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January 14, 2013

VIA ELECTRONIC AND U.S. MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: UM 1182 – In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation Regarding Competitive Bidding.

Enclosed for filing in Docket UM 1182 are an original and five copies of Idaho Power Company's Reply Testimony of M. Mark Stokes.

A copy of this filing has been served on all parties to this proceeding as indicated on the attached certificate of service.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Enclosures
cc: Service List

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET UM 1182

In the Matter of	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)
	)
Investigation Regarding Competitive Bidding.	)

IDAHO POWER COMPANY

REPLY TESTIMONY

OF

M. MARK STOKES

REDACTED

January 14, 2013

Q. Please state your name and business address.

A. My name is M. Mark Stokes and my business address is 1221 West Idaho Street, Boise, Idaho. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Manager of Power Supply Planning.

Q. Are you the same M. Mark Stokes who previously testified in this docket?

A. Yes. My witness qualifications are set forth in my Direct Testimony, Idaho Power/100.

Q. What is the purpose of your testimony in this matter?

A. My testimony will respond to the testimony filed by the Northwest Independent Power Producers Coalition ("NIPPC") on November 16, 2012. Specifically, my testimony will address inaccurate statements regarding cost over and underruns and heat rate degradation.

COST OVER AND UNDERRUNS

Q. Have you had an opportunity to review the direct testimony of Mr. William Monsen, witness for NIPPC, regarding the issue of construction cost overruns?

A. Yes, I have.

Q. Please describe your understanding of Mr. Monsen's recommendation regarding construction cost overruns.

A. Mr. Monsen developed proposed bid adders based upon numerical analysis by NIPPC using publicly available data for eight utility-owned generation ("UOG") plants in California.[1] The UOG plants included four CCCTs, three SCCTs and one reciprocating engine. Mr. Monsen concludes that a bid adder of 7.0 percent should

[1] Mr. Monsen's testimony presents his analysis as if it were based on 11 projects; in fact, four of the plants were developed simultaneously as a single project.

be applied to the estimate of initial construction costs for UOG projects, and additionally, cost calculations for UOG projects should include annual overrun additions equal to at least 5.7 percent of the initial capital costs (including the 7 percent adder) for the first five years of plant operations.

Q. Based upon your understanding of Mr. Monsen's proposal, would you agree that bid adders should be added to all UOG projects?

A. No, I do not agree that bid adders are appropriate. I agree with Staff Witness Robert Procter that the NIPPC analysis is not consistent with the framework of Phase II of this docket and that NIPPC's methodology and analysis is fundamentally flawed. NIPPC's proposed bid adders do not consider how the risk of a cost overrun is accounted for in Idaho Power's current bid evaluation process. NIPPC does not even determine whether a bias exists in the evaluation method. NIPPC just assumes that there is a bias in favor of the benchmark resource without presenting any evidence that such an assumed bias actually exists. Based on their assumption, NIPPC then proposes bid adders even though NIPPC has not evaluated Idaho Power's bid evaluation methodology.

Q. Please explain why you do not believe a bid adder is required for all UOG projects.

A. NIPPC's summary recommendation is a broad brush approach. If competing bids are not comparable because some bids do not include amounts for contingencies or future "cost of ownership," such as periodic major maintenance and parts, then adjusting bids to ensure comparability may be appropriate. However, the actual adjustment depends on the specific situation and specific evaluation. Idaho Power does adjust bids, both upward and downward, to ensure comparability between bids as part of the evaluation process. Moreover, none of the evidence presented by NIPPC suggests that Idaho Power systematically under-estimates construction costs in the utility bid. Therefore, there is no basis for including adders as proposed by NIPPC. In Idaho Power's case, a mandatory adder would act as a penalty to all proposals rather than a mechanism to "level the playing field." By definition, a mandatory adder to the baseline comparison bid adds costs to the resource acquisition. Idaho Power customers will end up paying the penalty for acquiring a higher cost resource because of the bid adders. It appears that the bid adder methodology proposed by NIPPC is designed to increase the costs of utility-owned generation which falsely makes independent power generation appear more attractive by comparison.

Q. Please provide an example of how Idaho Power's evaluation methodology already accounts for the concerns NIPPC is trying to address with its proposed bid adder.

A. A good example would be the Company's most recent UOG, Langley Gulch. Idaho Power requested that the utility bid for the Langley Gulch Request for Proposal ("RFP") include estimates for ongoing operating and maintenance costs and future capital expenses. The RFP team used this information to make an "apples to apples" total cost of ownership comparison between the OUG and the non-utility-owned proposals. The Company believes this approach, with careful consideration of estimated future costs of the UOG project when comparing to competing bids, not just initial installation costs, is necessary to ensure the proposals are evaluated on a level playing field. Applying general, arbitrary adders to utility-owned generation proposals is exactly that, arbitrary, with no consideration given to the actual details of the process used to evaluate the proposals. Requiring utilities to evaluate UOG proposals using a "total cost of ownership approach" is the more appropriate way to ensure bids are being evaluated fairly.

Q. Is it fair to assume that customers bear the risk if a utility self-build project exceeds the estimate that was used to develop the winning bid?

A. No, not at all. As I stated in my direct testimony, it is important to note that the actual costs that are incurred by a utility to acquire a utility-owned resource are included in rates only if the investment is determined to be prudently incurred. Thus, if construction of the utility-owned resource results in a cost overrun, the utility will be required to justify and defend that cost overrun before the full costs of the resource are included in rates. It is incorrect to assume that customers will always bear cost overruns.

Q. Did NIPPC rely on any data gathered from Idaho Power in determining their proposed bid adder?

A. No. Mr. Monsen did state that Idaho Power provided links to Certificate of Public Convenience and Necessity ("CPCN") documents, but that the applications only showed the Company's "commitment estimate." Mr. Monsen stated that it was not clear whether the commitment estimate was the same value as used in the bid for the plant. Instead, Mr. Monsen relied upon the publicly available data for eight California utility-owned generation projects I mentioned above.

Q. Is the commitment estimate the same as the cost estimate used in the RFP bidding process for a generation plant?

A. Yes. As I stated in my direct testimony, during the fully contested CPCN process before the Idaho Public Utilities Commission ("IPUC"), Idaho Power includes a commitment estimate, which is the Company's best estimate of the project capital costs that would be included in rate base. The term "commitment" is significant because Idaho Power commits to developing the project for the costs identified in the CPCN application. The commitment estimate is the same as the estimated costs included by Idaho Power in the self-build bid included in the RFP process. In other words, if the Company's self-build option is the winning bid in the RFP process, the Company must then obtain a CPCN from the IPUC and as part of the CPCN process the Company must commit to constructing the resource at the same cost that was included in the winning bid.

Q. Have you provided an exhibit that compares the actual installed costs of Idaho Power generation projects with the bid costs of those projects?

A. Yes. Idaho Power/201 is a summary table for the actual versus bid costs of the Company's last three generation projects. The three projects include Bennett Mountain, Danskin 1, and our most recent project, Langley Gulch. Both Bennett Mountain and Danskin 1 are SCCT gas plants and Langley Gulch is a CCCT gas plant.

Q. Please describe the information contained in Idaho Power/201.

A. For each of the three plants, Idaho Power/201 contains the actual installed costs (Column A); the dollar amounts the Company filed as its commitment estimates (Column B); and the final amount allowed to be recovered from customers (Column C). The last two columns (Columns D and E) provide a comparison between the first three columns.

Q. Does the information provided in Idaho Power/201 support Mr. Monsen's proposed need for a bid adder?

A. No, and in fact, a mandatory adder would have been an unreasonable penalty to UOG proposals and may have resulted in a winning bid that had higher costs to customers. What the exhibit does show however is that the Company's actual installed cost for these three projects was below their commitment estimates (which was the same as the bid cost). Langley Gulch was over $26 million below the commitment estimate. In addition, the amounts approved to be recovered through rates were below the actual installed costs incurred by the Company, again dispelling the myth that utilities are able to recover all of their costs from the customer, and dispelling the myth that customers bear the risk of cost overruns in utility-owned generation.

Q. Believing that UOG projects pose greater risk of cost overruns than IPP projects, Mr. Monsen recommends that the Independent Evaluator apply a 7.0 percent bid adder to the estimate of initial construction costs for UOG projects. Do you agree?

A. No. First, Mr. Monsen has not demonstrated that UOG projects pose a greater risk of cost overruns than IPP projects. Indeed, NIPPC has failed to produce any data, whether PPAs or EPC contracts or actual construction and operating cost data, related to IPPs.[2] Second, UOG bids become commitment estimates for utility cost recovery, and generally include contingency amounts to address unforeseen problems. The contingency amounts are specifically identified in the utility commitment estimates. Adding another seven percent to utility bids as suggested by Mr. Monson would needlessly add a second contingency.

Q. Do you agree with Mr. Monsen's implication that cost overruns are so frequent on UOG projects that an adder is necessary to account for the risk?

A. No. In Idaho Power's experience, cost overruns have not occurred such that an adder is necessary or even appropriate. Moreover, Idaho Power's state regulators can and will disallow recovery of unreasonable construction decisions that are within control of the utility or that represent optional investment beyond the base project. For instance, in Idaho PUC Order No. 32585, the Idaho Commission denied Idaho Power's request to recover transmission built at 230 kV rather than 138 kV to

[2] See NIPPC's Response to Idaho Power Request No. 2.4-2.6.

accommodate future need for Langley Gulch generation through an environmentally sensitive area. This same amount was not included in rates in Oregon, pursuant to a stipulation approved by the Commission.

Q. Mr. Monsen argues that under a PPA, the IPP would be forced to absorb any cost overruns. Is that true?

A. Mr. Monsen correctly describes a fixed price contract. However, he also presumes that no reopener exists in an IPP fixed bid for cost changes. In the event of a significant cost change that is greater than the "cushion" the IPP built into the bid, the IPP may be incentivized to breach the contract and simply pay liquidated damages. Idaho Power can argue that a cost adder to an IPP fixed bid is necessary to account for the risk that potential costs and losses exceed the liquidated damages threshold.

Q. Do you have any other concerns about the methodology and analysis Mr. Monsen used to develop his proposed adder?

A. Yes. In addition to the problems identified above, there are several additional problems with Mr. Monsen's analysis that are caused by the UOG projects Mr. Monsen selected for his analysis. First, and foremost, Mr. Monsen's conclusions are based on a sample size that is simply too small. Mr. Monsen supports a significant and fairly radical proposal to assign a 7 percent bid adder to all utility-owned projects. To support Mr. Monsen's conclusion that utilities systematically understate the capital costs for self-build projects, Mr. Monsen relies on only eight different projects built by California utilities. Analyzing only eight projects does not result in a statistically valid conclusion and in no way demonstrates that Idaho Power (or any other utility for that matter) systematically understates the capital costs for self-build projects.

Q. Are the eight UOG projects used by Mr. Monsen reasonably representative of a self-build option that Idaho Power would develop for purposes of an RFP?

A. No. The examples relied on by Mr. Monsen are atypical and are in no way representative of a normal self-build project that would be included in a competitive bidding process. For example, the Barre, Center, Grapeland, and Mira Loma plants were developed in response to an August 2006 mandate from the California Public Utilities Commission ("CPUC") directing Southern California Edison ("SCE") to develop up to 250 MW of black-start, dispatchible capacity by the summer of 2007.[3] The CPUC directed SCE to ignore its normal resource procurement process because there was insufficient time to conduct a full RFP in light of the anticipated reliability crisis that was expected in summer 2007. Within eight days of the CPUC order requiring SCE to develop these plants, SCE submitted an advice letter that included an estimate of the costs for the plant. According to the CPUC, SCE estimated that the costs would "probably exceed $250 million."[4] Ultimately, as expected by SCE and recognized by the CPUC, the costs exceeded this estimate. However, SCE explained that this occurred because SCE was required to submit its estimate quickly and therefore did not have sufficient time to "allow for site selection and for preliminary engineering to occur."[5] Indeed, SCE testified that if it had sufficient time, as would presumably have been the case in a normal resource solicitation process, the original estimate would have been greater. SCE also testified that the accelerated time line required by the pending reliability crisis contributed to their increased costs. In other words, these plants were developed outside of conventional resource procurement processes, were developed in

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[3] NIPPC/102 at 1-2.

[4] NIPPC/102 4.

[5] *Southern California Edison Peakers Cost Recovery Testimony*, Application No. A-07-12 at 27-28 (Dec. 31, 2007). This testimony is available at the following website: http://www3.sce.com/sscc/law/dis/dbattach1e.nsf/0/711F5C51C633EABC882573C50075E7C5/$FILE/A.07-12-029_Peakers+-+SCE+Testimony.pdf

response to an emergency, and the initial estimates were developed without sufficient time to conduct full site selection and engineering analysis. Mr. Monsen cannot reasonably claim that these plants demonstrate that in a normal competitive resource solicitation process Idaho Power systematically under-states capital costs.

Mr. Monsen also relied on the Gateway project developed by Pacific Gas and Electric ("PG&E"). However, again, the development of this project was anything but typical and should not be relied on to claim that utilities systematically under estimate project development costs. First, like the SCE plants discussed above, Gateway was not developed through a competitive solicitation process.[6] This plant was in the process of being developed by an IPP who subsequently abandoned the project and sold the partially constructed plant to PG&E. PG&E's original cost estimates were based on the IPP's original design and permits. However, in order to be constructed, PG&E was required to modify the design and in doing so incurred additional development costs. The CPUC approved these additional costs because "not constructing the unit could have significant adverse reliability and cost implications" and because the original agreement approved by the CPUC authorizing the development of the plant specifically contemplated that design modifications may be required and those modifications might lead to increased costs. In other words, the cost increase was specifically contemplated by PG&E and included as part of the CPUC approval process.

Mr. Monsen also relies on SCE's Mountainview project. Again, however, that project is simply not representative of a typical resource solicitation and therefore differences between SCE's anticipated costs and the actual development costs are

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[6] The CPUC's Resolution E-4054 describes this project and forms the basis of my testimony related thereto. This resolutions is available at the following website: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_RESOLUTION/64802.PDF

not typical of utility self-build options. First, this project was not subject to competitive bidding and therefore any cost estimate prepared by SCE was not prepared with the anticipation that it would be subject to an RFP process.[7] Second, this project was unique and, like the projects discussed above, developed in response to a crisis. Indeed, FERC noted that SCE "asserts that this is a unique request, unlikely ever to be repeated, because of the urgent need for new generating capacity in California."[8]

The resource acquisitions identified in Mr. Monsen's testimony demonstrate the flaws in Mr. Monsen's analysis. Mr. Monsen's conclusions are based on a statistically insignificant number of projects, the projects were not developed through competitive processes, the projects were developed in response to unique market conditions existing in California at the time (and that are not present in Oregon), and in the most egregious examples of cost-over runs the facts actually demonstrate that the utility's forecasted costs specifically warned the commission at the beginning of the resource acquisition process that there was the potential for significant cost overruns.

Q. What is the impact of removing just these three plants from Mr. Monsen's results?

A. Removing just these plants from Mr. Monsen's analysis results in his proposed adder being reduced from 7 percent to negative 0.5 percent—meaning that utility self-build projects should actually have their costs reduced by 0.5 percent to reflect the fact

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[7] The CPUC's Decision 03-12-059 describes this project and forms the basis of my testimony related thereto. This decision is available at the following website: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/32841.PDF

[8] *Southern California Edison Comp.*, 106 F.E.R.C. ¶ 61,183 at 2 (F.E.R.C. 2004). Portions of this FERC decision were included as part of NIPPC/105. However, the page relied on for this statement was not included by NIPPC.

that Mr. Monsen's data indicates that utility projects are built for less than the projected costs and customers realize the benefit of utility project that are constructed for less than the projected costs..

Q. Under the theory that utilities defer capital expenditures that should have occurred before plants come online, Mr. Monsen also proposes that the cost calculations for UOG projects should include an incremental bid adder equal to at least 5.7 percent of the initial construction costs per year for the first five years of plant operations. Is this proposal within the scope of issues to be addressed in this phase of UM 1182?

A. No. Order No. 12-324 identified four risks to be addressed in Phase II: Cost Overrun and Underrun Risk, Wind Capacity Factor Risk, Counter-Party Risk, and Heat Rate Degradation Risk. To the extent they are made, post-operating date investments in plant are not cost overruns and not appropriately considered in Phase II. Indeed, the parties specifically identified this as a separate issue that was not included in the final issues list approved by Commission in Order No. 12-324.[9]

Q. Why is it not appropriate to adopt NIPPC's deferred capital expenditure adder?

A. The adder described by Mr. Monsen attempts to over-generalize real issues encountered in the operation and maintenance of generation plants once online. Applying adders to any UOG bid seems too broad and without rigor given that bids often account for contingencies or future "cost of ownership," such as periodic major maintenance and parts. If utilities include these types of items in its bids and evaluations (as Idaho Power does), a mandatory adder would act as an unnecessary penalty to UOG proposals rather than a mechanism to "level the playing field."

[9] *See Staff's Recommendation for Initial Topics and Further Analysis* (March 19, 2012) (Item 8 was "Capital Additions over the Resource Life").

Q. Assuming that the deferred capital expenditure adder is determined to be appropriate, do you agree with how Mr. Monsen has calculated the 5.7 percent proxy?

A. No. Mr. Monsen calculated his adder by comparing the year-to-year changes in the Cost of Plant taken from FERC Form 1 filings. Mr. Monsen's adder is based on his entirely unsupported assumption that "any increase to the Cost of Plant above the expected value is assumed to be due to the capital expenditures that are deferred plant construction costs."[10] Mr. Monsen's generic adder ignores the possibility that other investments occur during the first five years that are unrelated to the construction of the plant. For instance, the balance could increase because of an investment in capital parts, which may be related to the plant's maintenance strategy if the utility determined that it was more cost effective to perform some maintenance and repairs to the plant itself rather than entering into a comprehensive service contract. These on-going capital investments also provide value for customers because long-term ownership motivates an owner to periodically invest to ensure the long-term viability of the plant. The fact that UOG has value beyond the term of the competing PPA is a benefit provided by UOGs that is lacking when compared with PPAs.

Q. On page 19 of his direct testimony, Mr. Monsen references Idaho Power's Bennett Mountain power plant and uses what he refers to as a "latent construction defect" to support his proposed 7 percent bid adder to cover ratepayer risk associated with cost overruns. Does Mr. Monsen accurately characterize the post-construction incident that occurred at the Bennett Mountain plant?

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[10] NIPPC/100 Monsen/21, lines 3-4.

A. No, he does not. First of all, the repair costs to the turbine were in excess of $15 million, not $14 million as stated by Mr. Monsen. Second, the repair costs were covered by insurance and Idaho Power's customers were never at risk of having to bear these costs.

Q. Was there an investigation following the incident?

A. Yes, there was. Following the incident, a root cause investigation and metallurgical examination were performed and it was determined that the damage to the turbine was due to an improperly installed bolt in the turbine's air inlet. On July 18, 2006, after the plant had been placed in service, the bolt ultimately came loose and was sucked through the turbine causing the damage.

Q. Was the project developer willing to accept responsibility for the improperly installed bolt and the resulting damage?

A. No, they were not. The project developer was a partnership of two IPPs, and when Idaho Power contacted the IPP partners following the incident, both IPP partners were unwilling to accept responsibility for the incident or the resulting damage. Because the damage was covered by Idaho Power's insurance, the IPP's contractual warranty obligations were not litigated. If the damage had not been covered by insurance, Idaho Power's customers would have been at risk of having to bear the cost due to the IPP's unwillingness to accept responsibility for the incident.

Q. Do you believe Mr. Monsen's testimony regarding the Bennett Mountain plant supports his proposed 7 percent bid adder to cover ratepayer risk associated with cost overruns?

A. No, I do not. As I previously explained, the incident that occurred at the Bennett Mountain power plant was covered by insurance and Idaho Power's customers were never exposed to the risk of a cost overrun as a result of the incident.

HEAT RATE DEGRADATION

Q. Has Idaho Power reviewed the direct testimony of other parties concerning heat-rate degradation?

A. Yes. NIPPC proposed a heat rate adder that purports to account for a plant's heat rate degradation, which increases the costs to operate a thermal plant. Idaho Power does not agree with the NIPPC conclusions.

Q. Do you agree that heat rates degrade over time?

A. Not exactly. It is true that without regular maintenance a unit's heat rate will generally degrade over time. However, with regular maintenance, a unit's efficiency will increase after scheduled maintenance is performed. Therefore, it is incorrect to assume that heat rates always degrade at a constant rate over time.

Q. Does Idaho Power conduct regular maintenance on its combustion turbine plants?

A. Yes, Idaho Power follows the manufacturer's recommended maintenance schedule and uses the replacement parts identified by the manufacturer. The Idaho Power combustion turbine plants all employ Siemens equipment. Idaho Power follows the maintenance schedule recommended by Siemens, uses Siemens technicians, and uses parts recommended by Siemens on the combustion turbines owned and operated by Idaho Power.

Q. Does Idaho Power account for heat-rate degradation in the bid evaluation procedure?

A. Yes. When developing a self-build bid, Idaho Power assumes that the unit's heat rate will degrade over time, consistent with the manufacturer's specifications. Assuming heat rate degradation at the manufacturer's specification for a self-build plant ensures that the self-build bid is fairly compared to PPAs, which, presumably, also assumes heat rate degradation. While the actual operating heat rate of an individual project will deviate from that used in the analysis, it is important to remember that with a UOG, the actual operating heat rate of the unit determines the costs to customers as opposed to a contractual heat rate. If efficiency improvements are made to a UOG, the cost reductions as a result of those improvements flow through to customers.

Q. Are there any conceptual flaws in NIPPC's approach to developing a heat rate adder?

A. Yes. Like Staff, the Company agrees that NIPPC has failed to provide a calculation of the actual risk associated with heat rate degradation. NIPPC assumes that customers bear a risk that a UOG plant will experience heat rate degradation but that customers bear no risk associated with heat rate degradation under PPAs. As Staff points out, assuming no risk associated with heat rate degradation with a PPA makes no sense because varying heat rates may well affect the total generation delivered under a PPA even if the cost per unit is fixed.

In addition, Mr. Monsen has not demonstrated, or even discussed, how heat-rate degradation differs between utility-owned generation and generation owned and operated by IPPs. Mr. Monsen has not provided historical data demonstrating the different risks or different values of heat-rate degradation in utility-owned and independent power producer generation. Mr. Monsen provides heat-rate degradation values in his testimony, but the specific risk or risks associated with heat-rate degradation are never calculated.

Q. Do you have any comments concerning the values used by Mr. Monsen to calculate his heat rate adder?

A. On page 16 of the Staff testimony, Mr. Procter summarizes heat rate degradation values using the dataset and the methods proposed by Mr. Monsen. Staff witness

Procter uses the proposed methodology and dataset provided by Mr. Monsen to calculate the Monsen heat-rate adder under different assumptions. Mr. Procter notes that the lowest value using Mr. Monsen's methods and dataset is 0.11 and the highest value is 5.6. The highest heat-rate degradation value using the dataset and methods of NIPPC witness Monsen is about fifty times the low value. My conclusion is that by using the methods and dataset provided by Mr. Monsen and making different but reasonable assumptions, the calculated values for heat-rate degradation may vary by as much as a factor of 50. Such wide variation leads me to question whether Mr. Monsen's proposed methods and dataset are sufficiently accurate for application in a regulatory proceeding such as Oregon UM 1182.

Q. Mr. Monsen's testimony also discusses the actual heat rates for Idaho Power's Danskin plant. He testifies: [begin confidential] "[redacted]." [end confidential] Is Mr. Monsen's testimony accurate?

A. No, Mr. Monsen's calculations are misleading and incorrect because Mr. Monsen is comparing two different heat rate values—the "high" and "low" heat rates. The "high heat rate," also referred to as the "gross heating value," is "the amount of heat produced by the complete combustion of a unit quantity of fuel."[11] The high heat rate is "obtained when all products of the combustion are cooled down to the temperature before the combustion [and] the water vapor formed during combustion is condensed."[12] The "low heat rate," or "net heating value," on the other hand, is "obtained by subtracting the latent heat of vaporization of the water vapor formed by

[11] http://www.engineeringtoolbox.com/gross-net-heating-value-d_824.html

[12] *Id.*

the combustion from the gross or higher heating value."[13] In other words, the high heat rate value assumes that at the end of the combustion reaction all of the water in the combustion reaction is liquid, while the low heat rate assumes that the water is vapor. The difference between low and high heat rate can be significant. Indeed, for natural gas, the difference between the high and low heat rate is over 10 percent.[14]

The distinction between low and high heat rates is important here because Idaho Power's FERC Form 1 data reports the low heat value whereas plant specifications submitted in bids usually refer to the high heat value. Mr Monsen's presumed heat-rate difference is based on incorrectly comparing the low heat value reported in the FERC Form 1 with the high heat value identified in the bids. As I stated earlier, Mr. Monsen's calculations are misleading and attempt to compare dissimilar information..

Q. Does this conclude your testimony?

A. Yes.

[13] *Id.*

[14] http://www.engineeringtoolbox.com/heating-values-fuel-gases-d_823.html

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1182

IDAHO POWER

Exhibit Accompanying
Reply Testimony of M. Mark Stokes

Idaho Power/201

January 14, 2013

Idaho Power Company Gas Plant Fleet
Actual Installed vs. Bid Cost
Power Plant Accounts Only

	A	B	C	D	E
	Actual Installed Cost [1]	Idaho CPCN Filed Commitment Estimate "Bid" [2]	In Rates per Idaho Final Order	A minus B Difference	A minus C Difference
Bennett Mountain	$53,096,364	$54,000,000	$50,124,997	-$903,636	$2,971,367
Danskin 1	$57,268,050	$60,000,000	$56,690,763	-$2,731,950	$577,287
Langley Gulch	$369,254,750	$395,857,639	$366,260,429	-$26,602,889	$2,994,322

1. Actual installed cost on primary plant work orders; Langley Gulch primary work order remains open therefore charges reflected through 11/30/2012.

2. Reflects plant cost commitment estimates filed, rather than actual amounts in CPCN final orders.

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in Docket UM 1182 on the following named person(s) on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below.

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DATED: January 14, 2013

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