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**	COMMENTS OF THE NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION

INTRODUCTION

Pursuant to the agreement of the parties set forth in Staff's letter to Administrative Law Judge Grant filed February 22, 2012, the Northwest and Intermountain Power Producers Coalition ("NIPPC") hereby files comments recommending how the Public Utility Commission of Oregon ("OPUC" or "Commission") should proceed in this investigation. As discussed below, NIPPC suggests the Commission should investigate development of bid price adders for utility-ownership generation ("UOG") bids into an Oregon request for proposals ("RFP") for (1) Capital cost overruns through the first 5 years of operation, (2) Decreased performance over that predicted, which would include heat rate degradation for a gas plant bid or lower than expected wind capacity factor for a wind bid, and (3) Increased fixed operation and maintenance expenses. For each of these categories, rigorous data exist to develop a bid price adder that would be significant in leveling the playing field between fixed price independent power producer ("IPP") bids and "cost-plus" UOG bids. The process need not be complex; indeed, NIPPC has already completed its own analysis for these factors, as discussed herein, and the Commission could easily incorporate the adopted bid adders into its existing RFP Guidelines.

BACKGROUND

This proceeding is part of a continuing effort by the Commission to provide ratepayers the benefits of a level playing field for IPPs hoping to participate in Oregon RFPs. In Docket No. UM 1066, the Commission explored the possibility of requiring utility-owned resources to be placed in rates at the market price used to bid into the RFP, just as an IPP plant would be treated under the terms of a power purchase agreement ("PPA"). In Docket No. UM 1276, the Commission considered mechanisms to incent a utility to enter into power purchase agreements. Instead of adopting either approach, in Order No. 11-001, the Commission re-opened this docket (UM 1182) to investigate revisions to the RFP Guidelines.

The Commission accepts "the premise that a bias exists in the utility resource procurement process that favors utility-owned resources over PPAs." Order No. 11-001, at p. 5. The Commission found, "This bias is really a logical inference drawn from an understanding of ratemaking practices and the effectiveness of incentives." *Id.* In short, "[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." *Id.* (quoting Commission Staff's Comments). The Commission stated, "Although these guidelines have greatly increased confidence that the utility RFP process is being conducted fairly and properly, we believe further *improvements are needed to fully address utility self-build bias*." *Id.* at p. 6 (emphasis added).

Relevant to these Comments, the Commission asked the parties to provide an analytic methodology to more completely address all of the relevant risks and costs associated with a utility-owned and PPA proposal, beyond that currently called for in Guideline 10(d).

The Commission 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.*

Id. at p. 6 (emphasis added).

The parties to this case commenced workshops to address this issue last fall. Per a request from Staff, NIPPC distributed its "White Paper," prepared by its consultant, MRW & Associates, LLC of Oakland, California, which presented approaches for using available national data in order to develop methodologies for accounting for potential risks similar to those described in Order No. 11-001. At a workshop on November 18, 2011, Commission Staff developed a list of potential factors. The list included:

Cost Over- and Under-Runs
End Effects/Options at the End of a Resource's Life
Environmental and Regulatory Risk
Wind Capacity Factor
Delay
Forced Outage Rates
Fixed Operation and Maintenance Increases over the Resource Life
Capital Additions over the Resource Life
Changes in ROE over the Resource Life
Output/Heat Rate/Power Curve at the Start of Resource Life
Counterparty Risk
Heat Rate Degradation

Another workshop date was set for February 9, 2012. NIPPC understood that the Commission Staff's intent for the workshop on February 9, 2012 was to whittle down the list of RFP Guideline 10(d) factors to only the 2-3 factors that had the most robust data and a quantifiably significant impact on the bidding process. Prior to the workshop, NIPPC circulated its detailed analysis of the bidding factors for which it had agreed to provide further analysis, focusing on the robustness of available data and ultimate impact in an RFP. *See Attachment No. 1* (*NIPPC's Technical Approach to Developing Bid Adders for Utility-Owned Generation Proposals*, prepared January 31, 2012). Commission Staff and PacifiCorp also circulated analysis for certain factors. The parties were unable to reach consensus on which factors warranted further investigation, and agreed instead to provide the Commission with comments on how to proceed.

COMMENTS

1. The Commission should further investigate development of bid adders.

A utility-owned resource is offered into an RFP on a cost-plus basis while third-party bidders are required to guarantee their price and performance parameters. An IPP must sign a PPA or tolling service agreement holding it to its price and performance parameters, and must provide substantial performance guarantees calculated to compensate the utility and ratepayers with liquidated damages or otherwise in the event of breach of contractual obligations.[1] In contrast, the Commission is generally required to pass on all just and reasonable cost increases

[1] NIPPC has attached its response to a data request from Portland General Electric Company, which provides additional analysis regarding model contracts used in RFPs and protections to utilities and their customers not provided by a UOG project. *See Attachment No. 2* (containing *NIPPC Response to PGE Request No. 3*). The provisions of the template agreements included therein demonstrate well these contractual commitments and ratepayer protections provided by PPAs.

throughout the life of the resource to the ratepayers and has chosen not to hold the utility to a "market rate" that the utility used to score the RFP. *See Re Investigation into Regulatory Policies Affecting Resource Development*, OPUC Docket No. UM 1066, Order No. 11-007 (2011); *see also Re Portland General Electric Company*, OPUC Docket No. LC 33, Order No. 04-376 (2004).

The utilities themselves appear to agree that the Commission should address this issue in UM 1182, rather than in any of the ongoing RFP dockets. In PGE's ongoing Capacity and Energy RFP, PGE stated, "the benefits and risks of both utility projects and PPAs should be fully debated in Docket UM 1182, the docket that the Commission has opened for that purpose, and not here." *Reply Comments of Portland General Electric Company*, *Re Portland General Electric: Request for Capacity and Energy Resource Proposals*, OPUC Docket No. UM 1535, p. 28 n.12 (March 7, 2012). NIPPC proposes that the bid adders could be incorporated into the Guideline 10(d) analysis and that the Commission could require the IE to apply each adder to the price evaluation of any bid that would result in utility ownership after commissioning the plant, for analysis of the RFP's short list selection. Under unique circumstances, a particular bid adder may not be applicable to a particular utility ownership bid (e.g., if the utility were to reflect future increases in heat rate for the UOG proposal, then a heat rate adder may not be needed). Therefore, NIPPC proposes that Guideline 10(d) could provide that the utility may prove a particular adder should not be used for a particular bid, and the utility will bear the burden of demonstrating to the Commission (after opportunity for comment by the IE, Commission Staff, and non-bidding stakeholders) that the utility ownership proposal properly takes into account the potential cost increase addressed by the particular bid adder.

2. NIPPC suggests further investigation of three factors that could be used in an RFP as bid adders to a UOG project bid.

Below is the list of factors NIPPC proposes to be developed into bid adders, in order of highest to lowest priority based upon the robustness of the available data and significance of the factor in the bid evaluation:

(1) Capital cost overruns through the first 5 years of operation;

(2) Decreased performance -- heat rate degradation (gas plants) or wind capacity factor (wind plants); and

(3) Fixed operation and maintenance.

NIPPC has attached its analysis circulated to the other parties in this docket prior to the February 9th workshop, to assist the Commission in deciding which factors to consider further.[2]

a. Capital costs through the first five years of a UOG Plant

At the February 9th workshop, all parties agreed construction cost overruns should be on the list of factors developed. Further development as a bid adder is clearly warranted. NIPPC has identified data that support an adder that relates to both the initial construction costs of the UOG project and also capital costs incurred during the first 5 years of operation. *See Attachment No. 1* at pp. 5-6. This approach is superior to focusing only on cost overruns up until the plant enters rate base, as some other parties may suggest.

The utilities appear to believe that their EPC contracts provide robust protections for ratepayers against UOG project cost overruns up to and shortly after commissioning. Thus, focusing on capital cost overruns only up to commissioning the plant is very likely to result in a mere continuation of the current IE practice of simply examining the protections afforded by an

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[2] As noted previously, NIPPC identified numerous potential risk factors associated with UOG projects. The three discussed here are presented to help prioritize the factors to consider in this docket.

EPC contract. *See* Order No. 11-001 at p. 6 (expressing dissatisfaction that, when the resource is a gas plant, "the evaluation has primarily focused on the terms of the engineering, procurement, and construction (EPC) contract.").

The main problem with focusing on EPC contracts or the contractual provision of some other "turn-key" arrangement is that even an EPC company's liability under the EPC contract ends typically within three years after commissioning. At and after that time, the utility cannot recover unexpected capital additions from anyone but its ratepayers. This is not merely hypothetical. For example, in the recent past, Idaho Power faced $14 million in capital additions on the $60 million Bennett Mountain Plant to correct a latent construction defect that manifested itself only after commercial operations.[3] Idaho Power could not recover costs from the counter party for the repair. As illustrated in this example, under a UOG model, contractual protections for unexpected capital cost increases are limited in duration.

Also, unlike a PPA, the EPC contract provides no assurance to ratepayers that the utility will not upgrade the plant shortly after commissioning. One way a utility could avoid having its benchmark fairly scored in an RFP is to plan to upgrade the plant or other necessary components like transmission shortly after commissioning, without including the cost of those plans in its proposal. As documented in Attachment 1, this has occurred in several instances, which supports inclusion of the first 5 years of operation in analysis of capital cost increases.

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3 *See Attachment No. 3* (containing Idaho Power's discovery response on the matter in a proceeding before the Idaho Public Utilities Commission to self-build its Langley Gulch plant). In Idaho Power's words, "the developer in a build and transfer arrangement has contractual warranty responsibility for a finite term after commencement of commercial operation of the facility, while the utility's operation and maintenance responsibilities extend through the life of the plant."*Id.* At Bennett Mountain, "the failure of the developer to fulfill its contractual obligation during construction contributed to creation of a latent defect that manifested itself after commercial operation and leading [sic] to a prolonged outage and direct repair expense in excess of $14 million." *Id.* Considering only the capital cost overruns up to the time of commissioning would fail to account for this type of risk with UOG projects.

Finally, focusing on only the first 5 years of operation limits the likelihood of the cost increase being the result of some regulatory change that was so unexpected (e.g., new environmental laws, etc.) that even a PPA would have resulted in a cost increase to the ratepayers through use of a force majeure clause. Instead, the proposed analysis will only capture the costs of latent defects, costs incurred during the "shakedown" period after the plant becomes operational, and previously ignored plans to upgrade the plant.

b. Decreased Performance

NIPPC has provided analysis of significant heat rate degradation from which a bid adder should be developed to reflect the Decreased Performance at a gas plant as it ages. *See Attachment No. 1* at pp. 7-8. The heat rate of gas-fired generation increases over time. It is for this reason that owners of gas-fired plants must perform minor and major maintenance on those plants on a periodic basis in order to attempt to improve the degraded efficiency. NIPPC developed a very conservative initial estimate of the extent of this degradation using one analytical technique. Commission Staff used the same database with a similar technique and some different assumptions to develop an estimate of a heat rate adder that was only slightly lower than NIPPC's.[4]

NIPPC also submitted striking evidence that almost all of PacifiCorp's wind plants have a lower than expected capacity factor, which data should be used to develop a bid adder for Decreased Performance at a wind plant. *See Attachment No. 1* at pp. 17-19. This warrants development of a bid adder. Even if forecasting errors may diminish in the industry over time, a utility will continue to have an incentive to over-forecast the production of its plant in an RFP.

[4] Some may argue that the data provided by NIPPC to estimate a heat rate adder is not "granular enough" to determine why a plant's heat rate degrades over time. However, the dataset provides historical annual fuel use, generation, and other operating data, which parties can use to derive models of heat rate degradation. For that reason, it is reasonable to allow parties to estimate a heat rate adder.

Some parties appeared to assume that a utility's ratepayers would be equally harmed by a lower-than-expected capacity factor at an IPP plant due to obtaining less energy and renewable energy credits than expected. But this ignores that ratepayers face far more risk under a UOG wind plant for wind forecasting errors. If the plant underperforms in a PPA, ratepayers are protected by contractual provisions that require payment to the IPP only for actual deliveries of electricity, and PPAs require IPPs to accept all risk of wind forecasting error. *See Attachment No. 2*. In contrast, ratepayers pay for all of the capital costs of a utility-owned wind plant regardless of its output (assuming that the plant remains used and useful).

c. Operation and Maintenance

NIPPC has attached very detailed analysis of extensive data regarding increased operations and maintenance costs over the life of the plant with calculations specific to gas and wind plants. *See Attachment No. 1* at pp. 9-14. Unlike a UOG project, ratepayers are protected in a PPA or tolling agreement from increased operation and maintenance costs, and a bid adder could easily be developed for this factor.

3. The Utilities' likely suggested focus on counter party risk and terminal value are beyond the scope the Commission's request for comment and investigation, and no analysis of those issues is warranted.

NIPPC suggests that the Commission should not investigate development of factors that provide additional scoring penalties for IPP projects, such as counter party risk and terminal value, because they are beyond the scope of the investigation.

a. Counter party risk is already included as a negative scoring factor for IPPs in Oregon RFPs, and addressed in performance assurances and liquidated damage provisions; further penalties to IPPs are not warranted.

Counter party risk is already fully addressed in Oregon RFPs, and clearly disadvantages IPPs' ability to compete against a UOG bid. For example, PGE's ongoing RFP in UM 1535 accounts for counter party risk in a non-price scoring factor under the category "credit," which is worth 7.5% of the overall bid score for short list selection. *See NIPPC's Comments, Re Portland General Electric: Request for Capacity and Energy Resource Proposals*, OPUC Docket No. UM 1535, pp. 11-13 (February 22, 2012). Counter party risk is also addressed through performance assurances in a PPA or tolling agreement, which require a successful bidder to post a substantial performance assurance necessary to insulate PGE's ratepayers against a risk of default. *Id.* UOG projects are not subjected to these same credit requirements and performance assurances in an RFP.[5] The purpose of this investigation is to level the playing field in a system that requires IPPs to post a bond guaranteeing performance and pricing, while allowing a utility to change its cost of service, to make unexpected capital additions, and to fail to perform as suggested when the UOG project was proposed as long as the changes are deemed just and reasonable. It would be inappropriate to use the investigation to pile on another penalty in RFPs for "counter party risk" when the issue is already addressed. [6]

b. The Commission has already expressed its dissatisfaction with focusing on the site's "terminal value," and the Commission should not adopt any suggestion to conduct further analysis of this factor.

In the very order initiating this investigation, the Commission expressed dissatisfaction with the focus on terminal value of a site. *See* Order No. 11-001 at p. 6 (expressing dissatisfaction that when the plant is a wind plant, "the evaluation has tended to focus on the value of the site location after the plant's useful life"). Moreover, the only information on the

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[5] According to PGE, "NIPPC's suggestion that 'the RFP should require PGE's shareholders to provide an equivalent level of assurance to its customers for its ownership options' . . . is misguided. Credit risk mitigation is by definition a counterparty risk mitigation." *Reply Comments of Portland General Electric Company*, *Re Portland General Electric: Request for Capacity and Energy Resource Proposals*, OPUC Docket No. UM 1535, pp. 8-10 (March 7, 2012).

[6] Further, developing a new penalty for counter party risk of IPPs implemented by the IE at final negotiations – the only phase where it is not already expressly addressed in Oregon RFPs – would be inconsistent with the policy that the IE is not necessarily even retained through final negotiations. *See* Order No. 11-340 at 4.

topic circulated by PacifiCorp was a study, dated 2008, which appeared to conclude that the impact could be either positive or negative,[7] therefore failing the requirement that the impact should be significant to warrant further study. Further development of this factor is not justified.

CONCLUSION

As discussed above, NIPPC suggests the Commission should further investigate development of bid price adders for proposed utility owned generating projects submitted into an Oregon request for proposals for (1) Capital cost overruns through the first 5 years of operation, (2) Decreased performance over that predicted, which would include heat rate degradation for a gas plant bid or lower than expected wind capacity factor for a wind bid, and (3) Increased fixed operation and maintenance expenses.

RESPECTFULLY SUBMITTED this 19th day of March, 2012.

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[7] In its concluding section, the 2008 paper stated terminal value "exists, and although they will generally be positive, they can also be negative depending upon circumstances."

UM 1182

In the Matter of
NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION

Petition for an Investigation Regarding Competitive Bidding

Phase 2 Comments of the Northwest and Intermountain Power Producers Coalition
March 19, 2012

Attachment 1

Technical Approach to Developing Bid Adders for Utility-Owned Generation Proposals

Technical Approach to Developing Bid Adders for Utility-Owned Generation Proposals

UM-1182 – Phase 2

Oregon Public Utility Commission

Northwest & Intermountain Power Producers Coalition [NIPPC]

January 31, 2012

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1. Introduction

The Oregon Public Utilities Commission convened Phase 2 of UM 1182 to develop an "analytic framework and methodologies that should be used to evaluate and compare resource ownership to purchasing power from an independent power producer," as required under Guideline 10(d).

Prior to a workshop on November 18, 2011, NIPPC circulated its "White Paper,"[1] which presented methodologies for using available data on utility-owned resources to account for some of the types of cost overruns described in Order No. 11-001 and also presented preliminary results of such analyses. At the workshop, parties agreed on a subset of cost-overrun categories to be evaluated and assigned responsibility for developing analytical methodologies among OPUC staff, the investor-owned utilities (IOUs), and NIPPC. Parties agreed to share their analytical framework with other parties by January 31, 2012, and to meet on February 9 for further discussion.

This paper provides additional technical detail on the frameworks developed in NIPPC's White Paper and introduces new frameworks, as needed, to guide the development of bid adders related to the following categories of potential cost-overruns and underperformance: capital costs (including construction costs), heat rate (gas-fired plants only), operations and maintenance (O&M) costs, plant availability, and plant obsolescence. For O&M costs and plant availability, separate adders are developed for gas-fired and for renewable generation. Plant availability is addressed for renewable plants via an evaluation of capacity factors and for gas-fired plants via an evaluation of forced outages.

NIPPC proposes that the bid adders be incorporated into the Guideline 10(d) analysis and allocated to the price evaluation of the utility's self-build benchmark, or to any bid that would result in utility ownership after commissioning the plant. NIPPC proposes that the Guidelines require the independent evaluator (IE) to implement the adder for such utility-ownership bids when it scores the utility ownership option for

[1] MRW & Associates, LLC. "Leveling the Bidding Field: Some Initial Steps Toward Fairly Comparing Proposals for Utility-Owned Generation and Independent Power Projects." November 16, 2011.

analysis of the short list selection. Under unique circumstances, a particular bid adder may be inappropriate for a particular utility ownership bid. Therefore, NIPPC proposes that Guideline 10(d) provide that the utility may prove a particular adder should not be used for a particular bid, and the utility will bear the burden of demonstrating to the Commission (after opportunity for comment by the IE, Commission Staff, and non-bidding stakeholders) that the utility ownership bid price properly takes into account the potential cost increase addressed in the particular bid adder. In all other circumstances, bid adders should be applied to utility-ownership bids.

2. Capital Cost Adder

NIPPC derived its capital cost adder based on a comparison of the recorded installed costs for Utility-Owned Generation (UOG) with the initial projection of these costs that the utility disclosed to its regulator. In particular, the adder is the capacity-weighted average percentage change in the installed cost relative to the cost that was initially announced or proposed.

The source for the initial announcement of installed costs is preferably a filing with the utility's regulator for the project. When that is not available, a press release or other public source might be used instead. The source for the actual installed costs of the project might be the utility's FERC Form 1, a filing by the utility with its regulator, or a decision from the regulator.

For an initial analysis, NIPPC relied on publicly available data for nine UOG projects located in California. The following table lists these projects, along with the plants' installed capacity and the percentage increase in costs relative to the costs that the utility initially proposed.

Table 1: UOG Plants Used in Installed Cost Analysis

Plant	Capacity	Owner	Technology	When Acquired or Proposed	Difference from Estimated Cost
SCE Peakers	200,000	SCE	CT	Developed with EPC	30%
Gateway	530,000	PG&E	CCCT	Bought Before Online	26%
El Dorado	480,000	SDG&E	CCCT	Bought After Online	14%
Miramar 1	46,000	SDG&E	CT	Bought as Turnkey	10%
Mountainview	1,054,000	SCE	CCCT	Bought Before Online	5%
Palomar	555,000	SDG&E	CCCT	Bought as Turnkey	2%
Colusa	660,000	PG&E	CCCT	Bought Before Online	-2%
Humboldt	163,000	PG&E	Recip.	Developed with EPC	-5%
Miramar 2	46,500	SDG&E	CT	Bought as Turnkey	-5%
Capacity-Weighted Avg.					8%

Each of these projects is a relatively new gas-fired generation project. Five of the projects (Gateway, El Dorado, Mountainview, Palomar, and Colusa) are combined-cycle combustion turbine projects. Three of the projects (SCE Peakers, Miramar 1, and Miramar 2) are simple cycle combustion turbine projects. One project (Humboldt) is a set of reciprocating engines.

Some of the projects (e.g., Gateway, El Dorado, Mountainview, Palomar, and Colusa) were originally proposed as independent power producer (IPP) projects but were acquired by a California IOU either before or after the project started operations. The change in cost for these projects was relative to the acquisition price that the utility announced when it proposed to purchase the project.

NIPPC has not yet evaluated the cost of unanticipated capital additions at these projects. However, it is important that these costs be included because capital additions are effectively an extension of plant construction. Moreover, in some cases capital additions, particularly during the first years of a plant's operations, are direct extensions of plant construction. For example, Idaho Power faced $14 million in capital additions on the $60 million Bennett Mountain Plant to correct a latent construction defect that manifested itself only after commercial operations.[2] The costs of capital additions at all plants should be included in the calculation of the final capital cost adder.

NIPPC tried to obtain data from the Oregon utilities related to the proposed and actual installed costs and capital additions for their power plants. However, as of January 31, none of the utilities have provided complete responses to NIPPC's initial data requests (submitted to the utilities on December 5, 2011) or its scaled-back information request (submitted to the utilities on January 13, 2012). Once the utilities provide these data, it may be possible to expand the analysis to include both fossil-fired and renewable utility-owned generating resources owned by the Oregon utilities.

Based on the data examined to date, NIPPC proposes an adder to UOG capital costs of 8%. However, this adder should be adjusted to account for capital additions and, if data are made available, to incorporate data pertaining to the Oregon utilities' plants.

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[2] Idaho Power Company's Response to Idaho Public Utilities Commission Staff's First Production Request in Case No. IPC-E-09-03, April 14, 2009. Response to Request No. 20.

3. Heat Rate Adder (gas-fired plants only)

NIPPC derived a heat rate adder that should be applied to proposed UOG projects that burn natural gas. NIPPC derived the heat rate adder from a database of annual cost and operating characteristics of utility-owned generation for the years 1981 and 1999, inclusive.[3]

NIPPC's approach is to compare the heat rate in each year of a plant's operating life to the heat rate in the first year of that plant's operations. Averaging these heat rate changes over all plants and all years would provide a measure of the average heat rate change over a plant's lifetime.

Given the limited number of years in the database, NIPPC was not able to capture the entire plant lifecycle. Instead, NIPPC compared each heat rate data point to the first heat rate available for that plant. This makes the assessment highly conservative because in most cases it excludes the degradation generally observed at the beginning and end of a plant's lifetime. In fact, the average starting age for plants in NIPPC's dataset is 23 years, and the average ending age is 37 years. This means that the majority of actual degradation is likely not incorporated into this assessment.

NIPPC filtered the database to include only natural gas-fired plants of at least 150 MW in states that did not deregulate their electric systems. NIPPC included in its sample only plants for which there were at least three heat rates reported in the database. In addition, NIPPC excluded from the analysis all heat rate reductions of more than 7.1%. This would be equivalent to a reduction from a starting value heat rate of 7,000 Btu/kWh down to less than 6,500 Btu/kWh, which would be physically unrealistic.

Observed heat rate "improvements" of more than 7.1% are artifacts of the limited dataset and in particular of the first-year heat rate in the database not representing the initial heat rate for each of the plants. When the first-year data is at a level higher than the starting level (i.e., when it already incorporates some heat rate degradation), a return to

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[3] Data files for Fabrizio, Rose, and Wolfram. "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency." *American Economic Review*, 2007, Vol. 97 (September): 1250-1277. Available at http://faculty.haas.berkeley.edu/wolfram/

normal levels appears in the analysis as a heat rate improvement, even though the heat rate remains at or above the plant's initial heat rate. This likely occurs for many of the plants in the dataset. NIPPC conservatively excluded only values above the 7.1% threshold and retained all other heat rate improvements. In all, NIPPC excluded 40 of 511 data points.

To develop the adder, NIPPC took the simple average of the remaining changes in heat rate and obtained an average heat rate increase of 5.6%. This indicates that actual heat rates for a plant are on average at least 5.6% higher than the plant's initial heat rate. Based on these findings, NIPPC recommends that the IE should include a heat rate adder of 5.6% when evaluating proposed utility-owned gas project.

4. O&M Adders

NIPPC derived separate O&M adders for gas-fired generation and for renewable generation.

4.1. Fixed O&M Adder for Gas-Fired Generation

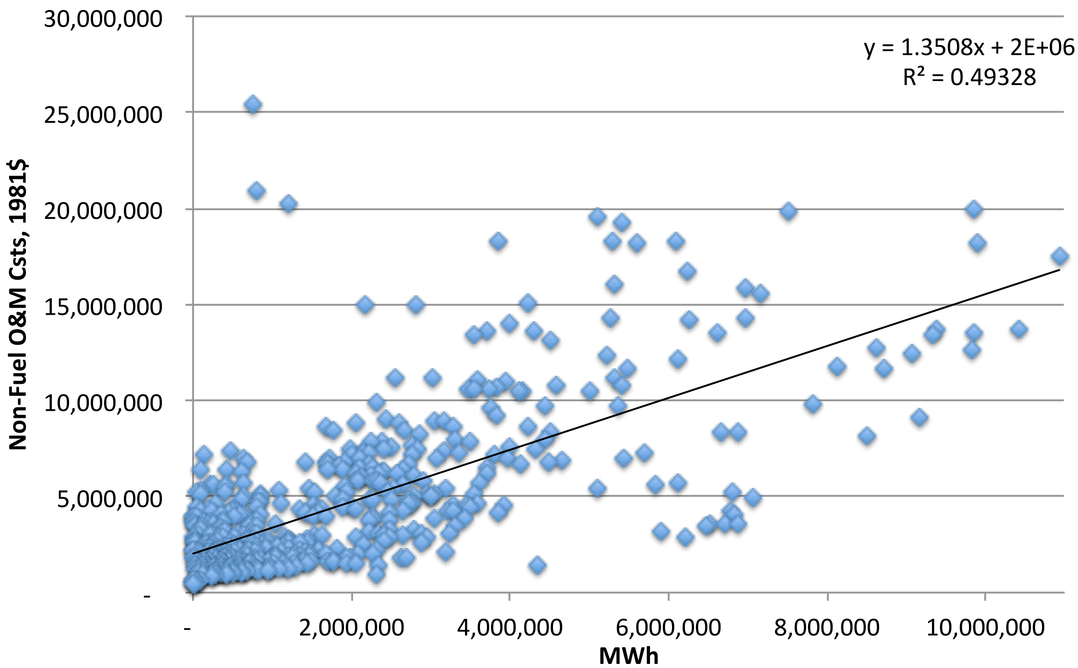
NIPPC derived a fixed O&M adder for gas-fired generation using the same database and following the same general approach used to derive the heat rate adder. However, one additional step is required to derive the Fixed O&M adder because the O&M data in the database includes both fixed and variable (non-fuel) O&M costs.

NIPPC used a simple model of total O&M costs to estimate variable O&M costs. The model is:

Total O&M Costs = Fixed O&M + Variable O&M * Generation

NIPPC used linear regression, with the dependent variable for the analysis being non-fuel O&M costs in 1981 dollars and the independent variable being the corresponding energy used by that plant during that year, to develop an estimate of variable O&M. The resulting scatter plot and regression formula are shown in Figure 1 below. (Each data point corresponds to a single year of data for a single plant.) The slope of the regression line equals the variable O&M rate, which is equal to $1.35 per MWh (in 1981 dollars).

Figure 1: Non-Fuel O&M Costs per MWh Regression Analysis



To obtain the fixed O&M cost, NIPPC calculated the variable O&M for each data point as $1.35 per MWh times the energy usage for the plant in the applicable year and subtracted this from the total O&M cost for that year.

Using this method, 78 of the 560 "fixed O&M" data points were less than zero, corresponding to negative fixed O&M costs. These unrealistic results indicate that the variable O&M estimate was too high for these plants in these years. For the seven plants that had one or two negative "fixed O&M" data points, NIPPC excluded the negative data points from the analysis and used the regression-based method for the remaining data points. For the 10 plants with at least three negative "fixed O&M" data points, NIPPC assumed that the reported costs did not include any variable O&M charges and used the full O&M costs for all data points for these plants. NIPPC applied the regression-based method to all the data points for the remaining 28 plants, as these plant did not have any negative "fixed O&M" data points.

Using the resulting dataset, NIPPC compared each fixed O&M data point to the first fixed O&M data point available for that plant. NIPPC then calculated the average of all of these changes in fixed O&M to be 83%. This indicates that over the course of the available data, the average fixed O&M cost across all plants was 83% higher than the O&M costs experienced during the first year of data for the plants. As with the heat rate analysis, this is a conservative assessment of the increase in O&M cost over the plant lifetime because the dataset covered at most a 19-year period and not the full plant lifetime.

Based on these findings, NIPPC recommends that the IE should include a fixed O&M adder of 83% when evaluating proposed utility-owned gas projects.

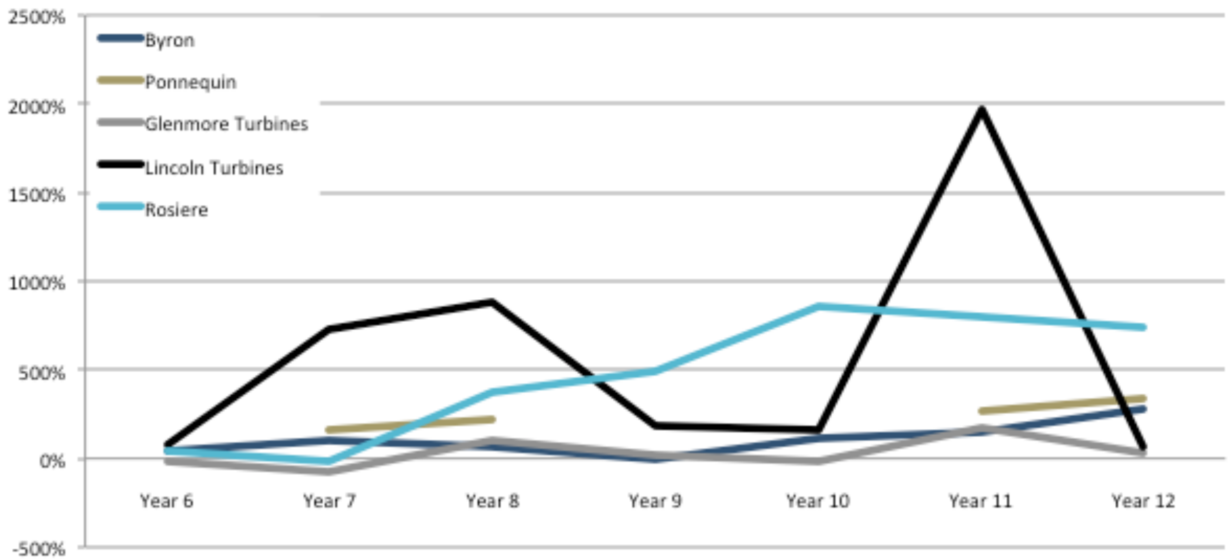
4.2. O&M Adder for Renewable Generation

O&M costs for wind projects and other renewable projects can increase for any number of reasons including unexpected maintenance, increases to labor costs, or component wear. NIPPC has found that O&M costs for wind projects increase significantly after the first five years of operation (which corresponds to the end of manufacturers' standard five-year service agreements). Using data from five utility-owned wind farms, NIPPC calculated the increase in O&M costs for these wind farms relative to the O&M costs reported by the utility for the first five years of the wind projects' lives. Based on this analysis, NIPPC proposes an adder to O&M costs for utility-owned wind projects for years 6 and beyond of 283% of the wind project's expected average O&M costs for the first five years of operation.

To derive the recommended O&M adder, NIPPC examined historic O&M costs of five utility-owned wind farms: Glenmore, Ponnequin, Byron, Lincoln, and Rosiere. The source of these data was the utilities' FERC Form 1s from 1999 through 2010. In certain cases, annual O&M cost data were not available from the FERC Form 1s. In those cases, NIPPC assumed that the O&M costs for the missing years were equal to the average of the O&M costs for the relevant time frame (i.e., either the first five years or the period after the first five years).

Starting with the O&M cost data from the FERC Form 1s, NIPPC converted the O&M costs into 2011 dollars using historic inflation rates based on the GDP Implicit Price Deflator. NIPPC then normalized the O&M costs by dividing the O&M costs by plant capacity. Next, NIPPC calculated the ratio of the O&M costs (on a $/kW basis) for operating years 6 and beyond to the average O&M costs for operating years 1-5. The following figure presents NIPPC's findings.

Figure 2: Increase in Wind O&M Costs Relative to First 5 Years of Operations



Note: Missing data excluded from figure

There are many years in which there are significant increases in O&M costs for years 6 and later relative to years 1-5.[4] For example, the Byron plant has O&M expenses in its 11th year of operation that are almost 2,000% higher than the average O&M expenses for years 1-5. On the other hand, there are a few years with O&M expenses that are lower than the average expenses for years 1-5 (e.g., years 6, 7, and 10 for Glenmore).

NIPPC compared the overall average of the O&M costs for the first five years with the overall average of O&M costs for the rest of the years across all the five wind farms. The average O&M costs for years 6 and beyond are 283% greater than the average O&M expenses for years 1-5.

NIPPC's results are consistent with the findings of Global Energy Concepts from a modeling study, developed on behalf of the National Renewable Energy Laboratory

[4] In the figure, 0% implies no increase in O&M costs relative to the average O&M costs in years 1-5.

(NREL), of wind turbine O&M costs over the first 20 years of a plant's operating life.[5] Relevant results from the Global Energy Concepts model are shown in the figures below. Figure 2 shows the number of major component replacements by year for a 60-MW project with 1,500-kW turbines. During years 1-5, an average of seven major components are replaced each year; during years 6-20, an average of 18 major components are replaced each year.

Figure 3: Replacements of Major Wind Turbine Components by Year

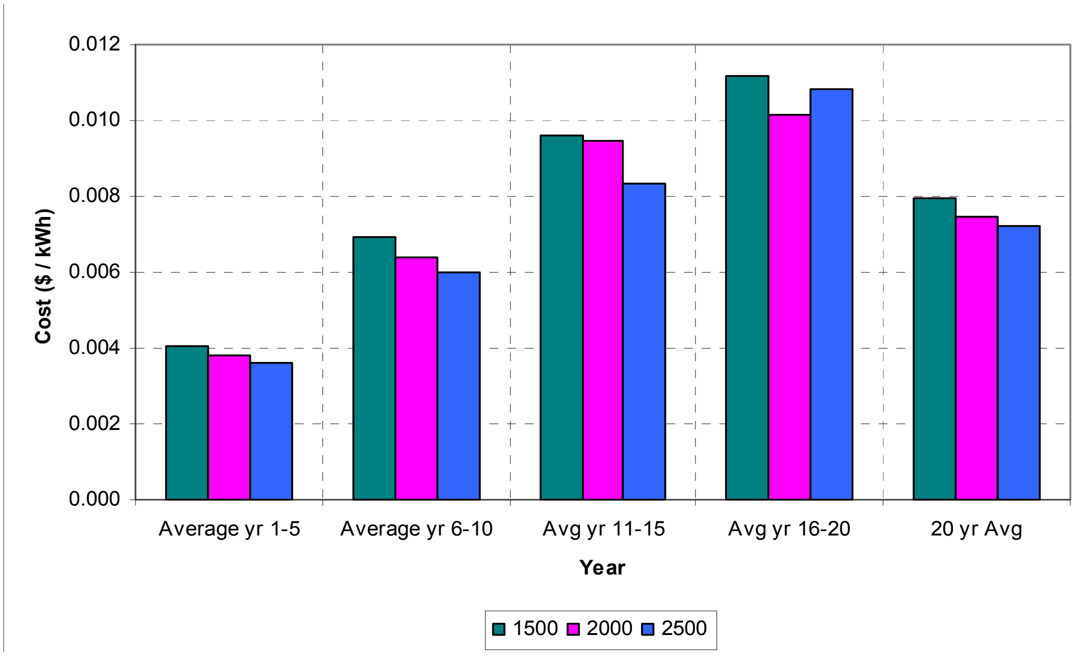
System	Component	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Rotor	Blade--struct. repair	0	0	0	1	0	0	1	0	0	1	0	0	0	1	0	0	1	0	0	1
	Blade--nonstruct. repair	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Drivetrain	Main bearing	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1
Gearbox and Lube	Gearbox--gear & brgs	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1
	Gearbox--brgs, all	0	0	0	0	0	0	1	0	1	1	2	2	1	3	2	3	2	3	3	2
	Gearbox--high speed only	0	0	0	0	0	0	1	0	1	1	2	2	1	3	2	3	2	3	3	2
Generator and Cooling	Generator--rot. & brgs	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1
	Generator--brgs only	0	0	0	0	1	1	2	2	3	4	4	6	5	6	7	6	7	7	6	5
	Power electronics	0	1	1	1	2	1	2	2	3	3	3	2	4	3	3	3	3	3	3	3
	Total	6	7	7	8	9	8	13	10	14	19	17	18	17	22	20	21	21	22	21	22

NREL, page 27

Figure 3 shows the cost implications of the increase in component failures over time. For all turbine sizes studied (1,500 kW, 2,000 kW, and 2,500 kW), average project costs during years 1-5 were at or below 0.4 cents per kWh. In subsequent years, costs increased to as much as 1.1 cents per kWh. An O&M cost estimate based on costs in years 1-5 would therefore significantly underestimate overall project O&M costs.

[5] R. Poore and C. Walford. "Development of an Operations and Maintenance Cost Model to Identify Cost of Energy Savings for Low Wind Speed Turbines. " Global Energy Concepts, LLC, on behalf of the National Renewable Energy Laboratory. Subcontractor Reports NREL/SF-500-40581. January 2008. [NREL] The study was developed using historic data on wind projects with different turbine types, ages, and geographic locations. However, since historic data are sparse for the large turbines being studied, much of the data were estimated and, as Global Energy Concepts notes, "the model is necessarily speculative" in these cases. The study excludes catastrophic events, including lightning, which has caused blade damage at numerous sites. It also excludes balance-of-plant and substation maintenance costs. NREL, pages 2-3.

Figure 4: Average Project Cost per kWh for 1,500-2,500 W Turbine Sizes, 60-MW Project



NREL, page 29

Based on these findings, NIPPC recommends that the IE should include an O&M adder to proposed utility-owned wind projects for years 6 and beyond of 283%. Barring additional analysis specific to solar, geothermal, and other project types, this adder could also be applied to proposals for these and other types of utility-owned renewable generation.

5. Plant Availability Adders

NIPPC derived separate plant availability adders for gas-fired generation and for renewable generation. For gas-fired generation, the analysis is based on forced outage factors at the plants. For renewable generation, the analysis is based on plant capacity factors.

5.1. Forced Outage Adder for Gas-Fired Plants

A forced outage adder would capture the difference between expected and actual forced outage hours and, in particular, the increase in forced outage hours as the plant ages. In order to understand the relationship between age of combined cycle plants and forced outage hours, NIPPC examined historic outage factors for gas-fired combined cycle generators.[6] The source for these data was a sample dataset from the North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) containing self-reported operating data for the years 1993-1997.[7] NIPPC believes that the results of the initial assessment are inconclusive because of a lack of data but that with access to a full set of data from GADS, it may be possible to derive a forced outage adder for proposed utility-owned combined cycle projects.

NIPPC's analysis focused on forced outage factors of combined cycle units in the NERC system. NIPPC examined the relationship between forced outage factors and unit age for plants that are 1 to 30 years old. The sample dataset (for reporting years 1993-1997) contained these data for 70 combined cycle units. The results from NIPPC's analysis relying on the sample dataset are shown in Figure 5 below.

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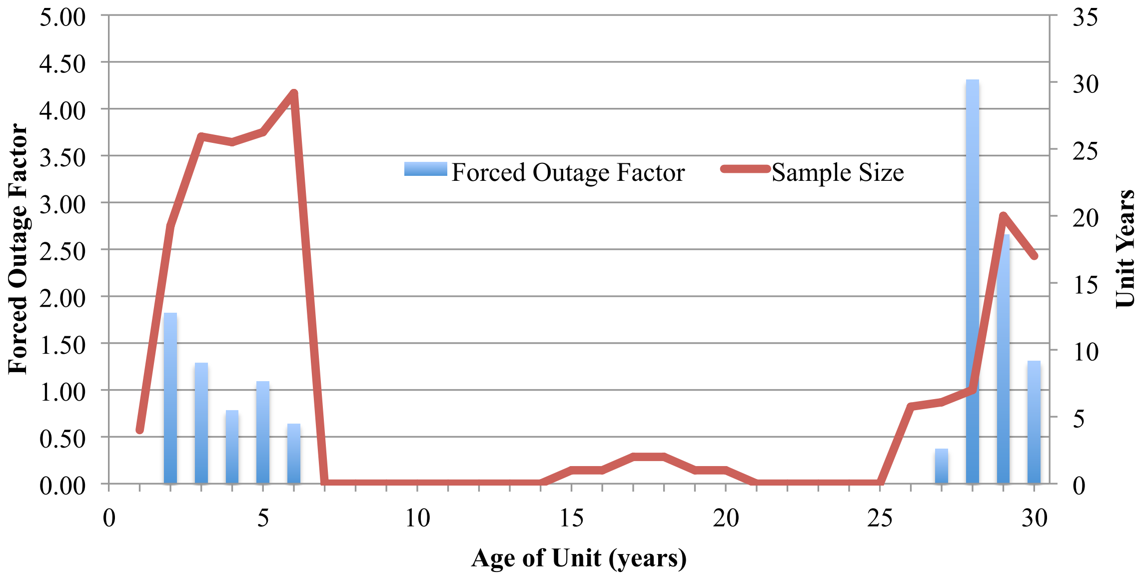
[6] Forced Outage Factor = (Forced Outage Hours / Period Hours) * 100%

[7] The full dataset contains complete operating information from 1982 to 2010.

Figure 5: Average Forced Outage Factor of Combine Cycle Units 1993-1997



As can be seen from the figure, there are very limited data about outages for combined cycle plants of ages 6-26 years in the sample dataset. This is due to three factors:

1. The sample dataset only presents outage rate results for years 1993-1997. Thus, the outage rates for any combined cycle plants that came online after 1997 are not reflected in the figure.
2. Few or no combined cycle plants came online between 1971 and 1991. Thus, the sample dataset does not present a good time-series of outage rate data for newer-generation combined cycle plants.
3. Because of confidentiality concerns, GADS does not report outage data for small sample sizes. For this reason, NIPPC could not obtain forced outage factors for plants that were 15-20 years old even though the data were present in the sample dataset.

Because of these data limitations, NIPPC was unable to draw definitive conclusions about the relationship between outage factor and age of plant. However, NIPPC believes that analysis of the full dataset, which contains data on 574 combined cycle units, may prove more conclusive. Such an analysis should be possible if NIPPC were to gain access to a full GADS database. NIPPC understands that an entity that licenses GADS can grant NIPPC access to the full GADS database at no cost to the member.

NIPPC recommends continued assessment of an adder for forced outages at gas-fired plants.

5.2. Capacity Factor Adder for Renewable Generation

NIPPC developed a capacity factor adjustment for utility-owned wind projects and other renewable projects based on the observed performance of PacifiCorp's wind plants compared to the capacity factors that PacifiCorp originally anticipated for the plants. For this analysis, NIPPC examined data associated with all 12 of PacifiCorp's wind plants that began operating prior to 2010: Foote Creek, Glenrock. Glenrock III, Rolling Hills, Goodnoe Hills, Leaning Juniper I, Marengo, Marengo II, Seven Mile Hill, Seven Mile Hill II, High Plains, and McFadden Ridge I.[8]

NIPPC collected annual capacity factors for the plants from PacifiCorp's FERC Form 1s. NIPPC determined the average actual capacity factor for each plant by calculating a simple average of the annual capacity factors for the plant in each year of operation. For the Foote Creek plant, NIPPC used data for 2004-2010 to calculate the average actual capacity factor because data from prior years were not available in PacifiCorp's FERC Form 1 filings. For expected capacity factors, NIPPC used data from various regulatory filings and regulatory Commission staff reports. [9]

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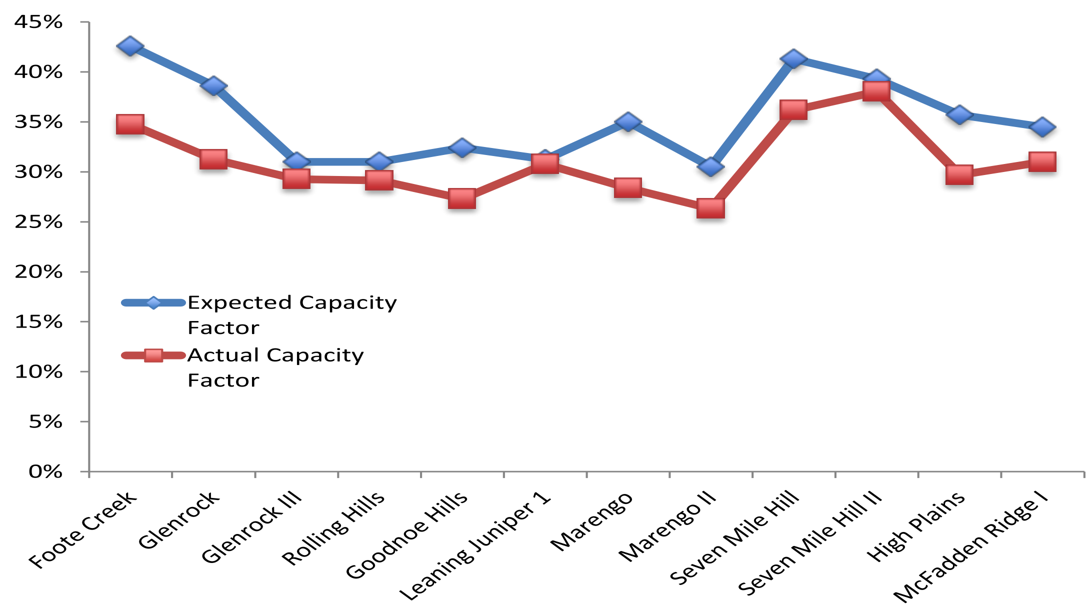
[8] The Dunlap wind farm is not included because it went into service in October 2010 and was therefore not represented in the 2004-2010 FERC Form 1s.

[9] These include:

- Rebuttal testimony of Robert A Lasich on behalf of Rocky Mountain Power in Docket 08-035-38 before the Utah Public Service Commission (PSC), March 9, 2009.
- Direct Testimony of Mark R Tallman on behalf of Rocky Mountain Power in Case PAC E 10 07 before the Public Service Commission of the State of Idaho, Exhibit 7, May 28, 2010.
- Rebuttal Testimony of Mark R Tallman on behalf of PacifiCorp in Docket UE-200 before the Public Utility Commission of state of Oregon, Exhibit PPL/203, August 22, 2008.
- Oregon Public Utility Commission. UE 200 Order No. 08-548 approving PacifiCorp's 2009 Renewable Adjustment Clause Schedule 202, November 14, 2008.

The following figure presents the expected and actual capacity factors for the PacifiCorp wind projects.

Figure 6: Expected and Actual Capacity Factors of PacifiCorp Wind Projects



This figure demonstrates that the actual average capacity factor for each of these wind projects has been lower than the corresponding expected capacity factor for the plant. In order to measure the deviation of actual to expected capacity factor across the PacifiCorp wind plants, NIPPC calculated the difference between the weighted average of expected capacity factors and the weighted average of actual capacity factors, based on the nameplate capacities for each plant. From this weighted-average, NIPPC found that actual average capacity factors for the set of projects were 15% lower than expected.

- Rocky Mountain Power Compliance Filing to the Utah PSC in Docket No. 03-035-14 – Quarterly Compliance Filing – Avoided Cost Input Changes, January 31, 2007.
- Rebuttal Testimony for Phase II of Charles E. Peterson for the Utah Division of Public Utilities in Docket 09-035-15 before the Utah PSC, Exhibit B, September 15, 2010.
- Direct Testimony of Mark Widmer on behalf of PacifiCorp in Docket 99-035-10 before the Utah PSC, September 20, 1999.

Therefore, NIPPC recommends that the IE should reduce the capacity factor for proposed utility-owned wind generation projects by 15% when comparing utility-owned projects against IPP bids. Barring additional analysis specific to solar, geothermal, and other project types, this adder could also be applied to proposals for these and other types of utility-owned renewable generation.

6. Obsolescence Adder

An obsolescence adder would capture the fact that, at some point during a plant's lifetime, a utility may add new generation technologies or more efficient plants to its system that could make the existing plant obsolete. The plant would be considered obsolete and would become a candidate for economic retirement when its total "going forward" costs (e.g., fuel, maintenance, operating costs, capital additions, and return of and return on ratebase) exceed the value of its output (i.e., the utility's marginal cost of power plus shortage costs). In this situation it would cost more to keep the plant online than to retire it and remove the asset from ratebase before the end of its useful life. Because future O&M costs, capital additions, plant efficiency improvements, new technologies, and fuel price changes are inherently uncertain, there is a risk with any new plant that it will cease to be economically viable at some point during its useful life. Failure to account for this risk underestimates the total levelized net cost of that plant.

The Northwest Power and Conservation Council (NWPCC) used the AURORA Electricity Market Model to develop a long-term wholesale electricity price forecast as part of its Sixth Power Plan analysis.[10] As explained in the Power Plan, AURORA's long-term resource optimization logic is "an iterative process, in which the net present value of possible resource additions and retirements are calculated for each year of the forecast period. Existing resources are retired if market prices are insufficient to meet the future fuel, operation and maintenance costs of the project."[11] In other words, existing modeling software is capable of projecting plant economic retirements based on a set of input assumptions.

Using a market model such as AURORA, one can estimate the likelihood that a plant constructed today will be retired for economic reasons in a future year, given a set of assumptions about the future. Given the need for agreement on which market model to use and the key input assumptions for that model, NIPPC has not attempted to calculate a specific adder at this time.

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[10] Northwest Power and Conservation Council. Sixth Power Plan. Appendix D, p. D-4. February 2010. (NWPCC Power Plan)

[11] NWPCC Power Plan, Appendix D, p. D-5.

7. Conclusion

Based on NIPPC's analysis to-date, NIPPC recommends that the IE be directed to apply bid adders to proposals for UOG projects to account for the cost to ratepayers from capital cost increases, heat rate degradation, O&M cost escalation, availability underperformance, and premature obsolescence. NIPPC has developed preliminary estimates of capital cost, heat rate, and O&M bid adders, and of the availability (capacity factor) bid adder for renewable projects. Additional analysis is required to develop a bid adder for gas-fired plant availability based on forced outage data in NERC's GADS database. Additional analysis is also required to develop an obsolescence bid adder. In addition, data from the Oregon utilities on their power plants would allow for refinements of the other bid adders.

UM 1182

In the Matter of
NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION

Petition for an Investigation Regarding Competitive Bidding

Phase 2 Comments of the Northwest and Intermountain Power Producers Coalition
March 19, 2012

Attachment 2

NIPPC Response to PGE Data Request 2

Portland General Electric Company Request 3:

Please provide a model PPA containing explicit contract language that protects the utility from the risks associated with the following items discussed at the November 18, 2011 workshop: technological obsolescence; environmental and regulatory risk; wind capacity factor; forecast error; delay; forced outages; operation and maintenance cost increases over the resource life; cost of capital additions over the resource life; and heat rate degradation.

NIPPC Response to Portland General Electric Company Request 3:

Without waiving any other objections, NIPPC objects to the extent that this request asks NIPPC to produce analysis not previously performed. A critique of PPAs was not the apparent purpose of this investigation to NIPPC based on a reading of OPUC Order 11-001, which reopened UM 1182 after stating "we believe further improvements are needed to fully address utility self-build bias." Until receiving the First Sets of discovery requests, NIPPC did not understand PGE's position, or that of any other utility participating in the docket, to be that PPAs provide inadequate protections to a utility.

Without waiving its objections *and without waiving its right to fully address this issue at a later point in this docket*, NIPPC provides the following response.

NIPPC suggests that PGE refer to template PPAs and tolling agreements in its own current and past RFPs.

The current template agreements for UM 1535 are available at http://edocs.puc.state.or.us/efdocs/HAH/um1535hah14104.pdf.

The template agreements for UM 1345, are available at http://edocs.puc.state.or.us/efdocs/HAH/um1345hah175211.pdf.

Additionally, NIPPC is aware of a model Master Purchase and Sale Agreement produced by the Edison Electric Institute (EEI MPSA), with input from utilities and other industry stakeholders, available to be downloaded at http://www.eei.org/ourissues/ElectricityGeneration/Pages/MasterContract.aspx.

Another example are the templates in PacifiCorp's ongoing UM 1540, "RFP Attachment 3: Power Purchase Agreement" and "RFP Attachment 5: Tolling Service Agreement" (filed with the OPUC on October 27, 2011), and available on the RFP website at http://www.pacificorp.com/sup/rfps/asrfp2016.html.

Below is a preliminary list with some excerpts of contract clauses, as requested.

Technological obsolescence: A PPA limits a utility's risk of technological obsolescence of the project because the PPA or tolling agreement is only in place for a set term. Each of the listed model or template PPAs calls for a specified term, which is presumably shorter than the life of the project.

In contrast, with a utility-owned project the utility (and its rate payers) are likely to remain obligated to pay for the resource for a longer period of time, even if the plant only operates at very limited levels.

Environmental and regulatory risk: For any new environmental or regulatory provision increasing operational costs or requiring equipment changes, but not rising to the level of a force majeure event as defined in the PPA, the PPA would continue to obligate the project owner to deliver at the contract price, without increasing that price. For example, see PGE UM 1345 "FORM WHOLESALE RENEWABLE POWERPURCHASE AGREEMENT," which contains price terms in Articles 1.1.9 and 2.3 that do not provide any mechanism to increase the contract price for new regulations. Force Majeure is defined in Article 4.1, but only relieves the obligation to perform, which would in turn relieve the utility's obligation to pay for output not delivered.

In contrast, *any* incremental increase in operating costs or changes in equipment associated with a new environmental or regulatory requirement would increase the level of rates the utility would expect to recover from its rate payers (assuming that the regulator found these increases in costs to be just and reasonable). This would be true whether the event would qualify as a force majeure event or not.

Wind capacity factor/Forecast error: A PPA protects ratepayers against an underperforming wind capacity factor or forecast error by containing a fixed price for the output with no capacity payment or fixed payments independent of the delivery of electricity and any associated renewable energy credits. Unlike cost-of-service rate treatment of a utility-owned wind plant, a utility (and its rate payers) do not typically pay a fixed capital cost for the output from a wind plant pursuant to a PPA. PPAs containing such a fixed energy price schedule include the PGE UM 1345 "FORM WHOLESALE RENEWABLE POWERPURCHASE AGREEMENT," which provided the following provisions:

Article 1.1.9 stated " 'Contract Price' means the United States Dollars to be paid per MWh for Energy delivered pursuant to this Agreement and for the Environmental Attributes produced by the Facility *[to be provided by Bidder] calculated as provided in Exhibit B.* The Contract Price includes payment for all Environment Attributes."

Article 2.3 stated "Price. PGE shall pay to Counterparty the Contract Price For Firm Energy as provided in Exhibit B."

Exhibit C states:

> 1.1.4 Facility Design. Counterparty shall be responsible for designing and building the Facility in compliance with all permits and according to Prudent Electric Industry Practice with respect to project design, engineering and selection and installation of primary equipment, including but not limited to: turbine nacelles, towers, blades, rotors, foundations, control systems, meters, transformers and collection and substation facilities. Counterparty shall provide PGE with copies of the site plan for the Facility and descriptions, reasonably requested by PGE and otherwise already in the possession of Counterparty, for the project design of the Facility. Any review by PGE of the design, construction, operation or maintenance of the Facility is solely for PGE's information, and PGE shall have no responsibility to Counterparty or Counterparty or any third party in connection therewith. Counterparty is solely responsible for the economic and technical feasibility, operational capacity and reliability of the Facility.

In contrast, the reasonably incurred capital costs of a utility-owned wind plant are recovered (along with a return on rate base) from ratepayers regardless of whether the wind plant's capacity factor is lower than projected (and assumed when the costs of utility-owned wind plant are evaluated in an RFP). *See NIPPC's White Paper*, pp. 13-14 (circulated No. 16, 2011), which discusses the average capacity factor shortfall of 15 percent for PacifiCorp's wind plants. In fact, in UM 1345 the IE specifically noted this distinction. *See Staff's Final Report of Oregon Independent Evaluator*, UM 1345, p. 3 (Jan. 28, 2009) (noting the risk of a lower than expected capacity factor, and stating the "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").

Delay: PPAs typically provide liquidated damage clauses that require the project owner to compensate the utility for the damages caused by the delay. These clauses apply for failure to deliver by the designated online date. They also can apply if the IPP fails to deliver as contracted at other times over the life of the agreement.

For an example of such clauses including compensation for replacement energy throughout the life of the agreement, see the EEI Master Power Purchase and Sale Agreement, sections 1.47 and 4.1.

Some contracts provide for a specified liquidated damages amount, not tied to the replacement energy costs. An example is PGE's UM 1345 "FORM WHOLESALE RENEWABLE POWERPURCHASE AGREEMENT," in Exhibit C, which would provided for damages due for the project's failure to achieve several milestones in the development process as well as a specified Contract Termination Damages amount.

Notably, the PPA in UM 1345 also addressed any shortfall in contracted deliveries throughout the life of the agreement in Articles 3.1.3 and 6.1, which provided such a liquidated damage clause for unexcused failure to schedule or delivery the "Product" during the contract term. Article 1.1.62 defines the "Product" which must be replaced as:

> 1.1.62 "Product" means 1) the Contract Quantity of Firm Energy and electric capacity, all reserves required by the WECC for all Scheduled Energy or other product(s) related thereto as specified in this Agreement by the Parties, and 2) Environmental Attributes.

Article 9 addressed performance assurance in the form of letter of credit or otherwise necessary to meet contractual obligations.

Another example is PacifiCorp's ongoing UM 1540 "RFP Attachment 3: Power Purchase Agreement," which provides as follows:

> 2.3 Daily Delay Damages. Seller shall cause the Commercial Operation Date to occur on or before the Guaranteed Commercial Operation Date but no earlier than [*? months*] prior to the Guaranteed Commercial Operation Date. If the Commercial Operation Date does not occur on or before the Guaranteed Commercial Operation Date, to compensate Buyer for the failure to provide energy and Capacity from the Facility, Seller shall pay Buyer delay damages equal to the Daily Delay Damages times Contract Capacity for each Day or portion of a Day until that Day that the Commercial Operation Date occurs from and after the Guaranteed Commercial Operation Date. . . .

In contrast, a utility would not be responsible for paying "damages" to ratepayers (e.g., in the form of rate reductions or rebates) associated with a delay in achieving the online date or shortfall energy throughout the life of the project, compared to the online date and energy production expectations used in evaluating the utility-owned resource option in the RFP.

Forced outages: A PPA or tolling agreement will typically require the project owner to guarantee a certain level of availability, and include liquidated damages for failure to meet that level.

For example, in PGE's current UM 1535 RFP, the TEMPLATE FOR TOLLING AGREEMENT (Attachment M in the draft filed January 25), the TEMPLATE contains the following provisions placing limits on scheduled outages and including liquidated damages for falling below a specified availability requirement due to forced outages:

> 4.2 Scheduled Outages.
> (a) Seller's Obligations Subject to Scheduled Outages. Seller's obligation to

deliver Energy and make available Contract Capacity pursuant to this Agreement shall be subject to planned outages necessary for maintenance procedures in accordance with the provisions of this Section 4.2 and Exhibit A ("Scheduled Outages"). PGE and Seller shall plan and coordinate Scheduled Outages as described in this Agreement, however, <u>in no event shall Seller schedule maintenance for more than four percent (4%) of the Facility's total capacity at any one time during any Contract Year</u> or during the Months of November, December, January, and February or July, August and September.

* * * *

9.5

(a) <u>Availability Guarantee</u>. During the Delivery Term, Seller shall deliver Energy and make available capacity from the Facility <u>not less than 97% of the hours in each Month</u> (exclusive of Scheduled Outages) (the "Availability Guarantee"). The Facility <u>shall not be considered available</u> for purposes of the Availability Guarantee during any period Seller has declared the Facility unavailable pursuant to Section 6.5, during any Force Majeure event affecting Seller, <u>during any Forced Outage</u>, to the extent affected by any Forced Derate, and for any period in excess of [____] minutes that is required for any Successful Start-Up (but only to the extent that such period affects delivery of any Scheduled Energy). A sample calculation of the availability formula is set forth in Exhibit D.

(b) Adjustments to Standard Capacity Charge. <u>If Seller fails to meet its Guaranteed Availability Factor (GAF), the Standard Capacity Charge shall be reduced by the amount of the Liquidated Damages</u> calculated pursuant to Exhibit G. If the amount of Liquidated Damages is larger than the Standard Capacity Charge, then Seller shall pay PGE the net difference within two (2) Business Days of receipt of an invoice from PGE.

(c) Termination Due to Failure to Meet Availability Guarantee. In the event Seller fails to meet the Availability Guarantee for a period of thirty (30) consecutive days or more during the Delivery Term, then in addition to other remedies provided under this Agreement, PGE shall have the right, to terminate this Agreement effective upon three (3) Business Days' notice to Seller. If PGE terminates this Agreement under this Section 9.5(c), then Seller shall pay PGE the Termination Payment within five (5) Business Days after the effective date of such termination. In the event of termination pursuant to this Section 9.5(c), neither Party shall, except as set forth in the preceding sentence, have any liability whatsoever to the other Party under or in connection with this Agreement; provided, however, that no such termination shall relieve either Party of liability for any costs or other obligations incurred prior to the effectiveness of such termination.

In contrast, a utility would expect to recover from its ratepayers any increased costs associated with increased incidents of forced outages above those initially expected and incorporated into the utility-owned resource bid price in an RFP. Specifically, in this example, PGE's self-build options in UM 1535 would not be subject to "liquidated damages" if the facility fails to meet an availability of 97% because PGE cannot assess or collect these penalties from itself. Also, NIPPC is unaware of any examples in which a utility has had its rate base reduced for a utility-owned plant as a result of higher-than expected forced outage rates. Finally, NIPPC expects that a utility would also expect to recover all fixed costs associated with any reasonably incurred repairs made to its plant to attempt to improve its plant's forced outage rates if the plant was under-performing.

Operation and maintenance cost increases over the resource life: A PPA typically provides for no increased payment to the project developer if the actual costs of operation and maintenance increase over time, yet requires the project owner to operate and maintain the facility to a specified standard.

For example, PGE's UM 1345 "FORM WHOLESALE RENEWABLE POWERPURCHASE AGREEMENT" provided for a fixed energy payment only for delivered energy, in Articles 1.1.9 and 2.3. Additionally, in Exhibit D, that form agreement stated:

> 1.4.2.1 Counterparty shall operate and maintain the Facility and its Meters and that portion of the Interconnection Facilities and related equipment and systems owned by Counterparty in a manner that is reasonably likely to: (i) maximize the output of energy and Environmental Attributes from the Facility and (ii) result in an expected useful life for such facilities of not less than thirty (30) years, all in accordance with Prudent Electric Industry Practice.

Likewise, in PGE's current UM 1535 RFP, the TEMPLATE FOR TOLLING AGREEMENT (Attachment M in the RFP draft filed January 25), provides for a fixed Operation and Maintenance payment per MWh of scheduled and delivered electricity, yet states that the project owner shall conduct operation and maintenance of the plant to a specified performance level in Articles 9.2 and 4.1.

In contrast, a utility would expect to recover from its ratepayers any O&M cost increases above those initially expected and incorporated into the utility-owned resource option bid price in an RFP (assuming that its regulator deemed those increased O&M costs to be just and reasonable).

Cost of capital additions over the resource life: As noted above, NIPPC has provided examples of PPAs containing fixed price terms. NIPPC is not aware of any PPAs explicitly allowing a project owner to pass on the costs of capital additions to the purchasing utility.

In contrast, a utility would expect to recover from its ratepayers for any reasonably necessary capital additions not initially expected and not incorporated into the utility-ownership resource option bid price in an RFP.

Heat rate degradation: A PPA with payments for electricity supplied will not typically provide for increased payments to the project owner in the event that the heat rate degrades at a greater level than expected in the PPA. An example is PacifiCorp's UM 1540 "RFP Attachment 3: Power Purchase Agreement" (filed October 27, 2011), which expressly requires a guaranteed heat rate in section 16.1.

A tolling agreement, where the utility supplies the gas and the project owner provides energy conversion services, would typically include a guaranteed heat rate to protect the utility against increased gas supply costs.

An example is PacifiCorp's ongoing UM 1540 "RFP Attachment 5: Tolling Service Agreement" (filed October 27, 2011), which expressly requires a guaranteed heat rate in section 16.1.

In addition, in PGE's current UM 1535 RFP, the TEMPLATE FOR TOLLING AGREEMENT (Attachment M in the RFP draft filed January 25), includes provisions for a "Guaranteed Net Heat Rate" in Article 3.2(b) and Exhibit B.

In contrast, a utility would expect to recover from its ratepayers any reasonably necessary increased fuel costs associated with increased heat rate degradation above that modeled into the utility-owned resource option bid price in an RFP. In addition, the utility would expect to recover any reasonably incurred capital additions that it makes to improve plant heat rate (assuming that plant heat rate was not meeting prior expectations).

UM 1182

In the Matter of
NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION

Petition for an Investigation Regarding Competitive Bidding

Phase 2 Comments of the Northwest and Intermountain Power Producers Coalition
March 19, 2012

Attachment 3

Idaho Power Discovery Response Regarding Cost Overrun at Bennett Mountain Gas Plant in Idaho PUC Case No. IPC-E-09-03

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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

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

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

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

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

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

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

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

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

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

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 19th day of March, 2012, a true and correct copy of the within and foregoing COMMENTS OF THE NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION was served as shown to:

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Signed________________________
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