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January 3, 2012

VIA ELECTRONIC AND U.S. MAIL

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

Re: Docket LC 53 - Idaho Power Company's 2011 Integrated Resource Plan ("IRP")

Enclosed for filing in the above-identified docket are an original and five copies of Idaho Power Company's Reply Comments to Staff's Final Comments and Recommendations. A copy of this filing has been served on all parties to this proceeding as indicated on the attached Certificate of Service.

Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

cc: Service List

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

LC 53

In the Matter of IDAHO POWER COMPANY'S 2011 Integrated Resource Plan	**IDAHO POWER COMPANY'S REPLY COMMENTS TO STAFF'S FINAL COMMENTS AND RECOMMENDATIONS**

Pursuant to the Administrative Law Judge's Ruling dated August 1, 2011, Idaho Power Company ("Idaho Power" or "Company") hereby files its response to the Final Comments and Recommendations and Proposed Order of Staff of the Public Utility Commission of Oregon ("Commission") on the Company's 2011 Integrated Resource Plan ("IRP" or "2011 IRP").

I. INTRODUCTION

Staff recommends that the Commission acknowledge the Company's 2011 IRP with revised Action Items, as described in Staff's Final Comments and Recommendations. Staff's Proposed Order states that the Company's 2011 IRP "reasonably adheres to the principles of resource planning set forth in Order No. 07-002 and should be acknowledged" with a list of enunciated Action Items. Notably, Staff recommends that the Commission acknowledge the preferred portfolio and action plan for the Boardman to Hemingway transmission project ("B2H" or "B2H Project") but that the Company provides updated assumptions and analysis as part of the Company's 2013 IRP. As described in greater detail below, the Company herein provides the Commission with updated information related to B2H and will provide the required updates and analysis recommended by Staff. In addition, Idaho Power uses these Reply Comments to respond to Staff's Comments and Recommendations as well as to provide additional details for certain proposed Action Items.

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II. DISCUSSION

A. Idaho Power Will Provide an Evaluation of Environmental Compliance Costs In the IRP Update Based Upon the Best Available Information It Has At That Time (Action Item 11).

Idaho Power currently has an ownership interest in three coal-fired generating stations: the Jim Bridger Power Plant ("Bridger"), the North Valmy Power Plant ("Valmy"), and the Boardman Power Plant ("Boardman"). Idaho Power is neither the majority owner nor the operator of any of these plants. As this Commission is well aware, Portland General Electric Company ("PGE"), the majority owner and operator of Boardman, has announced it will cease coal-fired operations at Boardman by 2020. In addition, and as described in the Company's Reply Comments submitted in this docket on November 8, 2011, the environmental compliance analysis that was used to reach the decision to cease coal-fired operations at Boardman will be very different than the analysis used to evaluate environmental compliance costs associated with Bridger and Valmy. Specifically, Idaho Power has not yet determined how pending or recently enacted rules and regulations may apply to Bridger and Valmy. That said, Idaho Power agrees with Staff that an evaluation of environmental compliance costs for Bridger and Valmy should be conducted. At this time, Idaho Power believes that the Company will be able to conduct an environmental compliance study in 2012. The study will include an evaluation of incremental investments in Bridger and Valmy to comply with enacted and reasonably anticipated legislation, rules and regulations, known by the Company at the time of the study. In addition, the study will include an economic analysis of the impacts associated with an early shut-down of individual units prior to the end of their anticipated useful lives.

Idaho Power anticipates the results of this study will be available in the fall of 2012 and will fully vet the results with the Company's Integrated Resource Planning Advisory Council ("IRPAC") and incorporate the results as part of the Company's 2013 IRP. In addition, the results from the study will be presented to the Commission as part of the

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2011 IRP Update that, pursuant to Commission rule, will occur within one-year of the date of a Commission Order acknowledging the 2011 IRP, as recommended by Staff.[1]

B. Idaho Power Will Provide Ongoing Analysis Related to the B2H Project as Recommended by Staff. (Action Item 7)

Idaho Power agrees with Staff's recommendation to continue providing updated analyses and assumptions related to the B2H Project. Specifically, the Company will provide a project update to the Commission as part of preparing and presenting the 2011 IRP Update and will continue to treat the B2H Project as an uncommitted resource in the 2013 IRP.

In the 2011 IRP, as well as past IRPs, Idaho Power indicated that it planned to develop B2H with equity partners. More specifically, the 2011 IRP analysis assumes that Idaho Power has a 28 percent equity ownership in B2H. Recently, Idaho Power announced it had entered into a Transmission Project Permit Funding Agreement ("Funding Agreement") related to the B2H Project with PacifiCorp and Bonneville Power Administration ("BPA").[2] The Funding Agreement provides for joint funding and support of the processes to complete environmental studies, including an environmental impact statement pursuant to the National Environmental Policy Act; and obtain governmental authorizations and permits for rights-of-way over public lands, necessary to develop the B2H Project. The Funding Agreement sets forth, among other items, (a) the respective funding obligations of the parties for the undertakings contemplated by the agreement; (b) the procedures for negotiation of construction development agreements, assuming receipt of requisite authorizations, for the parties who ultimately elect to participate in construction of the project; (c) terms pertaining to permitting project management; (d) the potential

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[1] OAR 860-027-0400(8).

[2] A copy of the Funding Agreement is publicly available on Idaho Power's Open Access Same-Time Information System web site: http://www.oatioasis.com/ipco/.

respective ownership interests in the project; and (e) terms pertaining to the effect of an event of default and the impact of withdrawal of a party.

While Idaho Power, PacifiCorp and BPA have agreed in principle to the terms of the Funding Agreement, the document itself has not yet been executed as it is subject to BPA's public review process. Idaho Power is hopeful that the BPA public process will result in BPA's execution of the Funding Agreement. At this time, however, Idaho Power is unable to predict the outcome of the BPA's administrative processes, whether the Funding Agreement will ultimately be executed or, if executed, the final terms of such arrangements. The Company will keep the Commission apprised as this matter progresses.

C. Idaho Power Will Provide Additional Detail In Future IRPs Related to Conservation Voltage Reduction ("CVR") (Action Item 4)

Idaho Power supports Staff's recommendation that the Company include an assessment of cost-effective CVR resource potential in its service territory as well as an action plan related to CVR as part of its 2013 IRP. Because details of Idaho Power's existing efforts regarding CVR were not highlighted in the 2011 IRP, the Company understands Staff's recommendation and will include additional details in future IRPs. Notably, Idaho Power has been working to implement all cost-effective CVR since 2007, and explains below the Company's CVR activities over the past several years.

The National Service Voltage Standard (ANSI C84.1) defines a "Range A" or normal voltage condition as 114 V to 126 V. CVR is a method to reduce peak demand and energy use by operating in the lower band of this acceptable voltage range. CVR can reduce peak demand (measured in kilowatts, "kW") and energy (measured in kilowatt-hours, "kWh") one to three percent by lowering the voltage by two to four percent. A typical urban feeder is relatively short in length and constructed with larger conductor sizes due to higher load density. This larger conductor size and shorter length leads to

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minimal voltage drop along the feeder length and results in urban feeders being good candidates for CVR implementation. Rural feeders are typically longer and serve lower density load with smaller conductor sizes. As a result, rural feeders experience a greater voltage drop along their length, and typically operate over the entire "Range A." This typically makes CVR implementation uneconomic on most rural feeders.

Idaho Power, along with thirteen other utilities in the Pacific Northwest, participated in the Northwest Energy Efficiency Alliance Distribution Efficiency Initiative Project in 2007. Idaho Power's results from this study showed that a voltage reduction of approximately three percent resulted in a savings of approximately 1.5 to 2.5 percent in kWh and approximately 1.8 to 2.6 percent in kW. Of these savings, 80 to 90 percent is on the customer side of the meter and 10 to 20 percent is due to an increase in power system efficiency. For a typical 1,000 kWh/month residential customer, this would result in a reduction of 90 to 180 kWh/year.

In 2009, Idaho Power initiated the CVR project, which was broken into 3 phases. Phase 1 focused on the most likely CVR candidates. These candidates were feeders where CVR could be implemented with transformer load tap changer (LTC) settings only—no feeder upgrades, no direct voltage feedback control and limited end of line (EOL) voltage monitoring. Phase 2 was to focus on feeders on which CVR could be implemented with modest feeder upgrades. Phase 3 would focus on feeders requiring more expensive capital upgrades such as re-conductoring feeder sections and potentially adding remote voltage sensing with communications back to the substation.

Idaho Power has more than 600 distribution feeders in its service territory. All of these feeders were reviewed for possible CVR implementation resulting in 264 potential candidates. Phase 1 studied these 264 distribution feeder circuits in 81 substations. This study focused on shorter and/or urban feeders that had the most potential of meeting Idaho Power's CVR goals. Phase 1 analyzed these feeders with extensive load flow

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analysis and eliminated feeders that did not meet the CVR goals. Of these 264 circuits, CVR was implemented on 30 feeder circuits. In 2010 and 2011, 69 additional feeder circuits out of the 264 were studied and/or re-examined. Of these 69 feeders, nine more circuits were found to be candidates for CVR. Implementation of CVR on these nine circuits is expected by spring 2012. In addition, 36 more circuits will be studied and/or re-examined in 2012.

In 2011, phase 2 of the CVR project was started and four feeder circuits were identified as CVR candidates with minimal feeder circuit upgrades. Cost estimates were obtained and are being reviewed as possible Idaho Power projects. Additional circuits will be examined beyond 2012 but a schedule has not been established. Phase 3 feeder circuits have not yet been identified. Additional cost/benefit analyses, additional modeling and load flow analyses as well as potential EOL monitoring and communications will be necessary to move on to phase 3 and a schedule for this work has not been established.

Low cost CVR implementation at Idaho Power has largely been implemented. Additional CVR implementation in phases 2 and 3 will require circuit upgrades. These capital upgrades can be expensive and will require additional analyses and cost justification. A broader scope Volt/VAR optimization system incorporating CVR will most likely be the best path for the future and is being examined for future implementation.

As noted above, Idaho Power will agree to provide greater detail related to its CVR activities in future IRPs.

D. Idaho Power Will Continue to Pursue All Cost Effective Demand Response That Can Be Successfully Used on Its System (Action item 3).

The Proposed order recommends that "the Company pursue all cost effective demand response through existing programs and consider new programs as applicable, including those using third party program administrators that would extend into September

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when peak management is also an issue."[3] In general, the Company agrees that it should pursue all cost-effective demand-response that can be successfully utilized on its system. That said, given the size and nature of the Company's system, there may come a point when too much demand response has potential adverse consequences. In both its IRP and its presentations to Staff, the Company discussed its analysis of the optimal level of demand response resources and, in Company presentations to Staff, Idaho Power noted the energy costs of demand response programs only to point out that too much demand response on the system can increase energy cost, which is why the Company has proposed aligning program design with system needs.[4]

As a point of clarification, Staff's comments and the Proposed Order state that the Company has "...switched from 'all cost-effective [demand side management] DSM' approach to a "need-based" approach."[5] Idaho Power has not altered its approach of pursuing all cost-effective energy efficiency. However, the Company believes that the level of demand response should be determined by how much can actually be utilized on Idaho Power's system.

Importantly, the Company's demand response analysis conducted for the 2011 IRP utilized load duration curves from the IRP load forecast and forecast water conditions used in the Peak-Hour Load and Resource Balance analysis beginning on page 44 of Appendix C – Technical Appendix. Using the load duration curves from this forecast, the Company determined the level of demand response needed under extreme load and water conditions. The Company stands by this analysis.

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[3] Proposed Order at 13.

[4] *See* 2011 IRP at 42.

[5] Staff Final Comments at 8.

As for costs, the Company has continued to base cost-effectiveness of demand response programs upon the capacity costs of a Simple Cycle Combustion Turbine ("SCCT"). The Company has not changed its cost-effectiveness tests for demand response in the 2011 IRP analysis. As stated on page 42 of the 2011 IRP: "The program (Irrigation Peak Rewards) continues to be less expensive that an SCCT from a capacity perspective, which is how the program cost-effectiveness is determined." Further, as stated on pages 67 and 68 of Appendix C – Technical Appendix, "For demand response or direct load control DSM programs operating during the summer peak, the $94 per kW becomes the cost threshold for program cost-effectiveness."

Notably, one of the Company's demand response programs, the FlexPeak Management program, is offered under a contract with a third party, EnerNoc, Inc. In addition, most of Idaho Power's demand reduction through demand response programs is accomplished through either turning off irrigation pumps or through control of air conditioners, which reduces the demand response potential outside the primary cooling and irrigation months of June, July, and August. However, in regard to the programs being available in September, the Company has historically changed program dates and hours of availability to better match the need with potential demand deficits. Idaho Power will continue to monitor program parameters in relation to system needs and propose changes as needed.

The Proposed Order also states that "the Company should pursue all the demand response it can in order to both offset need for supply side resources, and if properly designed, to offset the need for market purchases in peak periods."[6] It is important to note that using demand response programs that pay incentives to the customer whether they are used or not (A/C Cool Credit and FlexPeak Management) may reduce short term

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[6] Proposed Order at 13.

power supply costs slightly. However, much of the reduction in energy use during demand response events is simply shifted to another time period. The result of this is that purchased energy or generation costs are only reduced by the differential between the cost of energy between on-peak and off-peak time periods. In the case of the Irrigation Peak Rewards program with partially fixed and partially variable incentives, using this program can only decrease short term power supply costs if market prices are extremely high.

E. As Long as the Preferred Portfolio of B2H Is Acknowledged, Idaho Power Agrees that there is No Need for the Alternative Portfolio (Action Items 8 and 9)

The Commission's IRP guidelines require utilities to evaluate and select alternative portfolios, and in compliance with Commission requirements Idaho Power has done so.[7] Staff recommends that the Commission not acknowledge the Company's proposed Alternative Portfolio because "there are mechanisms available within the existing IRP process to deal with unforeseen circumstances, such as a delay in the acquisition of a major resource."[8] Idaho Power does not disagree with this premise and for that reason is comfortable with Staff's recommendation that the alternative portfolio not be included in the Commission's acknowledgement of the IRP. However, to the extent the Staff recommendation to specifically exclude the alternative portfolio from the acknowledgement order implies the IRP analysis was incorrect or somehow flawed, Idaho Power strongly disagrees. Accordingly, if the Commission adopts Staff's recommendation to not acknowledge the Company's alternative portfolio, Idaho Power respectfully requests that the Commission's final order clarifies the reasons for the refusal to acknowledge, as

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[7] *See Re Investigation Into Integrated Resource Planning*, Docket UM 1056, Order No. 07-002 at 11 (Jan. 8, 2007).

[8] Proposed Order at 15.

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specifically articulated in Staff's Comments, and to note that such refusal to acknowledge was not a result of a flaw or failure in the Company's IRP analysis.

F. Idaho Power Will Provide Refined Load Forecasts as Part of the 2011 IRP Update and the 2013 IRP.

Idaho Power appreciates and agrees with Staff's acknowledgement that it is not appropriate to "pick-and-choose selected items" for IRP acknowledgement purposes.[9] As explained by Idaho Power in its initial reply comments, Idaho Power must pick a point in time and, based upon the best information available to it, develop assumptions to be used in the IRP process. Load forecasting is one such item. That said, Idaho Power provided Staff with updated load forecasts in response to a data request in this proceeding (Staff Data Request No. 58) and will provide another load forecast update as part of the 2011 IRP Update which, pursuant to Commission rule, will be filed one-year after the Commission acknowledges the 2011 IRP.

Idaho Power reiterates that for the purposes of determining load forecasts, it is more appropriate to use Company-specific data as opposed to broad, industry wide data, such as EIA statistics. Relying on Company-specific data more accurately reflects the unique aspects of Idaho Power's system that is not captured by broad, national data (e.g. Idaho Power's relatively large irrigation load is not generally reflected in national data). Further, the Company disagrees with Staff's reliance on Oregon-specific historical load growth as an appropriate proxy for an Idaho Power-system wide load growth forecast.[10] Notably, the energy figures in the table included on page 12 of Staff's Final Comments are actual energy sales and are not adjusted for weather. Thus, it is not appropriate to use such figures for calculating growth rates. Also, forty percent of the energy sold to Oregon each

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[9] Staff Final Comments at 17.

[10] Staff Final Comments at 12.

year is to industrial customers (Schedule 19s), which typically are not weather-sensitive. In the last few years, sales to several of the largest industrial customers in Oregon have been impacted by the slow economic recovery. When the economy does recover (particularly the housing sector impact on cement production), industrial sales should rebound sharply.

Further, with regard to the growth rates in the Oregon specific table shown on page 12 of Staff's Final Comments, Idaho Power believes that use of the compound annual growth rate ("CAGR") metric can be misleading for purposes of long term IRP planning. Staff shows use per customer ("UPC") for the period 2000 to 2010 was a negative 0.14 percent. If, however, the CAGR is calculated for the period 2000 to 2009 (thus omitting the 2010 recessionary impact) the value is a positive 0.9 percent, a full 1.04 percentage point swing due to a single year's impact. As conveyed earlier, Idaho Power continues to update the load forecast within this rapidly changing economic environment; however, IPC believes the protracted economic downturn is reflective of a short-term cyclic event, not a pervasive system-wide trend change for the 20 year horizon of the IRP. Moreover, and partially independent from the macroeconomic environment, the load situation in Oregon could change quickly given the right microeconomic conditions. If the new large load special contract that was assumed in the 2011 IRP (as discussed in more detail below) would have materialized as forecast, the electricity sales to the Oregon jurisdiction would have increased 474,000 MWh by 2016, an increase of 75 percent in sales over 2010 at a rate which falls above the upper range considered in the 2011 IRP. Importantly, Idaho Power included a new large load, "Special Contract" as part of its 2011 IRP forecast. The Company made an allowance for such a new customer even though a long-term contract had not yet been fully executed. At the time the 2011 IRP forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was

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determined that the real possibility of the new large load was significant enough that it would be imprudent for the Company to ignore the possible impact. The anticipated load of the new Special Contract was included in the 2011 IRP forecast based on discussions with the interested parties. The existing special contracts and the potential new Special Contract together made up the Additional Firm Load category.

Since the 2011 IRP sales and load forecast was completed, a signed agreement with the Special Contract customer never materialized. Therefore, the sales and load assumptions associated with the Special Contract customer were removed from all subsequent forecasts. It was decided that in the future, only large load customers with signed energy service agreements ("ESI") would be considered to be included into the sales and load forecast. It was further decided that the 2011 IRP would propose to include new large loads without a signed ESI in the load and resource balance worksheet of future IRPs.

Therefore, the Company feels that it is appropriate to include an allowance for new large loads in the load forecast as an additional firm load category only if there is a signed ESI. Otherwise, the Company agrees with Staff that it is appropriate to include an allowance for new large loads in the load and resource balance, but the new large load must be based on specific supporting documentation.

G. Idaho Power Will Work With Staff and the IRPAC To Improve the Stochastic Risk Analysis In the 2013 IRP.

Idaho Power appreciates Staff's comments regarding the risk analysis in the 2011 IRP.[11] Idaho Power realizes that the stochastic analysis was complex and additional written details of the analysis would have been helpful. The stochastic analysis prepared by Idaho Power did include adverse combinations of multiple risk variables. In addition,

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[11] *See, generally* Staff Final Comments at 13-14.

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questions regarding whether to use a uniform distribution or a normal probability distribution were discussed with the IRPAC. At the end of the discussions, Idaho Power decided to continue with the uniform distribution, in part to increase the likelihood of drawing adverse combinations of the risk variables. Idaho Power recognizes that the choice of which probability distribution to use in the risk analysis is not unambiguous.

In preparing the 2013 IRP, Idaho Power will work with Staff and the IRPAC to modify and improve the stochastic risk analysis. Idaho Power strives to improve the risk analysis in every IRP and commends Staff for its diligence in working through the details of the stochastic analysis provided in the 2011 IRP.

As for incorporating hydro variability as a risk factor, Idaho Power has evaluated hydro generation variability in previous IRPs. The water planning criteria used for the IRP, 70^{th} percentile for energy and 90^{th} percentile for peak, already assume worse-than-median conditions for average monthly energy and a more extreme case for peak-hour capacity planning. Because worse-than-median hydro conditions are used to develop the load and resource balance for energy and capacity, the Company does not believe there is any additional value in including hydro generation variability in the risk analysis.

As an alternative to requiring this additional analysis in the 2013 IRP, Idaho Power proposes modifying the Proposed Order to require the Company to discuss and solicit input from the IRPAC on the value of including hydro generation variability in the risk analysis before making a determination of whether it should be included or not. As a member of the IRPAC and participant in the planning process, Staff would participate in this process so that they can express their concerns.

H. Wind Integration Studies Should Be Independent of the IRP Process.

On March 16, 2011, Idaho Power conducted an initial public workshop to solicit input on the design of the updated wind integration study. Since that time, Idaho Power has been working with a consultant, Energy Exemplar USA (formerly Plexos Solutions, Inc.) to

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complete the wind integration modeling and study report. Prior to publishing the study report, Idaho Power plans to conduct an additional public workshop to present the results to the public and interested stakeholders that will provide an independent technical review of the study.

Although the results of wind integration studies are factored into the IRP planning process, Idaho Power believes the topic of wind integration itself is overly technical as it relates to system operation and is best handled in a forum separate from the IRP planning process. Idaho Power plans to conduct future integration study updates in a similar manner and continue to involve the public and interested stakeholders in the process.

III. CONCLUSION

The Company appreciates the opportunity to file these comments and respond to concerns and issues raised by Staff's Final Comments. The Company respectfully requests that the Commission incorporate Idaho Power's comments made herein and acknowledge the Company's 2011 IRP, including its preferred portfolio.

Respectfully submitted this 3rd day of January, 2012.

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CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing documents on in Docket LC 53 on the following named persons on the date indicated below by e-mail addressed to said persons at his or her last-known address indicated below.

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DATED: January 3, 2012

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