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December 30, 2015

VIA ELECTRONIC EMAIL AND UPS

PUC Filing Center
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

Re: Docket LC 63 - Idaho Power Company's 2015 Integrated Resource Plan ("IRP")

Attached for filing in the above-identified docket is Idaho Power Company's Reply Comments.

Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Attachment

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

LC 63

In The Matter of: Idaho Power Company's 2015 Integrated Resource Plan.	**IDAHO POWER COMPANY'S REPLY COMMENTS**

I. INTRODUCTION

Idaho Power Company ("Idaho Power" or "Company") respectfully submits these Reply Comments to the Public Utility Commission of Oregon ("Commission"). These comments respond to the opening comments of Staff of the Public Utility Commission of Oregon ("Staff") and the Citizens' Utility Board of Oregon ("CUB").

Idaho Power requests that the Commission acknowledge the Company's 2015 Integrated Resource Plan ("IRP"). The IRP satisfies each of the Commission's procedural and substantive requirements and responds fully to each of the concerns raised by the parties and the Commission in the 2013 IRP proceeding.[1] The Company's short-term action plan and long-term resource portfolio are supported by robust and comprehensive analysis demonstrating the reasonableness of the plan.[2]

The Company's 2015 IRP identified and analyzed 23 different long-term resource portfolios, which is more than twice the number of portfolios included in previous IRPs.[3] Staff found that overall the 2015 IRP included a "more robust, comprehensive, and broad analysis of current and future issues that affect the Company's resource planning and

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[1] 2015 IRP, Appendix C at 181-216.

[2] *Re Investigation into Integrated Resource Planning*, Docket UM 1056, Order No. 07-002 at 2 (Jan. 8, 2007).

[3] By comparison, the 2013 IRP analyzed nine resource portfolios.

operations than provided in previous IRPs."[4] Staff specifically noted that customers will benefit from the Company's increased portfolio and resource analysis included in the 2015 IRP.[5]

Both Staff and CUB contend that the Company's analysis does not support the selection of its preferred long-term resource portfolio. Although Idaho Power disagrees, the Company takes the parties' concerns seriously and responds to issues raised by Staff and CUB in these comments. However, the parties' concerns must be understood in the context of the overall IRP. In recent IRPs, the Commission has been clear that its acknowledgement focuses on the near-term action plan and not on the long-term resource decisions that will necessarily be the subject of additional review and analysis in future IRPs. Here, the four-year action plan is fundamentally the same for the preferred portfolio and each of the portfolios Staff and CUB identified as potentially superior options. Therefore, even if the Commission finds that Staff's and CUB's criticisms have merit, that finding should not affect the Commission's acknowledgment of the 2015 IRP action plan.

II. DISCUSSION

A. The Commission should Acknowledge Idaho Power's Action Plan.

Idaho Power's IRP must select a "portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[6] Idaho Power's plan does this, as described herein. To select the preferred portfolio, the Commission requires the IRP to analyze a planning horizon of "at least 20 years."[7] While

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[4] Staff's Opening Comments at 1.

[5] Staff's Opening Comments at 1.

[6] *Idaho Power Company 2013 Integrated Resource Plan*, Docket No. LC 58, Order No. 14-253 at 1 (July 8, 2014); *see also Re Investigation into Integrated Resource Planning*, Docket UM 1056, Order No. 07-002 at 5 (Jan. 8, 2007) (Guideline 1(c): "The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.").

[7] Order No. 07-002 at 5.

the IRP identifies a preferred portfolio, the Commission's Guidelines also require the IRP to include an action plan that identifies the specific resource activities the utility intends to undertake in the next two to four years.[8] When acknowledging an IRP, the Commission acknowledges only the action plan and does not acknowledge action items planned to occur more than four years in the future.[9] Commission acknowledgment confirms that the action plan satisfies the procedural and substantive requirements of the Commission's IRP Guidelines and "seem[s] reasonable at the time acknowledgment is given."[10]

The 2015 IRP includes twelve items in its action plan.[11] These action items include ongoing permitting of the Boardman-to-Hemingway ("B2H") and Gateway West transmission lines, pursuit of all cost-effective energy efficiency, planning for implementation of Clean Air Act Section 111(d) rules, and coordination with NV Energy regarding depreciation rates and closure dates for both units at the North Valmy coal-fired power plant.[12] Although both Staff and CUB expressed concerns over the Company's chosen long-term resource portfolio, neither Staff nor CUB specifically challenged any of the IRP's action items. This fact is important in the 2015 IRP because the action plan is not dependent on the selection of the long-term resource portfolio—*i.e.*, the near-term action plan is the same for each of the portfolios the parties support. Therefore, the Commission should acknowledge the 2015 IRP's action plan.

Regarding specific action items, Staff was the only party to comment on the

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[8] Order No. 07-002 at 12 (Guideline 4(n)).

[9] Order No. 14-253 at 12; *Idaho Power 2011 Integrated Resource Plan*, Docket No. LC 53, Order No. 12-177 at 6 (May 21, 2012) ("We agree with Staff that the desired focus in the IRP is on actions over the next two to four years. We decline to acknowledge the long-term action items . . .").

[10] Order No. 07-002 at 2; *Re Portland General Electric Company 2007 Integrated Resource Plan*, Docket LC 43, Order No. 08-246 (May 6, 2008).

[11] 2015 IRP at 142-43.

[12] The action plan also includes several items related to licensing and upgrades for the Shoshone Falls hydroelectric resource and the installation of emission control technology at the Jim Bridger coal-fired power plant.

Company's transmission projects included in the 2015 IRP action plan and Staff supports acknowledgement of both B2H and Gateway West. Specifically, Staff recommends that the Commission acknowledge the permitting efforts of B2H because B2H "was part of the preferred resource portfolios of the Company's 2009, 2011, and 2013 IRPs, and is part of the five lowest-cost portfolios in this current 2015 IRP."[13] Staff also recommends that the Commission acknowledge the permitting efforts associated with the Gateway West transmission line "because of the preliminary benefits that this transmission line presents."[14] Based on these supportive comments, and the fact that no party has challenged any of the action items, the Commission should acknowledge the Company's 2015 IRP action plan.

B. The Company's Preferred Portfolio Satisfies the Commission's Least Cost/Least Risk Standard.

The Company's quantitative and qualitative analysis demonstrated that portfolio P(6)(b) represented the portfolio of resources with the best combination of expected costs and associated risks and uncertainties.[15] Portfolio P6(b) includes the following long-term action items:

- 2025—addition of B2H;
- 2025—full retirement of the North Valmy coal-fired power plant;
- 2030—addition of 60 MW of incremental demand response resource;
- 2030—addition of ice-based thermal energy storage ("TES");
- 2031—addition of a 300 MW combined cycle combustion turbine ("CCCT") gas-fired resource.[16]

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[13] Staff's Opening Comments at 15.

[14] Staff's Opening Comments at 16.

[15] Order No. 14-253 at 1.

[16] 2015 IRP at 103.

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Notably, under portfolio P6(b), the Company would not acquire a new resource until 2025, which is a significant advantage over many of the other analyzed portfolios. In this way, portfolio P6(b) mitigates uncertainty related to a host of risk factors, including uncertain levels of Public Utility Regulatory Policies Act ("PURPA") development and uncertain carbon regulations.[17] In addition, the preferred portfolio allows the Company time to effectively manage and mitigate risk related to the construction of B2H and closure of North Valmy.[18]

Staff and CUB both express concern with the selection of portfolio P6(b) as the preferred portfolio and question whether portfolio P6(b) reflects least-cost, least-risk planning. Staff and CUB identified several other portfolios, including portfolios P8, P9, P10, and P11, that they contend are superior to portfolio P6(b) and could have been selected as the preferred portfolio. Idaho Power disagrees with Staff's and CUB's analysis and recommendations, which are too narrowly focused on the quantitative cost and risk analysis. When, as discussed below, the analysis is extended to include ancillary cost considerations and qualitative risk factors, portfolio P6(b) emerges as the best combination of risk and cost.

1. Preferred Portfolio P6(b) has a Smaller Near Term Rate Impact than Alternative Portfolios.

Staff and CUB argue that preferred portfolio P6(b) has a higher cost than several alternatives, noting that its costs are as much as $75 million greater than the least-cost portfolio P9.[19] However, in addition to analyzing the cost of each portfolio, the Company maintains it is also important to consider the near-term impact to customer rates. For example, both portfolios P9 and P6(b) assume the early retirement of the North Valmy

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[17] 2015 IRP at 141.

[18] 2015 IRP at 141.

[19] Staff's Opening Comments at 3; CUB Opening Comments at 9.

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Units 1 and 2. Portfolio P9 retires Unit 1 in 2019, instead of its fully-depreciated life of 2031, and Unit 2 in 2025.[20] Any acceleration of the current depreciation schedule will require an immediate increase in customer rates during the shortened recovery period. However, the acceleration assumed in portfolio P9 would increase annual system revenue requirements a total of $15 million as opposed to the incremental $9 million associated with the 2025 end of life assumed in P6(b).[21] Thus, while the overall cost of portfolio P9 may be less, it will have a significantly greater impact on customer rates in the near-term.

It is also important to note the relative present value cost differences between portfolios P6(b) and P8, P9, P10, and P11. In fact, as set forth below, the total cost of portfolio P6(b) is within one percent of portfolios P8,P10, and P11 and portfolio P9 is only 1.61 percent less than the preferred portfolio.

TABLE 1: COMPARISON OF TOTAL PRESENT VALUE PORTFOLIO COST

Portfolio	Total Cost (billions)	% Difference
P6(b)	$4.595	0.00%
P8	$4.574	0.46%
P9	$4.521	1.61%
P10	$4.581	0.30%
P11	$4.549	1.00%

2. Preferred Portfolio P6(b) is Not Demonstrably Riskier than Alternative Portfolios.

Consistent with past IRPs and prudent utility planning, the 2015 IRP includes a stochastic risk analysis, which assesses the effect on portfolio costs as select conditions

[20] 2015 IRP at 105.

[21] Accelerating the end of life to 2025 for North Valmy Units 1 and 2 would increase annual depreciation expense by nearly $9.0 million, while an end of life for Valmy Unit 1 of 2019, as modeled in portfolio P9, would increase annual depreciation expense by an additional $6 million, totaling nearly $15 million of incremental expense. Moreover, with either a 2019 or 2025 retirement of North Valmy, customer rates would need to be adjusted to include incremental capital additions required to keep the plant operational during its remaining life. This adjustment would require even more acceleration if North Valmy's closure is assumed to be in 2019 rather than 2025.

vary from their planning-case levels.[22] The 2015 IRP conducted stochastic analysis for three variables: (1) natural gas prices; (2) customer load; and (3) hydroelectric variability. The stochastic analysis created 100 iterations and then analyzed the total portfolio cost under each iteration.[23] The purpose of this analysis is to determine whether a particular portfolio has markedly higher costs for a subset of the stochastic futures, which would indicate that the occurrence of these futures is likely to affect costs of the higher risk portfolio more severely than for other portfolios.

Relying on Figure 9.1 from the 2015 IRP,[24] Staff claims that portfolio P6(b) is riskier because it was "outperformed by three of the four alternative resource portfolios (P8, P9 and P11) *in every single risk iteration*."[25] This fact, however, is not necessarily evidence of a higher risk portfolio. A higher risk portfolio will be substantially impacted if one of the three studied variables differs from the planning assumptions, as compared to the other portfolios. The roughly parallel nature of the plotted lines in Figure 9.1 indicate that each portfolio's costs are similarly affected by the 100 stochastic futures considered, and thus no portfolio stands out as riskier than others. Referring to Figure 9.1, the IRP describes how the stochastic analysis identifies high risk portfolios:

> Significant crossing of lines in the exceedance graph is an indication of substantial portfolio disparity; portfolio cost performance in this case is markedly different across the set of stochastic iterations. As an example, a portfolio consisting of exclusively natural gas-fired generation would be expected to conspicuously cross lines on Figure 9.1 as portfolio costs range greatly from low to high natural gas-price futures. **Finally, the lack of significant crossing of lines is a testament to the resource diversity of Idaho Power's existing portfolio and the portfolios of new resources considered in the IRP; under no set of stochastic futures is a portfolio a clear and runaway cost winner, only to be**

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[22] 2015 IRP at 121.

[23] 2015 IRP at 122, Figure 9.1.

[24] 2015 IRP at 122.

[25] Staff's Opening Comments at 4 (emphasis in original).

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> **countered by a different set of futures for which it is just as clearly a losing portfolio susceptible to significantly higher costs than other portfolios.**[26]

Thus, Staff's conclusion that portfolio P6(b) is "riskier" than the others is not supported by the data.

3. The 2015 IRP's Qualitative Risk Analysis is Reasonable and Supports the Selection of the Preferred Portfolio.

Both Staff and CUB criticize the Company for relying on qualitative risk analysis to support the selection of the preferred portfolio.[27] However, the Company's robust qualitative risk assessment is an important factor that must be considered when identifying the portfolio with the best combination of costs and risks.

As stated in the 2015 IRP, the goal of the qualitative risk analysis is to select a portfolio likely to withstand unforeseen events that cannot be quantified.[28] Toward this end, the Company considers many risks, including those associated with long-term sustainability of the Snake River Basin, the relicensing of the Hells Canyon Complex, eventual ramifications of the final Clean Air Act Section 111(d) ruling, regulatory risk of future resource additions and removals and associated allowance for return on investment, resource commitment risk of developing PURPA projects and the permitting of transmission lines, resource adequacy of regional power supply, implementation of demand-side management ("DSM") programs, and the development of new technologies.

Given the relatively small difference in the present value portfolio costs associated with the various portfolios (1.6 percent or less), the results of the qualitative study appropriately drove the Company's ultimate selection of portfolio P6(b). The retirement of the North Valmy plant and the completion of B2H in 2025 balances the risks of Clean Air Act Section 111(d) and increases in unplanned intermittent and variable generation. The

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[26] 2015 IRP at 123 (emphasis added).

[27] Staff's Opening Comments at 4-8; CUB Opening Comments at 11.

[28] 2015 IRP at 125-130.

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preferred portfolio P6(b) also includes the addition of 60 MW of demand response and 20 MW of ice-based TES in 2030 and a 300-MW CCCT in 2013. These resource additions late in the planning period address projected needs for resources providing peaking capability and system flexibility, which will be necessary given the expected long-term expansion of variable energy resources.

4. Preferred Portfolio P6(b) Better Mitigates Uncertainty Related to PURPA Projects.

The 2015 IRP identifies a qualitative risk relating to the uncertainty caused by the 320 MW (as of April 2015) of yet-to-be-constructed PURPA solar resources and the effect of possible further project cancellations on capacity additions in the early 2020s.[29] Staff contends that PURPA risk affects all portfolios and therefore provides no basis to select portfolio P6(b) as the preferred portfolio.[30] Indeed, Staff asserts that PURPA risk actually supports selection of other portfolios because the cancellation of 141 MW of PURPA projects results in an earlier peak-hour capacity deficit for portfolio P6(b), while the cancellation has no impact on the first peak-hour capacity deficit for portfolios P8, P9, P10, and P11. Staff's analysis, which focuses exclusively on the change in the first peak-hour capacity deficit, is too narrow.

As an illustration, with the complete removal of the PURPA solar resources from the load and resource balance, portfolios with a 2019 retirement of North Valmy Unit 1 (portfolios P8 and P9) are projected to have capacity deficits of approximately 140 MW in July 2020, which will grow to nearly 300 MW by 2023. By comparison, delaying the retirement of North Valmy Unit 1 to 2025 (portfolio P6(b)), results in more manageable and moderate deficits of approximately 5 MW in 2020 and less than 160 MW through 2023. Thus, while portfolio P6(b)'s capacity deficit is earlier if PURPA projects are removed, the

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[29] 2015 IRP at 128.

[30] Staff's Opening Comments at 7.

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amount of the deficit is much more reasonable and manageable.

5. Preferred Portfolio P6(b) Reasonably Mitigates Risks Related to Early Closure of North Valmy.

The Company's qualitative risk analysis also considers the uncertainty related to retirement planning for a jointly-owned power plant.[31] Portfolios P8 and P9 include the closure of North Valmy Unit 1 in 2019, which is six years earlier than the preferred portfolio P6(b). Notably, the shutdown date for North Valmy is not within the complete control of Idaho Power. NV Energy, Idaho Power's co-owner and the operating partner of the North Valmy plant, has not indicated that 2019 is an acceptable date to discontinue operations of North Valmy Unit 1. Moreover, once Idaho Power and NV Energy agree on a retirement date, other actions will be needed in order to facilitate the plant retirement, such as regulatory approval for accelerated depreciation and accelerated recovery of closure costs. Thus, while the Company's action plan includes continued work with NV Energy on this issue, there is significant uncertainty associated with a 2019 shutdown for Unit 1. This uncertainty is significantly mitigated by the preferred portfolio, which retires both units at North Valmy in 2025.

Moreover, even if a 2019 shut-down of Unit 1 was feasible, the Company does not believe it would be reasonable or prudent to retire an existing resource with known fixed costs, which will result in an immediate need for additional cost recovery from customers. The planned retirement of both North Valmy units in 2025 is a lower risk option than a planned retirement of Unit 1 in 2019. Preferred portfolio P6(b) therefore contributes to near-term rate stability and represents a reasonable glide path toward reduced coal generation on Idaho Power's system.

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[31] 2015 IRP at 125-130, 141-143.

6. Preferred Portfolio P6(b) Reasonably Mitigates Uncertainties Related to Emission Control Permitting for the Jim Bridger Plant.

The IRP's qualitative analysis accounts for the risks related to the early retirement of Jim Bridger Units 1 and 2, which is included in two portfolios (P10 and P11) identified by Staff and CUB as having lower costs than the preferred portfolio P6(b).[32] For portfolios P10 and P11, the IRP assumes that the Jim Bridger units are permitted to operate until retirement without installation of selective catalytic reduction ("SCR") retrofits necessary for compliance with Environmental Protection Agency's regional haze regulations. This assumption contributes significantly to the lower cost of these portfolios, as compared to the preferred portfolio. However, while the Bridger SCRs are the subject of ongoing discussions with Wyoming regulators, the IRP correctly notes that it is "highly speculative" to conclude that Units 1 and 2 could operate without SCRs until retirement. Thus, portfolios P10 and P11 include significant risks that are not present in the preferred portfolio. The inability to successfully achieve permitting consistent with the assumptions in portfolios P10 and P11 would likely have a significant effect on the costs and feasibility of these portfolios.

C. The 2015 IRP Appropriately Models Demand Side Resources.

1. The Company's Portfolios Reasonably Include the Level of Achievable Energy Efficiency.

For the 2015 IRP, Idaho Power contracted with a third-party, Applied Energy Group ("AEG"), to conduct an energy efficiency potential study that resulted in a forecast of energy savings over the 20-year IRP planning period. AEG is an industry leader in potential studies, having performed more than 50 potential studies across the U.S. in the last five years and 20 studies in the Northwest. In addition to Idaho Power, AEG's clients include Avista Energy, Tacoma Power, Seattle City Light, and PacifiCorp. AEG keeps abreast of the Northwest Power and Conservation Council's ("NWPCC") plans and their

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[32] 2015 IRP at 127

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planning process, participates in the regional technical forum, and interfaces with state commissions, auditors, and stakeholders.

Using AEG's forecasts, Idaho Power included all achievable energy efficiency in every portfolio prior to any supply-side resources being considered, making energy efficiency the first resource the Company has included to meet future resource needs. While the IRP models include all achievable cost effective energy efficiency in each portfolio, Idaho Power does not consider the achievable energy efficiency as a ceiling and continues to pursue all cost-effective energy efficiency in actual operations. Thus, the Company has to date consistently exceeded its IRP target for energy efficiency savings on a cumulative basis.[33]

Staff noted that the Company's increase in cost effective energy efficiency included in the 2015 IRP is "encouraging and Staff appreciates the work of the Company in reporting efficiency results and in working with [AEG] to produce a comprehensive conservation potential study."[34] Staff did not raise any specific concerns with the Company's modeling, but indicated that it continued to study several aspects of the Company's modeling.

First, Staff seeks clarification regarding how energy efficiency savings produced by the Northwest Energy Efficiency Alliance ("NEEA") are reflected in the IRP.[35] NEEA does not forecast the energy savings anticipated from its 2015-2019 business plan or ongoing initiatives from the previous funding cycles at the funder or geographic level. Therefore, the Company cannot determine what percentage of the energy efficiency savings identified in the 2015 IRP action plan will be met explicitly by NEEA initiatives in the Idaho Power service area. Any energy savings from NEEA initiatives are imbedded in the

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[33] 2015 IRP at 42; CUB Opening Comments at 3.

[34] Staff's Opening Comments at 8.

[35] Staff's Opening Comments at 9.

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energy efficiency potential as determined by AEG in Idaho Power's 2014 Energy Efficiency Potential Study.[36]

Second, Staff seeks a better understanding of how short term market dynamics of program activity and customer interest intersect with ramp rates and acquisition targets resulting from the AEG conservation potential study.[37] The 2014 Idaho Power Energy Efficiency Potential Study is a long-term study that helps quantify energy efficiency as a resource over the 20-year planning period. The study is not designed as a program planning tool as there are often many differences between actual current program portfolios and the potential study. The cumulative savings over time is what is important for IRP planning. Fluctuations in year-to-year savings are expected.

As part of the forecast process, the Company provides historical savings and lists of current measure assumptions to AEG, which are then reviewed and incorporated into AEG's models.[38] At the time this study was completed the energy efficiency savings from

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[36] The estimated amount of regional energy savings included NEEA's 2015-2019 business plan can be found at: http://neea.org/docs/default-source/default-document-library/neea-2015-19-business-plan---board-approved.pdf?sfvrsn=2. Savings from previous initiatives can be found in the NEEA 2014 annual report found at: http://neea.org/resource-center/annual-report/letter-to-the-region. Historical trends of Idaho Power net market effects energy savings from NEEA initiatives can be found in Appendix 4 of Idaho Power's *Demand-Side Management 2014 Annual Report*, page 183, https://www.idahopower.com/EnergyEfficiency/reports.cfm.

[37] Staff's Opening Comments at 9.

[38] AEG explained their methodology that uses historical savings to estimate future potential as follows: "To develop estimates for achievable potential, we develop market adoption rates for each measure that specify the percentage of customers that will select the highest–efficiency economic option. For Idaho Power, the project team began with the ramp rates specified in the Sixth Plan conservation workbooks, but modified these to match Idaho Power program history and service territory specifics. For specific measures, we examined historic program results for the three-year period of 2009 through 2011, as well as partial-year results for 2012. We then adjusted the 2012 achievable potential for these measures to approximately match the historical results. This provided a starting for the 2012 potential that was aligned to historic results. For future years, we increased the potential factors to model increasing market acceptance and program improvements. For measures not currently included in Idaho Power programs, we relied upon the Sixth Plan ramp rates and recent AEG potential studies to create market adoption rates for Idaho Power." *2014 Idaho Power Energy Efficiency Potential Study* at 11.

the 2014 program activities were not known and the trend over the previous years had a downward slope: 22.10 aMW, 20.94 aMW, 19.64 aMW, 12.23 aMW, for the years 2010, 2011, 2012, 2013, respectively. Consequently, following this trend AEG forecasted the energy efficiency potential for 2015 at 12 aMW. This downward forecast was also influenced by the lower DSM alternative costs identified in the 2015 IRP, as compared to the 2013 IRP, that were used for actual program planning and energy efficiency acquisition in 2014 operations.

In their comments, Staff correctly identifies that there are timing challenges between assumptions used in the studies compared to real time program acquisition. It is important to recognize that there can be annual increases or decreases in energy efficiency savings. There is a natural ebb and flow of projects. Many of the more complex projects in the commercial and industrial sectors have substantial savings associated with them and can take years to complete. The timing of these projects might be impacted by capital budget processes or other factors internal to customers' businesses. In addition, factors, such as changes in codes and standards, successful market transformation, or the state of the local and national economy can also dramatically influence customers' energy efficiency project decisions, which directly affect program savings, applicability, or cost-effectiveness.

Third, Staff seeks a better understanding of how the Company calculated energy efficiency savings from special contract customers and the relative risk in the acquisition of those energy efficiency savings.[39] The following table includes the energy efficiency savings reported in the AEG study and those expected from special contracts. This analysis is based on historical energy efficiency savings from special contract customers:

[39] Staff's Opening Comments at 9.

TABLE 2: SPECIAL CONTRACT ENERGY EFFICIENCY SAVINGS

	2015	2019	2024	2029	2034
Baseline projection - including IPC Special Contracts (GWh)	**14,599**	**15,287**	**16,247**	**17,474**	**18,750**
Cumulative Savings (GWh)					
Achievable Potential (AEG)	99	697	1,401	2,029	2,471
Achievable Potential (Special Contracts)	8	41	82	123	164
Total	107	738	1,483	2,152	2,635
Cumulative Savings as a % of Baseline					
Achievable Potential (AEG & Special Contracts)	0.7%	4.8%	9.1%	12.3%	14.1%

Forecasting the energy savings potential for Idaho Power's special contract customers is challenging. Although all three current special contract customers are highly engaged in energy efficiency programs provided by Idaho Power and have long histories of successful energy efficiency projects, the savings are large and the projects are often intermittent and complex, which creates difficulties in forecasting savings.

Fourth, Staff seeks a better understanding of how the monthly forecasted energy efficiency set forth in Appendix C of the 2015 IRP (the Monthly Average Energy Load and Resource Balance analysis[40]) relates to the Company's existing DSM peak-hour resource (in the Peak-Hour Load and Resource Balance analysis[41]) for similar time periods.[42] The referenced values contained in the tables on pages 29 to 48 of the 2015 IRP, Appendix C, represent the monthly average megawatts ("aMW") of energy efficiency forecasted for the planning period as determined by dividing the forecasted monthly megawatt hours of energy efficiency by the number of hours in any particular month. The referenced values

[40] 2015 IRP, Appendix C at 29-48.

[41] 2015 IRP, Appendix C at 50-69.

[42] Staff's Opening Comments at 9.

contained in the tables on pages 50-69 of the 2015 IRP, Appendix C, represent the forecasted monthly levels of energy efficiency, as measured in megawatts at the time of the forecasted monthly system peaks. The single monthly peak hour contribution from energy efficiency is determined using annual hourly load shapes provided from the AEG study, which provide the total megawatts of energy efficiency that are forecast to exist in each hour of each month during the planning period. This information is compared to the forecast monthly system peak hours to determine the level of energy efficiency that will exist in each of those peak hours. The megawatts of monthly peak-hour contribution from energy efficiency will always exceed the average megawatts for each month.

CUB expressed concern with the Company's estimate of energy efficiency used in the 2015 IRP. Specifically, CUB contends that the Company inappropriately included the amount of "achievable" energy efficiency, which CUB claims underestimates the actual energy efficiency savings that can be expected during the planning period.[43] However, CUB's criticism appears to be based, at least in part, on CUB's misunderstanding of the Company's historical performance. CUB points to the Company's *cumulative* energy efficiency savings as compared to IRP targets and claims that the "gap between projected and actual EE [energy efficiency] only seems to increase over time, 2014 seems to carry the largest gap at roughly 47 aMW."[44] It is not surprising that the 2014 gap is the greatest, however, because the data CUB is analyzing is *cumulative*. In fact, for 2014, the difference between the IRP's incremental targets and incremental energy savings is only about two aMW, not 47 aMW.

CUB also compares Idaho Power's energy efficiency potential with that included in the NWPCC's draft seventh power plan as further evidence that the Company has

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[43] CUB Opening Comments at 3-6.

[44] CUB Opening Comments at 3.

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understated its energy efficiency targets.[45] Contrary to CUB's criticism, however, the Company's analysis is consistent with the NWPCC plan. In fact, for Idaho Power's 2014 Energy Efficiency Potential Study, AEG's ramp rates and acquisition factors for all years are either equal to or greater than the acquisition rates used in the NWPCC's sixth power plan (which was the plan available during the development of the 2015 IRP) and by the end of the planning period are all equal to the NWPCC's rates. Moreover, comparisons to the draft seventh plan are premature, given that it has yet to be vetted by the region or even accepted by the NWPCC.

CUB further claims that "low-balling of EE [energy efficiency] can lead to overestimating load growth, resulting in unneeded capacity at a very real cost to ratepayers."[46] CUB's comments imply that the Company's preferred portfolio includes the acquisition of a CCCT resource every five years during the planning period.[47] Contrary to CUB's claims, however, the preferred portfolio does not include a new CCCT resource every five years. In fact, the preferred portfolio does not include any new resources until 2025, or any energy deficits until 2026, or any CCCTs until 3031.

2. The 2015 IRP Reasonably Models Demand Response.

CUB claims that the Company under-forecasts the available capacity of its demand response programs and alleges that the Company does not give equal treatment to both supply-side and demand-side resources.[48] Both of CUB's criticisms are misplaced.

First, the Company reasonably forecasts its demand response resources based on the risks and uncertainties related with this peaking resource. Like energy efficiency, demand response is difficult to forecast because it depends on customer participation and,

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[45] CUB Opening Comments at 5-6.

[46] CUB Opening Comments at 7.

[47] CUB Opening Comments at 4, 7.

[48] CUB Opening Comments at 7-8.

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in some cases, customer action. The results from dispatching demand response programs can vary based on the time of season, weather variation, and economic conditions.

Second, Idaho Power disagrees with CUB that it does not give equal treatment to demand-side and supply-side resources. In the Monthly Average Energy Load and Resource Balance analysis[49] all achievable cost effective energy efficiency is included prior to any new supply-side resources.

Moreover, Idaho Power is operating and promoting its demand response programs in compliance with the settlement agreement signed by Staff, Idaho Power, and other stakeholders and approved by the Commission.[50] Under the terms of the stipulation, the Company must "maintain[] current [demand response] programs even in years when Idaho Power does not anticipate peak-hour capacity deficits, so that the program infrastructure will be ready when capacity deficits return."[51] Thus, Idaho Power has been able to operate its demand response resource and has forecasted that resource in the IRP at current levels of enrollment.

D. The Company's Modeling of Residential Solar Photovoltaic ("PV") Capital Costs is Appropriate.

Staff questioned the Company's modeling of residential solar PV capital costs. Specifically, Staff claims that residential solar PV systems should be considered net metering systems whereby the customer, not Idaho Power, incurs the capital costs to construct the resource.[52] Idaho Power notes that the inclusion of capital costs associated with resource construction is consistent with the treatment for other resources considered

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[49] 2015 IRP, Appendix C at 29-49.

[50] In The Matter of Idaho Power Company, Staff Evaluation of the Demand Response Programs, Case No. UM 1653, Order No. 13-482 (December 19, 2013).

[51] *Id.* at 3.

[52] Staff's Opening Comments at 10.

in the IRP, thus allowing meaningful cost comparisons between resources.[53] Excluding a portion of the resource costs for certain resources as suggested by Staff would likely lead to uneconomic resource procurement and inefficient deployment of capital on the part of Idaho Power and its customers.

E. The Company will Notify CUB of all Future Stakeholder Meetings.

CUB expressed a concern with the IRP process, noting that it was not invited to any of the Company IRP stakeholder meetings until January 2015.[54] This omission was an oversight on Idaho Power's part. Although Idaho Power's stakeholder process was publicly posted on its website, the Company has taken steps to ensure that CUB will be fully informed of all future stakeholder meetings related to its IRPs.

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[53] The Company calculates the costs of residential solar PV resources using the same levelized cost of energy ("LCOE") methodology as every other potential resource. The LCOE is described by the U.S. Energy Information Administration ("EIA") in a June 2015 paper as a summary measure allowing assessment of the overall competitiveness of different generating technologies. http://www.eia.gov/forecasts/aeo/pdf/electricity_generation.pdf. The EIA in the June 2015 paper defines the LCOE as "the per-kilowatt hour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle." The EIA further provides that key inputs to the LCOE calculation include capital costs, fuel costs, fixed and variable O&M costs, financing costs, and an assumed utilization rate for each plant type.

[54] CUB Opening Comments at 13.

III. CONCLUSION

The Company appreciates the opportunity to file these comments and respond to concerns and issues raised by Staff and CUB. The Company requests that the Commission acknowledge its 2015 IRP, including its action plan.

Respectfully submitted this 30th day of December 2015.

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