financial performance risk to IPP lenders (i.e., credit risk) is transaction specific.

Because IPP's form SPE's to hold generating assets, it is not feasible to assess credit that cannot yet exist and can depend as much upon on PPA prices as all other considerations combined. This problem of timing cannot be solved, and the attempt to devise solutions has prompted proposals that are neither transparent nor fair.

Q. Could you explain what you mean by the special purpose entity structure and the timing problem?

A. For a wide variety of reasons beyond the scope of this proceeding, almost all IPPs will place generation assets in a SPE. The SPE is created *in part* to address the risk to the plant owner of having a single source of revenue, the utility. This can readily be appreciated by a thought experiment: two PPAs are signed, one by a utility with a large and diversified fleet of supply resources including 40% IPP sources, one by a utility that has opposed IPPs for 20 years. The credit, the willingness to lend, will be distinctly different, even if the two PPAs are the same. Therefore, if one is going to use a PPA to induce a power plant to be built, with all its output dedicated to one buyer, this timing issue will always be present. Examples of IPP power plants owned outside an SPE, or financed entirely and for its useful life from a holding company balance sheet, are rare if they can be found at all. The entity derives its credit from the PPA with the utility.

The timing problem is that prior to executing a PPA, the SPE cannot provide specific credit information that is relevant. Thus scoring credit prior to execution of the PPA is problematic because the utility's credit is both for all plant and not based on comparable production specified terms.

Q. You stated that the specific proposals in this docket for treatment of credit are not feasible. Aside from the timing problem, could you explain why?

A. Specific proposals in this docket to score or assess credit are not feasible. PacifiCorp's Direct Testimony proposes applying a probability of default to customer costs:

> For those counterparties that are rated by Moody's, utilizing the credit rating (with its corresponding probability of default), for each bid, the Company could multiply the probability of default for the relevant tenor (e.g., four years), by the incremental cost to the customer (above the amount of any credit assurances posted), should default occur. If default is driven by cost overruns in a given RFP project, then those costs *could* be paid by the Company (if project completion remained prudent, and after utilizing any posted credit assurances from the counterparty) and ultimately be borne by the customer. This expected cost of default could then be added to each bid's cost.[1]

This is not a feasible approach. The probability of loan default was developed by rating agencies to describe the probability of loan default. It is a statistic from which nothing else can be properly inferred. It cannot be properly applied to "customer costs", *even if any were to exist*. So there is nothing to multiply the probability of default by.

Q. Would a utility ever need to pay an IPP for the IPP's cost overruns?

A. It is my opinion from having reviewed PacifiCorp's Top Of The World Wind PPA, as well my knowledge and experience with PPA's in general, that PPA's do not make it possible that ratepayers "could" ever come to be obligated to pay a "cost overrun" rather than the PPA's agreed price. While there are many other reasons projects fail or are abandoned, "cost overruns" under most PPAs are a risk borne by the equity participant in the power plant. Lenders protect themselves by so requiring, and loans are not in default when equity losses are incurred. Therefore, while the consummation of financial default of the loans will involve losses to equity, one cannot say that a statistic describing loan default can be applied directly to sources of equity

[1] PAC/100, Kusters/28:2-10 (emphasis added)

lost (i.e., cost overruns) that occur in a graduated manner before loan default, if any, could ever occur. Many more instances of equity loss occur without loan impairment than not. In fact, it is rather common and one reason why ratepayers benefit from this form of procurement: if the utility owned the plant the utility would look to the ratepayers to pay the increased cost.

Q. PacifiCorp states that events could transpire which would "require" PacifiCorp to assume incremental costs to customers.[2] Do you agree that this is a realistic risk?

A. No. Even in such a situation, wherein the SPE goes bankrupt before the commercial operation solely because of cost overruns, there is no basis for assuming that the utility would choose to become the owner of that plant, or the Commission would find it prudent to do so, under step in rights that are optional in nature, or simply as a buyer of a distressed property. There is no situation wherein PacifiCorp would be "required" to step into the contract and the seller's debt, under any PPA I have reviewed. Almost by definition, if it were prudent to buy a plant out of bankruptcy, it would not be because one accepted the very losses that wiped out the equity and put it into bankruptcy in the first instance. Buying a distressed property for 5 cents on the dollar does not make the lost equity of 95 cents the buyer's burden. Nor can it shift to ratepayers losses properly borne by lenders that may have deviated from sound underwriting practices. It is hard to imagine it would ever be prudent to take on another's duly incurred losses, and PacifiCorp has provided no examples of this ever actually occurring.

Q. What will be the end result of PacifiCorp's proposal for most bidders?

A. The result of the method is that the credit score is 0 because under PPAs there are no "customer costs", there is only the agreed price for power delivered. Furthermore, no proposal is made to fairly compare the utility plant credit. The credit in the utility-owned generator is

[2] PAC/100, Kusters/29:16-20.

provided by the ratepayers and features of the regulatory compact not made available to IPPs. I have included some of the discovery responses relevant to this inquiry as NIPPC/401. PacifiCorp suggested in discovery that 10 percent of the non-price score be used to "assess" the probability of default.[3] PacifiCorp has used non-price scores weighted at 30% of the total score in past solicitations.[4] Assuming that PacifiCorp proposes to continue that practice, the resulting contribution to the total score would be 3 percent, or 10 percent of 30 percent. Idaho Power's 2012 RFP weighted credit 5% of the total score,[5] and PGE stated that it has used 5.5 percent in one past RFP.[6] But the "assessments" of credit proposed do not produce a number to weight.

Q. Are there any other problems with the proposed credit scoring?

A. Yes. It lacks transparency. For credit scoring or assessment to be feasible, they must also be transparent, a matter discussed in more detail below. As a preliminary matter, two suggestions involving credit by utilities purport to be feasible solutions but are so lacking in transparency that they cannot actually be evaluated for feasibility. The first utility suggestion lacking transparency is to simply postpone the difficulty: allow utility staff to conduct ongoing reviews of credit terms immediately prior to the RFP process. This suggestion is based on the assertion that credit terms need to be fully reflective of a momentary "market dynamic" of un-described pertinence to a PPA that will induce construction of a new generator or finance operations for decades. Timeliness is not an excuse to avoiding putting forward a specific credit standard for public review and comment, and the time such a process takes to complete. These transactions are not power sales taking place in a dynamic wholesale market. They are long term contracts fully dedicating the output of the plant. The feasibility problem cannot be kicked like a can down the

3 NIPPC/401, Collins/3(containing PacifiCorp's Response to Staff Request No. 8.)
4 NIPPC/401, Collins/1-2 (containing PacifiCorp's Response to Staff Request No. 4).
5 NIPPC/401, Collins/4-5 (containing Idaho Power's Response to Staff Request No. 5).
6 NIPPC/202, Collins/1-3.

road by suggesting that something in market conditions changing in a few months will exceed in importance of credit terms lasting 20 or more years.

Similarly, proposing some subsequent "standardizing" of credit terms to be met during the solicitation, for credit that cannot yet exist and derives from the PPA, *all* its terms, *and* the price, is not feasible and is likely to result in an unfair outcome where post-bid negotiation ensues.

Q. What is the second faulty suggestion that will result in a lack of transparency?

A. The second suggestion that can lead to a lack of transparency is use of step in rights.[7] Step in rights are a complicated topic that lack transparency and could in fact be used to significantly undermine the fairness of any solicitation or PPA that results. To reach that conclusion, it is first necessary to set out some of the conundrums involved in utility procurement more generally. It would not be hard to imagine PPA terms so harsh that financial distress of the supplier would be as likely as not. Vulture capitalism or distressed asset financial terms involve practices for allocating ownership of the borrower's project upon failure , and it is a serious concern in a monopsony or monopoly market where the buyer would prefer to own the resource than purchase its output. To create as a condition of sale the separate right to benefit from failed projects, *before* they have failed, is to decide with their lender how to divide the assets. When not all the contracting parties have all the same information about a transaction, such "separate" agreements can contain almost a surprise quality for the project in distress. A tendency to seek to benefit from the failure of projects can evolve without deliberate intention, simply by requiring ever stricter PPA terms that gradually increase the probability that financial distress will result, particularly in jurisdictions with extended post-bid negotiations or without a

[7] PAC/100, Kusters/29:18-19.

wholesale clearinghouse. In the context of a new power plant fully dedicated to a utility, extended post-bid negotiations of discretionary and inter-related terms are themselves the hallmark of unfair competition, a conclusion more easily reached when few contracts result. The seller is over a barrel because all the PPA terms were not put out to bid. The price bid cannot therefore include the full consequences of all known terms like credit, damages, and step in rights that reveal rather than obscure ownership transfer upon failure. Sellers get whittled away at in these types of solicitations.

It is a hallmark of monopsony buying power that utility buyers often do not clearly evaluate the distinction between a tough but fair bargain and one simply too good to be true. It is a special problem associated with monopsony buying: one cannot always know how aggressive to be in seeking the best terms, and the bar keeps getting raised in a situation where the buyer does not have to buy anything *at all*. In this context, to presume that the buying utility, having agreed to an extremely strict package of terms with full knowledge of the industry's standards, practices and prices, "could be" the new owner of a distressed project and assume costs previously incurred by and causing the demise of the seller, is to raise the possibility of a reward for bad faith, or a lack of regulatory supervision. To heap upon that additions to rate base in the form of a third party's cost overruns would simply add insult to injury, were the Commission to ever allow such a thing.

Q. Are there any examples offered of step in rights in this proceeding, where the ratepayer could be harmed?

A. I understand that only one PPA for a major resource in excess of 100 MW has been executed as a result of an Oregon RFP since 2006. I reviewed the terms of that agreement to better understand PacifiCorp's statements regarding step in rights and potential risk to ratepayers. [redacted]

Q: Have utilities proposed credit assessments that are derived from sufficiently transparent sources for transactions imbued with a strong public interest in a reasonable cost of supply?

A: No. Direct Testimony reflects the difficulty of scoring bidders for credit strength generally, and in particular for those who do not have a rating agency rating.[8] Transparency is lacking. Bidders therefore lack adequate specifications to this element of the scoring or ranking. The hope that this problem can be solved by outsourcing is more likely to decrease than increase transparency.[9]

Idaho Power lists the following components to a credit "assessment": "liquidity ratios, leverage ratios and trends, payment trend, profitability ratios, revenue trends and industry/peer ratio comparisons."[10] This hodge-podge is the antithesis of clear specifications. No bidder could determine in advance how all these components enter into a single calculation and result in a pass or fail rating. One could not know whether the revenue trend weighs more or less than the other elements. One could not evaluate the number and kinds of profitability ratios used, how they are weighted relative to each other, or how they are weighted relative to the liquidity ratio. Idaho Power stated in discovery that its "internal credit model" calculates a pass or fail,[11] but this reply to Commission staff is a non-answer to their question of how it is done.

Comparing IPPs to each other, PacifiCorp struggles to rank or score very dissimilar bidders in a transparent manner.[12] I do not believe there is a benefit to ratepayers from eliminating bidders who cannot provide audited financial statements, or requiring of them costly

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[8] PAC/100, Kusters/25:9-10 ("internal credit rating" and "proprietary credit scoring model"); PGE/100, OBMH/31:21 (unquantified letter of credit); Idaho Power/100, Stokes/9:15 ("'pass' or 'fail' rating").

[9] Idaho Power/100, Stokes/11:7-10 ("prepared by consultants").

[10] Idaho Power/100, Stokes/9:11-12.

[11] NIPPC/401, Collins/4.

[12] PAC/100, Kusters/26:23 – 27:6.

letters of credit just to make the short list. These requirements will only increase the costs to participate in the RFP, without any benefit to ratepayers.[13] Two fundamental misunderstandings are at issue. First, that the utility's credit could be "used," either by the smaller competitors or large utilities like Duke Energy.[14] In fact, the credit to develop, build and operate a power plant comes from the stability of the revenue commitment in the PPA, which is in turn a feature of government regulation and review, without which large and long term investment does not occur in the face of excess supplies in the reserve margin. Utility supply markets involve unique features caused by building generation supply ahead of load demands, and the relative insecurity lenders find when there is only a single revenue source. Options PacifiCorp may negotiate to step into a failed project do not constitute having its credit "used" by an IPP, big or small. The only prudent exercise of such an option, per se, would be of net benefit to ratepayers who are protected by the PPA from ever seeing backstop credit exercised.

The second fundamental misunderstanding is that the credit quality of the utility comes from shareholders.[15] Again, it is the government that provides the regulatory compact and revenue requirement to build ahead of load demands, and the ratepayers that pay for the additional financing costs of financial stability in the form of a guaranteed rate of return on higher equity required. Ratepayers, not shareholders, fund and pay for the life of prudently invested plant, used or not. Outside the regulatory compact encompassing the totality of utility plant, property and equipment, it is hard to imagine a shareholder that would continue to support an individual generation investment close to retirement, with no productive capacity to generate income, just because of a reasonable expectation decades ago. The critical point is that it is not

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13 PAC/100, Kusters/25:20.
14 PAC/100, Kusters/27:4-5 ("Company's credit").
15 Idaho Powers/100, Stokes/10:11-12.

fair to compare utility credit to IPPs before there is a PPA or before the project is commercially operating.

Q: Are there special problems with the transparency of credit rating agency opinions?

A: Yes. Prior to 2008, one might have said that turning to ratings agencies to compare IPP credit quality to the utility plant was better than nothing, were that fair. The same conclusion cannot be supported today. Rating agencies have regulatory flaws widely and publicly considered since 2008, and regulatory reform is in the first of many stages to come. Ratings agencies provide statistics for investment grade credits that are superior in quality to the inferences that could be drawn from non-investment grade credits. Non-investment grade credits are lacking in homogeneity, and that problem attends IPP credits even more than most. IPP credit ratings do not have either the longevity or the sample depth of utility credit ratings.

Much of the IPP history in this country has been unrated. Most of the IPP history in this country involves single sources of revenue, a particular problem in credit evaluation that distinguishes the true default probabilities of otherwise equal credits. Ratings agencies do not disclose their data samples, so their opinion cannot be evaluated for the depth of the sample, which is central to mathematical principles that would allow one to make reasonable inferences from a sample to the population. Rating agencies are selling their opinion, not the data they base it on. All of this weakens the inferences one could draw from the ratings of credit rating agencies, even if one thought they were more credible than Congressional testimony of their employees would suggest.

Q: Are the proposals utilities have made fair methods for evaluating financial performance risks of IPPs?

A: No. In addition to being infeasible and non-transparent, they are not a fair way to evaluate competitors, particularly when utility plant is in the competition, all PPA terms are not bid on, and post-bid negotiations are used.

The methods proposed are not related to future financial performance: they tend to focus on the development and construction stage, or times proximate to the solicitation, and those financial performance risks are not ones that ratepayers have any exposure to, as discussed above and below.

The methods proposed are not related to financial capacity, because the PPA price and contract execution itself is crucial to determining a financeable project. While one might not want to pay the price of a financeable project to a bidder with no experience at all, it is that price that would make such a thing feasible. Many parties with no prior experience successfully navigated the hazards during California's boom.

The methods proposed put a backwards focus on the credit quality subsidy or enhancement provided by ratepayers. It is not how much "less" others' credit may become in the fullness of time, but how much "more" strong the utility's credit is due solely to special terms <u>it and no other is offered</u>, due to means entirely within its control. The methods proposed relate to a financial performance risk that is not borne by ratepayers, but by lenders to the IPP. In my experience, no PPA puts the consequences of bad or excessively aggressive lending on ratepayers. While other supply relationships of shorter term and type justify the utility taking a different credit monitoring posture, a long term full output PPA is not the proper object of this power sales practice.

III. CONTRACTUAL PROTECTIONS

Q: Do long-term PPAs protect ratepayers from identifiable risks of financial performance of an IPP?

A: Yes. Generalizing about PPA's is hazardous, because each one can have a unique combination of contractual elements. In general, PPA's protect utilities and their ratepayers from failed projects, before or after commercial operation. The utilities' assertions of actual damages they and their ratepayers have suffered are overstated, or entirely misplaced.

Three important foundational elements need to be appreciated before evaluating any particular allegation of "damages" by a utility faced with breach of a PPA. First, many utilities prefer to earn on generation they own to all other options, a natural consequence of serving shareholder interests. Second, it is ratepayers that subsidize the redundancy and reliability levels associated with the entire fleet of resources used to supply the load. While this subsidy takes many forms, two of the most important are: (1) maintenance of a significant reserve margin, and (2) price protections, in many forms, which are not limited to a specific resource failure. Extra resources are available to cover any and all contingencies, not just one, and it is usually (but not always) unreasonable to buy long run price protection for one plant. Actual damages to ratepayers are therefore unlikely to exist. The "insurance" is available, as is prudent, for any of the many possible supply problems that regularly occur.

In evaluating potential ratepayer impacts of IPP credit, it is important to understand the context of ratepayer's protection from supply interruptions that come after the state of a generator's commercial operation. The "insurance" against each and every form of non-performance is paid by ratepayers regardless of who owns the plant by paying the costs of maintaining a reserve margin. Utilities that complain of damages understandably do not want non-utility plants to rely upon that mutualized and reasonably incurred cost. Yet the IPP industry's post-COD performance has not been demonstrated to be quantitatively inferior over long horizons.

PPA terms that protect ratepayers, paying only for production, are the very terms that avoid casually assumed use of the ratepayer supported excess supply. If it were not sufficient, a utility acting in good faith would put out to bid a liquidated damage remedy with well-defined costs for it to cover non-performance, and elicit from all the bidders and the competitive process the higher price for power that this increase in unnecessary protection would occasion. One cannot, when two sophisticated contract parties are involved, reasonably assume they don't know this about the basic structure of the PPA. For all the belly aching about "damages" or counterparty risk, one might suppose that utilities would put out an RFP on a PPA that allows only 50% debt and passes through their regulated return, whether the plant is operating or not. That never seems to happen.

Q. Do you have a specific example?

A. As one example of the challenges inherent in these general principles, one can examine the PPA of PacifiCorp, the Top of the World PPA, and find that [redacted]

[redacted]

Q: Are the PPA terms such that one can discover the value or bargain inherent in third party procurement compared to utility owned plant?

A: No. Despite the ease with which the value of the regulatory compact supporting utility generation could be determined, a PPA that offers IPPs equivalent return for lower leverage is not, to my knowledge, a contract form that utilities choose to put out to bid as a way of comparing the value of this contract form to those generally used in PPAs. Yet the essence of fair competition is to specify adequately the thing or things one is considering purchasing. When reasonable people are not sure which of two forms are better, they put them <u>both</u> out to bid so that the commercial value of the meaningful differences in form of contract can be established by the market participants, and a good decision made.

Q: Does credit need to be used to cover some generalized risk of doing business with an entity other than the utility itself?

A: No. Every day, the public schedules and flies on Delta Airlines, unaware of the non-investment grade quality of the bonds of Delta. Just as the Federal Aviation Administration ensures the public trust, the North American Electric Reliability Corporation (NERC) standards maintain minimum reliability, at ratepayer cost. Operational performance risks of all supply are mutualized. The role of the PPA is to deter unreasonable reliance by the IPP on that fact. Reliability in operating performance, which PPA terms incentivize by paying for production, is not properly coupled to financial performance of the loans. The credit quality of Exelon was not materially altered the day before and after its decision to stop payment on the loans of its wholly owned Boston Generating facilities, before a multi-year work out of debt transpired. Creditors have access and means to keep plants running under these circumstances. It might be worth considering the extent to which other suppliers of the utilities, whether for poles or rail cars, are required to have comparable letters of credit in order to provide adequate "assurance" of their ability to <u>receive</u> revenue for product.

Q: Does any utility offer specific and concrete financial performance risks to be protected against?

A: No. Idaho Power argues it is concerned with levelized payments to IPPs, where it states the IPP can somehow benefit from its demise after receiving allegedly front-loaded *over*-payments.[16] Idaho Power cited an example of a 10 MW qualifying facility (QF) project losing its steam to demonstrate this risk. I disagree that this is a credit or counterparty issue that should be addressed at the RFP stage by scoring credit. It <u>is</u> a contracting issue that involves the calculation of levelized or unlevelized payments used consistently both before *and* after termination to evaluate whether there are any net damages at all. I have never been involved in a case that found the mathematical balance, after evaluating the full term, created **any** net damages. Even if such a situation occurred, one must look very carefully (and well beyond a utility's assertions) at replacement power costs in order to evaluate whether ratepayers were better off with the early termination, despite the use of levelized payments before termination. In

[16] Idaho Power/100, Stokes/12:23- 13:5.

such cases, there are often grounds asserted by both parties as to what “could have” been the price. No early terminations have been identified that arose from a root cause of financial performance, or some slick motivation to put one over on a utility. A QF losing a steam host is not a financial performance issue, even if the Commission thought that relevant for procurement more generally. It may be driven by economic changes for the host, but it does not involve the transfer of lending risk to ratepayers. Root cause matters when evaluating the financial performance of the loans (i.e., credit) and any theoretical ratepayer exposure. Confounding financial performance with operating performance or contracting terms is imprecise. A PPA with larger damage provisions and more security would result in a higher price for power. Sophisticated parties know, all the terms of a PPA are fully reflected in the price. This is true whether the price is cleared, negotiated, or set by a regulator. In the RFP context, if one is willing to pay for it, there is always more than can be done to specify rights and obligations between parties, but it would not necessarily result in a reasonable cost of procurement.

**Q.	Are you aware of any examples where an IPP plant went bankrupt due to a purely financial problem?**

A.	The one experience I have seen involving a primarily financially caused bankruptcy was settled in its first three months, when it was discovered that there were inter-locking directors between the lenders and the equity holders. The PPA was terminated: ratepayers were better off *because replacement power costs were cheaper*. Utilities build ahead of load by a wide margin of safety. Absent some rash of bankruptcies never heard of outside organized clearinghouses, individualized project risk is already covered and paid for. Bankruptcy is not a fast or cheap process, and the truth of illicit transactions does ultimately come to light. Failed projects fail for reasons other than financial performance, which is consequence, not cause. It is incorrect to state that because money is fungible, and thus would “resolve” financial distress, that the project individually or IPP sources collectively were unworthy of the effort to obtain for ratepayers the benefits of diversified capacity.

IV. POLICY RESPONSES

Q: Do you have any recommendations for how the Commission could improve Oregon RFPs, in light of the proposals utilities have made that are not feasible, transparent or fair?

A: One simple adjustment to the competitive process in place would be to eliminate credit scoring entirely prior to execution of the PPA. If a bidder cannot provide credit assurances a reasonable amount of time *after* the PPA is signed, it would terminate automatically and the utility would turn to the next lowest bidder. In this manner the utility gathers continuous feedback to calibrate whether it is driving too hard a bargain, rendering the PPA unfinanceable.

Q: Can you recommend policy actions congruent with the utility positions on credit scoring submitted in this docket, in order to level the playing field in bid evaluation with regard to credit?

A: Yes. My suggestion for how the Commission could level the playing field and thereby provide a robust and fair solicitation for ratepayers is to partially adjust for the credit benefit provided to the utilities by the ratepayers in the evaluation process. This could be accomplished by using an adder applied to the utility’s bid up to an amount (at this time) of approximately 9%. That figure is comprised of two items: (a) a spread representing the amount of the ratepayer subsidization of utility credit, and (b) a multiplier set by the Commission that reflects good faith progress towards a diversified supply in generation.

Q: Can you explain the source and amount of the spread component?

A: Yes. As of the date of this writing on January 6, 2013, the amount would be 2.92%. (Were it as high as 3%, the adder would be up to exactly 9%.) This is the difference between a an exchange traded fund representing a basket of investment grade bonds (ticker LQD) at 3.84% and an exchange traded fund representing a basket of non-investment grade bonds (ticker HYG) at 6.76%. The LQD basket is: 1.04% AAA, 12.35% AA, 43.26% A, 41.58% BBB, 0.60% BB, and 1.17% other. The HYG basket is: 1.20% AAA, .09% A, 1.55% BBB, 33.46% BB, 47.90% B, 12.68% Below B, and 3.05% other.

Rather than attempt to credit score bidders who do <u>not</u> have the benefit of the regulatory compact supporting their credit, this spread attempts to quantify the inverse and represents more "rough" justice: the quantity associated with the utility's high quality credit, which ratepayers pay for. Not all bidders will be of either the higher or lower grades represented, but the adder is not designed and intended to be used to evaluate credit quality between IPPs. It merely recognizes the credit enhancement paid for by the public, as just <u>one of many</u> features of the regulatory compact that makes this competition biased in utilities' favor. Because it under-corrects, it is not a fatal flaw that it is in the nature of a benchmark, and not participant derived.

Q: Can you explain the source and amount of the multiplier component?

A: Yes. Considerable precedent exists for deterring uncompetitive behavior with the application of triple damages in law. For a utility that the Commission finds is unwilling to make progress towards diversified supply, a multiplier of 3 may be appropriate and in the public interest. Because the Commission's procurement review process is insulating utilities from civil liability for unfair competition, it is incumbent upon the Commission to evaluate the value of the public immunity it is providing against the outcomes that have resulted from Oregon RFPs. Any multiplier from 1.0 to 3.0 is well within the range of reasonableness and discretion Commissions typically exercise, and can be set in light of all the particular circumstances attending each utility's existing, retiring, and new resource management actions, which the Commission supervises for cost impacts on an ongoing basis and with which it is fully familiar.

Q. Do you believe that a utility should be allowed to choose between this credit adder and other options?

A. Yes. I would recommend that the Commission allow utilities to choose between the credit adder (a first option) and two others. In this manner the Commission can better assess the good faith and fair dealing of utility procurement efforts. The second option would be for the utility to choose to hold its generating asset in the unregulated arm of its holding company, and have the same PPA as third parties. The third option would be for the utility to choose to put out an RFP with a utility-equivalent leverage limit and the same post-COD return as the regulatory compact provides. Regulated rates of return can simply be passed through by a contract that approximates utility plant treatment.

Q: What aspects of the utilities' Direct Testimony support this approach to allowing utilities to pick from these three alternatives?

A: In my opinion this is appropriate given: (a) the PPA terms I have reviewed, (b) the lack of identified "financial performance risks" the ALJ ruling specified in Item 11 and the Commission adopted for comment – separate from other performance risks that are protected by PPAs, (c) the absence of identified ratepayer harm from non-payment of project loans, (d) the complaints of damages that were fully specified in PPAs at agreed upon prices, prices that would naturally have been higher were unreasonably larger amounts of contract protection specified, and (e) the excessive and additional costs of procurement generated by credit related items, on top of PPA incentives to produce, which duplicate the costs ratepayers already bear for preserving the reserve margin in the event of non-performance from any resource.

Utilities on the topic of counterparty risk in both Direct Testimony and discovery display an attempt to demutualize a nebulous counterparty risk by requiring *at a very early stage* and long before a final contract a very large performance assurance. Combined with the fact that the assurance is needed from a party that is going to receive money for power produced, some better equilibrium in the competitive process may prove productive. In a portfolio of PPA contracts, the vast majority of cash flow goes from the utility to generators the vast majority of the time. Utilities are addressing tail risk that is very small with a sledge hammer. Demutualized risk is not cheaper. Diversified supply is not inherently riskier to ratepayers when taken in the aggregate, a fact the Commission can fully explore through its relationship with the extremely small projects in the Oregon Energy Trust,[17] and jurisdictions open to IPPs. How much cash flow, as a percentage of the annual amount sent to the Trust's projects, ever was required by contract to be returned to the Trust? Experience requirements are a far more reasonable and fair way to address legitimate concerns.

Idaho Power in particular exhibits a subtle but discernible horror of the special purpose entity liability limitation that they themselves occasion as sole revenue source to the project, one that has earned a bit of a reputation for hostility towards IPPs. The Commission may wish to consider allowing Idaho Power to have only the last two options (i.e., an unregulated generation asset or a PPA with regulatory compact terms).

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[17] The Energy Trust's expenditures on renewable development projects are detailed in Commission reports. *See* EconNorthwest, *Report to Legislative Assembly on Public Purpose Expenditures January 2011 – June 2012, Final Report*, (Dec. 13, 2012), available online at http://www.oregon.gov/puc/electric_restruc/purpose/13PPCSpendingReport.pdf (last accessed January 13, 2013).

The Commission should also give great weight to the practices described by the IE in "Report of the Independent Evaluator on Negotiations In PacifiCorp's 2008R-1 Request For Proposals for Renewable Electric Resources", Sept 18, 2009, p.10. Also, the memo dated July 31, 2009 [redacted]

Q: Can the Commission evaluate utility responses to the proposed policy above and use those responses to re-evaluate the appropriateness of allowing utility plant to bid directly against IPPs, rather than be set aside with its own allocation?

A: Yes. Utilities surely can anticipate that their very response to this proposal may become grounds for a public re-examination of the wisdom of a procurement process that seeks to compare two very different types of financial support for supply, combined with the non-transparency and discretion of post-bid negotiations. Their own responses will suggest to the Commission whether fair competition is likely to be attainable by adjustments to the current guidelines. It might also be worth noting that utilities have been known to misjudge the strength of their regulatory immunity.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE

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UM 1182

PHASE 2

	)
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NORTHWEST AND INTERMOUNTAIN	)
POWER PRODUCERS COALITION	)
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Northwest and Intermountain Power

Producers Coalition Exhibit 401

PacifiCorp and Idaho Power Company Data Requests Regarding Credit

January 14, 2013

UM-1182 / PacifiCorp
December 28, 2012
OPUC Data Request 4

OPUC Data Request 4

Please provide more specifics with respect to the following (see: Kusters, pg. 6, lines 10-15):

(a) The relative importance of the price and non-price scores.
(b) What is evaluated in the 'best and final' offers (e.g., fuel contract, financing, etc.).
(c) How the evaluation of each component of a bid is performed (i.e., How the fuel contract, etc. are evaluated).
(d) What is input into the models, the models that are used, and the sequence in which the models are used;
(e) Explain how the analysis of the best and final offers is used in developing a final short list. That is, what parts of this further evaluation are used to reach the final short list? How is the model output used in this step?
(f) Explain the criteria that are used to take the results from this evaluation to achieve the final short-list.

Response to OPUC Data Request 4

(a) The price score comprises 70 percent of the total score in the selection of the initial screening. The non-price score comprises 30 percent of the total score in the selection of the initial screening. The development of the non-price score criteria in the All Source request for proposals (RFPs) and the renewable RFPs are specific to each RFP. Please refer to Table 1 below, which provides references to price and non-price evaluations of each RFP. The RFP documentation is provided with the Company's response to OPUC Data Request 3; specifically Attachment OPUC 3 -2:

Table 1

RFP	Issued	OR Docket #	Type	Price and Non-Price Section
2009 Flexible Resource	September 2005	UM-1208/UM-1360	All Source	Section 4, page 25
2012 All Source	April 2007	UM-1208/UM-1360	All Source	Section 4, page 38
2008 All Source 2008R-1 Renewable	October 2008 October 2008	UM-1208/UM-1360 UM-1368	All Source Renewable	Section 5, page 45 Section 5, page 19
2009 All Source	December 2009	UM-1208/UM-1360	All Source	Section 5, page 43
2009R Renewable	July 2009	UM-1429	Renewable	Section 5, page 13
2016 All Source	January 2012	UM-1540	All Source	Section 5, page 41

(b) The best and final offer is specific to the bidder's resource price. This provides the bidder the ability to update its price so it does not have to hold the price firm for an extended period of time. The pricing update is subject to a 10 percent cap. The RFP for the 2016 resource (issued January 2012) provides the detail on how the best and final pricing is updated and evaluated. Please refer to the RFP documentation provided with the Company's response to OPUC Data Request 3; specifically Attachment OPUC 3 -2 (2016 RFP - Section 6, page 55).

(c) The evaluation of each component is evaluated using the RFP base model. This is further explained in each of the Sections listed in Table 1 in subpart (a) above, and in the Bid Evaluation sections of each of the same RFP documentation.

(d) The evaluation of each component of a bid is done on a price and non-price basis. The inputs required to complete the price evaluation are outlined in each of the Sections listed in Table 1 in subpart (a) above. As indicated, starting on page 50 of the 2016 RFP, initial screening is done in the RFP base model, a Microsoft Excel-based model. In Step 2, evaluation of the initial shortlist occurs in the System Optimizer model (SO Model). Finally, risk analysis occurs in the Planning and Risk model (PaR Model), for portfolios advanced from Step 2. Please refer to the RFP documentation provided with the Company's response to OPUC Data Request 3; specifically Attachment OPUC 3 -2 (2016 RFP).

(e) In order to complete the best and final evaluation, bidders update only the price of their proposals or indicate that the price remains the same. The Company then repeats the evaluation previously conducted to determine if the initial shortlist needs to be updated. The RFP for the 2016 resource (issued January 2012) provides the detail on the evaluation process. Please refer to the RFP documentation provided with the Company's response to OPUC Data Request 3; specifically Attachment OPUC 3 -2 (2016 RFP - Section 6, page 48).

(f) Once the initial shortlist is completed then a final shortlist is determined. The final shortlist will be comprised of Step 2 and Step 3 outlined in the RFP for the 2016 resource (issued January 2012). Please refer to the RFP documentation provided with the Company's response to OPUC Data Request 3; specifically Attachment OPUC 3 - 2 (2016 RFP – Section 6, page 55).

UM-1182 / PacifiCorp
December 28, 2012
OPUC Data Request 8

OPUC Data Request 8

Please identify what type of non-price scoring for credit risk the company you are proposing or considering and how the company may determine the probability of default and the role that it could play during initial bid evaluation (pg. 30, lines 11-13). Please be specific.

Response to OPUC Data Request 8

The Company would propose including a 10 percent non-price score in each of the request for proposals (RFP) that would score from 1 to 10 percent based on a sliding scale tied to the credit rating of the actual entity that the bidder proposes to enter into a binding agreement with the Company. The credit rating score would be assessed on the actual bidder name and entity. For example, if the bidder is a limited liability company (LLC) and not a credit worthy bidder, the bidder would receive 1 percent. However, if the actual bidder is investment grade and has a credit rating of A or above, then the bidder would receive a 10 percent non-price score. The Company would assess the probability of default once a final shortlist has been determined based on the term, conditions, quantity, and whether an existing asset or construction of a new asset is proposed by the bidder.

The Company would propose calculating the probability of a bidder's default once the final shortlist is determined. Because an RFP may take up to 18 months to complete, a bidder's credit assessment at the time of the initial bid evaluation may change over that period. The Company would recommend the RFP provide a process under which a probability of default assessment could be completed among the proposals on the final shortlist, based on a period no earlier than the date of the final shortlist. This determination would be specific to the bidder's credit rating, the proposal it is providing (existing or new asset), and the term of the transaction.

STAFF'S DATA REQUEST NO. 5:

On pg. 9, lines 9-14 of Opening Testimony, the issue of credit worthiness is addressed. Stokes identifies the various ratios that are used to reach a pass or fail rating.

a. **Please explain what circumstances have resulted in a 'pass' versus those that have resulted in a 'fail.'**
b. **Credit assessment is said to be one data element. Please identify the other data elements and how the set of data elements are combined.**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 5:

a. With respect to the quantitative financial ratio analysis used to determine creditworthiness, Idaho Power offers the following explanation and a comparison of circumstances with various counterparties that have resulted in pass versus fail ratings.

Counterparty risk is the exposure to loss due to a specific counterparty failing to meet contractual obligations. Counterparties are extended credit based on a number of factors pertaining to the financial health of the company, internal reviews and ratings from external credit agencies like S&P and Moody's. Standalone credit may be extended to a company based on the company's willingness and ability to pay financial obligations.

The internal credit model calculates a score or rating to determine creditworthiness. Internal scores are typically based on historical financial data such as balance and income sheet strength and ratios. External credit reviews, if available, will be included in the internal assessment as a qualitative metric for a complete counterparty review. An internal rating is a first step to setting and extending credit limits that define how much exposure Idaho Power is prepared to accept with a particular counterparty. An example of Idaho Power's credit requirements are provided on page 12 of the 2012 Baseload Generation RFPs (Attachment 1).

If a counterparty is not able to pass a standalone internal credit evaluation and it is determined that the counterparty may not be able to meet financial obligations, then the credit department may make a determination to reject a bid (resulting in a fail rating) or not to conduct further business with the counterparty. Receipt of a fail rating may be due to a number of factors including poor credit ratings from external agencies, insufficient credit history, poor liquidity measures, inadequate assets and/or equity, or a history of losses posted in revenue or net income. If a counterparty is not able to pass an internal evaluation, there are further options for establishing credit or financial backing such as securing a letter of credit, a prenatal guaranty or posting collateral or prepaid funds. If sufficient credit support from a creditworthy counterparty can be established, then a satisfactory or pass rating may be established subject to the approved credit support arrangement.

b. While the different data elements or evaluation factors may be combined, or weighted, differently to reflect the important characteristics associated with each RFP, this can be illustrated with a specific example.

In Idaho Power's 2012 Baseload Generation RFPs, which resulted in development of Idaho Power's Langley Gulch project, the criteria for scoring proposals was outlined on page 14 of the RFP document (Attachment 2). As you can see from this document, the evaluation criteria consisted of price and non-price factors with the price factor equating to 60 percent of the total score and non-price factors making up 40 percent of the total score. The six non-price factors and their respective weightings, as outlined in the RFP, are as follows:

Project Development	8 percent
Project Characteristics	8 percent
Product Characteristics	8 percent
Project Location	8 percent
Environmental	3 percent
Credit Factors and Financial Strength	5 percent
Total	40 percent

BEFORE THE

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UM 1182

PHASE 2

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Northwest and Intermountain Power Producers Coalition Exhibit 500
Reply Testimony of Allen Kasper

January 14, 2013

I. Introduction

Q. Please state your name and occupation.

A. My name is Allen Kasper, and I am currently employed as an independent consultant with assignments that have included securing and negotiating engineering, procurement and construction (EPC) contracts for combined-cycle power plants; arranging for the sale of partially developed power plants; assisting in obtaining power sales arrangements for proposed power plants; preparing direct and rebuttal testimony in a case involving closed versus open cycle cooling for two different existing power stations. I am providing testimony on behalf of the Northwest and Intermountain Power Producers Coalition (NIPPC) in this proceeding.

Q. Could you please explain your background and qualifications?

A. My educational and professional qualifications are set forth in NIPPC/501. To summarize, I have been working in the energy industry for over forty-five years. I have been involved in the design, construction and operation of power plants. These plants have employed coal, oil, natural gas, waste wood, wood waste, bagasse, municipal solid waste and refinery waste gasses as fossil fuel sources. In addition, during the same time I also worked on about twenty different nuclear power plants in various capacities and two geothermal power station projects overseas. For the past eighteen years, I have been working on EPC contracts for power plants, principally for simple and combined cycle stations in both the United States and Canada, including two projects in the Pacific Northwest. I have, in multiple roles, been involved in the negotiation of over fifteen EPC contracts for both utilities and independent power producers (IPPs).

Q. Please provide an overview of your testimony

A. I will testify in response to the testimony filed by Idaho Power Company, PacifiCorp, and Portland General Electric Company (PGE) regarding the protections that EPC contracts provide to a utility during and after development of a power generation project that the utility will own. As I will describe in more detail below, even a well-drafted EPC contract will not protect the utility or its ratepayers against all contingencies and risks. For example, an EPC contract typically allows for change orders that can increase costs above those projected due to certain contingencies, such as unexpected conditions at the site which is owned by the utility. An EPC contract will also not protect against latent defects that arise one to two years after construction. For these and other contingencies, the utility and its ratepayers would remain at risk for cost-overruns. Additionally, the protections that current market conditions allow the utilities to obtain in their EPC contracts may change once the economy recovers, and EPC contractors may not be willing to provide the same protections that the utilities testify they are able to obtain today.

For these reasons, I recommend against the assumption that an EPC contract will always insulate the utility/owner against cost overruns compared to the expected costs projected in the EPC contract.

II. <u>Risk of Cost Overruns</u>

Q. In your experience, are cost overruns a risk when constructing a utility-scale electricity generation facility?

A. The short answer is YES. The answer is true regardless of whom the owner is, no owner is immune to risks associated with building a new generation resource. No technology choice comes with fewer basic project risks than any other choice. Each technology choice only adds risk singularly associated with that technology.

Q. Who bears the risk of a cost overrun?

A. There are two answers to this question. In the case of a utility owning and operating its own project, only the utility or its ratepayers will ever pay for these overruns to the extent that they cannot be passed onto some other potentially liable party, such as an EPC contractor. In the case of an IPP selling to a utility under a PPA or tolling agreement, the IPP (not the utility) will most likely bear the entire risk of a cost overrun because PPAs do not typically offer a means to renegotiate the contract afterwards due to poor management of risk on the part of the IPP.

The only potential mitigating factor is some form of insurance, but no insurance policy for any risk is without a deductible which must be borne by the owner. In some cases, part or all of this deductible may be transferred to an EPC contractor or Original Equipment Manufacturer (OEM). That is not a free transfer as the EPC contractor or OEM supplier will do a risk assumption calculation to determine how much of his potential exposure will be covered by his traditional margin on his cost. That will be adjusted to meet his risk tolerance before bidding. Any attempts by an owner (whether a utility or an IPP) to try to transfer too much risk to the EPC or OEM will most likely be met first with resistance and if it persists by bid withdrawal. Note that obviously the utility bears substantial risk if it owns the plant, and one would assume the utility's ratepayers will bear this risk.

Q. What are some of the primary causes of these risks?

A. Some examples of the risks and causes are as follows:

Poor Permitting Strategies. Too many owners get bullied into OEM specific permit applications by regulators who are simply too lazy to permit an envelope type application allowing the owner flexibility in later OEM selection. Premature OEM selection can handicap the owner from both a bus bar delivered price and operational flexibility standpoint.

Over Reliance on Historical Parochial Beliefs. Most utility owners add new resources in a lumpy fashion and thus are not in the market often enough to catch market trends. Unfortunately, owner's engineers are only partially useful in filling this gap as most have limited if any real generation project construction experience.

Poor Scope Definition. This is the most important effort at every stage of the development of a new generation resource and often is not done well. Blaming the party you ask to complete a project development step after it is done only shows you were expecting them to be clairvoyant enough to know what you really wanted them to do. Unfortunately, this is an all too often observed behavior.

Bad Bidding Strategies. Here, all too often the staff involved on the owner's side is simply too proud to accept their own ignorance. The management is too invested in the same staff to seek outside independent temporary help. The result is bid lists populated by the firms who are willing to spend maximum marketing dollars and not the best parties for a specific application. Seeking and qualifying good bidders is a real effort that is all too often not observed.

Incomplete Risk Management. Too often one observes risks that should have been addressed in contracts being assigned to nobody. "What If" is a question that needs to be continually asked. Really examining a bidders' actual prior performance is instructive. When risk management failures are observed one needs to determine if real corrective action has been taken to eliminate that risk path on a going forward basis. It is foolish to assume that failures will not repeat themselves if the same staff are following the same procedures. Simply because you see an initial lower price does not mean you have the obvious best choice. Some contractors are known to pursue contract forms with many possible change order claims hidden therein.

Inadequate Insurance Coverage. Owners are again handicapped by their infrequent forays into the marketplace. This is one where outside professional help will awaken the owner to the risks involved and the means of protection and mitigation. For an extended period of time, many owners had no idea why contractors were insisting upon delayed opening and marine cargo coverage being part of the Builders All Risk policy. A few examples of cargoes falling off of ships while in route from foreign suppliers to the project site brought this issue into the realm of awareness. Any project specific insurance coverage will be part of the contractors' cost calculation as will some fraction of his base policy costs.

Q. You stated that you have experience in negotiating EPC contracts with utilities and IPPs. Could you provide a brief description of the services covered by a typical EPC contract for a utility-scale electric generation facility?

A. Generally speaking, the EPC contractor agrees to deliver a fixed scope of work, at a fixed price, by a date certain, with a guaranteed performance while meeting a set of predetermined technical requirements and permit limitations. In some, but not all cases, the owner enters into a separate contract with an OEM for a power block, which for a combined cycle project includes at least the gas turbine(s), heat recovery steam generator(s), steam turbine(s) and may also include such items as a control system, a condenser, and a steam bypass system. If there is a separate contract with the OEM for these power block items it will be on a designed, manufactured and delivered basis and may include a long term service agreement (LTSA) with that OEM. In some cases, the owner will assign the OEM power block supply contract to the EPC contractor, and in others it will remain a separate stand-alone contract. Some owners provide detailed design constraint type specifications and others only provide higher level performance focused specifications.

Q. Could you explain some of the risks and issues that arise in the EPC contracting process?

A. I will briefly discuss some risk issues that are always present for the owner of the project with some commentary on how they may be treated:

Damages for Delay. As I mentioned, an EPC contract will typically include a pre-determined online date. Owners are pushing contractors to try to get ownership of the float in the project schedule. Contractors build this in to the overall project schedule to ensure they will be able to tolerate some unforeseen delays in equipment delivery or subcontractor availability. Contractors are pushing back on this but a hungry contractor might be tempted to give in and find himself in a position where he cannot meet the overall schedule and elects to then walk away if he cannot get relief. Therefore, even if the utility/owner is able to negotiate a clause requiring the contractor to assume the risk of unforeseen delays, it may be cheaper for the contractor to walk away from the contract rather than complete the work. In that circumstance, the utility/owner is left to decide how to complete the project, possibly at an increased cost.

In addition to this, some owners frequently attempt to include contract clauses that severely limit or exclude recovery of damages for owner-caused delays. The primary contractor also may attempt to shift the risk of contractor-caused delay damages onto lower-tier subcontracted parties with similar clauses. As a result, lower-tier parties may assume the majority of the financial responsibility for all delays on a project.

Differing Site Conditions. If existing site conditions are materially different from those indicated in the contract documents or from what was expected by the contracting parties, costs can increase at an alarming rate. If a differing site conditions clause is not included in a contract, the contractor may dramatically increase its contingency to account for the risk. It is very unlikely that an EPC contractor would ever agree to assume the risk of a cost overrun caused by a differing site condition, without a large premium for that risk.

Consequential Damages. Consequential damages for an owner include loss of revenue, loss of beneficial occupancy resulting from delays, or governmental penalties or sanctions imposed on the owner. For a utility, this could include increased power supply costs resulting from a delay. However, consequential damages are not limited to damages caused by delays. Most EPC contracts do not require either party to assume the responsibility for consequential damages caused by the actions of the other party or any outside parties, and instead provide for liquidated damages that are capped. Therefore, even for an event covered by a liquidated damages clause, the utility/owner may incur consequential damages above the predetermined cap that might arise from a mishap in developing the project.

New or Unfamiliar Technology. With new or unfamiliar technology, it is important that the risk of its performance is appropriately allocated in the event of failure. Although it seems clear when a party should take the responsibility for new or unfamiliar technology, contracts often do not clearly specify risk allocation. As technology in the power industry advances, it will become increasingly important that the functionality risk of new technology is properly allocated.

Latent Defects. The protections of the EPC contract do not normally extend beyond one or two years, and therefore latent defects are a risk that are not eliminated by an EPC contract. For example, if a supplier or the contractor were to employ a welding procedure that resulted in built-in, very slow materializing failures, the owner would only experience them well after any warranty period would have expired. Insurance is the only real defense against this risk.

Force Majeure. Force majeure ("Act of God") clauses, particularly considering the catastrophic damage to the U.S. Gulf Coast in August and September 2005 as a result of Hurricanes Katrina and Rita, are an important factor. It is not common for an EPC contractor to agree to assume the risk of a delay or cost overrun that occurs as a result of a force majeure event. If a force majeure event occurs, the EPC contractor will likely claim force majeure prevented the EPC contractor from completing the project on schedule and/or within any specified cost or performance parameters set forth as "guarantees" in the EPC contract. EPC contracts usually specify what local weather conditions are covered by the contract without a change order being given to the contractor. Typically, if an event is beyond the scope of those typically experienced in the area, the event will be considered abnormal and will be the subject of a change order.

Change of Laws. Another risk that is beyond the control of either party to an EPC contract is a change in law. Both parties agree up front to cooperate to try to reduce the chances of these impacting the project but neither can eliminate third parties from forcing a court action that results in new requirements being imposed upon a partially or fully completed project. In most EPC contracts, a date is fixed for laws in affect for the contract and anything that comes thereafter is the subject of a change order.

Labor Availability. This is a very timely one to mention given the recent events on the east coast associated with Hurricane Sandy. It also happened when Hurricane Katrina occurred. The on-going development of the shale gas supply is also causing distortions now in some labor markets. Labor will naturally go where it can get paid the most and can live at home. If untoward events occur, like the two storms, suddenly there is an inordinate demand for labor in one local area and wages will rise and additional compensation will be offered to attract that labor. That will distort the normal labor market the owner and contractor assumed when initially agreeing to the EPC contract. In my experience, an intelligent EPC contractor will not allow for these labor shortages to be a risk borne entirely by the EPC contractor. Protection needs to be included to cover this eventuality in the form of insurance and contingency. However, even with proper planning and insurance, the utility/owner will be the party that will need to pay the insurance deductibles.

Materials Price Escalation. EPC contractors will bid based upon assumptions they make with regard to expected price escalation. Owners often will push back against clauses which ask them to assume the risk for escalation beyond these assumptions. Non-Force Majeure events can be the causes of significant abnormal behavior in this arena. For example, an inordinate demand increase due to a decision by the Chinese government to accelerate their power plant construction program caused a very sharp and unexpected run-up in copper prices. Depending on the terms of the EPC contract, this could result in a change order by the EPC contractor.

Ambiguous Acceptance Criteria. Frequently, acceptance criteria include phrases that specify that the work be completed so that it is "fit for purpose" or "to the owner's satisfaction." This can lead to a situation where the contractor may feel that it has achieved the acceptance criteria, but the owner views the contractor's performance as falling well short of acceptance. Some contractors feel that ambiguously defined acceptance criteria can lead to the owner using the punch list as a catch-all to modify or fine-tune the design to make it "acceptable." If the acceptance criteria are not well defined, therefore, the utility/owner will be at risk of needing to incur additional expenses to complete the project to the level of performance the utility/owner believes is necessary for the plant. This can lead to increased costs to the utility/owner above those expected.

Q. PGE testified that an EPC contract provides cost guarantees that essentially shift construction cost overruns away from the plant owner to the third party manufacturer and EPC companies, thereby largely eliminating cost overrun risk for utility customers.[1] Do you agree?

A. No. A prudent EPC contractor will always reserve the right for change orders which can lead to costs in excess of projected costs or guarantees. PacifiCorp acknowledges this risk and even states that it has attempted to account for the risk of contingencies associated with change orders somewhat in its some past RFPs.[2] According to PacifiCorp, accounting for contingencies is "consistent with industry practices." I am attaching PacifiCorp's Response to NIPPC data requests on this topic as NIPPC/502, which further explains how PacifiCorp has attempted to address this issue. According to PacifiCorp:

> Conditions that can result in change orders (Change in Work) that may increase EPC costs are as follows:
>
> 1. Owner directed changes; these may include design or equipment changes implemented to provide for efficiency, reliability, availability or safety upgrades.
> 2. Changes in an Owner acquired permit.
> 3. Uncovering work as directed by Owner that proves not to be defective.
> 4. Changes in law.
> 5. Owner caused delay.

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1 PGE/100, Outama-Bettis-Mody-Hager/20.
2 PacifiCorp/100, Kusters/ 20.

6. Materially differing subsurface conditions.

7. Owner's hazardous waste.

8. Force Majeure.

9. Suspension of work by Owner.

10. Miscellaneous events specified in a contract that may entitle Contractor to request a Change in Work.[3]

This contains many of the items on my list of potential causes of cost overruns. PacifiCorp developed a specific contingency cost adder for EPC bids in past RFPs, and also appears to recognize that there is no need to use these contingency cost assumptions in a PPA bid.[4] A prudent IPP would build this contingency cost into its bid price for the output of its plant. Calculation of the appropriate cost adder to use for these cost overrun contingencies is addressed by NIPPC witness Bill Monsen.

Q. PGE also stated that, "The market for power plant engineering, procurement, and construction has advanced and standardized significantly over the last few years in such a manner that this issue is effectively diffused for both utility-owned and IPP projects.[5] Do you agree?

A. As noted above, I do not agree that the issue is diffused because the risk of change orders and latent defects still exists. Additionally, there is no assurance that EPC contractors will offer the same protections in a few years from today. Markets for resources and labor fluctuate. Material and labor may be more scarce once the economy again picks up from the current recession or other factors, such as recent natural disasters, make materials and labor more scarce.

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[3] NIPPC/502, Kasper/2.
[4] NIPPC/502, Kasper/1, 3.
[5] PGE/100, Outama-Bettis-Mody-Hager/20.

Q. You stated that the protections for the utility or an IPP in an EPC contract will end at some point. What is the typical period of time after which the EPC contract protection provisions end?

A. A typical EPC contract has a one-year warranty period. In some cases a two-year period is negotiated between the parties, usually at a higher price to the owner. The warranty clause usually has a one-year from repair or replacement provision in it. In other words, if a particular component of the project breaks prior to expiration of the original warranty period, the warranty period will be reset for that component after it is repaired such that the component will continue to be covered until it performs properly for the full warranty period. However, this clause also has a final termination/sunset provision (normally two years from project completion) so as to prevent some form of an evergreen warranty provision. The EPC contractor never wants to assume the risk of the actual operation of the plant unless he is actually doing so. Most but not all warranty clauses also contain some form of an "in and out" clause. This addresses who covers the cost of getting actual access to a warranted item to repair or replace it as well as restoration of the plant to "as found" status after the repair or replacement is complete. This could cause an unexpected cost increase to an owner even for a covered repair.

A few EPC contractors and some power block OEMs will offer a total plant operations and maintenance contract after this period. Power block OEM long term service agreement contracts often but not universally have some form of a risk sharing formula for later in life unforced outage caused failures, which could include any outage in which the owner elects to shut down the unit to perform a repair at his convenience. While I am aware of many IPPs that secure these types of long-term arrangements where the owner essentially contracts with another party to operate the plant, the Oregon utilities appear to largely operate their own power plants instead of contracting operation of the plant to third parties.

The subject of collateral damage is also an issue. Collateral damage is damage to an adjacent piece of equipment due to the failure of another piece of equipment. For example, a turbine or compressor blade fails, exits the unit casing and damages or destroys a nearby pump or valve. Normally, the owner covers this additional damage through a combination of insurance and possible cost recovery from the OEM. OEM and EPC providers will seek to cap their exposure to lower limits, especially with utilities which traditionally carry much higher self-insurance coverage. Thus, in most cases, the utility/owner has the responsibility for this cost, although some contracts have some participation on the part of the EPC contractor.

Finally, there is normally a dollar value limit on warranty exposure in an EPC contract. Normally this is some fraction of the total contract value for total claims.

Q. How are performance parameters addressed?

A. The guaranty portion of an EPC contract is somewhat more complex. In the case of total project performance parameters (output, heat rate, etc.) there are usually formulas where the EPC contractor is at risk for Liquidated Damages (LDs) up to certain limits for individual parameters. Normally, this does not extend to emissions limits where the contractor must meet these with his exposure capped up to the limit of the total contract value. All of these clauses are usually based upon a new and clean plant. In some cases, owners have been able to negotiate degradation clauses for some period of time following initial operation. It is possible to obtain certain performance guarantees in an LTSA, such as a heat rate guarantee. However, in exchange for such a guarantee, the OEM will require that it have the discretion to require capital upgrades and expenditures paid for by the utility in order to keep the plant running within the specifications.

Because the OEM will require these protections, the LTSA arrangement will impose additional costs in the form of a conservative program for regular capital upgrades and frequent scheduled outages that the OEM will require to keep the plant within the performance guarantees. These LTSA agreements therefore impose the potential for ongoing upgrades that must be built into the cost assumptions for the plant. They obligate the EPC contractor and/or power block OEM supplier to take corrective action up to a predetermined limit to arrest excessive plant performance degradation. These clauses can include emissions as well.

Q. Have you reviewed actual EPC contracts of Oregon utilities?

A. Yes I have reviewed the following contracts which were provided in response to discovery requests:

- Idaho Power's EPC Contract for the Langley Gulch Project;
- Idaho Power's Engineering and Construction Contract for Danskin Units 2 & 3 project;
- Idaho Power's Contract for Purchase of Bennett Mountain project;
- Portland General Electric's EPC contract for Port Westward.

The utilities did not provide detailed appendices to the EPC contracts, so I could not review those appendices.

Q. Do these EPC contracts each relieve the utility of the risk of cost overruns?

A. Based upon my review of the materials provided, none of these contracts insulate the utility against all risks of cost overruns either during the building or operation of the new resource.

[redacted]

[redacted]

[redacted] Buying what you really do not want because the price or schedule or performance (or all of them are in combination) is right is not the best choice. I understand that in the case of Bennett Mountain, the plant experienced a latent defect that imposed a substantial cost on the utility after it acquired the plant.[6] [redacted]

[6] *See* NIPPC/100, Monsen/19; NIPPC/122.

[redacted]

Q. You mentioned force majeure earlier. Are the risks equivalent to the utility under an EPC structure and a PPA structure in the event of a force majeure event?

A. Not necessarily. My understanding from working in the industry is that the risks are slightly different because with the EPC structure the utility still owns the site and the power generation project. It is typically understood that a PPA relieves the IPP of the requirement to deliver power in the event of a force majeure. A force majeure clause will typically relieve the IPP of damages incurred by the utility during the delay (such as increased power supply costs). However, the force majeure clause is unlikely to entitle the IPP to a renegotiation of the contract price for the plant's output if that force majeure event causes a cost overrun or decreased performance at the plant. Additionally, if an event of force majeure prevents the IPP's performance for a lengthy period of time, a PPA may provide the utility with the right to walk away from the project and thereafter not assume any of the resulting liabilities or increased costs to complete or salvage the project.

In contrast, if the utility contracts with an EPC contractor to build the plant for the utility, a force majeure event will never allow the utility to simply walk away from the failed project. Instead, the force majeure event that caused an increase in costs would relieve the EPC contractor of the obligation to complete the project as scheduled and/or budgeted, and the utility/owner would need to absorb cost increases to complete the project. The utility owns the project and will be incented to see the project through, by paying for the increased cost to complete the project. Thus, even with an EPC contract, the utility-ownership model presents a unique risk in the event of force majeure. One would assume that the utility could look to its ratepayers to recover increased construction costs that were occasioned by the force majeure event.

Q. Could you provide an example?

A. Yes. This risk differential is demonstrated by actual contracts with Oregon utilities**.** [redacted]

[redacted] I have included the applicable excerpt of those PPAs provided in discovery in this case as NIPPC/503.

[redacted]

[redacted]

I have included the applicable excerpt of the EPC contract provided in discovery as NIPPC/504. [redacted] This dichotomy demonstrates the risks inherent with owning the project, regardless of the terms of an EPC contract.

Q. Do you have any concluding remarks about the materials reviewed?

A. Based on my experience and review of the materials, I would not be comfortable assuming that the risk of cost overruns was eliminated by the EPC contracts the Oregon utilities provided for review or EPC contracts that they might enter into. As I stated at the beginning, the risk remains for a cost overrun with an EPC contract, and as PacifiCorp has acknowledged, it is standard industry practice to build cost contingencies into cost estimates.

Q. Does this conclude your reply testimony?

A. Yes.

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Northwest and Intermountain Power

Producers Coalition Exhibit 501

Witness Qualification Statement of Allen Kasper

January 14, 2013

WITNESS QUALIFICATION STATEMENT

NAME: Allen Kasper

ADDRESS: 1280 Devries Road, Oak Harbor, WA 98277-9014

EDUCATION: United States Naval Academy, B.S. in Marine Engineering, 1965
Naval Nuclear Power Training Program and Submarine School

EXPERIENCE:

After receiving his engineering degree, Mr. Kasper served for 10 years of active duty in the U.S. Navy as an officer. In this capacity, Mr. Kasper had increasing responsibility for both power plant operations and maintenance. He completed one 14 month shipyard overhaul in which the power plant was decontaminated and refueled.

Mr. Kasper then was employed for 20 years with a major power plant equipment supplier where he performed tasks including nuclear power plant design, start-up, retrofit and maintenance; fossil fuel (coal, oil and gas) power plant retrofit and maintenance; waste (wood and garbage) power plant construction, retrofit and maintenance; fossil fuel (oil and gas) power plant conversion to newer technology.

Mr. Kasper subsequently was employed for 10 years with a major EPC contractor. He was engaged in securing and negotiating of EPC contracts for waste-to-energy power plants, conventional coal-fired power plants, and gas-fired combined-cycle and simple-cycle power plants.

Most recently, Mr. Kasper has been engaged for 8 years as an independent consultant with assignments that have included securing and negotiating EPC contracts for combined-cycle power plants; arranging for the sale of partially developed power plants; assisting in obtaining power sales arrangements for proposed power plants; preparing direct and rebuttal testimony in a case involving closed versus open cycle cooling for two different existing power stations.

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Northwest and Intermountain Power

Producers Coalition Exhibit 502

PacifiCorp Response to NIPPC Data Requests 4.14, 4.15, and 5.1

January 14, 2013

NIPPC Data Request 4.14

Reference PacifiCorp/100, Kusters/20 stating, "For third party proposals or the utility cost-based benchmark resource, contingency reserves are applied to the proposal price consistent with industry practices."

(a) Please describe with specificity how contingency reserves are applied for third-party proposals and for utility cost-based benchmark resources.

(b) Please clarify whether contingency reserves are included in the benchmark resource bid price that is compared to third-party bids.

Response to NIPPC Data Request 4.14

(a) For the most recent 2016 Resource request for proposals (RFP), a contingency reserve amount of 5 percent was applied to either an asset purchase and sale agreement (APSA) or an engineer-procure-construct (EPC) at the Currant Creek plant site or an APSA at a bidder's site. This percentage was applied to the fixed EPC price. This excluded owner's direct costs and startup/fuel and testing, transmission interconnection-directly assigned costs and network upgrades, capital surcharge, capitalized property taxes and allowance for funds used during construction (AFUDC). In the latest 2016 Resource RFP, there was no utility cost-based benchmark; therefore, EPC bidders could bid on the construction of a resource located at Currant Creek as part of the overall Resource RFP in lieu of a standalone utility benchmark.

In prior resource RFPs, for the utility cost-based benchmark based on a resource constructed at the Lake Side plant site (Lake Side 2), the benchmark capital cost included a contingency amount based on the fixed EPC cost amount; this contingency amount was approximately 5.3 percent of the total project cost (or approximately 6.2 percent of the fixed EPC cost).

Project specific capitalized property taxes and AFUDC were determined based on the individual project cash flows as proposed.

(b) As noted in the Company's response to subpart (a) above, contingency reserves are included in both the benchmark resource and third party EPC and APSA bids.

NIPPC Data Request 4.15

Reference PacifiCorp/100, Kusters/21 discussing change orders. Please specify the conditions under which a change order may increase PacifiCorp's EPC costs under a fixed-price EPC contract.

Response to NIPPC Data Request 4.15

There are multiple issues that can result in change orders that increase the cost under an engineer-procure-construct (EPC) contract. These issues, though, are typically mitigated to the extent possible in the terms and conditions of the EPC contract. Although change orders result in an increase in the original EPC cost, prudent owners typically include a level of contingency reserves over and above the original EPC contract amount to address change orders which are typical in any major construction project.

Conditions that can result in change orders (Change in Work) that may increase EPC costs are as follows:

1. Owner directed changes; these may include design or equipment changes implemented to provide for efficiency, reliability, availability or safety upgrades.
2. Changes in an Owner acquired permit.
3. Uncovering work as directed by Owner that proves not to be defective.
4. Change in Law.
5. Owner caused delay.
6. Materially differing subsurface conditions.
7. Owner's hazardous waste.
8. Force majeure.
9. Suspension of work by Owner.
10. Miscellaneous events specified in a contract that may entitle Contractor to request a Change in Work

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December 13, 2012
NIPPC Data Request 5.1

NIPPC Data Request 5.1

Reference PacifiCorp/100, Kusters/20-21, stating that PacifiCorp has utilized a contingency cost for potential cost overruns or other unforeseen items in RFPs for bids that do not have fixed prices. For each RFP in the past ten years:

(a) Please provide and explain the basis for the percentage value of the contingency used as compared to overall bid cost in evaluating the utility benchmark bid;
(b) Please provide and explain the basis for the percentage value of the contingency used as compared to overall bid cost in evaluating any Build-Own-Transfer bids;
(c) Please provide and explain the basis for the percentage value of the contingency used as compared to overall bid cost in evaluating in evaluating PPA bids.

Response to NIPPC Data Request 5.1

The Company objects to this request because it is unduly burdensome and overbroad. Without waiving this objection, the Company responds as follows:

(a) The percentage values used for contingency in the most recent request for proposals (RFP) (All Source RFP – Resource 2016) and the RFP that resulted in the Lake Side 2 resource (2009 All Source RFP) were provided with the Company's response to NIPPC Data Request 4.14 subpart (a). The basis for the contingency amount to be included in a major construction project depends on a number of factors which include identified risks, length of the construction period, complexity of the project, unforeseen and unpredictable conditions (such as weather and soil conditions), uncertainties within the defined project scope, terms and conditions of the underlying engineer-procure-construct (EPC) contract and experience.

For the most recent RFP (All Source RFP – Resource 2016), there was no utility benchmark; for consistency a uniform contingency level was applied to all Build-Own-Transfer/EPC proposals.

(b) Please refer to the Company's response to (a) above.

(c) No contingency is included in the evaluation of power purchase agreement (PPA) bids.

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Northwest and Intermountain Power

Producers Coalition Exhibit 503

Excerpts from PacifiCorp's Top of World Wind PPA and PGE's Yamhill Solar PPA

January 14, 2013

Northwest and Intermountain Power Producers Coalition Exhibit 503 contains confidential material and has been redacted

BEFORE THE

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Northwest and Intermountain Power

Producers Coalition Exhibit 504

Excerpts of Idaho Power's Langley Gulch EPC Contract

January 14, 2013

Northwest and Intermountain Power Producers Coalition Exhibit 504 contains confidential material and has been redacted

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 14th day of January, 2013, a true and correct copy of the within and foregoing REPLY TESTIMONY OF NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION IN DOCKET UM 1182 (Redacted Testimony to all parties via electronic mail; Confidential Testimony to those parties so designated via U.S. Mail):

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