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December 8, 2017

VIA ELECTRONIC AND US MAIL

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

Re: Docket LC 68 - Idaho Power Company's 2017 Integrated Resource Plan ("IRP")

Attached for filing in the above-identified docket is Idaho Power Company's Reply Comments. A hard copy of this filing along with confidential copies will be sent to the Filing Center via US Mail. Please note that Confidential Attachments 2.1-2.5 are being provided on a CD.

Please contact this office with any questions

Very truly yours,

Alisha Till

Alisha Till
Administrative Assistant

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 68

In the Matter of: IDAHO POWER COMPANY'S 2017 Integrated Resource Plan.	**IDAHO POWER COMPANY'S REPLY COMMENTS**

December 8, 2017

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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"), the Oregon Citizens' Utility Board ("CUB"), STOP B2H Coalition ("STOP B2H"), Sierra Club, the Renewable Energy Coalition ("Coalition"), and Gail Carbiener.

Idaho Power requests that the Commission acknowledge the Company's 2017 Integrated Resource Plan ("IRP"). The IRP satisfies each of the Commission's procedural and substantive requirements. 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.[1] An important baseline assumption of the 2017 IRP, included in the short-term action plan for acknowledgment, assumes that Idaho Power will shut down its ownership share of coal-fired operations at North Valmy unit 1 by year-end 2019 and from North Valmy unit 2 at year-end 2025. In addition, this IRP served to inform two key resource decisions related to the Boardman to Hemingway ("B2H") 500-kV transmission line and the selective catalytic reduction ("SCR") investments required for units 1 and 2 of the Jim Bridger coal-fired plant. Based on the outcome of the extensive IRP public process and the Company's detailed analytics, the preferred portfolio in the 2017 IRP (portfolio P7) includes the B2H line as a least-cost, least-risk resource, but does not include installation of SCR systems at units 1 and 2 of the Jim Bridger plant.

The B2H line meets Idaho Power's demonstrated capacity need at nearly half the cost of the next best resource. The line also provides increased reliability benefits and grid flexibility directly to Idaho Power customers, while increasing the overall reliability and resiliency of the regional grid and enabling greater ability to integrate renewable generation.

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

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B2H provides all these benefits without the risk associated with constructing a new fossil-fuel-based resource.

The 2017 IRP represents a key milestone in the Company's ongoing efforts to develop the B2H line. Originally specified as a 285 MW transmission capacity resource in the Company's 2006 IRP's preferred resource portfolio, increasing Idaho Power's connection to the Pacific Northwest power markets, the B2H project has been a critical component of Idaho Power's preferred portfolios since the 2009 IRP and has consistently represented the least-cost, least-risk resource for customers. In each of the last four IRPs, the Commission has recognized that continued development of the project was reasonable. In this case, the Company's least-cost least-risk preferred portfolio again includes the B2H project as a transmission resource. But in this case, the Company requests acknowledgment of the decision to continue permitting activities and, more importantly, to begin preliminary construction activities for the B2H transmission line. The Company intends to use the acknowledgment of B2H in the 2017 IRP to support its application before Oregon's Energy Facility Siting Council ("EFSC"). Thus, acknowledgment of this IRP is critical to allow project development to move forward so that the transmission line can be in-service to meet the needs of Idaho Power's customers.

Staff, along with several intervenors, are critical of aspects of the Company's case supporting acknowledgment of B2H as the least-cost, least-risk resource. The Company recognizes that the stakes in this case are arguably higher than prior IRPs and acknowledges Staff's and intervenors' concerns. Therefore, concurrent with these reply comments, the Company is also filing Appendix D: B2H Supplement to the 2017 IRP that focuses exclusively on the B2H line and responds in depth to the concerns raised by the parties by providing additional explanation and analytic support for the reasonableness of the project. Together with these reply comments, Appendix D: B2H Supplement further demonstrates that the preferred portfolio identified in the 2017 IRP is least-cost, least-risk, and should be acknowledged.

In addition to the selection of B2H, Staff and intervenors were also critical of the Company's methodology for selecting resource portfolios for modeling, arguing that there were too few portfolios and that the portfolios lacked resource diversity. The Company's portfolio design and analysis in this IRP was driven by the two key resource decisions at issue—B2H and the Jim Bridger SCRs. The Company specifically tailored its portfolios to focus on these decisions by evaluating a diverse set of resources prior to designing the portfolios and selecting the most cost-effective resources that, when combined, provided an acceptable level of reliability. Although this "pre-screening" resulted in fewer portfolios than the 2015 IRP, the studied portfolios adequately reflected and compared the most cost-effective resources and produced results that demonstrate that constructing the B2H line and not investing in the SCRs are the least-cost, least-risk decisions for customers.

Finally, in these reply comments, Idaho Power addresses concerns over the Company's modeling of coal plant retirement scenarios, demand-side management ("DSM") resources, and forecasting methodologies, among other issues. The Company's coal retirement scenarios reasonably account for existing and expected environmental regulations and market conditions and represent a prudent transition away from coal; the Company has continued to aggressively pursue DSM resources and included all cost-effective DSM resources before any other resource; and the Company's forecasting methodologies are consistent with prior IRPs and industry standards and reflect a reasonable basis for analyzing Idaho Power's future resource needs. In sum, these comments demonstrate that the Company's portfolio design, modeling, and assumptions are reasonable and produce a preferred portfolio that is least-cost and least-risk.

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II. STANDARD FOR IRP ACKNOWLEDGMENT

Idaho Power's IRP must: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) aim to select a resource portfolio with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.[2] The primary goal of an IRP is to select the least cost/risk portfolio for the utility and customers.[3] To meet this goal, the Commission requires the IRP to analyze a planning horizon of "at least 20 years."[4] While the fundamental goal of the IRP is the identification of the 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.[5] When adopting the IRP guidelines, the Commission noted that, "in an IRP, the Commission looks at the reasonableness of individual action items in the context of the entire plan."[6]

When acknowledging an IRP, the Commission generally acknowledges only the action plan and does not acknowledge action items planned to occur more than four years in the future.[7] Commission acknowledgment confirms that the action plan satisfies the procedural and substantive requirements of the Commission's IRP guidelines and is "reasonable based on the information available at that time.[8]

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[2] *In the Matter of Idaho Power Company, 2013 Integrated Resource Plan*, Docket No. LC 58, Order No. 14-253 at 1 (July 8, 2014).

[3] Order No. 07-002 at 5 (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.").

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

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

[6] Order No. 07-002 at 25.

[7] Order No. 14-253 at 12; *In the Matter of Idaho Power Company, 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 . . . .").

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

Importantly, the Commission has repeatedly "reaffirm[ed] [its] long-standing view that decisions made in IRP proceedings do not constitute ratemaking."[9] "Decisions whether to allow a utility to recover from its customers the costs associated with new resources may only be made in a rate proceeding."[10]

III. BOARDMAN TO HEMINGWAY

A. Transmission and the IRP Process

The Company seeks Commission acknowledgment of its preferred portfolio in the 2017 IRP, which includes the Company's proposal to begin construction activities for the B2H line. This proposed line is considered as a resource that will provide the Company with critical capacity required to serve its Oregon and Idaho retail customer loads and to maintain system reliability, without adding a carbon-producing resource. Pursuant to Commission Orders Nos. 89-507 and 07-002, the Company seeks acknowledgment from the Commission that the Company's planned transmission line is reasonable, cost effective, and necessary to ensure that the Company's customers receive adequate services at reasonable rates.[11] The Company does ***not*** request that the Commission review, approve, or acknowledge the specific routing of the line nor the ratemaking treatment of the line.

1. Idaho Power's IRP Establishes its Specific Resource Need, but Broader Regional Planning is Also Legitimately Considered as Part of Need.

Idaho Power's preferred portfolio includes the B2H capacity resulting from the Company's ownership share of the line. The Company is therefore seeking acknowledgment of only its proportional capacity as the least-cost, least-risk resource for Idaho Power customers. This approach is consistent with the treatment of other resources in which the Company has shared ownership. Acknowledgment of Idaho Power's resource

[9] Order No. 14-253 at 1.
[10] Order No. 14-253 at 1.
[11] *Re Least-cost Planning for Resource Acquisitions*, Docket No. UM 180, Order No. 89-507 (April 20, 1989); Order No. 07-002.

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need, therefore, does not require that the Commission also acknowledge a specific resource need for Idaho Power's co-participants, PacifiCorp and the Bonneville Power Administration ("BPA"). While Idaho Power seeks acknowledgment of only its share of B2H, the Company recognizes that the overall cost-effectiveness of the resource relies on shared ownership and that the Company will likely not move forward with B2H alone (as discussed in greater detail in Section III.E.2, below).

Moreover, although the Company is not seeking acknowledgment of the total capacity of the proposed B2H line, the Commission can consider the regional need for the B2H line and the broader benefits it provides. This regional approach was established by the Commission in its 1976 order granting a certificate of public convenience and necessity ("CPCN") to Pacific Power & Light ("PP&L") to construct a 500 kV transmission line from southern Idaho to Medford, Oregon.[12] In that case, PP&L argued that the proposed transmission line was needed to transmit energy from its Wyoming generating plant to customers in the western portion of its system. In addition to serving PP&L's own customers, the Commission noted that the proposed transmission line would also increase capacity, stability, and reliability for the Northwest transmission grid and the Northwest Power Pool.[13] While PP&L presented the Commission with alternatives to the proposed line, the Commission found that the alternatives "would not yield the same advantages to the regional and inter-regional transmission grids and inter-connected power systems as the proposed transmission line."[14] The Commission issued the CPCN because it concluded (1) that the proposed transmission line was necessary for PP&L to provide adequate service at reasonable rates, (2) that it was justified as in the public interest, and (3) that the public

[12] *Application of Pacific Power & Light Co. for Certificate of Public Convenience and Necessity*, Docket UF 3182, Order No. 76-359 (May 28, 1976) (343 of the 478 miles of proposed transmission line were in Oregon).
[13] Order No. 76-359 at 4.
[14] Order No. 76-359 at 5.

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convenience and necessity required the line to be constructed along the route approved by the Commission.[15] Thus, the Commission's analysis focused not only on benefits to Oregon customers, but also on supporting the needs of the regional transmission grid. As discussed below in more detail, B2H provides significant benefits to the regional grid.

2. IRP Review Focuses on General Resource Needs, Not on Siting.

In describing IRP requirements for transmission projects, the Commission's guidelines state that the utility must include cost information for a proposed transmission project, as well as possible alternatives to the proposed project.[16] The Commission's orders do not require detailed routing information nor is a determination of the route appropriate for an IRP proceeding. The Commission has noted that, "To keep the IRP process separate from the procurement process, we prefer to acknowledge general, not specific, resources in the IRP process."[17]

3. EFSC Review Involves Detailed Analysis of Site Selection.

In contrast, EFSC is specifically tasked with establishing siting standards for energy facilities in Oregon and ensuring certain transmission line projects, including B2H, meet those standards.[18] Before the Company can begin construction on B2H in Oregon, it must obtain a site certificate from EFSC.[19] This certificate authorizes the construction of the proposed transmission line along a route reviewed and approved by EFSC.[20] Thus, the ultimate decision as to the siting of the proposed B2H line belongs to EFSC—not to the Commission.

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[15] Order No. 76-359 at 6. Although the Commission approved the project in this order, the full route was not approved until February 22, 1979.
[16] Order No. 07-002 at 13.
[17] Order No. 07-002 at 25.
[18] *See generally* ORS 469.300-469.563, 469.590-469.619, and 469.930-469.992.
[19] ORS 469.320(1) and ORS 469.450(1).
[20] ORS 469.401(1).

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EFSC engages in a robust public engagement process in reviewing the proposed route. Oregon statutes require EFSC to hold public meetings in the area affected by the siting proposal, and elsewhere as deemed appropriate.[21] During the process members of the public may testify at the public hearings or submit written comments by the comment deadline. EFSC will conduct a contested case proceeding, and parties who have an interest in the outcome of the proceeding or represent a public interest may participate in that proceeding provided that they follow certain procedural requirements.[22]

EFSC siting standards address a range of issues, including land use planning, protection of cultural resources, and protection of the environmental. To receive a site certificate, Idaho Power must establish that the B2H line satisfies the applicable siting standards and that there is a need for the transmission line.

4. Idaho Power Seeks to Satisfy the EFSC "Need" by having the Commission Acknowledge B2H in the IRP.

EFSC will issue a site certificate authorizing the construction of a transmission line ("non-generating facility") only after the Company demonstrates a need for the facility in accordance with EFSC's least-cost plan rule or system reliability rule.[23] The requirements of the least-cost plan rule can, in turn, be met through a Commission acknowledgment of the resource in the Company's IRP.[24] In this case, Idaho Power seeks to satisfy EFSC's least-cost plan rule by having the Commission acknowledge the Company's IRP in this docket.

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[21] ORS 469.370(2).
[22] ORS 469.370; OAR 345-015-0016. To participate in the contested case proceeding, a party needs to: (1) have an interest in the outcome or represent a public interest; (2) provide sufficiently specific comments on the Draft Proposed Order (DPO) on an issue within the Council's jurisdiction before the close of the record in the DPO hearing (unless the party is commenting on an issue that is a material change from the DPO to the Proposed Order); and (3) timely file a petition for party or limited party status meeting the requirements specified in OAR 345-015-0016.
[23] OAR 345-023-0005(1).
[24] OAR 345-023-0020(2).

If the Commission acknowledges the Company's proposed plan, however, that does not mean that EFSC will automatically issue a site certificate and authorize construction along the route proposed by the Company. A demonstration of need is only one of many requirements the Company must satisfy before issuance of the site certificate.[25]

Following the issuance of the site certificate by EFSC, the Company must then seek a CPCN from the Commission.[26]

B. Resource Need

Idaho Power's 2017 IRP relies on the same methodologies used in prior IRPs to identify its first capacity and energy deficits over the IRP planning period. Based on the Company's preferred portfolio, the first capacity deficit occurs in 2026, unless the Jim Bridger units are retired early, in which case the first capacity deficit occurs as early as 2023.[27] The first energy deficit occurs in 2029, or as early as 2024 with Jim Bridger retirements.

Once these deficits were identified, Idaho Power then studied the resources available to find the least-cost, least-risk combination of resources to meet the need. The Company's analysis consistently selected portfolios that included B2H as a least-cost, least-risk resource because its capacity costs are nearly half of the next best alternative, it provides grid flexibility, and allows the Company to avoid the acquisition of a carbon-producing resource. Contrary to the implications made in several comments, the Company did not identify a need for additional *transmission* resources, and then selected B2H as the least-cost, least-risk *transmission* resource. Rather, the Company identified a need for a supply-

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[25] *See* ORS 469.310 (siting decisions must be consistent with the health and welfare of the people of Oregon); OAR 345-022-0000 to 345-022-0120 (general standards for siting facilities).
[26] *See* ORS 758.015.
[27] Idaho Power Company's 2017 Integrated Resource Plan at 96 (hereinafter "2017 IRP").

side resource and B2H consistently and substantially outperformed the competing alternative resources.

1. B2H is Properly Characterized as a Supply-Side Resource.

Consistent with its historical treatment of B2H in prior IRPs, the Company's modeling treats B2H as a supply-side resource because it allows greater access to Northwest markets, thereby allowing Idaho Power to import additional lower-cost energy to serve its Oregon and Idaho customers. STOP B2H argues that transmission lines are not supply-side resources and that the IRP is "devoid of any analysis of the underlying power resource actually represented by B2H in the IRP, which are short-term forward capacity purchases[.]"[28] This claim is both factually incorrect and misunderstands the Commission's requirements for modeling transmission resources in an IRP.

The Commission's IRP guidelines describe the requirements for transmission resources and specifically state that "utilities should consider . . . electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability."[29] Consistent with this requirement, Idaho Power has appropriately accounted for the costs of the underlying market transactions when determining the forecasted overall costs and benefits associated with the B2H line.[30]

2. The 2017 IRP Demonstrates that B2H Meets an Identified Resource Need.

Staff expressed a concern that the Company was "using overly conservative assumptions in its energy deficit analysis" and indicated that the Company had not clearly

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[28] STOP B2H Coalition Comments on LC 68 Idaho Power[']s 2017 IRP at 4 (hereinafter "STOP B2H Comments").
[29] Order No. 07-002 at 13.
[30] To be clear, the capacity costs of B2H do not include the cost of the underlying market transactions that will be facilitated by the line, just as the capacity cost for a natural-gas-fired plant does not include the underlying costs of the gas that will be burned to generate electricity. The market transaction costs are included as an energy cost in the overall portfolio modeling.

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presented how it determined its need or explained its assumptions.[31] The Company appreciates Staff's concern and provides the following description of its calculations demonstrating the reasonableness of the Company's calculated needs, along with an explanation of how B2H specifically meets the need identified in the 2017 IRP.

a. Overview of Resource Need.

Idaho Power has an obligation to serve customers' loads regardless of the water conditions that may occur. Historically, prior to the 2002 IRP, the Company's plan was to acquire or construct resources that would eliminate expected energy deficiencies in every month of the forecast period whenever median or better water conditions existed, recognizing that when water levels were below median, Idaho Power historically relied on market purchases to meet any deficits.

However, with market price movements at historical highs during the summer of 2001, Idaho Power reevaluated the planning criteria. Greater planning reserve margins or the use of more conservative water planning criteria were suggested by the public, commissions, and legislature.

Due to the public input to the planning process, Idaho Power proposed and adopted a resource planning criteria that was based upon a lower-than-median level of water. With the 2002 IRP, Idaho Power began using the 70th percentile and 90th percentile water conditions planning criteria in determining average energy and peak-hour deficits, respectively. The Company has continued to use this planning criteria in each of its IRPs since 2002, each of which have been accepted and acknowledged by both the Idaho and Oregon Commissions.

To identify the need for and timing of future resources, Idaho Power prepares a load and resource balance that accounts for generation from all of the Company's existing

[31] Staff's Opening Comments at 6.

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demand- and supply-side resources, planned energy purchases, projected wholesale market purchases across existing transmission interconnections,[32] and possible retirement of existing coal resources. The IRP analysis begins by developing a monthly load forecast that incorporates the future electricity needs of customers. The load forecast consists of both average monthly energy and monthly peak-hour capacity conditions. The existing Idaho Power resources (generating, demand-side management, energy efficiency, and transmission) are evaluated against the load forecast. The load less the resources determines the load and resource balance. Months where the load exceeds the resources defines the need for resources to reliably serve Idaho Power's customers.

b. Determining the Peak Capacity Assumptions and Need.

As Staff points out, the IRP uses the 90th percentile water and 95th percentile load in its peak hour capacity deficit analysis.[33] Using the 90th percentile water conditions means that, when Idaho Power determines the hydro generation available to serve peak load, the Company conservatively assumes that the water inflows to the Brownlee Reservoir will be exceeded 90 percent of the time (*i.e.*, the inflows are assumed to be in the bottom 10 percent of likely conditions). These assumed low inflow conditions reduce the generation available from hydro generation to meet peak load.

Using the 95th percentile load means that the assumed peak load is in the top 5 percent of expected monthly peak-hour load events. The top 5 percent of loads are usually associated with an extreme weather event. Together, the Company uses a conservative forecast that assumes low hydro generation and high peak loads to help ensure that Idaho Power will reliably meet peak load under adverse weather conditions.

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[32] Using firm import capability over the Idaho-Northwest and Montana-Idaho paths, and capacity imports over the Idaho-Nevada path. Idaho Power provides discussion of the assumed capacity imports over the Idaho-Nevada path on pages 68-69 of the 2017 IRP.
[33] Staff's Opening Comments at 6.

In addition to hydro output, when determining peak capacity needs, the existing capacity of coal and gas resources are added at their full output rating, which is an appropriate assumption because these types of resources can be reliably dispatched during peak hour conditions. Solar resources are included at 51 percent of nameplate capacity and wind resources are added at 5 percent of nameplate capacity, reflecting the intermittent qualities of these resources and the level of peak-hour production likely to occur with 90 percent confidence (i.e. solar and wind resources are held to the same reliability standard as hydro). Other cogeneration and small power production ("CSPP") and power purchase agreements ("PPA") contracts, such as geothermal and biomass resources, are forecast at the average energy forecast provided by the project. The transmission forecast reflects all available transmission capacity to external markets. All existing demand response and energy efficiency programs are also included. Based on this methodology under the preferred portfolio, the first capacity deficit with existing resources occurs in 2026, or as early as 2023 with planned coal unit retirements.[34]

The Company's methodology for determining its capacity deficits in the 2017 IRP is the same as in prior IRPs and reflects industry-standard assumptions designed to produce a reasonable assessment of the Company's future capacity needs using drier-than-median water conditions and higher-than-median load conditions. Indeed, Idaho Power has used the same methodology since the early 2000s, when it was adopted following planning criteria discussions held with state utility commissions and the public. Targeting a balanced position between load and resources, while using the conservative water and load conditions, is considered comparable to requiring a capacity margin in excess of load while using median load and water conditions. Both approaches are designed to produce a

[34] 2017 IRP at 96. Notably, July is the most resource constrained month for the Idaho Power system. Consequently, the tables in the IRP provide average-energy and peak-hour deficits only for July; deficits for other months are lesser in magnitude. Idaho Power emphasizes that the deficits in the IRP's load and resource balance indicate that the current system, or the current system as modified by retired coal capacity, will be deficient and in need of new resources.

system that has sufficient generating reserve capacity to meet daily operating reserve requirements.

Staff also asked for clarification on how the peak-hour deficit case corresponds with a one-in-ten loss of load probability ("LOLP").[35] Staff claims that utilities "traditionally" plan for a "one-in-ten" loss of load expectation ("LOLE"),[36] "meaning that they view themselves as resource adequate if they expect to have to shed load for cumulatively less than one day over the course of ten years."[37] Based on this understanding, Staff suggests that Idaho Power may have no need for an additional resource like B2H. The LOLP presented in the 2017 IRP, however, is not related to the determination of need or the resource adequacy of the portfolios analyzed. Rather, the LOLP is a reliability metric that Idaho Power agreed to calculate as part of the settlement of docket UM 1719 to determine the capacity contribution of solar resources in IRPs.[38]

Importantly, the settlement of docket UM 1719 allowed Idaho Power to continue to use its existing methodology for estimating the capacity contribution of wind and solar generators, which used the 150 high-load hours, subject to the requirement that the Company verify the reasonableness of its methodology by also performing an evaluation based on 8,760 hours in the 2017 IRP.[39] As required by the settlement, the Company conducted this analysis in the IRP. The LOLP analysis requires that Idaho Power model its system with a failure-to-serve-load rate roughly equivalent to the one day in ten years metric and then evaluate the hours during the year when outages occurred to determine an hourly LOLP. The failure of the system to serve load are called loss of load events. The

[35] Staff's Opening Comments at 6.
[36] The LOLP and the LOLE are means of measuring system reliability. The LOLP is the probability of a loss of load event in which the system load is greater than available hourly generating capacity. The LOLE is the sum of LOLPs during a planning period, usually one year, for example, 0.1 days per year.
[37] Staff's Opening Comments at 6.
[38] In the Matter of Public Utility Commission of Oregon, Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity, Docket No. UM 1719, Order No. 16-236 (Aug. 26, 2016). The Commission specifically described LOLP as a measure of system reliability.
[39] Order No. 16-236, Appendix A at 13.

expectation was that the loss of load hours would fall within or close to the 150 high-load hours Idaho Power used in its existing methodology, which are primarily in the summer months. The results of the outage simulations showed a wider range of loss of load hours than anticipated, with many occurring in non-summer months. The capacity value of solar is impacted by the time of year the outages occur because solar produces differing amounts of energy during different times of the year as the solar angle changes with the seasons.

Thus, based upon the results of the LOLP analysis in the 2017 IRP, the Company has included in the 2017 action plan an action to re-evaluate the capacity value of solar using an LOLP or approximation method for the 2019 IRP. But, to be clear, the LOLP and LOLE metrics were not used by Idaho Power to determine resource adequacy, contrary to Staff's implication.

c. Determining the Average Energy Assumptions and Need.

To evaluate average energy needs, Idaho Power uses the 70th percentile load forecast and the 70th percentile hydro forecast. Based on these percentages, the future average monthly loads can be expected to exceed the planning case forecast 30 percent of the time and actual hydro conditions can be expected to be worse than the expected case flows 30 percent of the time.

In addition to load and hydro forecasts, the average energy need analysis includes existing capacity of coal and gas resources. All CSPP and PPA contracts including solar and wind are forecast using a monthly average energy forecast derived from either historical generation performance by the individual project or an estimated generation forecast provided by the project. The transmission forecast reflects all available transmission capacity from the Northwest. Demand response programs are not included in the energy forecast.

Load less all resource forecasts results in either a surplus or deficit position for each month. Surplus or deficit positions in the average forecast help the Company understand

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its market risk. Market risk can be mitigated by either selling excess power (in a surplus position) or purchasing power from the market (in a deficit position). The first energy deficit based on the preferred portfolio occurs in 2029 and as early as 2024 under earlier coal unit retirement scenarios.[40]

Like the methodology used to calculate capacity deficits, the energy deficiency calculations used here are consistent with prior IRPs and reflect reasonable assumptions.

d. B2H Will Meet the Capacity Deficit Present in 2026.

When early coal unit retirement scenarios are considered, the Company has capacity deficits ranging from 213 MW beginning in 2023 to 34 MW in 2026 (preferred portfolio capacity deficit is 2026). These deficits continue to grow throughout the 20-year planning period reaching 967 MW and 635 MW for the retirement and non-retirement scenarios, respectively, by 2036. B2H provides 500 MW of capacity starting in 2026 to reduce the deficiencies through 2031, at which time another resource is needed.

e. Idaho Power's Existing Transmission Capacity Does Not Allow for Sufficient Imports from the Northwest.

STOP B2H claims that Idaho Power already has more long-term firm import capacity from the Northwest than it did in the 2015 IRP because of the capacity reallocation between Idaho Power and PacifiCorp.[41] STOP B2H accuses Idaho Power of failing to disclose the asset exchange to the Commission and claims that, because of the exchange, Idaho Power now has sufficient firm transmission to the Northwest and does not need B2H. STOP B2H is wrong on all counts.

First, in the asset exchange, Idaho Power acquired assets associated with the Idaho-to-Northwest path from PacifiCorp. By acquiring these assets, Idaho Power has been able to reduce wheeling costs associated with importing energy across the Idaho-to-Northwest path. Idaho Power also addressed any uncertainty around future usage by now owning—

[40] 2017 IRP at 96.
[41] STOP B2H Comments at 5.

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rather than merely using—the assets. However, contrary to STOP B2H's claims, the asset exchange did not provide Idaho Power with any new capacity. Idaho Power was utilizing this capacity prior to the asset exchange, and continues to utilize this capacity post-asset exchange. Thus, the asset exchange increased system utilization/efficiency through reduced wheeling costs—not increased capacity.

Second, there is no additional transmission capacity available for imports to Idaho Power from the Northwest. Idaho Power is a summer peaking utility, while the remainder of the Northwest is winter peaking. Therefore, the Northwest has a surplus of electrical power capacity and energy during Idaho Power's peak demand period. Idaho Power currently utilizes the Northwest power markets to meet peak demand needs in late June and early July and to make economic market resource purchases throughout the year. However, the transmission system between the Northwest and Idaho is capacity constrained. Idaho Power is unable to deliver incremental market purchases to customers in the Idaho Power service territory. The B2H project will increase transmission capacity between the Northwest and Idaho that will allow Idaho Power to deliver additional lower-cost energy to Idaho Power customers from resources in the Northwest.[42]

Third, Idaho Power fully disclosed to the Commission the effects of the asset exchange with PacifiCorp. In fact, the Company obtained Commission approval for the asset exchange[43] and the transmission rights resulting from the asset exchange are properly modeled in the IRP.

[42] Page 58 of the 2017 IRP provides more information about the existing transmission capacity constraints, and the issue is also addressed in greater detail in the B2H addendum.
[43] *In the Matter of PacifiCorp, dba Pacific Power and Idaho Power Company, Request for Approval to Exchange Certain Transmission Assets Associated with the Jim Bridger Generation Plant*, Docket No. UP 315, Order No. 15-184 (June 9, 2015).

3. B2H Satisfies an Identified Regional Transmission Need.

In response to Staff's request for more discussion of B2H's role in regional transmission planning,[44] the Company notes that, in addition to meeting an identified Idaho Power resource need, B2H has long been identified as a critical transmission project to bolster the reliability and resiliency of the regional transmission grid. Regional transmission planning occurs primarily through two processes.

First, through the WECC Path Rating Process, Idaho Power coordinated with other utilities in the Western Interconnection to determine the maximum rating (power flow limit) across the proposed transmission line under various stresses on the bulk power system, such as high winter or high summer peak load, light load, high wind generation, and high hydro generation. Based on industry standards to test reliability and resilience, Idaho Power simulated various outages, including the outage of B2H, while modeling these various stresses to ensure the power grid was capable of reliably operating with increased power flow. Through this process, Idaho Power also ensured that the B2H project did not negatively impact the ratings of other transmission projects in the Western Interconnection. Idaho Power completed the WECC Path Rating Process in November 2012, and achieved a WECC Accepted Rating of 1,050 MW in the west-to-east direction and 1,000 MW in the east-to-west direction. As a result of this process, the Company confirmed that the B2H project, when constructed, will add significant reliability, resilience, and flexibility to the Northwest power grid.

Second, B2H was selected as a necessary project in the regional transmission planning processes administered by the Northern Tier Transmission Group ("NTTG"), a FERC required regional planning organization, and ColumbiaGrid—two key regional planning organizations.

[44] *See* Staff's Opening Comments at 6.

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The NTTG is a group of transmission providers and customers that are actively involved in the sale and purchase of transmission capacity of the power grid that delivers electricity to customers in the Northwest and Mountain States. NTTG coordinates individual transmission systems operations, products, business practices, and planning of the high-voltage transmission network to meet and improve transmission services that deliver power to consumers. Several state regulatory commissions, including Oregon, are also represented on various NTTG committees. Following extensive analysis, B2H has been, and remains, an integral part of NTTG's 10-year plan. Indeed, B2H is one of the key projects comprising the NTTG 2014-2015 Biennial Plan, and the soon-to-be published NTTG 2016-2017 Biennial Plan.[45] According to the NTTG Revised Draft Final Report, which will be finalized and published at the end of 2017, the NTTG Technical Workgroup (a subcommittee reporting to the NTTG Planning Committee) "found the NTTG area would be reliably served in the year 2026 only by including the following Non-Committed regional projects: . . . Boardman to Hemingway," among a list of other projects.[46]

Similarly, ColumbiaGrid's mission is to improve the reliability and efficient use of the Northwest's transmission grid. ColumbiaGrid performs grid expansion planning, and develops and implements solutions related to the expansion, operation, reliability, and use of the interconnected Northwest transmission system. In carrying out its mission, ColumbiaGrid endeavors to provide sustainable benefits for its members and the region, while considering environmental concerns, regional interests, and cost-effectiveness. Both the NTTG and ColumbiaGrid consolidate each of its members' local transmission plans and establish a regional plan that can meet the needs of the members in a more efficient or cost-effective manner. B2H is a committed project in the most recent ColumbiaGrid 10-year

[45] The relevant NTTG plans are attached to Appendix D: B2H Supplement.
[46] NTTG 2016-2017 Revised Draft Final Regional Transmission Plan (Draft 09.01.17) at 24 (attached to Appendix D: B2H Supplement) (emphasis added).

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plan.[47] B2H is required for both its west-to-east and east-to-west capacity to meet the regional needs identified by NTTG and ColumbiaGrid in a cost-effective manner for regional utility customers.

In addition, the regional importance of B2H was recognized by President Obama when he selected it as one of seven nationally significant transmission projects that, when built, will help increase electric reliability, integrate new renewable energy into the grid, create jobs, and return savings to consumers.[48] The administration explained that "[b]uilding a smarter electric grid will create thousands of American jobs and accelerate the growth of domestic clean energy industries translating into more energy choices and cost savings for American consumers, and a more secure energy future for our country."[49] Notably, despite the numerous policy differences between the current and former administrations, the importance of B2H has been emphasized by both. When BLM released is record of decision ("ROD") in November 2017, the acting Assistant Secretary for Land and Minerals Management emphasized that the B2H line "will help stabilize the power grid in the Northwest, while creating jobs and carrying low-cost energy to the families and businesses who need it."[50] Additionally, Secretary Ryan Zinke said "The Boardman to Hemingway Project is a Trump Administration priority focusing on infrastructure needs that support America's energy independence."[51]

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[47] The most recent 10-year plan can be found at: https://www.columbiagrid.org/books/pdf/2017%20SA%20Report_Final.pdf

[48] U.S. Dep't of the Interior, *Obama Administration Announces Job-Creating Grid Modernization Pilot Projects: Seven Transmission Projects Across 12 States Will Increase Grid Reliability and Integrate Renewable Energies*, News Release (Oct. 5, 2011), available at: http://boardmantohemingway.com/documents/RRTT_Press_Release_10-5-2011.pdf ("Obama Administration News Release").

[49] Obama Administration News Release at 1.

[50] Dep't of Interior, *DOI Announces Approval of Transmission Line Project in Oregon and Idaho*, Press Release (Nov. 17, 2017), available at: https://www.doi.gov/pressreleases/doi-announces-approval-transmission-line-project-oregon-and-idaho

[51] https://www.doi.gov/pressreleases/doi-announces-approval-transmission-line-project-oregon-and-idaho

In sum, B2H has substantial and widely-recognized benefits for the regional grid transmission, supporting its inclusion as part of Idaho Power's preferred portfolio.

4. Idaho Power Requires Acknowledgment of B2H in the 2017 IRP.

Both STOP B2H and Mr. Carbiener suggest that Idaho Power delay construction of the B2H line.[52] This proposal is not feasible. Because of the long lead time associated with permitting and constructing the B2H line, delay will mean that the line will not be in-service to meet the Company's capacity needs in 2026. Specifically, Idaho Power intends to rely on an acknowledged IRP to satisfy the need requirement at EFSC; therefore, the Company seeks to have an acknowledged IRP prior to issuance of the draft proposed order that is expected in early 2018.[53] Idaho Power cannot wait to receive acknowledgment of B2H until its 2017 IRP Update or until its 2019 IRP. The critical path for project development requires acknowledgment in the 2017 IRP in order to meet the capacity and energy deficits identified in the 2017 IRP.

C. Costs

1. The Costs of B2H Compare Favorably to Competing Resources.

The B2H line has consistently been the most cost-effective resource modeled in Idaho Power's IRP. When evaluating and comparing alternative resources, there are two major cost components: (1) the fixed, or capacity cost of the project; and (2) the variable, or energy cost of the project. The capacity costs for a resource reflect the estimated cost to construct the resource. The energy costs are calculated using a detailed model (the AURORA model) that considers forecasted natural gas prices, coal prices, hydro conditions, loads, and numerous other factors intended to provide a comprehensive forecast of the resource's

[52] *See* Gail Carbiener's Comments at 5 (suggesting delay until the 2019 IRP); STOP B2H Comments at 32 (supporting BPA's partnership in B2H because they have only agreed to fund permitting).
[53] *See* Gail Carbiener's Comments at 5 (suggesting delay until the 2019 IRP).

operation and dispatch over a long-term planning horizon, taking into consideration how the proposed resource will interact with Idaho Power's existing resource portfolio.

Different resources will have different capacity and energy costs, reflecting the fact that some resources are expensive to build, but generate low-cost electricity (*e.g.*, a solar plant), while other resources are low-cost to construct, but have high operating costs (*e.g.*, a diesel generator). Therefore, an assessment of total resource costs requires consideration of both capacity and energy costs.

The table below provides the capacity costs for several different types of resources considered in the 2017 IRP.[54] Please note that solar costs have been updated from those reported in the IRP with capital costs from the November 2017 Lazard energy cost report[55]. The capital costs for B2H in the table below reflect the inclusion of interconnection costs, and consequently also differ from the per kW cost reported in the 2017 IRP - Appendix C:Technical Report. Please note that the local interconnection costs for B2H were included in portfolio cost modeling performed for the IRP.

[54] The original table is found on page 73 of the 2017 IRP Appendix C Technical Report.
[55] https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf

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Table 1: Total Capital $/kW for select resource considered in the 2017 IRP

Resource Type	Total Capital $/kW	Total Capital $/kW-peak	Depreciable Life
Boardman to Hemingway	$783*	$548**	55 years
CCCT (1x1) F Class (300 MW)	$1,344	$1,344	30 years
SCCT – Frame F Class (170 MW)	$995	$995	30 years
Reciprocating Gas Engine	$887	$887	30 years
Solar PV – Utility Scale 1-Axis	$1,382	$2,692	25 years

* Utilizes the B2H 350 MW average capacity
** Utilizes the B2H 500 MW average capacity

As indicated in the table, the total capital costs (peak) for B2H are 62 percent of the cost of the next lowest-cost resource. Additionally, as a transmission line, B2H will depreciate over 55 years, as compared to 30 years for a gas plant—meaning that B2H will continue to provide customer benefits long after the competing resources will have been retired. Importantly, the B2H cost estimate above includes a 20 percent contingency that is not included for any of the other resources. Thus, the construction costs of B2H could increase significantly and it would still have lower capital costs than the competing resources by a substantial margin.

The energy costs associated with B2H reflect the increased market transactions enabled by a larger connection to Northwest markets. The price of market purchases in the summer months is generally a function of the price of natural gas. With B2H, Idaho Power would therefore pay a slight premium for market power, as compared to owning a natural gas plant. This slight premium is reflected by the fact that in each resource portfolio that includes B2H, the portfolio has a higher energy cost than the non-B2H portfolio.

Although B2H has a slightly higher energy cost compared to alternatives, its dramatically lower capacity costs far outweigh the increased energy costs. Thus, portfolios containing B2H are consistently lower-cost than portfolios that do not.

Staff suggests that energy efficiency or a combined-cycle combustion turbine plant ("CCCT") could be comparable to if not less expensive than B2H.[56] Idaho Power agrees

[56] Staff's Opening Comments at 8.

with Staff that both energy efficiency and a CCCT are compelling alternatives to B2H. However, the 2017 IRP already includes all cost-effective energy efficiency in all the portfolios and therefore incremental energy efficiency is not available to displace B2H. And although a CCCT is a reasonable alternative, the Company's portfolio analysis indicated that it did not perform as well as B2H in the portfolio modeling.

Moreover, B2H has been a cost-effective resource included in the Company's preferred portfolio since the 2009 IRP. The fact that it has consistently out-performed competing resources, despite changing market conditions and resource costs over the last eight years, reflects favorably on its durability and ability to withstand dramatic changes in market conditions. B2H project brings additional benefits beyond cost-effectiveness. The B2H project will increase the efficiency, reliability and resilience of the electric system by creating an additional pathway for energy to move between major load centers in the West. The B2H project also provides the flexibility to integrate any resource type and move existing resources during times of congestion, benefiting customers throughout the region. According to the U.S. Energy Information Administration (EIA), different resource types have different values to the system[57]. Idaho Power believes that B2H provides value to the system beyond any individual resource because it enhances the flexibility of the existing system and facilitates the delivery of cost-effective resources not only to Idaho Power customers, but customers throughout the Pacific Northwest and Mountain West regions.

STOP B2H requests that the Company provide an estimate of the customer bill impact associated with the B2H line.[58] The estimated system revenue requirement impact for B2H will be approximately $38 to $45 million.[59] The Oregon-jurisdictional share of the revenue

[57] US Energy Information Administration, "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014", April 2014.
[58] STOP B2H Comments at 14.
[59] The Company's website contains a report called the "Estimated Revenue Requirement Impact Disclosure," which is intended to provide Idaho Power customers with a resource for identifying and understanding potential large capital projects and investments. The current report includes

impact would therefore be approximately 5 percent, or $1.9 to $2.25 million. More importantly, however, because the B2H portfolio is the least-cost portfolio in the 2017 IRP, the estimated customer rate impact associated with not building B2H will necessarily be higher.

2. The Contingency Costs included for B2H Reasonably Account for the Risk of Cost-Overruns.

Staff expresses a concern about the possibility of cost-overruns for a project of this magnitude.[60] STOP B2H states definitively that cost-overruns "for transmission lines are between 30-50%" and questions whether the Company has accounted for the possibility of a cost-overrun.[61] As set forth above, the costs of B2H used in the portfolio modeling include a 20 percent contingency intended to capture the risk associated with possible cost-overruns. And even with the 20 percent contingency, the costs of B2H are substantially below the next best alternative. Moreover, STOP B2H's definitive claim that cost-overruns "are between 30-50%" is based on a limited set of examples of projects constructed by other utilities in other parts of the country. The detailed cost estimate for the transmission line construction was prepared by HDR, the Owners' Engineer for the B2H Project. HDR relied on experience and industry knowledge to prepare estimates. Idaho Power calibrated HDR estimates against recent transmission line projects in the West, including recent projects for both Bonneville Power Administration and PacifiCorp. There is no evidence that the cost-overruns that occurred for those few other projects will definitively occur here.

STOP B2H also claims that the contingency costs must account for the costs associated with burying certain segments of the proposed line and the potential litigation associated with permitting the construction of the line. The Company's cost estimates for

information for projects identified for the first ten-year period in the preferred portfolio of the 2015 IRP, Order No. 16-160; however, for B2H, the estimated revenue requirement is still consistent with Idaho Power's 2017 IRP estimates. The report is available at the following link: https://www.idahopower.com/about-us/company-information/rates-and-regulatory/reports/

[60] Staff's Opening Comments at 13.

[61] STOP B2H Comments at 8.

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B2H include permitting costs, which account for litigation costs, and 20 percent contingency is for any unexpected cost increase.

3. The Costs of B2H are Properly Modeled over the 20-Year IRP Planning Horizon.

STOP B2H argues that Idaho Power has understated the true costs of B2H by limiting its analysis to only the 20-year planning horizon used for the IRP. Specifically, STOP B2H claims that Idaho Power should model the inflation rate and financing costs for the entire life of the resource.[62] Modeling B2H as a 55-year resource, as STOP B2H recommends, would create a mismatch with the 20-year planning horizon used in the IRP, making it inapt to compare B2H to competing alternative resources with shorter lives. The Company's modeling is consistent with the Commission's IRP guidelines and is consistent with generally accepted financial accounting practices for comparing projects with unequal lives.

Moreover, as noted above, B2H has a lower installed capacity cost than competing resources and will have a longer useful life. Thus, the extended life does not disadvantage customers even though the depreciable life will be longer than a generation resource. Indeed, all portfolio modeling could be extended to 55 years, requiring a "replacement chain" analysis to be performed. However, the result would simply demonstrate even higher net present value benefits associated with B2H by virtue of its longer useful life.

Finally, contrary to STOP B2H's implication, the Company's estimated cost of capital is included in the cost estimate for B2H, just as those costs are included in the construction costs of the other competing resources on a consistent and comparable basis.

4. Idaho Power Appropriately Modeled the Energy Costs Associated with Market Purchases Facilitated by B2H.

STOP B2H claims that the IRP "ignores the cost of wheeling PNW power to the Idaho Power system" because B2H "will not access any power plants directly."[63] This is incorrect.

[62] STOP B2H Comments at 13.
[63] STOP B2H Comments at 10.

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The AURORA model used to develop energy costs includes wheeling expenses and line losses when determining the economics of importing energy within the hourly dispatch optimization.

D. Market Purchases

1. The Northwest Market Depth is Sufficient to Support the Modeled Imports Enabled by B2H.

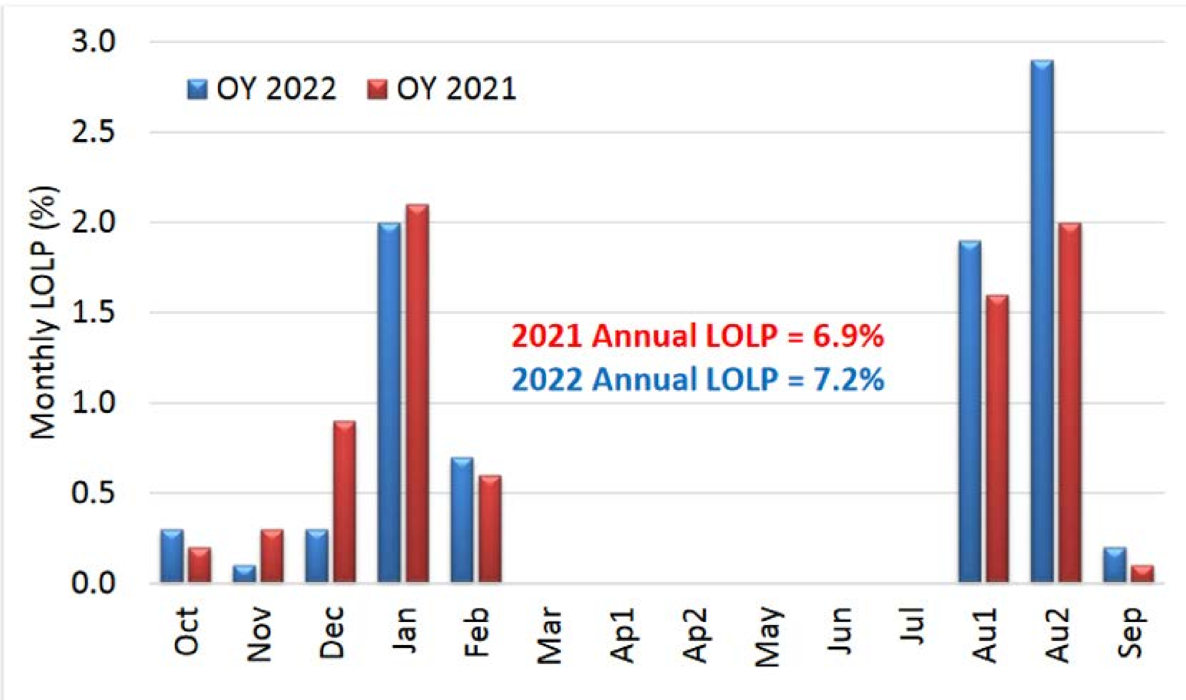
Staff requested clarification on the level of market purchases the Company believes it can rely on for resource adequacy.[64] The Company has conducted extensive analysis of expected market conditions and is confident that there is sufficient market depth to allow the Company to utilize the market transactions that B2H will allow. The market purchases included in the cost analysis are determined during the AURORA modeling. The AURORA model determines the lowest cost alternative of either self-generating or importing via a market purchase with losses and transmission wheeling costs to serve load, and considers both generation and market constraints in its modeling.

The Northwest Power and Conservation Council recently studied the Northwest power system to determine resource adequacy utilizing a five-year forecast. In July 2017, the NWPCC published their 2022 Assessment. The NWPCC, through their analysis, attempt to quantify resource adequacy through a loss of load probability (LOLP) analysis. In the figure below, a higher LOLP indicates worse performance (more customer risk), and a lower number indicates better performance. Idaho Power's peak load occurs in a narrow window in the late-June / early-July time frame. The figure illustrates that the Northwest will continue to have sufficient resources available for Idaho Power to purchase and deliver to Idaho Power customers across the B2H line.

[64] Staff's Opening Comments at 7.

The NWPCC figure suggests that the Northwest region, as a whole, must add resources to address deficiencies in the winter and late summer. Resource additions to address these needs will further increase late-June / early-July resource availability.

Figure 1: Monthly LOLP



Adding to the NWPCC analysis, the recent IRPs of various regional utilities indicate new resources will be built in response to coal retirements, load growth, and renewable portfolio standards ("RPS"), thereby providing the market volumes necessary to support the imports assumed in the B2H portfolios. The below table summarizes the recently filed IRP's resource additions, retirements, and market purchase plans to reliably meet their load.

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Table 2: Integrated Resource Plan Summary for Various Western Utilities

Integrated Resource Plan Summary for Varoius Westerm Utilites

Resource Additions, Retiments and Market Purchases

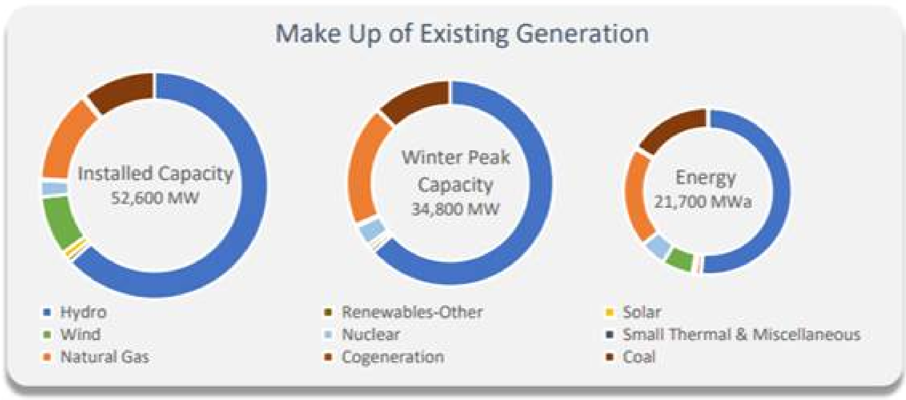
As of October 2017

Row Labels	Sum of Idaho Power	Sum of Avista (1)	Sum of PacifiCorp (2)	Sum of Portland General (3)	Sum of Puget Sound (4)	Sum of Seattle City Light	Sum of BC Hydro (5)	Total
1X1 CC								-
Battery								-
CCCT	300	192	436		1,154			2,082
CCCT (Remaining 25% of Silverhawk)								-
Dispatchable Standby Gen				60	126			186
Efficient Capacity (CCCT)				389	805			1,194
Generic (Frame Gas CT)		143		1,294	1,495			2,932
Geothermal			30					30
Hydro							1,100	1,100
Landfill						8		8
Natural Gas			877					877
Nuclear (Diablo Canyon)								-
Peaker								-
Reciprocating engines	180							180
Reduction in Coal / Gas	(226)		(1,636)					(1,862)
Reduction in Coal / Gas (Ft Churchill 2, Tracy 3) Jan 2029								-
Reduction in Coal / Gas (Boardman and Mkt Purc	(55)		(387)	(497)	(1,315)			(2,254)
Reduction in Coal / Gas (Reid Gardner Unit 4)			-					-
Reduction in Coal / Gas (Tracy 4 & 5)								-
Reduction in Coal JB 2	(168)		(359)					(527)
Reduction in Coal JB1	(168)		(359)					(527)
Reduction in Gas			(358)					(358)
Repowered Wind			905	515				1,420
SCCT								-
Solar		15	1,041					1,056
Storage		5						5
Thermal								-
Thermal Upgrades		136						136
Wind			1,959	1,545	1,086	392		4,982
Wood						44		44
Transmission Capacity	726		730					1,456
Grand Total	**589**	**491**	**2,879**	**3,306**	**3,351**	**444**	**1,100**	12,160
								-
Total Resource Additions	480	491	5,248	3,803	4,666	444	1,100	16,232
Total Resource Retirements	(617)	-	(3,099)	(497)	(1,315)	-	-	(5,528)
Total Transmission Capacity Additions	726	-	730	-	-	-	-	1,456
Total	589	491	2,879	3,306	3,351	444	1,100	12,160

1 Avista 2017 IRP published Aug. 31, 2017.
2 Pacificorp 2017 IRP published April 4, 2017
3 Portland General IRP published Nov, 2016.
4 Puget Sound IRP published Nov, 2015. 2017 IRP available in Nov 2017.
5 BC Hydro IRP published in 2015. Triennial filing available in 2018.

Further, Idaho Power's assessment of market liquidity demonstrates the reasonableness of its reliance on future market transactions facilitated by the B2H line. The Mid-Columbia market hub ("Mid C") is a hub where power is traded actively both financially (derivative) and physically in different blocks: long term, monthly, balance-of-month, day-ahead and hourly. The Mid-C market exhibits all six characteristics of a successful electric trading market[65]. Figure 2, below, shows the relative volume of energy in the Northwest.

Figure 2: Northwest Regional Forecast



PNUCC
2017 Northwest Regional Forecast 5

The Mid C market is very liquid. In 2017, on a day-ahead trading basis, daily average trading volume during heavy load hours during the months of June and July ranged from nearly 40,000 MWh to over 51,000 MWh. When combining heavy load hours with light load hours, on a day-ahead trading basis, the monthly volumes for June and July were each approximately 2,000,000 MWh. These volumes are in addition to month ahead trading volumes. Mid C is by far the highest volume market hub in the west which includes: COB, Four Corners, Mead, Mona, Palo Verde, SP15. In fact, frequently Mid C volumes are greater than the other hubs listed above combined, as shown for late November 2017 in the table below.

[65] Appendix D: B2H Supplement at 8.

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Table 3: West Day Ahead Indices

WEST Day Ahead Indices												
Hub	Wtd Avg Index	Change($)	Change(%)	High	Low	Vol(Mwh)	No. of Trades	No. of Companies	Weekly Avg	Monthly Avg	Begin Date	End Date
COB Off-Peak	22.00	-3.25	-12.87%	22.00	22.00	4,000	5	5	23.63	25.90	11/23/17	11/24/17
COB Peak	30.00	-4.50	-13.04%	30.00	30.00	1,200	3	2	32.25	36.51	11/24/17	11/24/17
Four Corners Off-Peak	20.33	-3.55	-14.86%	21.00	20.00	2,400	3	3	20.33	23.40	11/23/17	11/24/17
Four Corners Peak	24.00	-2.50	-9.43%	24.00	24.00	400	1	2	24.00	27.50	11/24/17	11/24/17
Mead Off-Peak	24.08	-1.42	-5.57%	25.25	23.00	2,400	3	6	24.79	26.15	11/23/17	11/24/17
Mead Peak	29.00	-2.81	-8.83%	29.00	29.00	1,200	3	4	30.41	32.53	11/24/17	11/24/17
Mid C Off-Peak	19.15	-5.77	-23.15%	20.25	17.50	32,000	39	17	22.04	23.65	11/23/17	11/24/17
Mid C Peak	24.14	-2.24	-8.49%	25.50	23.25	25,600	64	16	25.26	26.91	11/24/17	11/24/17
Mona Off-Peak	20.00	-3.00	-13.04%	20.00	20.00	2,400	3	3	21.50	22.69	11/23/17	11/24/17
Mona Peak	22.00	-4.00	-15.38%	22.00	22.00	400	1	2	24.00	26.24	11/24/17	11/24/17
Palo Verde Off-Peak	21.90	-2.06	-8.60%	23.25	20.00	9,600	12	11	22.93	24.81	11/23/17	11/24/17
Palo Verde Peak	26.38	-2.17	-7.60%	27.00	26.00	4,000	10	5	27.47	29.68	11/24/17	11/24/17
SP15 EZ Gen DA LMP Peak	38.00	-13.88	-26.75%	38.00	38.00	400	1	2	44.94	45.27	11/24/17	11/24/17

In 2017, Idaho Power averaged approximately 55,000 MWh of Mid C purchases in June and July. As stated previously, the average monthly volumes at Mid C, on a day-ahead basis, were approximately 2,000,000 MWh. Based on these averages, Idaho Power's purchases represented less than 3 percent of the total market volumes in June and July. Based on the total transactions, Idaho Power represents a very small fraction of the Mid C volume during the months when Idaho Power relies on Mid C the most, further demonstrating that Mid C is a highly liquid market with sufficient depth to meet future resource needs.

In addition, Idaho Power's market price risk analysis demonstrates that even if supply decreases and prices increase, B2H remains least-cost of a broad range of future market prices. In fact, B2H portfolios remain the least-cost portfolios for all natural gas price/market price sensitivities except the sensitivity that assumes a 400 percent natural gas increase over the planning case. Based on this sensitivity analysis, the Company is confident that B2H remains least-cost over the reasonable range of future market price scenarios.

STOP B2H argues that the Company's assumption that by 2026 almost 18 percent of forecasted peak load will be met by imports "lacks credibility."[66] Idaho Power's review of regional resource adequacy assessments conducted by the Northwest Power and

[66] STOP B2H Comments at 7.

Conservation Council and BPA indicates that B2H will provide access to a wholesale electric market with capacity for meeting summer load needs. In addition, B2H provides expanded access to the Northwest wholesale market and its attendant diverse mix of low-cost energy resources and abundant zero-carbon energy.

2. The IRP's Forecasted Market Prices Account for Coal Plant Retirements.

STOP B2H further claims that the IRP has insufficient analysis of the effect of retired coal capacity on spot market power prices.[67] In fact, the planned retirement of coal plant capacity is reflected in the spot market prices in the AURORA portfolio analysis. Prior to conducting its portfolio analysis, the Company performed a long-term capacity buildout using AURORA, to determine which regional coal plants would likely be retired during the IRP planning period. This buildout was included in the Company's portfolio analysis.

Table 4, below, represents the coal units retired in the AURORA long-term capacity run. The Boardman, Valmy and Jim Bridger units were not selected by AURORA to retire in the long-term run. Table 4 shows the over 8,600 MW of capacity that was retired in the AURORA long-term capacity buildout during the Company's 20-year planning period.

[67] STOP B2H Comments at 8.

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Table 4: AURORA Capacity Build-Out Coal Retirements

Name	Utility	Heat Rate	Nameplate Capacity (	Fuel	Resource Begin Date	Resource End Date
Apache Station ST3	Arizona Electric Power Coopera	10293	204	CoalUS	7/1/2001	12/31/2018
Neil Simpson II (Gillette) (Unit 2)	Black Hills Power & Light Comp	12400	80	CoalUS	9/1/1995	12/31/2017
Colstrip 3	PPL Montana LLC	9952	778	CoalUS	1/1/1984	12/31/2025
Colstrip 4	PPL Montana LLC	10167	778	CoalUS	4/1/1986	12/31/2026
Corette 1	Montana Power Co The - M	11011	172.8	CoalUS	6/1/1968	12/31/2022
Reid Gardner 4	Nevada Power Co - NV	9674	294.8	CoalUS	7/1/1983	12/31/2017
Centralia 1	TransAlta Centralia Gen LLC	10774	729.9	CoalUS	12/1/1972	12/31/2028
Naughton 1	PacifiCorp	9730	163.2	CoalUS	5/1/1963	12/31/2017
Naughton 2	PacifiCorp	9895	217.6	CoalUS	10/1/1968	12/31/2017
Naughton 3	PacifiCorp	9762	326.4	CoalUS	10/1/1971	12/31/2017
Cherokee 3	Public Service Co of Colo	10481	170.5	CoalUS	1/1/1962	12/31/2017
Cherokee 4	Public Service Co of Colo	10113	380.8	CoalUS	1/1/1968	12/31/2020
Hayden 1	Public Service Co of Colo	11484	190	CoalUS	7/1/1965	12/31/2037
Hayden 2	Public Service Co of Colo	9845	275.4	CoalUS	9/1/1976	12/31/2037
Valmont 5	Public Service Co of Colo	10439	191.7	CoalUS	1/1/1964	12/31/2017
San Juan 3	Public Service Co of New	9433	555	CoalUS	12/1/1979	12/31/2017
Coronado 1	Salt River Project - AZ	9860	410.9	CoalUS	12/1/1979	12/31/2026
Coronado 2	Salt River Project - AZ	10413	410.9	CoalUS	10/1/1980	12/31/2023
Navajo 1	Salt River Project - AZ	9829	803.1	CoalUS	5/1/1974	12/31/2019
Craig 2	Tri-State Generation & Transmi	9974	446.4	CoalUS	11/1/1979	12/31/2020
Nucla 1	Tri-State Generation & Transmi	11489	11.5	CoalUS	11/1/1959	12/31/2018
Nucla 2	Tri-State Generation & Transmi	11670	11.5	CoalUS	11/1/1959	12/31/2018
Nucla 3	Tri-State Generation & Transmi	11670	11.5	CoalUS	11/1/1959	12/31/2018
Nucla 4	Tri-State Generation & Transmi	11670	79.3	CoalUS	1/1/1991	12/31/2017
Springerville 2	Tucson Electric Power Co	8905	424.8	CoalUS	6/1/1990	12/31/2034
WYGEN #1-Gillette	Black Hills	11140	88	CoalUS	6/1/2003	12/31/2017
Removed Two Elk	Postponed Indefinitely - North American Power Group	10000	300	CoalUS	1/1/2017	12/31/2017
Hardin Generator Project	Rocky Mountain Power Inc	10000	115.7	CoalUS	3/1/2006	12/31/2033
Lamar Plant #4A-4B	Lamar CO City of	12000		CoalUS	5/1/2008	12/31/2022
Lamar Plant #6	Lamar CO City of	12000	18.5	CoalUS	3/1/2008	12/31/2017
Total			8,640.2			

Even accounting for the impact of coal retirements, the Company's preferred portfolio, which includes B2H, remains the least-cost, least-risk scenario.

3. The IRP's Forecasted Market Prices Appropriately Reflect the Relationship Between Natural Gas and Electric Prices.

STOP B2H claims that the IRP "fails to account for the relationship between daily natural gas prices and the daily market price of power in the PNW" because, according to STOP B2H, the Company used only a single point estimate for monthly power prices.[68] On the contrary, Idaho Power used extensive natural gas price sensitivities, not single point estimates, to determine how the B2H portfolios withstood dramatically different forecasted market prices. In every scenario except the most extreme (*i.e.*, a 400 percent price increase), the B2H portfolios outperformed the next best alternatives.[69]

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[68] STOP B2H Comments at 8.

[69] To the extent that STOP B2H is focused on the fact the IRP used monthly, instead of daily, prices, that concern is unfounded. For purposes of a 20-year planning study, there is no need for the granularity provided by daily pricing.

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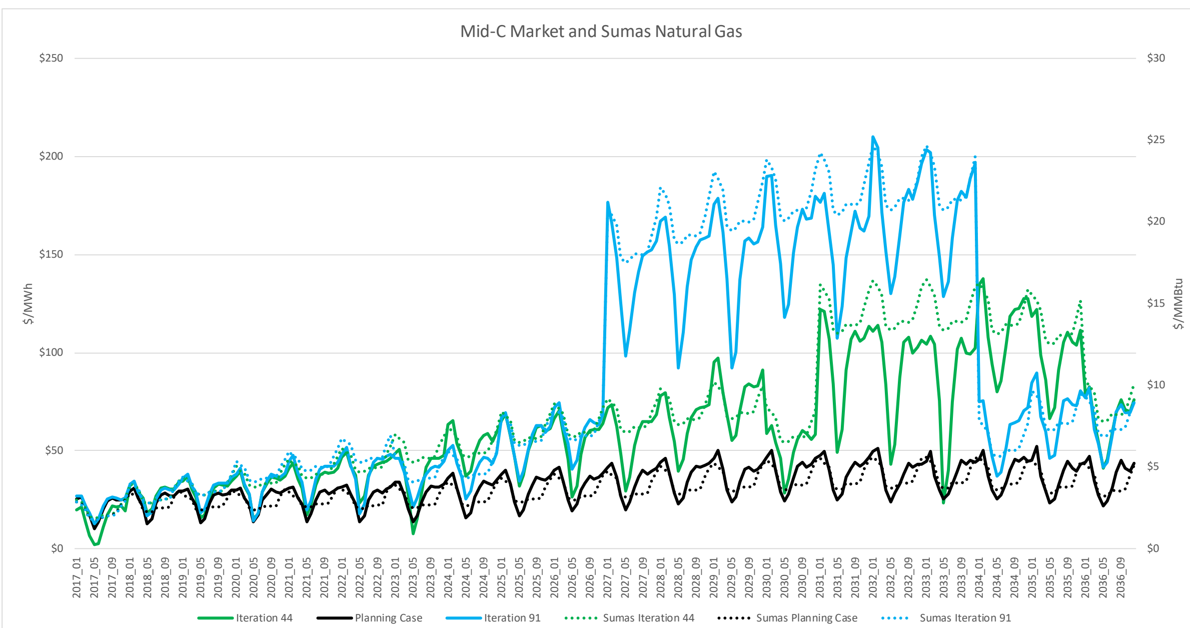
STOP B2H further argues that the IRP "penalize[s] non-B2H portfolios in the high gas price sensitivities based upon the higher cost of dispatching existing and new gas-fired resources, but does not similarly penalize B2H Portfolios that rely on relatively higher cost market purchases in this higher gas environment."[70] Again, this is untrue—the market prices used in the IRP correctly correlate natural gas and electric market prices. Figure 2, below, illustrates three stochastic iterations that show how natural gas prices and Mid-C market prices share the same shape. This graphic shows that gas fired resources and Mid-C market prices for import on B2H correctly correlate and thus are treated fairly.

Figure 2: Mid C and Sumas Natural Gas Prices



4. B2H is Necessary for the Company to Enter Into Bilateral Contracts.

Staff claims that Idaho Power has not "presented a clear indication that it has investigated medium-term bilateral contracts" as an alternative to the B2H line.[71] Bilateral market transactions, however, are not an alternative to B2H—they are the resulting energy resource *facilitated by* B2H. As discussed above, the Company has no incremental

[70] STOP B2H Comments at 10.
[71] Staff's Opening Comments at 8.

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transmission capacity from the Northwest. Therefore, without incremental transmission, the Company cannot move generation from additional bilateral transactions with Northwest generators to its service area. To engage in additional bilateral market transactions, the Company needs B2H. Thus, contrary to Staff's claim that bilateral transactions and B2H are competing resources, they are complementary and B2H is a prerequisite to the Company entering into additional bilateral contracts.

5. The IRP's Transmission Topology Accurately Reflects the Benefits of B2H.

Staff argues that the IRP does not provide enough detail on "whether or how connectivity between a low-priced node and two higher-priced nodes would be used to lower costs for Idaho Power ratepayers in Oregon."[72] AURORA makes the optimal economic decision on where to purchase market energy based on transmission constraints and resource dispatch costs. If transmission is available to one low-priced zone and two higher-priced zones, then AURORA will choose to purchase power from the lowest cost zone—taking into consideration wheeling costs and transmission line losses. Economically using regional resources to achieve the lowest cost power supply helps to lower the cost for Idaho Power customers in Oregon.

Staff also requests clarity on whether B2H would provide a conduit to the Mona substation in Utah.[73] The B2H line will not provide Idaho Power access to Mona. But that fact does not diminish the line's economic benefits because it was never designed or intended to provide access to the Mona substation.

E. Risks

1. Additional Explanation of Risks Identified by Staff.

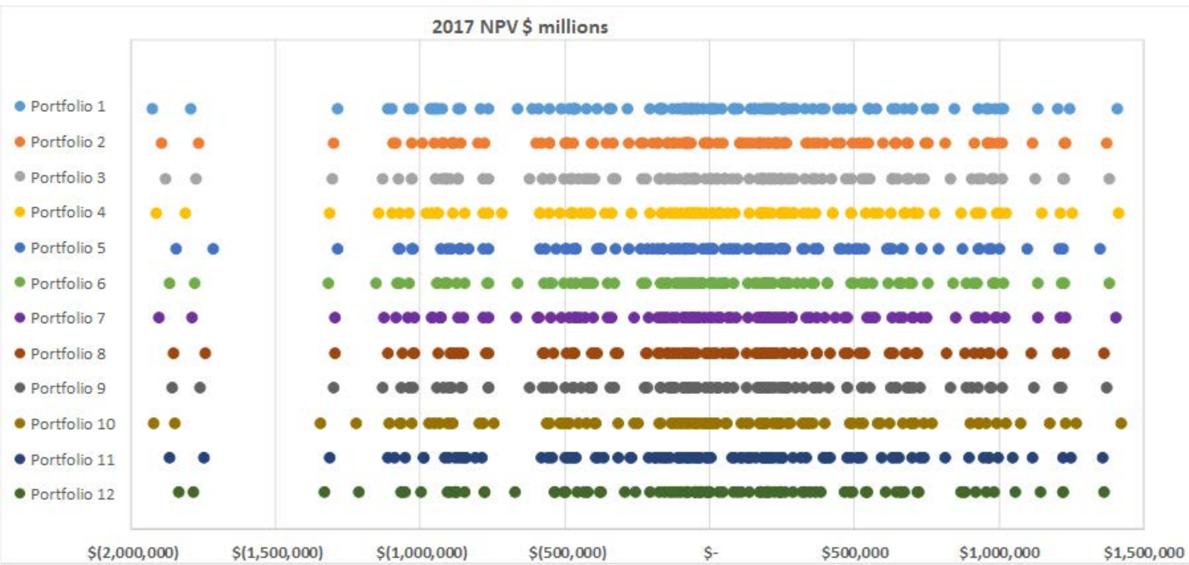
The Company's selection of a preferred portfolio including B2H reflects the fact that B2H is both least-cost and *least-risk*, when compared to available alternatives. Staff

[72] Staff's Opening Comments at 10.
[73] Staff's Opening Comments at 10.

indicated that it continues to evaluate the risks associated with B2H, but asks for additional explanation of certain aspects of the Company's analysis.

First, consistent with the IRP guidelines, the Company's risk evaluation studied both the variability of costs and the severity of bad outcomes.[74] Specifically, Idaho Power created a set of 100 iterations based on the three stochastic variables (hydro condition, load, and natural gas price). Idaho Power then calculated the 20-year net present value ("NPV") portfolio cost for each of the 100 iterations for all 12 portfolios. Figure 9.5 of the 2017 IRP graphically depicted the distribution of portfolio costs, showing both the variability of costs under different scenarios and the severity of the bad outcomes. Staff asked the Company to de-mean and de-scale the figure to provide higher clarification.[75] Figure 3 below provides Staff's requested modifications.

Figure 3: Distribution of Portfolio Costs



The adjusted table in Figure 3 above, differs from the original Figure 9.5 in the 2017 IRP by subtracting the average of all 100 NPV values from each NPV iteration. The original Figure 9.5 provided the NPV values for all 100 risk iterations.

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[74] Order No. 07-002 at 6.
[75] Staff's Opening Comments at 9.

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Second, Staff requests that the Company explain how the construction bidding process used for B2H will mitigate risk associated with the line.[76] Idaho Power, PacifiCorp, and BPA have not entered into contracts governing the construction phase of the project. Idaho Power understands there are risks inherent to any construction contract the size and scope of the B2H project, and that these risks must be properly managed to ensure success. Should Idaho Power facilitate the construction phase of the project, to mitigate construction contract risks, Idaho Power will prequalify bidders, then solicit bids from only those prequalified bidders. Idaho Power will then rate and score the bidders against a list of criteria that will include (but not be limited to) financial resources, technical expertise, recent relevant experience, quality of bonding and insurance, safety, satisfactory record of past performance and legal and regulatory compliance. Where subsidiaries are included in a bid, Idaho Power will seek to negotiate for a Parent Guaranty whereby a parent, as guarantor, assumes the responsibility for the payment or performance of the contract or obligation of its subsidiary by agreeing to compensate the beneficiary in the event of any non-payment or performance deficiency. Idaho Power will then award the contract to the contractor that presents the best mix of capabilities, qualifications, and offered services reflected by the scoring matrix.

Third, Staff faults the Company for not explaining the costs and risks of physical and financial hedging.[77] The 20-year IRP forecast is developed using a monthly time step to determine energy and capacity deficits while physical and financial hedging activity takes place in a near-term time frame with the objective of minimizing market exposure within established risk tolerances. Idaho Power's Risk Management Policy is a predetermined framework that is applied in an objective, systematic manner. The Risk Management Policy will be employed regardless of the portfolio chosen and cannot be quantified in advance.

[76] Staff's Opening Comments at 9.
[77] Staff's Opening Comments at 9.

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Rather, it is an interim strategy to identify, quantify, and manage the market-driven risks inherent in the Company's operations. Additional market import capacity will increase the ability to hedge price risks via market purchases identified in Idaho Power's Risk Management Committee process, and will help mitigate potential high-power supply costs for customers.

Fourth, Staff suggests that the IRP does not account for possible delays in additional generation development that will limit the ability to use B2H to import low-cost energy, and that this delay may reveal a "tipping point" that might make B2H uneconomic.[78] As discussed above, regional utility planning documents indicate that there will be sufficient generation in the Northwest to support the level of market purchases forecasted in the Company's modeling.

2. Co-participant Risks will be Mitigated Prior to Construction.

At the Commissioner Workshop, held on November 7, 2017, Commissioner Bloom asked the Company to explain whether PacifiCorp and BPA have committed to the construction of their pro-rata shares of B2H and what Idaho Power would do if they withdraw from the project. In the same vein, Mr. Carbiener argues that the IRP should account for the risk of PacifiCorp and BPA declining to maintain support for the B2H project.[79]

Idaho Power, BPA, and PacifiCorp have entered into a joint permitting agreement, but have not yet entered into construction and operating agreements. Under the current agreements either PacifiCorp or BPA can withdraw as a co-participant in the B2H project. If that occurs, it is possible that another party may have an interest in potential ownership of the project, resulting in Idaho Power maintaining the same or substantially similar ownership interest in the line.

[78] Staff's Opening Comments at 10.
[79] Gail Carbiener's Comments at 5-6.

More importantly, however, if either PacifiCorp or BPA or both withdraw from the B2H project prior to construction, Idaho Power will evaluate its potential ownership cost and capacity allocation based on the resulting ownership structure. Based on that updated analysis, Idaho Power will move forward with B2H only if it remains cost-effective for Idaho Power customers and subject to obtaining the necessary regulatory approvals due to the change in ownership. Based on what is known today, Idaho Power would likely not go forward with B2H on its own, nor would the Company commence construction without knowing with certainty its resulting ownership interest is appropriate. Thus, while there is uncertainty associated with changing ownership structures, Idaho Power intends to resolve that uncertainty prior to construction. Acknowledgment of Idaho Power's IRP would satisfy the "need" rule of the EFSC permitting process, which creates more certainty for all co-participants.

3. B2H Does Not Pose Any Greater Risks Due to Terrorism or Wildfires.

STOP B2H claims that a centralized transmission system is not in the public interest because it is vulnerable "to terrorism or forest fire" damage.[80] However, B2H is no more vulnerable to a terrorist attack or fire than any resource, and, in fact, may mitigate the effect of an attack on a generation resource. It is true that a direct physical attack on the B2H transmission line will remove the line's ability to deliver power to customers. In this respect, B2H is fundamentally no different than any other specific supply side resource. On the other hand, because the B2H project is connected to the transmission grid, a direct physical attack on any specific generation site in the Northwest or Mountain West region will not limit B2H's ability to deliver power from other generation sites in the region. In this context, B2H provides additional ability for generation resources to serve load if a physical attack were to occur on a specific resource or location within the region and therefore increases the resiliency of the electric grid as a whole.

[80] STOP B2H Comments at 32.

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Regarding wildfires, the transmission line steel structures are constructed of non-flammable materials so wildfires do not pose a physical threat to the transmission line itself. However, heavy smoke from wildfires in the immediate area of the transmission line can cause flashover/arcing between the phase conductors and electrically grounded components. Standard operation is to de-energize transmission lines when fire is present in the immediate area of the line. Transmission lines generally remain in-service when smoke is present from wildfires so long as the wildfire is not in the immediate vicinity. By comparison, solar photovoltaic ("PV") is susceptible to smoke, which can move into areas even if fires are not in the immediate vicinity of the solar generation. For example, the forest fires in the Northwest in 2017 created substantial smoke along the proposed B2H corridor and in the Northwest more broadly. The B2H line would likely still operate in such conditions, whereas solar PV generation could be substantially compromised.

F. B2H Provides Substantial Reliability Benefits

Staff requests greater detail on the reliability benefits provided by the B2H line.[81] Major 500 kV transmission lines, such as B2H, substantially increase the electrical grid's ability to recover from major unexpected disturbances. Although unexpected disturbances are difficult to predict, they do occur and the presence of B2H will mitigate the adverse impact of those outages. B2H will specifically mitigate the impact of outages along the Hemingway – Summer Lake 500 kV line, the loss of two Jim Bridger units during peak summer conditions, the loss of a single 230 kV transmission tower in the Hells Canyon area, or outages on any of the three 230 kV lines connecting the Idaho Power system to the Northwest. B2H will also improve operational flexibility by increasing the ability to perform maintenance on other transmission lines and manage Idaho Power's system during outage situations or other emergencies.

[81] Staff's Opening Comments at 8.

Transmission lines are more reliable than traditional supply-side resources. According to North American Electric Reliability Corporation ("NERC"), transmission lines have a forced outage rate of less than 1 percent, compared to traditional supply-side resources with forced outage rates of 7 to 10 percent.

G. B2H will Support Idaho Power's Participation in the Energy Imbalance Market.

Staff requests that the Company provide analysis or documents presenting the benefits of Western energy imbalance market ("EIM") participation and how it might impact the B2H project.[82] The regional high-voltage transmission system is critical to the realization of additional EIM benefits not previously considered, and expansion of this transmission system (*i.e.*, B2H) facilitates the realization of these additional benefits. As fluctuations in supply and demand occur for EIM participants, the market system will automatically find the best resource(s) from across the large-footprint EIM region to meet immediate power needs. This activity optimizes the interconnected high-voltage system as market systems automatically manage congestion on transmission lines, helping maintain reliability while also supporting the integration of intermittent renewable resources and avoiding curtailing excess supply by sending it to where demand can use it.

Staff's general criticism over the lack of analysis supporting the decision to participate in the EIM is unfounded. In the 2015 IRP, Staff initially recommended that Idaho Power include analysis of the costs and benefits of the EIM in its 2015 IRP Update.[83] In response to Staff's recommendation, Idaho Power argued that cost-benefit analysis associated with EIM participation should not be evaluated within the context of the IRP process because it is not directly related to the long-term resource plan.[84] Staff then dropped its

[82] Staff's Opening Comments at 26.
[83] *In the Matter of Idaho Power Company's 2015 Integrated Resource Plan*, Docket No. LC 63, Staff's Final Comments at 16 (Jan. 22, 2016).
[84] Idaho Power indicated that it would keep the Commission and Staff apprised of its decision-making process related to the EIM through other channels, as it has done, for example, when it filed its request for a deferral of EIM costs (IPC-E-16-19 and UM 1821).

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recommendation and the Commission order acknowledging the 2015 IRP did not require EIM analysis in the 2017 IRP.[85] In this case, the Company included the EIM in its action plan primarily for informational purposes.

Notwithstanding the Company's position that the EIM is not a resource decision that belongs in the IRP, Attachment 1 to these comments is the Company's economic analysis supporting its decision to participate in the EIM. This same economic analysis was filed with the Commission in docket UM 1821 in support of the Company request for authorization to defer certain costs associated with its participation in the EIM. When recommending approval of the Company's deferral, Staff noted that it "believes the Company's participation in the EIM is likely to result in long-term power cost savings for customers."[86]

H. The 2017 IRP Reasonably Accounts for Third-Party Transmission Revenue.

The inclusion of estimated third-party transmission wheeling revenue is new in the 2017 IRP. To accurately quantify the total cost of the B2H line, additional third-party transmission wheeling revenue resulting from the B2H line is appropriately included as a revenue credit or an offset to the costs in the B2H portfolios.

STOP B2H doubts the existence of this third-party transmission wheeling revenue.[87] STOP B2H also claims that the Company "hardwired" these revenues into the AURORA model.[88] STOP B2H is incorrect. The wheeling revenue is not an input or output from the AURORA model. The additional transmission revenue is calculated separately and included in the B2H portfolios.

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[85] *In the Matter of Idaho Power Company's 2015 Integrated Resource Plan*, Docket No. LC 63, Order No. 16-160 (Apr. 28, 2016) (not requiring future EIM cost-benefit analysis; Staff's final recommendation no longer includes EIM cost-benefit analysis).
[86] *In the Matter of Idaho Power Company, Application for Deferral of Costs Associated with Participation in an Energy Imbalance Market (EIM)*, Docket No. UM 1821, Order No. 17-215, Appendix A at 3 (June 14, 2017).
[87] STOP B2H Comments at 11.
[88] STOP B2H Comments at 11.

I. Commission Acknowledgment of B2H Does Not Conflict with BLM Requirements

In item 1 of his second round of comments, Mr. Carbiener asserts Idaho Power is asking the Commission to authorize the Company to begin B2H activities on federal lands without BLM's approval, conflicting with BLM's Record of Decision. Mr. Carbiener is mistaken.

Idaho Power is requesting that the Commission acknowledge B2H is reasonable, cost effective, and necessary to ensure that the Company's customers receive adequate services at reasonable rates—Idaho Power is not asking the Commission to authorize the Company to begin construction of B2H without first obtaining the requisite permits and authorizations from the relevant land-management agencies, including BLM and EFSC. With the Commission's acknowledgment, the Company must still obtain BLM approval to begin preliminary construction and construction-related activities on federal lands. Accordingly, the Commission's acknowledgment will not conflict with any provisions in BLM's Record of Decision requiring BLM pre-approval.

J. Commission Acknowledgment of B2H Does Not Conflict with EFSC Requirements.

In Mr. Carbiener's second round of comments, he points out that the majority of the B2H route through Oregon is on private property. Mr. Carbiener reasons that, because approval of the route is required by EFSC, and because EFSC has not yet issued a site certificate, Commission acknowledgment of B2H "will put the Commission in conflict with EFSC."[89] Again, Mr. Carbiener appears to believe that Commission acknowledgment would grant Idaho Power authority to begin construction. This is incorrect. Commission acknowledgment does not authorize Idaho Power to access either private or public lands, nor does it give Idaho Power the necessary state and federal authorizations to construct transmission facilities. As explained in Section III.A, above, EFSC has jurisdiction to review

[89] Carbiener Second Comments at 3.

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and approve the transmission line's route; the Commission is only asked to consider whether planned transmission line is reasonable, cost effective, and necessary to ensure that the Company's customers receive adequate services at reasonable rates. This acknowledgment would then provide the basis of the Company's "need" showing at EFSC—just one of many separate standards Idaho Power must satisfy to receive a site certificate.

IV. PORTFOLIO DESIGN

A. The 2017 IRP Allows for Effective Comparison of the Least-Cost Resources

Idaho Power evaluated twelve resource portfolios, with an emphasis on making an informed decision concerning the two most significant near-term resource decisions—whether the B2H line remained least-cost and least-risk, and whether to invest in SCR systems at Jim Bridger units 1 and 2. These resources were previously evaluated as part of the Company's resource portfolios in the 2015 IRP, though neither the SCRs nor construction of B2H were included in the action plan for acknowledgment.

1. Idaho Power's Portfolio Modeling Reasonably Focused on Major Resource Decisions.

Staff expresses concern that the Company's IRP portfolio selection and analysis lacks "diversity and robustness" because the evaluated portfolios do not include a wider array of resource compositions.[90] Staff asks that the Company restructure its portfolio development for the 2019 IRP using capacity expansion modeling. Sierra Club similarly argues that the Company's portfolio design is flawed because Idaho Power did not use capacity expansion models.[91]

The Company appreciates Sierra Club's and Staff's concern, and is amenable to evaluating capacity expansion modeling and more diverse portfolio selections in the 2019 IRP cycle. Nonetheless, the Company believes that its specific portfolio selection in this

[90] Staff's Opening Comments at 14.
[91] Sierra Club Comments at 3-4.

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IRP was appropriate because it allowed for levelized, dollar-per-MWh comparison of the most cost-competitive resources, while fulfilling the projected capacity deficiencies.

While the Company's modeling did not make use of resource-intensive capacity expansion modeling, the Idaho Power IRP process included a Long-Term Optimization ("LTO") run using the AURORA model. The LTO run iterates through multiple generation resource build-outs (not transmission) with the objective of minimizing the WECC power supply cost. The LTO run for the 2017 IRP placed no new resources in the Idaho Power bubble over the 20-year analysis period. Idaho Power was not satisfied with the expected reliability resulting from the AURORA LTO for its system and performed the portfolio analysis presented in the 2017 IRP.

2. The Company's Portfolios Reasonably Compared the Most Economical Resources to Guide Key Resource Decisions

Idaho Power agrees with Sierra Club's characterization of the B2H transmission line and retrofit investments in Jim Bridger 1 and 2 as major and discrete investment choices deserving focused analysis.[92] However, the Company disagrees with Sierra Club's comments suggesting that the IRP's portfolio analysis is deficient simply because it does not use capacity expansion modeling. While the Company is not opposed to investigating capacity expansion modeling, as suggested by Staff for the 2019 IRP, the portfolio analysis for the 2017 IRP is purposefully focused—as appropriate to guide the Company's key business judgments. Thus, the Company's lack of capacity expansion modeling does not undermine the Company's portfolio analysis.

In the 2017 IRP, the Company's portfolio analysis was limited to only the most cost-effective resources that, when combined, provided an acceptable level of reliability. Consequently, many of the potential resources evaluated during the development of the IRP were not ultimately selected for inclusion in a portfolio. By limiting the resources to only the

[92] Sierra Club Comments at 4.

most cost-effective options, the Company was able to limit the variables influencing the SCR and B2H resource evaluation.

In order to effectively evaluate the Company's key resource decisions, the portfolios included the following new resource options: transmission, single-axis tracking solar PV, additional demand response, natural gas reciprocating engines, and CCCT. The set of resource options analyzed for the IRP included varying levels of technological maturity and market penetration, allowing for a diverse resource set. The resource options comprising the IRP portfolios were selected from this diverse set in order to develop portfolios using the most cost-competitive resources. While including additional resources may have broadened the diversity of portfolios, the higher levelized costs[93] would merely yield a more diverse array of more costly alternatives.

3. Additional Tipping Point Solar Analysis Supports the Company's Portfolio Selections.

To ensure that the Company's resource selection included the most economic options, and at the recommendation of the IRPAC, the Company conducted a solar tipping point analysis to evaluate the sensitivity of the portfolio rankings to a reduction in solar cost.[94] Only when solar PV prices dropped more than 50 percent did the NPV ranking of the preferred portfolio (P7) change.

In light of Staff's concerns regarding the robustness of the 2017 IRP portfolios, the Company has prepared a supplemental tipping point analysis comparing resource costs, including projected capital cost declines for solar and lithium-ion battery resource options, in Figure 4. The graph includes the levelized cost of capacity ("LCOC") for solar and battery storage resource options from the 2017 IRP source document for these costs (2016 Lazard

[93] 2017 Appendix C – Technical Report, p. 76.
[94] 2017 IRP at 118.

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cost reports[95]), and adds updated capital cost estimates from recently released (November 2017) Lazard resource cost reports. The graph also includes the LCOC for B2H and natural gas-fired resources.[96]

The graph plots LCOC as a function of percentage of capital cost decline, where only the battery and solar resources are assumed to experience capital cost declines. The graph also uses resource cost data from the November 2017 Lazard cost reporting on energy and storage resources.[97] When compared to the 2016 Lazard cost reports, the recent report indicates a modest decrease in average solar capital costs ($1,375/kW to $1,238/kW) and a significant decrease in average lithium battery capital cost ($3,114/kW to $1,748/kW). The most recent Lazard cost of storage report projects lithium battery capital costs to decline at an annual rate of 10 percent through 2021, with 2021 capital costs projected to have declined by 36 percent.

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[95] https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf and https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf

[96] The graph is expressed in dollars per on-peak kW per month, rather than cost per installed kW per month. Expressing LCOC in this manner does not affect the dispatchable resources (i.e., batteries and natural gas-fired generators) or B2H, but the LCOC of solar is affected due to its contribution to on-peak capacity, 1 kW of installed solar capacity equals 0.51 kW of on-peak capacity. Additionally, the LCOC metric reflects the costs to own a resource, including fixed O&M costs, and carry the resource as a part of the system ready to operate.

[97] Lazard's Levelized Cost of Energy Analysis – Version 11.0, November 2017; Lazard's Levelized Cost of Storage Analysis – Version 3.0, November 2017 - https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf

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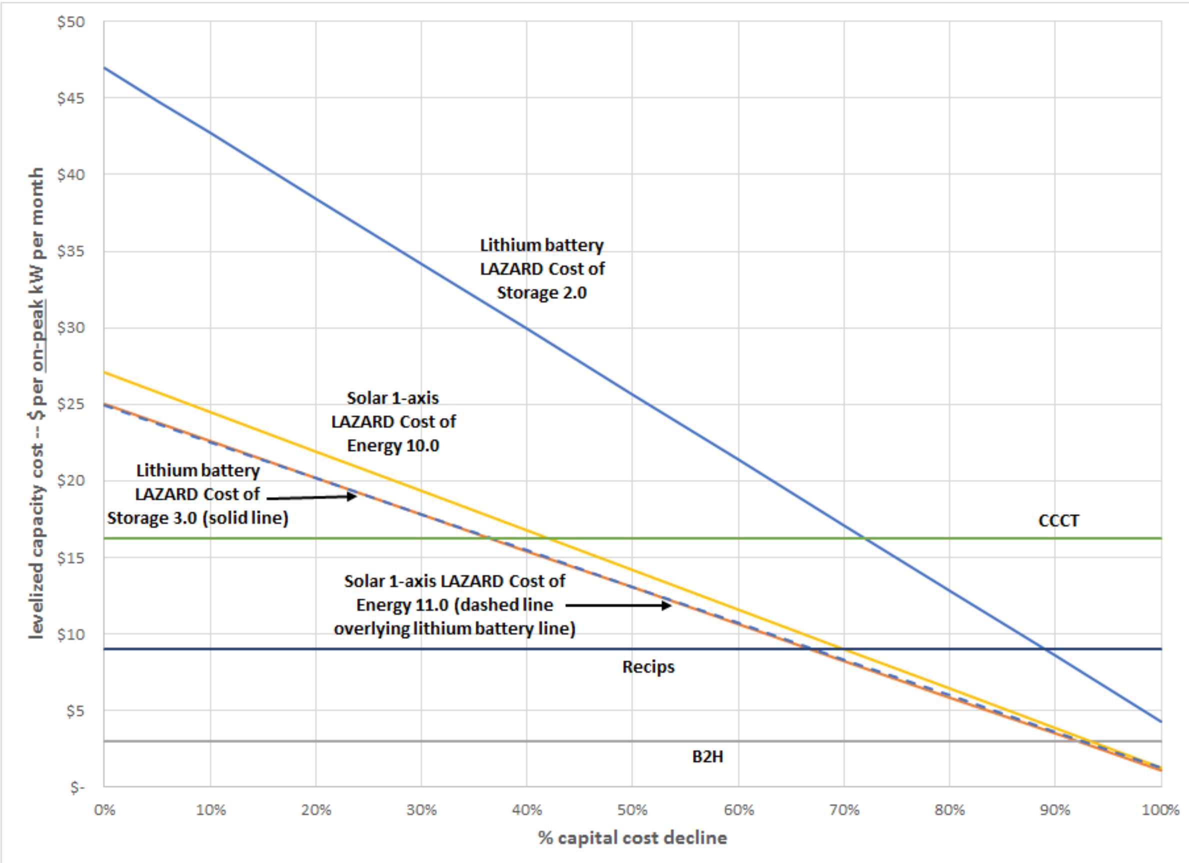
Figure 4: Capital Cost Tipping Point



The tipping point graph indicates that the costs for solar and battery storage resources must decrease more than 90 percent from their current levels to be less costly than B2H in terms of cost-per-kilowatt of on-peak capacity. Solar and battery storage costs drop below a CCCT at capital cost declines exceeding 35 percent and below the reciprocating engines at capital cost declines exceeding 65 to 70 percent.

The findings of the tipping point analysis indicate that B2H is the low-cost source of on-peak capacity, and is likely to remain so even with steep declines in solar and storage capital cost. The analysis indicates that solar and battery storage may outcompete natural gas-fired resources with substantial continued declines in capital cost. Given the projected capital cost decline reported in the latest Lazard cost of storage report, battery storage is likely to become cost competitive with natural gas-fired resources over the coming years.

Notably, the levelized peak capacity cost of the Lithium Battery 3.0 and Solar 1-axis 11.0 overlay the same line, suggesting that these may be comparable resource options.

In sum, the Company's portfolio analysis for the 2017 IRP was intentionally focused on guiding the Company's major resource decisions. However, the Company recognizes that the parties value greater diversity in the evaluation of portfolios, and will continue to enhance its portfolio analysis in future IRPs.

B. The Preferred Portfolio is the Least-Cost Option

CUB suggests that the preferred portfolio is not the least-cost option because P7 did not rank first in each individual ranking.[98] This criticism ignores the fact that the IRP process requires a comprehensive, total cost perspective in the evaluation of IRPs.

In developing the IRP, Idaho Power evaluated each portfolio by the various cost components: variable costs (determined through the AURORA model), new resource fixed costs, and remaining Jim Bridger costs.[99] The portfolios were then ranked based on the relative cost in each category. Lastly, each portfolio was ranked based on total portfolio cost. Only at this point was a preferred portfolio identified as the best overall combination of cost and risk. Thus, while P7 had portfolio rankings other than "1" in the individual categories, as pointed out by CUB, it remained the least-cost portfolio on a total-cost basis. Indeed, no single portfolio ranked the same in variable cost and new resource fixed costs.

The Company also performed sensitivity analyses on each of the 12 portfolios to determine the robustness of the portfolio rankings. These analyses included stochastic risk analysis of natural gas prices, hydroelectric production, and system load.[100] Overall, the preferred portfolio consistently outperformed other portfolios in the Company's cost analysis:

[98] CUB Comments at 2.
[99] 2017 IRP at 111.
[100] 2017 IR at 116-117, Figure 9.5 and Table 9.6.

- P7 has the lowest total portfolio cost under planning case conditions.[101]
- P7 has the lowest total portfolio cost for all but the 400 percent of planning case natural gas price sensitivity.[102]
- P7 has the lowest total portfolio cost for 92 of the 100 stochastic iterations.[103]

As a result, the Company reasonably concluded that the preferred portfolio is the least-cost, least-risk option.

CUB argues that certain cost differences between the portfolios are not statistically significant based on the *p* value.[104] CUB is correct that Portfolio 4 is only slightly greater in total portfolio cost than Portfolio 7. The costs are close precisely because the Company constructed portfolios using only the most cost-competitive resources.

CUB is also correct that ANOVA (analysis of variance) results provided by Idaho Power in discovery demonstrate a *p*-value of 0.0895 when testing average costs between the four treatment levels for Jim Bridger units 1 and 2; a *p*-value of 0.0895 exceeds the common standard of 0.05. This slightly higher observed *p*-value suggests that the four treatment levels are not significantly different (*i.e.*, it is inconclusive that the 2028 and 2032 retirement scenario is the low-cost treatment level).

Idaho Power agrees with CUB that the statistical results with respect to the cost differences between the four Jim Bridger retirement scenarios are less conclusive than the statistical results of testing whether there are cost differences between the primary portfolio elements. The testing whether there are cost differences between the primary portfolio elements notably finds, with statistical significance, that the B2H-based portfolios are lowest cost[105]. However, using the tabular presentation of portfolio cost results in factorial design format, Idaho Power continues to view the results of the portfolio cost analysis as more

[101] 2017 IRP at 111, Column 13, Table 9.3.
[102] 2017 IRP at 113, Tables 9.4 and 9.5.
[103] 2017 IRP at 116.
[104] Opening Comments of the Oregon Citizens' Utility Board at 2-3 (hereinafter "CUB Comments").
[105] Idaho Power's ANOVA results were provided as an Attachment to CUB's Data Request No. 3.

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broadly indicating that operation of Jim Bridger units 1 and 2 beyond 2021 and 2022 is lower cost than retiring these units in 2021 and 2022. But even if those units are retired in 2021 and 2022, there is no capacity deficit until 2023—meaning that the Company has time to further evaluate the impacts of retirement scenarios.[106]

C. The Preferred Portfolio, Which Includes Continued Operation of the Bridger Units, is Not Illegal.

Sierra Club argues that more than half of Idaho Power's resource portfolios, including the Company's preferred portfolio, are illegal because they involve ongoing operation of the Jim Bridger units 1 and 2 without the installation of SCRs.[107] But far from relying on "hopeful speculation regarding the future leniency of regulatory agencies," Idaho Power engages in reasonable planning based on established precedent. For instance, in 2010, Portland General Electric Company ("PGE") successfully negotiated an alternative compliance plan for the Boardman coal plant, which otherwise would have been subject to mandatory installation of emission control technologies.[108] Under the revised rules adopted in December 2010, the Oregon Department of Environmental Quality ("DEQ") did not require the installation of SCR on Boardman, instead requiring installation of less expensive controls, in combination with an earlier closure deadline for the Boardman boiler.

Idaho Power incorporated a comparable compliance scenario into its IRP analysis. All portfolios were designed to either (1) comply with Regional Haze rules or (2) be subject to a negotiated settlement with the Wyoming DEQ and the Environmental Protection Agency that would allow continued operation without SCRs. To the extent that Sierra Club disagrees with the likelihood of achieving such a settlement, this is a difference of opinion concerning regulatory behavior—not a legal or statistical argument. Moreover, the coal unit modeling considered the Clean Power Plan CO_2 emissions limits, and complied with the state mass-

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[107] Sierra Club Comments at 7-8.
[107] Sierra Club Comments at 7-8.
[108] *See* State of Oregon, Dept. of Env. Quality, Permit No. 25-0016-TV-01, PGE Boardman 2011 Permit Modification.

based approach. The Company's IRP clearly and fully conforms to legal and regulatory compliance requirements.

V. SUPPLY SIDE RESOURCES

A. Valmy

Staff requests that the Company evaluate 2019 and 2025 end-of-life dates for Valmy unit 1 and explain the change from the Company's 2015 IRP.[109] Mr. Carbiener similarly suggests that the Company consider retiring both units in 2025.[110] Staff further asks for clarification regarding what resources will replace the capacity currently provided by Valmy unit 1.[111] The Company has performed these additional analyses, which support the Company's inclusion of a December 2019 retirement date for Valmy unit 1.

In this IRP, Idaho Power is requesting Commission acknowledgment of Idaho Power's intent to shut down its ownership share of coal-fired operations at North Valmy unit 1 by year-end 2019 and from North Valmy unit 2 at year-end 2025. Acknowledgement will serve to inform future ratemaking proceedings regarding the Valmy plant.

1. Qualitative Risk Analysis Supports Earlier Retirement of Valmy Unit 1.

In the Idaho Power's 2015 IRP, the Company anticipated retiring both units 1 and 2 in 2025, in part to shield the resource plan from certain risk factors. These risks included (1) the possible failure of PURPA solar projects to come online; (2) uncertainties surrounding development of the B2H line; and (3) the feasibility of arriving at a mutually agreeable retirement date with Valmy co-owner, NV Energy. Each of these—and solar development in particular—have sufficiently progressed to support an earlier retirement date for Valmy unit 1.

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[109] Staff's Opening Comments at 12.
[110] Gail Carbiener's Comments at 3.
[111] Staff's Opening Comments at 12.

a. Significant PURPA Solar Development has Occurred.

At the outset of the 2015 IRP process, the Company had 461 MW of PURPA solar projects under contract. This amount was ultimately reduced to 320 MW, following the cancellation of 141 MW during the IRP development process. In light of these cancellations, it was unclear how much of the remaining 320 MW of capacity would ultimately be realized. In the face of potential declining output, maintaining the Valmy units' 2025 retirement date effectively shielded against a capacity shortfall.

Since that time, the pending PURPA solar projects have been built, with an established capacity of 270 MW.[112] Thus, the uncertainty regarding projected solar capacity is no longer relevant, and there is no need to preserve Valmy unit 1 as a resource beyond 2019.

b. Permitting Risks for the B2H Line Have Diminished.

As discussed above, the B2H line will provide access to additional capacity through access to regional resources. However, when the Company's 2015 IRP was in development, the permitting process was far less certain, making it a relatively higher risk resource.

Since that time, the Company has substantially advanced the permitting process. Notably, the BLM issued its Record of Decision (ROD) for B2H on Nov. 17, 2017. The ROD allows BLM to grant right-of-way to Idaho Power for the construction, operation, and maintenance of the B2H Project on BLM-administered land., suggesting that the risk of constructing B2H has reduced significantly. As a result, there is a diminished need to maintain Valmy unit 1 in operation past 2019.

c. Joint Planning Supports Proposed Retirement Dates.

As the parties note, there is a unique challenge in planning for retirement of the Valmy units given that the project is co-owned by NV Energy. While this challenge remains, both

[112] An additional 29 MW are under construction or under contract.

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Idaho Power and NV Energy continue to work together to synchronize depreciation dates and to coordinate Valmy's retirement timeline.

Taken together, reduction in relative risks support adopting an earlier retirement date for Valmy unit 1. And as suggested by this discussion, the incorporation of additional solar capacity and the Valmy transmission line to Nevada will effectively replace any needed capacity lost by retiring Valmy unit 1. Indeed, since the 2015 IRP, Valmy unit 1 has primarily functioned as a capacity resource during periods of high energy demand—infrequently needed and consequently replaceable by means of market imports from places other than the northwest.

2. Quantitative Cost and Risk Analysis Supports Earlier Retirement for Valmy Unit 1

Idaho Power performed analysis related to the impacts of a December 2019 Valmy unit 1 retirement on fixed costs and variable costs in accordance with assumptions from the 2017 IRP. This analysis is included here as Confidential Attachment 2 which is the same analysis Idaho Power provided to the Commission in docket UE 316 as part of the Company's request to accelerate the Valmy end-of-life. The results of the analysis are summarized in the tables below.

Table 5: Valmy 1 Shutdown Fixed Cost Impact
Modification from December 2025 to December 2019
Present Value of Revenue Requirements
($ millions)

Cost Component	**Incremental Impact**
Accelerated Depreciation	$10.979
Return, Tax, Interest – Existing Investment	($18.636)
Non-Fuel Operations & Maintenance Expense	($19.958)

Run Rate Capital	($4.100)
Return, Tax, Interest – Run Rate Capital	($1.304)
Total	($33.019)

Table 6: Valmy Unit 1 Shutdown Variable Cost Impact
Modification from December 2025 to December 2019
Multiple Gas Price Scenarios
($ thousands)

Year	**IRP Planning Case Gas**	**200% Gas**	**300% Gas**	**400% Gas**
2020	($19)	($92)	$795	$4,437
2021	($14)	$282	$5,427	$14,974
2022	($37)	$1,647	$6,413	$11,727
2023	($47)	$3,308	$10,736	$17,901
2024	($40)	$4,634	$12,408	$20,351
2025	($35)	$6,335	$14,458	$22,669
Nominal Impact	($192)	$16,114	$50,238	$92,059
NPV Impact	($123)[113]	$9,614	$31,068	$58,174

As detailed in Tables 5 and 6, the Company's quantitative analysis indicates that cost savings are achieved through movement of the Valmy unit 1 retirement date from December 2025 to December 2019 in all cases ranging from the Planning Case to the 300 percent gas case. Only at the 400 percent gas case or higher does the variable cost impact exceed the fixed cost benefit of $33.019 million, as detailed in Table 5.

[113] Counterintuitively, the analysis of variable cost impact indicates a small benefit (NPV of $123,000) associated with the earlier retirement under the IRP Planning Gas Case. This benefit is viewed as immaterial from a resource planning perspective, with the result effectively interpreted as zero cost impact associated with earlier retirement.

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In sum, several of the qualitative risk factors that existed when the Company's 2015 IRP was developed have been mitigated in the intervening two years. Further, the Company's updated quantitative analysis reflects cost savings by retiring Valmy unit 1 in 2019, without having an impact on system reliability. Based on this combined qualitative and quantitative analysis, Idaho Power continues to include the 2019 retirement of Valmy unit 1 in its preferred portfolio.

B. Jim Bridger

The Jim Bridger plant plays an important role in Idaho Power's system by providing approximately 700 MW of baseload capacity, as well as serving as a dispatchable resource responsive to load balancing requirements. Idaho Power uses Jim Bridger extensively to provide ramping services, increasing overall system flexibility. These services are particularly important to allow for increased renewables penetration, many of which entail substantial output volatility. The Jim Bridger plant is also used in concert with the Company's hydro resources, supporting hydro's ability to serve as a responsive resource as well.

Much as the parties describe—and the Company acknowledges—the multiple benefits of energy storage resources, the Bridger Plant provides system-support services beyond its capacity and energy contributions. The Company relies on dispatchable resources like Jim Bridger to provide adequate flexibility to follow variable energy resources.

Nonetheless, the Company is moving toward a smooth transition from coal resources. One of the primary goals in the Company's portfolio design for the 2017 IRP was to evaluate SCR investments and retirement dates for the Jim Bridger coal plant. In this analysis, a key shift from the Company's 2015 IRP analysis to its 2017 IRP analysis involved the impact of substantially lower natural gas price forecasts.[114] These lower price forecasts emphasized

[114] The parties' comments concerning the Company's natural gas forecasts are discussed in more detail below, in section VII.B.

the need for careful review of the possible SCR investments. As Idaho Power decreases its reliance on a coal-powered fleet over time, the Company must establish a responsible and practical path forward to protect the reliability of the grid, to minimize costs to customers, and to fulfill its obligation to serve.

1. The Anticipated Retirement Dates for Jim Bridger are Appropriate.

The Company's preferred portfolio includes the early retirement of unit 1 in 2032 and unit 2 in 2028.[115] Staff and Sierra Club both request additional explanation for the Company's selection of these retirement dates.[116] Sierra Club, in particular, argues that even earlier shutdown dates would be possible—including immediate shutdown in 2018 or 2020,[117] while Staff suggests that Idaho Power's forecasts may be too reliant on the possible repeal of the Clean Power Plan ("CPP").[118]

As an initial matter, retirement dates for the Jim Bridger units should correspond with PacifiCorp's target dates. Given that PacifiCorp is 67 percent owner of the units, unilateral action in this case is not possible.[119] In part for this reason, Idaho Power selected a range of retirement and SCR options that correspond to those considered by PacifiCorp's 2017 IRP.[120]

Further, and contrary to the parties' assertions, the Company's analysis does not assume any specific regulatory treatment in the future. Indeed, Idaho Power does not doubt that there may be some form of carbon-emission regulation in the next 20 years, and has expressed the objective of transitioning away from coal-fired capacity more generally. The Company has also indicated that declining to pursue the SCRs at Jim Bridger units 1 and 2 is consistent with a future with increased emissions regulation—wherein coal-fired

[115] 2017 IRP at 8.
[116] Staff's Opening Comments at 16; Sierra Club at 28.
[117] Sierra Club Comments at 28.
[118] Staff's Opening Comments at 15.
[119] PacifiCorp 2017 IRP at 77.
[120] PacifiCorp 2017 IRP at 171.

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generation will fare worse and will face likely retirement.[121] Thus, where Sierra Club argues that "retiring the Bridger units in the early 2020s is preferable to retrofitting them with SCR," this argument presents a false dichotomy.[122]

Critically, a decision not to pursue investment in SCRs in no way precludes shutting down the units at a revised date, depending on the outcome of ongoing discussions Idaho Power and PacifiCorp are having with the Wyoming Department of Environmental Quality. In any event, any ongoing operation of the Jim Bridger units will comply with all necessary environmental regulations.

Thus, in order to effectively coordinate with the co-owner, and in light of ongoing negotiations with regulators, the Company has reasonably included retirement dates of 2028 and 2032 in its preferred portfolio, without including SCR investments.

2. Risks Associated with the Retirement of the Jim Bridger Plant.

CUB suggests that Idaho Power should explain the risk of having a different retirement date for Jim Bridger than PacifiCorp, the principal owner.[123] Idaho Power's dates for the retirement of units at Jim Bridger are consistent with PacifiCorp, with one unit retiring in 2028 and the other in 2032. As stated earlier, Idaho Power uses Jim Bridger extensively to provide ramping services, increasing overall system flexibility. The specific unit retirement, whether it be unit 1 or 2 in 2028 and the other unit in 2032, is inconsequential to the analysis because both units have a similar maximum dependable capacity. Idaho Power will work closely with PacifiCorp to ensure that both utilities are aligned on the future of Jim Bridger and that their resource actions are in the best interest of Idaho Powers customers.

[121] 2017 IRP at 123.
[122] Sierra Club Comments at 14.
[123] CUB Comments at 3.

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3. The Jim Bridger Units Remain Economic Resource Options.

Sierra Club argues that the Jim Bridger units are, even now, uneconomic, reasoning that the Company's analysis understates various costs and miscalculates the relative value of new solar capacity.[124]

Idaho Power acknowledges that "the utility has an obligation to serve energy with the lowest reasonable costs to its ratepayers."[125] However, Sierra Club is incorrect that the Jim Bridger units fail to provide this least-cost resource.

Sierra Club argues that the SCR scenario portfolios fail to account for any Bridger costs beyond 2034, and they also assume a rapid tapering of incremental capital investment in the years leading up to 2034.[126] Idaho Power does not, as a general rule, include the fixed cost of its existing and committed generation in the IRP portfolio costs because excluding common fixed costs between portfolios does not impact portfolio ranking results.

Evaluating scenarios that contemplate varying operating lives of existing resources requires a different modeling approach. For the portfolios that include SCR investments at Jim Bridger units 1 and 2, Idaho Power calculated the estimated fixed costs of their current depreciable life of 2034 in the Idaho jurisdiction. For these scenarios, Idaho Power did include variable O&M and fuel expense associated with Jim Bridger generation modeled in 2035 and 2036 and those costs were included in the overall portfolio cost through the AURORA model output. For the portfolios without SCR investments at Jim Bridger units 1 and 2, the Company calculated the estimated fixed costs of operating the Jim Bridger plant to the various accelerated end-of-life dates. The fixed costs for the four Jim Bridger units 1 and 2 retirement scenarios were calculated and included in the total portfolio cost evaluation.

In its comments, Sierra Club imputes the impact of including fixed costs to the end of the planning period for portfolios that include the SCR investment. Idaho Power estimates

[124] Sierra Club Comments at 23 (stating that "Bridger is uneconomic on a going forward basis").
[125] Sierra Club Comments at 24.
[126] Sierra Club Comments at 13.

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that including the present value of the 2035 and 2036 fixed O&M costs, as the Sierra Club recommends, increases the NPV costs of these portfolios by approximately $5.5 million. The addition of $5.5 million to the SCR investment portfolios only make them less attractive. The selection of portfolio 7, which does not include SCR investment on Jim Bridger units 1 and 2, still represents the least cost, least risk portfolio.

Regarding the tapering of capital investments, as a coal plant nears the end of its useful life, capital expenditures will decrease as long-term capital projects cannot be justified over a short remaining life. Most capital projects are additions, improvements or refurbishments. Additions and improvements will no longer be needed as the plant gets closer to retirement. Refurbishments that can be capitalized will continue, and some maintenance items that were previously replaced as a capital project, will be repaired. Reducing capital expenditures does not necessarily reduce reliability. Idaho Power chose to reflect a reduced base capital investment need as Jim Bridger units 1 and 2 reached the end of their planned operating life. These assumptions were validated based on common industry factors and Idaho Power's investments at the Boardman plant which will cease coal fired operations at the end of 2020. Additions and improvements will no longer be needed as the plant gets closer to retirement.

Sierra Club argues that the Company's IRP analysis relies on misplaced assumptions regarding coal costs and market prices, excessively favoring the Jim Bridger units as capacity resources.[127] Sierra Club is correct that historical fuel prices have increased over the past few years, mainly due to decreased generation at the plant, resulting in decreased production at the mine, and recent damage to a longwall mining system. These increases are not forecasted to continue at the present pace. The Company relies on the most current data when preparing its IRP analysis and believes the coal forecast is an appropriate reflection of likely future outcomes at the time the IRP was prepared.

[127] Sierra Club Comments at 14.

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Idaho Power, in conjunction with co-owners/operators PacifiCorp, is engaged in a long term fueling plan to select the least cost/least risk fuel for the Jim Bridger plant on an on-going basis. The analysis considers different volumes of coal from several different suppliers.

Additionally, Idaho Power does not produce an electric market price forecast. The Company uses the AURORA model to quantify the variable costs of each portfolio. The resulting market prices are a product of the AURORA model and the prices differ with the unique characteristics of each portfolio. Contrary to Sierra Club's assertion, Idaho Power has not skewed market prices to favor the economics of the Jim Bridger plant.

Sierra Club also suggests that solar could be used to replace any capacity need created by the retirement of the Jim Bridger units.[128] For reasons discussed in Section V.C, below, the Company disagrees that new solar development would provide a lower-cost resource option than the existing Jim Bridger units.

C. Solar PV

Sierra Club argues that Idaho Power improperly modeled escalating solar costs and, as a result, failed to adequately value solar as a supply-side resource.[129] Sierra Club highlights that, over the past seven years, the unsubsidized levelized cost of utility-scale solar has declined by 85 percent.[130] Sierra Club argues that Idaho Power is unreasonably pessimistic in forecasting levelized capital cost prices going forward, because solar is not a "mature technology."[131] Under the Company's forecasts, Sierra Club notes, the unsubsidized levelized cost of solar would cease to decrease, and would instead increase by 13 percent between 2017 and 2023.[132]

[128] Sierra Club Comments at 20.
[129] Sierra Club Comments at 19-20.
[130] Sierra Club Comments at 19.
[131] Sierra Club Comments at 19.
[132] Sierra Club Comments at 19.

The Company disagrees with Sierra Club's critique. Idaho Power relies on Lazard reporting for is estimates of capital costs associated with solar resources. Additionally, Idaho Power tracks solar-based power purchase agreements made regionally, nationally, and internationally. While the Company recognizes that solar is becoming increasingly cost-effective, the parties fail to give adequate weight to two major hindrances associated with increased solar capacity development: (1) its relative on-peak capacity credit and (2) its unpredictability and variability. Idaho Power has calculated that, in order to provide 1 MW of on-peak capacity need identified in the IRP's resource adequacy assessment, the Company would need to install roughly 2 MW of nameplate capacity solar.[133]

Moreover, solar carries reliability and cost impacts, as the Company's dispatchable resources must be modified to accommodate solar generation's unpredictability and variability. Idaho Power's study of these costs, released in 2016, suggests modest solar integration costs; however, this study was conducted using synthetic solar production data. Since that time, Idaho Power has interconnected nearly 300 MW of solar capacity to its system and is assessing the variability and uncertainty of the actual solar production data to verify the 2016 study results.

Critically, even if solar resources become significantly more cost-effective, the Company's tipping-point analysis suggests that the capital costs of solar would need to reduce by more than 35 percent before the resource would become cost-competitive with natural gas-fired resources, and more than 90 percent from their current levels to be less costly than B2H in terms of cost-per-kilowatt of on-peak capacity.[134] As a result, the Company is confident that its preferred portfolio accurately represents the appropriate relative value of solar, as necessary to guide the Company's key decisions.

[133] 2017 IRP at 37, Table 4.1.
[134] *See* Figure 4 in Section IV.A.3, above.

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Sierra Club further suggests that the phasing out of the federal investment tax credits ("ITCs") will not preclude solar resource development between now and 2023, as some measure of ITC benefit will remain.[135] While Sierra Club is correct that solar resources may continue to be developed through PURPA or individual development, the Company's 2017 IRP shows Idaho Power has no need for additional resources through 2023. The Company would not have a need to build additional resources, and therefore, the costs of building additional resources when they are not needed would not be prudently incurred. Future IRP's will evaluate solar costs at that point in time and will capture any cost decreases if they exist.

D. Energy Storage

Staff and Sierra Club both encourage the Company to revise its assessment of energy storage. Staff states that Idaho Power's IRP "only seems to have modeled energy storage as a capacity resource."[136] And Sierra Club argues that the Company failed to model substantial decreases in the future price of energy storage.[137]

For its argument that the Company should have applied a different methodological approach to storage, Staff points to docket UM 1751. In that docket, the Commission specifically directed PGE and PacifiCorp to adopt a modeling approach for energy storage, consistent with the implementation of the Energy Storage Program and House Bill 2193.[138] Recall, this legislation did not extend to Idaho Power therefore the Company was not a party to that docket, and thus was not directed to adopt that methodology.

Nonetheless, Idaho Power recognizes that energy storage is "capable of providing multiple services" and is decreasing in cost. The Company further understands that, with

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[135] Sierra Club Comments at 20.
[136] Staff's Opening Comments at 16.
[137] Sierra Club Comments at 20 (arguing that "most battery storage technologies remain relatively nascent").
[138] *In the Matter of Pub. Util. Comm'n of Or. Implementing Energy Storage Program pursuant to House Bill 2193*, Docket No. UM 1751, Order No. 17-118 (Mar. 21, 2017).

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batteries' decreasing price, this resource may provide balancing and flexibility to the future grid. Indeed, batteries and transmission provide similar grid service, by moving existing energy to where it is needed—be it in time (batteries) or in place (transmission). However, the Company also recognizes two barriers to aggressive storage implementation: (1) even with substantial price drops, energy storage continues to demonstrate substantially higher capital costs than other resources, including highly flexible natural gas-fired reciprocating engines, which also provide grid-support services; and (2) the lifetime cycles of these resources remain uncertain, complicating long-term analysis and planning.

To be clear, Idaho Power understands (and shares) parties' interest in further comparisons of the costs of solar and storage with B2H and natural gas-fired resources. This shared interest prompted the Company to prepare additional tipping point analysis in Figure XX in Section IV.A.3, above, which illustrates the LCOC for each resource. As noted in the discussion accompanying that graph, however, capital costs for storage—like for solar—would need to drop by more than 90 percent to out-compete B2H in terms of cost-per-kilowatt of on-peak capacity, 35 percent to out-compete a CCCT, and between 65-70 percent to out-compete reciprocating engines. As a result, even if parties are correct that more substantial capital cost savings might be expected from these resources, storage remains a higher-cost option compared to B2H for many years to come.

E. Cloud Seeding

Staff expresses doubts about the cost-effectiveness of Idaho Power's cloud seeding, suggesting that "[a] demonstration of net benefits to the ratepayer may be needed."[139] Idaho Power disagrees, and believes that the cost-effectiveness of cloud seeding is beyond the scope of the IRP. While the benefits of cloud seeding are indirectly included by virtue of possible increased hydro production, they are not the appropriate subject of IRP review

[139] Staff's Opening Comments at 16.

because cloud seeding does not represent a resource decision.

F. Wind

Sierra Club objects to the Company's treatment of existing wind contracts, stating that Idaho Power fails to explain why it assumes that some contracts will be renewed and not others.[140] In particular, Sierra Club compares two sets of PURPA contracts as evidence that the Company's approach is arbitrary: approximately 584 MW of wind contracts are forecasted to expire during the planning period, while 502 MW of contracted non-wind renewable generators are not similarly forecasted to expire. Sierra Club instead urges the Company to assume, "barring any specific evidence to the contrary," that wind QFs will renew contracts because of their negligible operating costs.[141]

In Idaho Power's experience, PURPA contracts involving small hydro, biomass, cogeneration, and other renewable resource types have been renewed with little or no additional investment required to maintain generation capacity. By comparison, the cost of repowering wind QFs is less certain, and the Company cannot as accurately predict whether these generators will choose to repower, resulting in no contract renewal. Idaho Power understands that repowering wind turbines is being actively examined and pursued in the wind industry, but is not yet clear when or how this approach will be adopted for particular projects. Idaho Power continues to monitor developments in wind repowering and may choose to adjust future planning processes accordingly.

G. Distributed Generation

STOP B2H presents a number of arguments suggesting that Idaho Power has failed to adequately value distributed generation. Broadly, STOP B2H urges the Company to "use efficiencies and build at the smallest scale possible," while nonetheless "ensuring [that]

[140] Sierra Club Comments at 11.
[141] Sierra Club Comments at 12.

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utilities remain a reliable engine of economic prosperity and environmental sustainability."[142] More specifically, STOP B2H argues that the Company failed to analyze the full benefits of distributed generation resources such as solar and battery installations, arguing that the Company opposes PURPA development of solar and battery storage "because Idaho Power cannot maximize its profits by building these resources themselves."[143] Instead, STOP B2H proposes its own resource portfolio, including substantial distributed generation.[144]

While Idaho Power appreciates STOP B2H's general sentiment concerning the need to balance efficiency, economic benefits, and sustainability, STOP B2H fails to recognize the internal inconsistency in its recommendation to build at the smallest scale possible, while "us[ing] efficiencies": economies of scale favor utility-scale investment, a method that also protects customers from unnecessarily inflated rates. Indeed, the portfolio alternatives to B2H modeled by the Company's IRP included new resources to account for load growth or coal retirements; in those contexts, the efficiency of investments like B2H and CCCT resulted in their selection as the most cost-effective resources over the 20-year study period.

While STOP B2H is also correct that the IRP portfolios did not include large quantities of distributed solar and storage in its portfolios, the Company focused its portfolio design on cost-competitive resources in order to helpfully guide the Company's decision-making, without unnecessarily modeling significant numbers of high-cost portfolios that would unavoidably fail to provide customers with the least-cost, least risk resource profiles. At present, neither distributed solar nor storage resources represent cost-effective resources, particularly on a scale necessary to supplant a resource like the B2H line.

Separately, STOP B2H discusses the lack of Combined Heat and Power ("CHP") opportunities for Idaho Power customers, noting that "[t]he cost to deploy CHP is far less

[142] STOP B2H Comments at 23.
[143] STOP B2H Comments at 24.
[144] STOP B2H Comments at 28-32.

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than the cost to build standalone generation."[145] STOP B2H highlights the potential of above-ground compressed air energy storage installation as a novel installation model with promising implementation prospects.[146]

Idaho Power is greatly interested in CHP, which was discussed at multiple IRPAC meetings. However, STOP B2H fails to account for substantial logistical and administrative difficulties, which have proven surprisingly challenging. For instance, the timing of production and costs needed to make a CHP project economically viable has been more elusive than STOP B2H's analysis would suggest. Nonetheless, the Company is open to evaluating additional CHP projects as either the need or the opportunity arises.

VI. DEMAND SIDE RESOURCES

A. Energy Efficiency

Prior to the 2017 IRP process, Idaho Power contracted with a third-party consultant, Applied Energy Group ("AEG"), to produce an Energy Efficiency Potential Study. AEG is an experienced and reputable third-party contractor in conducting DSM potential studies, having conducted studies in over 25 states and provinces for over 40 energy providers, including multiple studies for 13 companies in the Northwest. Using AEG's forecasts, Idaho Power included all achievable energy efficiency in every portfolio prior to any supply-side resource being considered, making energy efficiency the first resource the Company has included to meet future resource needs. Idaho Power's 2017 study determined that the Company cumulatively has 273 aMW of achievable energy efficiency potential and 483 MW of achievable peak potential by the end of the IRP planning cycle in 2036. AEG estimated this level of achievable potential using acquisition rates similar to the 85 percent acquisition rate used by the Northwest Power and Conservation Council.

[145] STOP B2H Comments at 27.
[146] STOP B2H Comments at 27.

Idaho Power believes that the amount of energy efficiency determined by AEG is cost-effective and achievable and sets an appropriate and prudent target for energy efficiency for long-term planning purposes. As the Company evaluates its resource adequacy over the planning period through the load-resource balance, energy efficiency is the first resource applied to serve the projected load. Including unrealistic amounts of energy efficiency potential in the load-resource balance may understate the need for future resources and undermine the Company's obligation to reliably serve its load. To be clear, however, the Company does not consider the achievable potential as a ceiling or limit for the Company's energy efficiency efforts. This is demonstrated by the fact that Idaho Power has exceeded its energy efficiency potential estimate in three of the last four years.

Staff raised questions regarding how Idaho Power relied on the AEG potential study for purposes of determining its load and resource analysis.[147] Starting with the 2015 IRP, the Company switched to hourly energy efficiency forecasts for the peak load and resource analysis. Hourly load shapes were provided to Idaho Power by AEG as part of the potential study process, which made it possible to calculate the coincident cumulative savings for any hour over the IRP planning period. Prior to the 2015 IRP, Idaho Power shaped energy efficiency potential by average monthly energy and not at the hourly level. As an example of the impact to the load and resource analysis, the hourly methodology increased the on-peak potential energy efficiency value by 43 percent by 2036 over the pre-2015 IRP method used in the load and resource balance. When combined with demand response, in 2036, demand-side resources account for more than 900 MW of reduced system peak, which equates to a nearly 18 percent reduction in system peak load.

Idaho Power did not use the peak analysis provided by AEG because the analysis was not dynamic relative to the Company's forecasted peak hours and the forecast only provided estimates for peak summer and peak winter months. The peak forecasts provided

[147] Staff's Opening Comments at 19.

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by AEG in the potential study document are a simple summer peak capacity allocation based on a fixed peak hour estimate from 2015 Idaho Power peak system data. To estimate peak forecasts for all months and years in the IRP planning horizon, Idaho Power created an hourly shaped forecast and merged the results with the forecasted monthly system peak hours across all 20 years for the load and resource analysis.

Staff has consistently raised concerns about the presentation of peak energy efficiency data in both the 2015 and 2017 IRP's even though Idaho Power considers its methods to be rigorous and as or more detailed than other methods in the region for determining on peak capacity of energy efficiency. The method that Idaho Power has developed is recognized by utility peers as an effective model and has been shared and discussed with other regional utilities.

Sierra Club raises concerns about declining forecasted savings due to ongoing changes in lighting standards that will culminate in 2020 and argues that the Company should model declining savings prior to the final 2020 phase-in of standards.[148] It is important to clarify that when savings are lost from Idaho Power's program portfolio due to manufacturing standards or code changes, the savings then become part of the load forecast econometric process, which incorporates data and trends related to codes and standards into the forecast. Thus, total impacts from energy efficiency, whether the savings come from codes and standards or achievable potential from utility programs, are fully accounted for in the IRP process prior to the consideration of any new supply side resources.

In their opening comments, STOP B2H claims that Idaho Power has added only two new energy efficiency programs since 2009.[149] As described in more detail in Appendix B to the 2017 IRP, Idaho Power has continually added new measures to its 23 energy

[148] Sierra Club Comments at 10-11.
[149] STOP B2H Comments at 16.

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efficiency programs, and all but two are offered in both the Idaho and Oregon jurisdictions. These 23 programs comprise over 275 energy efficiency measures.[150] In fact, since 2009, Idaho Power not only added two new programs that STOP B2H identified, but has also added the Multifamily Energy Savings program and expanded the measure offerings in its Energy House Calls program, Simple Steps, Smart Savings program, Heating & Cooling Efficiency Program, and Commercial & Industrial Energy Efficiency Program. Idaho Power has a standing program planning group,[151] participates in Northwest Energy Efficiency Alliance ("NEEA") Regional Emerging Technology Advisory Committee ("RETAC"), is a voting member of the Northwest Power and Conservation Council's Regional Technical Forum ("RTF"), and is a member of E Source, a national organization of electric utilities and energy providers focusing on energy efficiency and potential new programs and measures.

Additionally, Idaho Power disagrees with Stop B2H's assertion that "Idaho Power has achieved much less in energy relative efficiency saving when compared to other utilities."[152] The 2017 State Energy Efficiency Scorecard[153] lists Idaho as one of the most-improved states this year. Idaho, 95 percent of the Company's service area posted the largest point increases over its previous year's score. The following excerpt summarizes Idaho's 2017 score:

> Idaho added the most to its score this year, rising in the ranks from 33rd to 26th. Although the state's utility savings have yet to rebound to peak levels seen in 2010 and 2011, they have edged upward recently thanks to resurgent levels of spending on demand-side management programs. Idaho has also seen a recent increase in electric vehicle registrations and updates to building energy codes modeled on the 2015 International Energy Conservation Code (IECC),

[150] *See* 2017 IRP, Appendix B, DSM Report at 196.
[151] 2017 IRP, Appendix B, page 153.
[152] STOP B2H Comments at 15.
[153] The 2017 State Energy Efficiency Scorecard, American Council for an Energy-Efficient Economy, September 2017 Report U1710, page viii.

> due to take effect in January 2018. This was the state's best finish since 2012.

Although the score relates to the entire state, not just Idaho Power, the Company's substantial contributions are a key driver in the state's overall energy efficiency performance.

The Company is committed to pursuing all cost-effective achievable energy efficiency. While the Company does not view the amount determined in the Potential Study to be a ceiling by any means, it does represent a prudent target for long-term resource planning.

B. Avoided Cost Analyses

In their opening comments, Staff requested that the Company confirm when it is resource deficient, and how the generation or capacity deferral value is utilized as part of its energy efficiency avoided costs.[154] Based on the preferred portfolio and the retirement dates of 2028 and 2032 for Jim Bridger units 1 and 2, the first peak-hour load deficiency of 34 MW occurs in July 2026 and the first energy deficiency of 143 aMW occurs in July of 2029.

The DSM alternative energy costs are based on both the projected fuel costs of a peaking unit and forward electricity prices as determined by Idaho Power's AURORA power supply model. The avoided capital cost of capacity is based on a gas-fired, simple-cycle combustion turbine ("SCCT"). In the 2017 IRP, the levelized capacity cost of a 170 MW SCCT is $122 per kilowatt/year ("kW/year") over a 35-year period. The DSM alternative energy costs derived from AURORA are averaged and placed into pricing categories; Summer Mid-Peak, Summer Off-Peak, Non-summer Mid-Peak, Non-Summer Off-Peak. For the Summer-On Peak pricing category Idaho Power uses the annual operations and management costs of the 170 MW SCCT combined with the capacity costs of $122 kW/year divided by the number of hours in the Summer-On Peak pricing category (508-520 per

[154] Staff's Opening Comments at 20.

year).[155] This Summer-On-Peak value is applied to all years of the measure life. The load shape of specific energy efficiency measures assumes that energy efficiency provides a cumulative resource that has existed for many years and is already avoiding additional on-peak generation capacity.

Additionally, Staff requested that Idaho Power make changes to its avoided cost methodology and re-run its cost effectiveness analysis and report back on the impact to the amount of energy efficiency selected for its IRP forecasts (including a revised table 5.3 from page 52 of the IRP) and detail the estimated impact on energy and peak-hour load and resource balance analysis.[156]

In response to Staff's request, Idaho Power substituted an average of AURORA peak prices for the hours covered by Summer-On Peak. The chart below compares published 2017 DSM Alternate Summer-On Peak Costs with the 2017 Aurora on-peak values.

Figure 5: DSM Alternative Cost

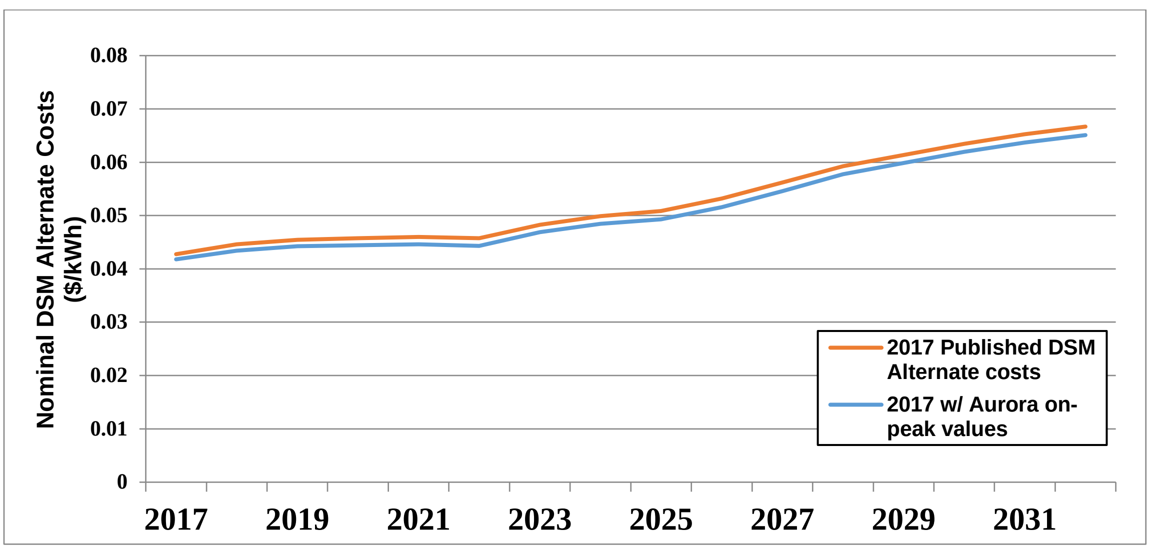

Table 7 below shows the cost-effectiveness summary substituting the AURORA on-peak values for the published Summer-On Peak DSM Alternate Costs.

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[155] 2017 IRP, Appendix C at 62-66.
[156] Staff's Opening Comments 20-21.

Table 7: Total energy efficiency cost-effectiveness summary (Aurora on-peak values)

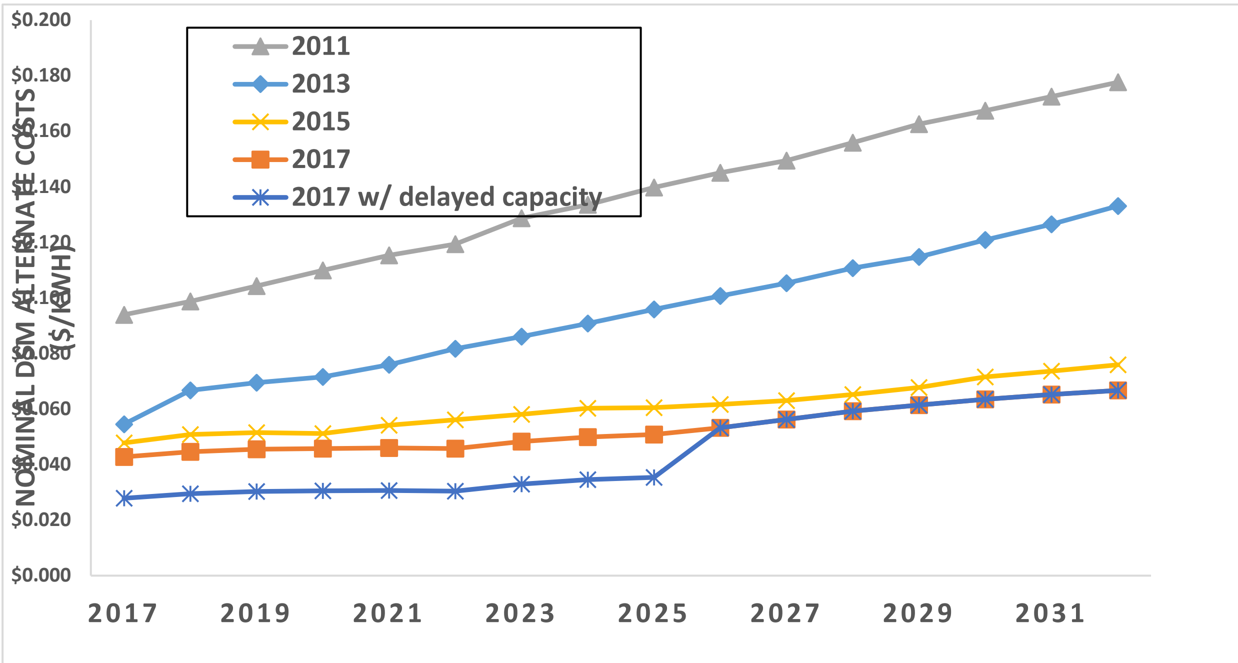
	2036 Load Reduction (aMW)	Utility Costs ($000s) (20-Year NPV)	Resource Costs ($000s) (20-Year NPV)	Total Benefits ($000s) (20-Year NPV)	TRC: Benefit/ Cost Ratio	TRC Levelized Costs (cents/kWh)
Residential	66	$78,908	$155,425	$271,630	1.7	6.7
Industrial/Commercial/Special Contract	176	$157,520	$302,559	$522,992	1.7	3.9
Irrigation	31	$23,828	$81,981	$122,165	1.5	6.7
Total	**273**	**$260,255**	**$539,964**	**$916,786**	**1.7**	**4.8**

Using the AURORA on-peak prices for the Summer-On Peak DSM Alternative Costs it would decrease the level of energy efficiency and its effect on peak in the load and resource balance analysis.

Another change Staff requested was to apply the capacity deferral value of $122/kW per year for all measures with a measure life that extends into the first-year Idaho Power is capacity deficient, which is 2026 in the 2017 IRP.[157] The chart below shows the 2011-2017 DSM Alternate costs with capacity benefit in the Summer-On Peak hours included plus the stream of DSM Alternative costs with the capacity costs deferred until 2026.

[157] Staff's Opening Comments at 21.

Figure 6: DSM Alternative Costs with Generation Deferral Value Beginning at Capacity Deficiency



The majority of Idaho Power's energy efficiency measures have a measure life that would extend to 2026 with the weighted average measure life of 12 years. Using a capacity benefit only after 2026 or only for measures with measure lives extending to 2026 would decrease the level of energy efficiency and its effect on peak in the load and resource balance analysis.

The last change requested by Staff was that Idaho Power develop a new transmission and distribution ("T&D") deferral value that more closely resembles the methodology deployed by PGE and/or PacifiCorp.[158] Staff notes that this change should include projected costs of future T&D investments over the course of the IRP, not just those in the three-year 2016 budget.[159]

Idaho Power participated with other northwest utilities, including PGE and PacifiCorp, in a Northwest Power and Conservation Council workshop on T&D deferral on August 22, 2017. While Idaho Power's method of estimating T&D deferral from energy efficiency is

[158] Staff's Opening Comments at 20.
[159] Staff's Opening Comments at 21.

thorough and defensible, the Company will work with PGE and PacifiCorp to ensure fundamental consistency between methodologies. Additionally, Idaho Power will calculate the T&D deferral costs and benefits over a 20-year period in future energy efficiency T&D deferral benefit studies for use in future IRPs.

C. Demand Response

The goal of demand response ("DR") programs is to minimize or delay the need to build new on-peak supply-side resources. On a comparative basis, DR as a resource[160] is a very economic capacity resource and a very expensive energy resource.[161] Unlike supply-side resources, DR programs must acquire and retain participants each year to maintain a level of demand-reduction capacity for the Company. Idaho Power plans for its DR capacity based on Commission orders[162] in both Idaho and Oregon and assesses its DR capacity through actual annual deployment of these resources. Idaho Power experiences its system peak in the summer months, so its DR programs are offered from June 15 to August 15 of each year.

Several intervenors were critical of Idaho Power's DR programs.[163] Idaho Power has three DR programs: A/C Cool Credit, Flex Peak Program, and Irrigation Peak Rewards, all offered in Idaho and Oregon.[164] The A/C Cool Credit program is a direct load control ("DLC") program that allows Idaho Power to remotely cycle participants' residential air conditioners on and off to reduce summer-time demand on its system. The Flex Peak Program is a behavioral load control program for commercial and industrial customers. Participants nominate load reduction at their facilities and reduce load through managing their energy

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[160] 2017 IRP at 87, Figure 7.5.
[161] 2017 IRP at 89, Figure 7.6.
[162] For demand response Idaho Power complies with Order No. 13-482 IRP guideline 7.
[163] *See* Staff's Opening Comments at 22; STOP B2H Comments 19-21.
[164] 2017 IRP, Appendix B at 33, 126, 140.

use. The Irrigation Peak Rewards Program is a DLC program by which Idaho Power can remotely turn off irrigation pumps to reduce system load.

Idaho Power has 390 MW of DR load control, which is over 11 percent of its all-time system peak. The Northwest Power and Conservation Council's 7th Power Plan[165] "assume[s] the technically achievable potential for DR in the region is over eight percent of peak load during winter and summer peak periods by 2035," while Idaho Power currently has 11 percent of its summer peak load under DR control. Idaho Power provides the most summer DR in the Pacific Northwest region according to the Seventh Power Plan.[166]

As part of the public workshops on Case No. IPC-E-13-14 and docket UM 1653, Idaho Power and other stakeholders agreed on a new methodology for valuing DR. The settlement agreement, as approved in Order No. 13-482 and IPUC Order No. 32923, maintains the current DR programs even in years when Idaho Power does not anticipate peak-hour capacity deficits, setting in place the program infrastructure for when capacity deficits return.[167] The settlement and subsequent orders stipulated when and how each program will be utilized, allowing for the deployment of each program three times per season even when the programs are not needed. Additionally, the stipulation even prescribes what programs can be actively marketed or expanded.

Staff contends that Idaho Power's DR programs should be capable of being called for more than a select number of events strictly correlated to near-emergency capacity conditions and that Idaho Power should be exploring DR opportunities that have arisen through advancements in technology that increase participation from the residential and commercial sectors.[168]

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[165] Northwest Power and Conservation Council's 7th Power Plan, Chapter 14 Demand Response, page 14-2. Available at https://www.nwcouncil.org/media/7149925/7thplanfinal_chap14_dr.pdf
[166] Northwest Power and Conservation Council's 7th Power Plan, Chapter 9 Existing Resources and Retirements, page 9-28. Available at https://www.nwcouncil.org/media/7149929/7thplanfinal_chap09_existresources.pdf
[167] Order No. 13-482 at 3.
[168] Staff's Opening Comments at 22.

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Critically, the reliability and viability of DR programs are highly dependent on attracting and retaining participants. If these programs were used to their fullest extent when not needed, participation would decline as would the megawatt capacity. This is consistent with the settlement approved in docket UM 1653, in which the Company and parties agreed that DR programs should be called a minimum of three times per season with no marginal costs; however, the DR programs can be called for up to sixty hours per season if required. By using DR programs in this manner, the programs can be relied on when the system really needs them.

Staff states that Idaho Power's DR capacity relies on an older technology backbone and that the resource itself may not be currently utilized to the best of it capabilities.[169] STOP B2H argues that Idaho Power has "failed to build-out its metering . . . costing customers the savings they would receive from having digitally mediated demand response in place."[170] Idaho Power disagrees with these views. The Company uses a power line carrier system, Aclara Two Way Automated Communications (TWAC) system and its Automated Meter Infrastructure system (AMI) to deploy most of its DLC programs (A/C Cool Credit and Irrigation Peak Rewards). Additionally, the Company uses a cell phone system to deploy some of the Irrigation Peak Rewards for participants that do not have AMI communications. Idaho Power currently has 99 percent of its customers on the AMI with a 99.9 percent read success rate and 91.3 percent of its Oregon customers on the AMI system with the same 99.9 percent read success rate. The Company continually upgrades and expands its AMI capability and believes AMI is an efficient and effective system for many operations—including DR—considering the geography, topography, and density of its service area.

The Company would like to clarify STOP B2H's statement that "no one is going to attach that framework to a customer electric panel" to participate in the Irrigation Peak

[169] Staff's Opening Comments at 22.
[170] STOP B2H Comments at 19.

Rewards program.[171] In 2016, Idaho Power had 2,286 service points (panels) with DR devices attached, with 50 in its Oregon area.[172] Additionally, in 2016, 28,315 A/C Cool Credit participants had DR devices on or near their central A/C units, with 368 in Oregon.

Idaho Power believes that it is effectively deploying demand response for its customers, and will continue to improve and upgrade its technology as economically and logistically feasible.

VII. FORECASTS

A. Load Forecasts

Staff requests more detailed load forecasts or an explanation of why Idaho Power does not provide more granular forecasts, instead of only yearly load data.[173] Idaho Power does develop a monthly load forecast in formulating the analysis presented in the narrative of the IRP. Details on the monthly load forecast is included in Appendix C: Technical Report of the IRP on pages 1-60. Regarding the econometric architecture of the forecast models, Idaho Power does not utilize interval or daily data. Only a subset of customers are equipped with interval meters and so interval data is not available for the entire class. Daily data is available for the population, but this is true for only four years, a span that fails to capture the diversity of macro-economic influence and outcomes required of a long-term capacity planning model.

Further, Idaho Power's commercial models are based on economic data with a native annual frequency (or quarterly trued to annual revisions), additional frequency conversions outside this frequency were not used. In evaluating the optimal model for commercial energy forecasting given its reliance on this data, it has been determined that using annual energy avoids the potential pitfalls of economic data conversion.

[171] STOP B2H Comments at 19.
[172] See 2017 IRP, Appendix B, DSM Report at 196.
[173] Staff's Opening Comments at 23.

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For weather sensitivity of Idaho Power's commercial and industrial models, the Company did consider the intra-annum distribution of energy use. Due in part to the significant manufacturing presence in Idaho Power's economic service area, the commercial class historically presents a stable bimodal seasonal energy use pattern. For these reasons, the Company has chosen an annual or monthly frequency, concluding that for purposes of both operational and long-term IRP capacity planning an annual or monthly model (depending on customer class) provides superior accuracy, fit, and robustness.

In their opening comments, Staff suggests that the IRP over-forecasts load because it assumes non-recession growth rates for the entire forecast period and fails to anticipate gains or losses of special contract customers.[174] Staff is mistaken on this point. The econometric models used by Idaho Power in forecasting each major customer class, as outlined in the IRP, are informed by a period of historical sales data. This data includes: the pre-recession era, the great recession of 2007-2009, and the subsequent period of moderate growth. Thus, the load forecasting models do not rely solely on non-recession data and are reflective of the central tendency of a range of economic scenarios. The forecast result is itself a baseline, by definition, the probability that the economy will perform better than this is equal to the probability that it will perform worse. Additionally, recessionary impacts are also associated with the high medium and low forecasts that feed into the stochastic modeling.

Regarding special contract load, the Company bases these forecasts on estimates provided by its special contract customers. Therefore, any anticipated expansion or contraction of energy needs by the special contract customers during the IRP forecast period would be submitted to Idaho Power by the individual special contract customers. Detail of the monthly forecast of these customers in the 2017 IRP can be found in Appendix C: Technical Report of the IRP pages 1-18 under Additional Firm. While Staff

[174] Staff's Opening Comments at 23.

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requests modeling of a no special-contract load growth scenario, the Company does not believe that such a scenario would be informative. The Company's three special contract customers are located in Idaho and the state of Idaho does not have direct access like the state of Oregon.

Moreover, Staff believes that the IRP's probability assessment is limited because it fails to stack possible impacts.[175] While historic weather patterns may be inclusive of certain "stacking" scenarios and the subsequent impact on retail sales, notably in the irrigation space, the probabilities of weather occurrences with these parameters are appropriately reflected in the distribution of the outcomes.

Lastly, Sierra Club argues that the IRP fails to model load stochastically, allowing for year-to-year variation and systemic variation.[176] The Company utilized load forecasts with different starting points to perform the stochastic modeling in the AURORA model. The Company believes this view of load is valuable in determining the impact of a low or high load environment on portfolio performance. A more varied load stochastic may be considered for the 2019 IRP.

B. Natural Gas Price Forecasts

Several parties criticized Idaho Power's selection of the Planning Case natural gas price forecast.[177] Idaho Power attempts to use the gas price forecast that most closely aligns with future expectations. Prior to the 2013 IRP, Idaho Power's natural gas forecast was internally developed using several blended proprietary forecasts, resulting in a non-public natural gas forecast. In the 2013 IRP, Idaho Power began using an Energy Information Administration's ("EIA") forecast as the basis for the IRP natural gas forecast, in order to increase transparency. The Company used the EIA Reference case as the

[175] Staff's Opening Comments at 23.
[176] Sierra Club Comments at 30-31.
[177] *See* Staff's Opening Comments at 25; Sierra Club Comments at 30; Renewable Energy Coalition's Comments at 4.

Planning Case natural gas forecast in the 2013 and 2015 IRP's. In a departure from the 2013 and 2015 IRP's, the Company selected the High Oil and Gas Resource and Technology ("EIAHO") case from the 2016 EIA Annual Energy Outlook for the 2017 IRP Planning Case.

The Company chose the EIAHO case forecast as its Planning Case because actual natural gas prices have consistently been lower than the Idaho Power IRP Planning Case EIA forecast selected in the past several IRP cycles. A detailed review of the Intercontinental Exchange ("ICE") settled forward contracts demonstrated ICE to be a more accurate indicator than the EIA Planning Case forecast used in the IRP over the past few years. Comparing the ICE reviewed data to the 2016 EIA forecasts available, the 2016 EIAHO case forecast was selected, as it closely followed the ICE forward contract prices as compared to the other available EIA forecasts.

Staff and others question the use of ICE data to substantiate the selection of a natural gas price forecast for the IRP.[178] Idaho Power believes it is appropriate to validate the gas forecast and doing so in this manner served to confirm the selection of the EIAHO case over the EIA Reference Case. Settlement prices that ICE publishes are based off actual market transactions. ICE uses these transactions along with its own fundamental review of the market (including the EIA forecasts) to provide monthly prices throughout the time horizon that it publishes. These published prices are accepted and used by the market as not only a basis for forecasting, but also to set margin requirements leading to the exchange of real dollars on a daily basis.

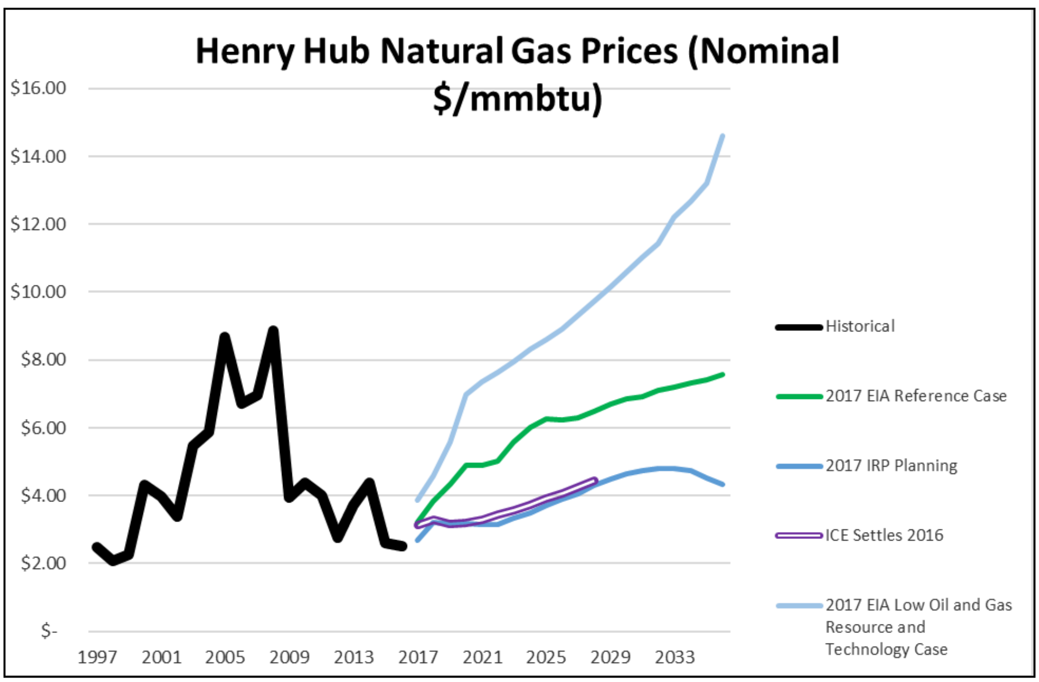
Additionally, the natural gas industry uses the Henry Hub futures contract as a basis for determining forward prices and applies a basis differential to adjust for locational differences. For example, most of the gas that Idaho Power purchases for its power plants is bought at the U.S./Canadian border at Sumas, Washington. For forecasting and hedging

[178] *See, e.g.*, Staff's Opening Comments at 25; Renewable Energy Coalition's Comments at 8.

purposes, Idaho Power would use the Henry Hub futures contract in combination with a Sumas basis swap to represent the forward price of natural gas at Sumas. Both the Henry Hub futures contract and the Sumas basis swap are traded and cleared on the ICE platform, as are hubs from all over the country. Idaho Power uses the Sumas Hub because this is where most of its firm pipeline transportation is sourced from and is where the Company buys most of its physical natural gas supply.

As shown in the graph below, the 2017 IRP Planning case (EIAHO case) and the ICE settled contracts line up very well through 2028, which is the extent of ICE data available at the time.

Figure 7: Henry Hub Natural Gas Prices (Nominal \$/mmBtu)



As future natural gas price assumptions influence the financial results of the operational modeling used to evaluate and rank resource portfolios, the Company also evaluated historical price trends to inform the selection of a natural gas price forecast for

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the IRP. The natural gas price forecast in the last two IRPs have consistently overstated the gas price forecast when using the EIA Reference Case, as shown in the graph below.

The confidential graph below compares natural gas prices from ICE Henry Hub contract settles and EIA forecasts from 2009 to 2016. The graph shows a strong correlation between the ICE and EIA futures in 2009, 2010, 2011, and 2012. Starting in 2013, the futures begin to diverge with EIA continuing to show a much larger increase in the forecast and ICE contracts showing a much flatter future. Looking at the actual Henry Hub line, which is flat or declining from 2009 forward, Idaho Power believes the past seven-year trend of low prices (dotted pink line) will persist—as does the market, as shown by the 2016 ICE contracts (solid pink line).

[redacted]

In the 2017 IRP, Idaho Power's planning case natural gas forecast (the EIA High Oil and Gas Resource and Technology Case) was analyzed over varying price sensitivities (or scenarios). Pages 112-113 of the 2017 IRP describe the analysis in which Idaho Power analyzed natural gas price sensitivities ranging up to 400 percent of planning case natural gas price forecast. For the stochastic risk analysis, described on pages 114-117 of the 2017 IRP, Idaho Power analyzed 100 different natural gas price scenarios.[179] While the price sensitivities only evaluated upward pressure on natural gas prices, the stochastic risk analysis sampled prices above and below the planning case, in line with Sierra Club's concern that gas prices should allow for the risk that prices will rise or fall.

An additional argument against the selection of the EIAHO natural gas price forecast is the concern that it will lead to underinvestment in conservation. It is true that the DSM alternative costs that are used for program cost-effectiveness are based on the 2017 IRP preferred portfolio using the 2017 IRP planning case natural gas price forecast. That said, the Company has been pursuing—and continues to pursue—all cost-effective achievable energy efficiency. As discussed above, the Potential Study provides a prudent target for long-term planning purposes, but it is not viewed as a ceiling or cap by the Company.

C. Coal Price Forecasts

Sierra Club recommends that coal prices should be included in the stochastic analysis.[180] Idaho Power believes that by varying the natural gas prices relative to the coal price and limiting the new resource technologies to B2H, solar, and natural gas in the portfolio design, the Company's analysis has effectively tested the viability of coal to economically compete in the future.

VIII. OTHER

A. Environmental Regulations and Climate Change

Staff has urged Idaho Power to account for climate-related variables such as increased summer peaks, increased forest fires, and decreased snow pack in its IRP analysis.[181] Staff

[179] 2017 IRP at 114, Figure 9.2.
[180] Sierra Club Comments at 31.
[181] Staff's Opening Comments at 28.

notes that it is “deeply concerned that Idaho Power may not be addressing the real and present risk of climate change and impending necessity of adaptation and mitigation.”[182]

The Company has not—and does not—make predictions specific to changes in the scale and timing of hydrologic effects or any other aspect of the Company due to future climate variability. Outside of the IRP process, the Company does track the latest science related to future climate impacts on the scale and timing of the hydrology. The Company is an active participant in the ongoing River Management Joint Operating Committee[183] meetings and keeps up-to-date with other publications related to the Pacific Northwest climate variability.

While not related to climate-change predictions, the Company’s stochastic risk analysis assesses the effect on portfolio costs when select variables take on values different from their planning-case levels. The stochastic variables are selected based on the degree to which there is uncertainty regarding their forecasts and the degree to which they can affect the analysis results. The stochastic variables include natural gas prices, load, and hydro generation. Each of the variables can be influenced by climate change as described in Staff’s comments.

IX. CONCLUSION

Idaho Power appreciates the opportunity to file these comments and supports the robust public process and participation in this case. Based on the detailed and comprehensive analysis set forth in the 2017 IRP, along with these comments and Appendix D: B2H Supplement, Idaho Power has demonstrated that the B2H transmission line is the least-cost, least-risk resource that meets the resource need identified in this IRP. Idaho Power respectfully requests acknowledgment of the Company’s 2017 IRP as meeting both the procedural and substantive requirements of Order Nos. 89-507, 07-Q02, 07-747, and

[182] Staff’s Opening Comments at 27.
[183] A forum of water managers, hydrologists, and power schedulers from Reclamation, US Army Corp of Engineers, and BPA.

12-013. The Company also requests that the Commission specifically acknowledge two action items, (1) Idaho Power's intent to shut down its ownership share of coal-fired operations at North Valmy unit 1 by year-end 2019 and unit 2 at year-end 2025 and (2) Idaho Power's acquisition of B2H in the Action Plan to satisfy EFSC's "Need" standard under its Least Cost Plan Rule, so that the Company can continue forward on the path and achieve an in-service date consistent with its 2026 capacity deficit.

Respectfully submitted this 8th day of December, 2017.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 68

IDAHO POWER COMPANY

Attachment 1
Idaho Power Company's
Energy Imbalance Market Analysis

December 8, 2017

An IDACORP Company

Idaho Power Company
Energy Imbalance Market Analysis

February 2016

Energy+Environmental Economics

PLEXOS®
Integrated Energy Model

Idaho Power Company Energy Imbalance Market Analysis

February 2016

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Energy Exemplar

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Acronyms

APS	Arizona Public Service Company
BA	Balancing Authority
BAA	Balancing Authority Area
BAU	Business-as-usual
CAISO	California Independent System Operator
DA	Day-ahead
EIM	Energy Imbalance Market
FERC	Federal Energy Regulatory Commission
HA	Hour-ahead
IPC	Idaho Power Company
LMP	Locational Marginal Price
NVE	NV Energy
NWPP	Northwest Power Pool
PACE	PacifiCorp East
PACW	PacifiCorp West
PGE	Portland General Electric Company
PNNL	Pacific Northwest National Laboratory
PSE	Puget Sound Energy
WECC	Western Electric Coordinating Council

Executive Summary

Over the past year, in an effort to increase operational efficiency and create cost savings for IPC customers, Idaho Power Company (IPC) has been exploring participation in the energy imbalance market (EIM) operated by the California Independent System Operator (CAISO). As part of its assessment of opportunities for regional coordination, IPC engaged Energy & Environmental Economics, Inc. (E3), to analyze the potential economic benefits of IPC's participation in the Western EIM. This report describes the results of our study.

The analysis uses production simulation modeling in PLEXOS to estimate IPC's benefits resulting from participation in the EIM by comparing IPC's real-time generation costs as an EIM participant, as well as any revenues or costs from transactions with other EIM participants, against those of a business-as-usual (BAU) case in which IPC does not participate in the EIM. To focus on the incremental impact of IPC participation, the BAU case includes operations of a "current EIM" consisting of the seven BAAs that were participating or had announced plans to participate in the EIM at the start of this study. These BAAs are listed in the table below.

Table 1: BAA Participants in EIM in BAU Case

Current EIM participants for BAU Case
CAISO
PacifiCorp East (PACE)
PacifiCorp West (PACW)
NV Energy (NVE)
Puget Sound Energy (PSE)
Arizona Public Service (APS)
Portland General Electric (PGE)

Under the Base Scenario simulated for the year 2020, the analysis estimates that EIM participation would produce $4.5 million in annual sub-hourly dispatch cost savings for IPC. Under an alternative scenario with higher renewable buildout in the region, EIM participation created $5.1 million in total sub-hourly dispatch cost savings to IPC. Savings due to reduced flexibility reserves (from the diversity provided by the EIM) were not estimated in this study, but would provide savings in addition to the figures stated above. For example, in a previous study E3 estimated that PGE would receive $0.8 million in savings due to reduced flexibility reserves from joining the EIM.

Table 2. Annual Savings to IPC from Participation in EIM (2015$ million)

Scenario	EIM Savings to IPC
Base Scenario	$4.5
No APS or PGE	$4.2
Early Coal Retirement	$4.1
High RPS Case	$5.1

Overall, this study estimates that participation in the EIM would produce modest positive savings for IPC, and that savings from participation would be larger in the presence of larger renewable resource buildout. In addition to savings to IPC, we also estimate that IPC participation in the EIM would produce over $2 million in incremental savings for the current EIM participants.

Base Scenario savings to IPC are positive and modest due to a combination of factors. Monthly 2020 gas prices came from OTC Global Holding Natural Gas Forwards & Futures (provided by SNL) for selected hubs in the West region; the average price for IPC area generators was $3.27/MMBTU for 2020 (in 2015 dollars). These relatively low gas prices moderated the value of EIM flexibility to IPC. Additionally, IPC's generator portfolio modeled for 2020 includes flexible hydro resources that can respond quickly to changes in sub-hourly needs, making IPC's flexibility needs lower than those of a utility without much flexible generation.

The model's Base Scenario sets California's renewable build to meet a 33% RPS target. Recently approved legislation raises that state's renewable portfolio target to 40% by 2024 and 50% by 2030,[1] in addition to customer-side renewable resources such as rooftop solar. These developments may provide increasing opportunities for EIM participants to purchase energy from California in real time at a low cost.

The focus of this analysis is to provide consistent, conservative estimates of operational cost savings to IPC for evaluation of participation in the EIM. The study does not quantify potential benefits from improved dispatch in the hour-

[1] See California Legislature, 2015: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

ahead (HA) market or day-ahead (DA) market, which may develop over time as information produced by the EIM informs more efficient DA and HA trading. The study also does not quantify any potential reliability benefits from EIM participation, which are difficult to quantify but may be substantial if participation ultimately assists participants in avoiding a major outage. The study does not quantify potential cost impact on generator maintenance cost as a result of reduced ramping of thermal units. The study does not compare the savings to the incremental costs of joining an EIM. Finally, the study does not estimate savings to IPC or other EIM participants arising from flexibility reserve reductions due to load and variable resource diversity across the footprint.

EIM market discussion

The EIM is a balancing energy market that optimizes generator dispatch within and between Balancing Authority Areas (BAAs) every 15 and 5 minutes.[2] The EIM can create real-time dispatch cost savings for EIM participants by: (1) using software tools to identify sub-hourly transactions that produce an optimized dispatch and minimize production costs, while respecting reliability limits; (2) bringing this optimized dispatch down to a 5-minute interval level; and (3) incorporating optimized real-time unit commitment of quick-start generation.

Additionally, by allowing BAs to pool load and generation resources on a sub-hourly basis, the EIM can enable participants to reduce the number of units they individually need to commit to provide flexibility reserves within the hour. In

[2] For more information regarding the EIM, see https://www.caiso.com/informed/Pages/EIMOverview/Default.aspx.

December 2011, the CAISO implemented a flexible ramping constraint in the five-minute market optimization to maintain sufficient upward flexibility in the system within the hour.[3] Each generator chosen to resolve a constraint is compensated at the marginal generator unit's shadow price, which reflects the opportunity cost for production. The CAISO's calculation of flexible ramping constraints for EIM participants is adjusted downward to reflect diversity of net loads for all participants, subject to transmission constraints. The CAISO determines flexible ramp constraint requirements for each EIM participant based on the aggregate load, wind, and solar resource forecasts and expected variability. By establishing the requirements based on the aggregate load and resource profiles, the benefits of diversity can be reflected in the EIM flexibility reserve requirements. The flexible ramping constraint in the EIM also compensates resources for their contribution to meeting the flexibility constraint. While pooling of flex reserves can reduce variable dispatch and generator commitment costs over time as operators accumulate greater experience with the EIM, participation in the EIM does not reduce the physical generation capacity that a BA needs to serve peak loads and provide system flexibility. Long-term capacity decisions are beyond the scope of this report and are more appropriately examined using other analytical approaches and modeling tools.

[3] See CAISO, 2014: Flexible Ramping Constraint Penalty Price In the Fifteen Minute Market. Available at: http://www.caiso.com/Documents/TechnicalBulletin-FlexibleRampingConstraintPenaltyPrice-FifteenMinuteMarket.pdf. The CAISO is in the process of introducing a flexible ramping product, which would allow economic bids to be submitted to procure upward and downward ramping capability. https://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.

Modeling Approach

This study analyzes the impact of IPC participation in the EIM using the PLEXOS production cost modeling software to simulate sub-hourly operations in the Western Interconnection for the year 2020. Energy Exemplar provided technical support to this study and implemented the sub-hourly production simulation runs in PLEXOS. Savings were identified as *sub-hourly dispatch benefits*, which realize the efficiency of optimized combined 15- and 5-minute dispatch and real-time unit commitment between IPC and the current EIM footprint.

As a starting point, this study used the PLEXOS database developed by Pacific Northwest National Laboratory (PNNL) for the Western Electricity Coordinating Council's (WECC) Variable Generation Subcommittee (VGS) study from 2012-13[4] and revised as part of the NWPP Phase 1 EIM study from 2013.[5] Similar to those two studies, this analysis used a three-stage simulation process, including DA, HA, and real-time simulations stages to represent the different time horizons of actual power system operations. The DA and HA stages are simulated on an hourly basis.

The initial dataset used for this study is the database used in E3's *PGE EIM Comparative Study: Economic Analysis Report*[6], which updated the database

[4] See WECC, 2013, Balancing Authority Cooperation Concepts to Reduce Variable Generation Integration Costs in the Western Interconnection: Intra-Hour Scheduling. Available at http://energyexemplar.com/wp-content/uploads/publications/Balancing%20Authority%20Cooperation%20Concepts%20-%20Intra-Hour%20Scheduling.pdf.
[5] See Samaan, NA, et al., 2013, Analysis of Benefits of an Energy Imbalance Market in the NWPP. Available at: http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-22877.pdf.
[6] See E3, 2015, PGE EIM Comparative Study: Economic Analysis Report. Available at: http://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf

from E3's 2014 EIM study for Puget Sound Energy with input from PGE along with representatives from several northwestern BAs. The 2014 PSE database applied PSE- and CAISO-specific updates to the database originally developed for the NWPP Phase 1 EIM analysis.

E3 quantified the sub-hourly dispatch savings from IPC's participation in the EIM by (1) running a real-time BAU case that holds energy transfers between non-participating BAs (which include IPC) equal to the scheduled levels from the HA simulation but allowing EIM participants to transact with other participating BAs in the same real-time market, subject to transmission transfer limits; and (2) running EIM cases (starting from the same HA simulation as the BAU case) that each allow IPC to transact power within the hour with other EIM participants. The increased flexibility in the EIM cases produces a reduction in real time production costs for the region, which represents the total societal EIM-wide savings as a result of IPC participation. Benefits are then divided between IPC and the current EIM participants based on the change in their generation cost and their net purchases and sales in real time through the EIM.

Scenario Description

The Base Scenario of this analysis uses gas hub prices from OTC Global Holding Natural Gas Forwards & Futures, which are $3.27/MMBtu on average for 2020 (in 2015 dollars). The Base Scenario also includes renewable resource development to meet current RPS targets and projected renewable buildout for 2020. This includes a 33% RPS for California, a 15% renewable penetration for IPC, and an average 15% renewable share for other Northwest region BAAs not participating in the EIM. We also analyzed alternative scenarios which model a higher renewable penetration in the west: a 40% RPS for California, a 20% renewable share for IPC, and a 20% renewable share for the other Northwest region BAAs not participating in the EIM.

Summary of results

The base scenarios analyzed through this conservative approach resulted in modest positive sub-hourly dispatch cost savings in 2020 for IPC of $4.5 million in the EIM. IPC participation also provides incremental savings to other EIM participants. These savings are largely robust to the additional retirement of regional coal generation or the absence of planned APS and PGE participation in the EIM, with savings to IPC remaining above $4 million in all scenarios. A higher RPS would result in larger benefits for IPC participation, estimated at $5.1 million per year.

1 Introduction

Idaho Power Company (IPC) engaged E3 to analyze the potential economic benefits of IPC's participation in the Western EIM. This study seeks to identify the savings potential of IPC's participation in the Western EIM and includes a parametric sensitivity analysis to test the robustness of savings results. Sensitivity scenarios include early retirement of certain coal plants in the West, altered participation of other BAs in the EIM, and the penetration level of intermittent renewable resources.

1.1 Context for Study

Utilities throughout the WECC have been increasingly interested in exploring a wider range of opportunities for improved coordination between neighboring BAAs. These have included the

+ Western EIM (previously referred to as the CAISO EIM), which allows for a voluntary 5-minute market. The EIM began operating in November 2014 with PacifiCorp and CAISO as initial members. NV Energy began participating in 2015. Puget Sound Energy and Arizona Public Service have announced participation to begin in 2016. Portland General Electric Company has announced participation to begin in 2017.

- Northwest Power Pool investigation of a SCED for real time sub-hourly transactions, similar to an EIM, as well as other opportunities to promote more active and liquid 15-minute trading in the region.

A number of studies have highlighted the benefits of improved regional coordination, particularly in a context of higher renewable and intermittent resources on the system. These types of resources incur higher variability and forecast error for each BA, and without regional coordination each individual BA would be forced to maintain higher flexibility to combat this increased intermittency. IPC engaged E3 to conduct a comparative study of the impact and potential savings from IPC participation in the EIM. E3, working with Energy Exemplar, analyzed IPC participation using a three-stage zonal production simulation model of the Western Interconnection in PLEXOS. This study was done in close coordination with Energy Exemplar and IPC staff.

1.2 Structure of this Report

The remainder of this report is comprised of the following sections:

- **Section 2** describes the key study assumptions and methods used in this analysis.
- **Section 3** presents the results of our analysis of IPC participation in the Western EIM.

2 Study Assumptions and Approach

2.1 Overview of Approach

The Western EIM allows participating Western BAs to voluntarily participate in CAISO's real-time energy market. EIM software dispatches generation across participating BAAs every 15 and 5 minutes to solve imbalances, as well as committing quick-start generation every 15 minutes using security constrained unit commitment (SCUC). An important distinction between the EIM and a Regional Transmission Organization is that in the EIM each participating BA remains responsible for meeting its own operating reserve and planning reserve requirements, and the EIM does not replace participating BAs' existing operational practices for unit commitment and scheduling in advance of real-time.

This study quantifies the benefit of sub-hourly dispatch capability using a three-stage simulation process in PLEXOS consistent with the approach developed for the WECC Variable Generation Subcommittee (VGS) and refined in PNNL's Phase 1 Report for the NWPP MC Initiative. This methodology is described in detail in Section 2.4 below.

This study is designed to measure one principal type of benefits: **sub-hourly dispatch benefits**. Today, each BA in the Western Interconnection outside of the EIM typically dispatches its own internal generating resources to meet imbalances within the hour, while holding real-time exchange with neighboring BAs fixed to the hour-ahead schedule. The EIM can net energy imbalance across participating BAs and economically dispatch generating resources across the entire EIM footprint to manage the imbalance, resulting in operational cost savings. IPC's participation in an EIM enables incremental dispatch efficiency improvements relative to an EIM without IPC.

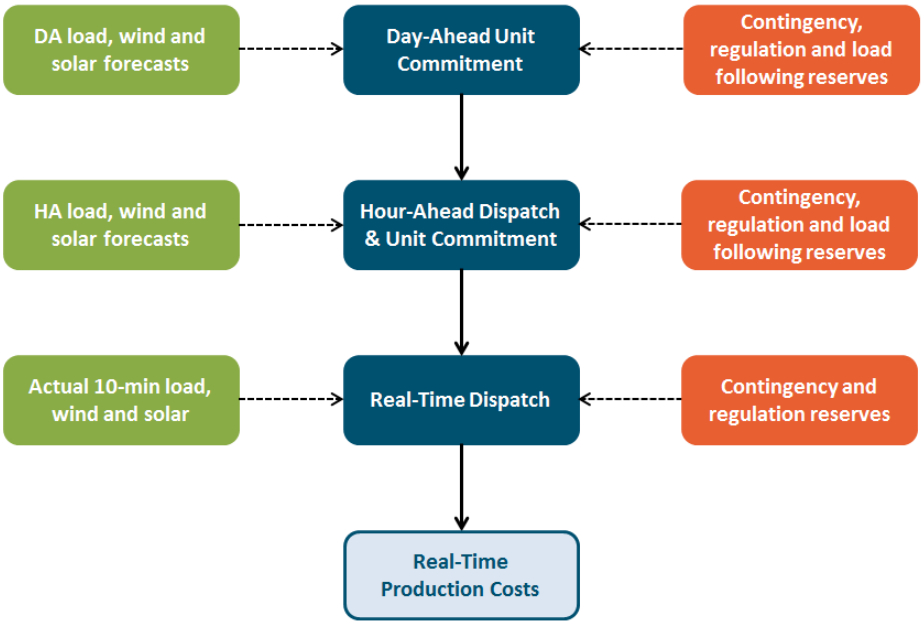
This study does not quantify savings associated with flexibility reserve reductions. Pooling flex reserves can reduce variable dispatch and generator commit costs, especially as operators accumulate greater experience with the EIM. However, each BA still needs to serve peak loads and provide system flexibility; thus, participation in the EIM does not reduce the physical generation capacity that a BA needs. Long-term capacity decisions are beyond the scope of this report and are more appropriately examined using other analytical approaches and modeling tools.

2.2 Sub-hourly Dispatch Benefits Methodology

2.2.1 PRODUCTION COST MODELING

This study used PLEXOS, a sub-hourly production cost model, to estimate sub-hourly dispatch benefits in 2020. PLEXOS, like other production cost models, simulates bulk power system operations by minimizing the variable cost of operating the system subject to a number of constraints. PLEXOS includes a three-stage sequential simulation process to model DA, HA, and real-time operations, as shown in Figure 1 below.

Figure 1. PLEXOS Three-Stage Sequential Simulation Process



The primary purpose of the DA simulation is to generate daily unit commitment schedules for long-start units, while the HA simulation determines the HA dispatch as well as hourly interchange schedules between BAs. During the real-time simulation, the “actual” load, wind, and solar data are used to generate dispatch, and flexibility reserves are “released” so that the capacity reserved from the HA simulation is allowed to serve real-time imbalances. The DA, HA, and real-time sequential simulation approach allows PLEXOS to differentiate operations for BAs participating or not participating in the EIM. When a BA is not participating in a real-time market, then: (a) interchange is unconstrained during the DA and HA simulations; and (b) during the real-time simulation, the HA interchange schedule is locked down, resulting in the BA managing its imbalances with its own generation.

In contrast, during the real-time simulation, BAs participating in the EIM can re-dispatch generation and exchange power with the rest of the EIM footprint during each of the 10-minute intervals, subject to transmission transfer limitations, which are discussed in Section 2.3.2 below.

While the Western EIM operates down to a 5-minute level in practice, the most validated sub-hourly WECC dataset available for this analysis includes 10-minute intervals. Using the 10-minute intervals is a practical but conservative compromise of modeling 15-minute optimization with higher EIM transfer capability and modeling 5-minute optimization with potentially more limited EIM transfer capability across paths limited by dynamic transfer limitations across the California-Oregon Intertie (COI) and BPA network. In the final stage, the RT simulation for this study is run with 10-minute intervals, using actual wind, load, and solar output for each interval. While actual EIM operations are on a 5-minute basis, a complete and validated PLEXOS dataset for 5-minute simulation was not available at the time of this study. This study's use of 10-minute time step in the real-time stage (to make use of the WECC VGS dataset) produces EIM benefits results that we expect may be conservatively low, as the 10-minute time step reduces the amount of variation within the hour to a small extent, slightly moderating the need for operational flexibility that an EIM could provide. Overall, however, we expect the 10-minute time step to capture the majority of the real-time dispatch efficiency savings.

2.2.2 BAU SIMULATION

In the BAU case, IPC does not participate in the EIM, and must resolve its real-time imbalances with internal generation only. IPC's real-time import and exports are held fixed to the hour-ahead schedule.

Real-time sub-hourly interchanges are simulated among BAAs that are modeled as existing participants in the Western EIM, reflecting the operational efficiencies realized by the EIM before including IPC participation. In other words, the Western EIM is assumed to be fully operating without IPC's participation. As a result, savings and efficiencies associated with sub hourly dispatch for each alternative are included in the system cost. These costs serve as the "control" case to compare against the cases with IPC participation.

The BAU case includes operations of a "current EIM" consisting of the seven BAAs that were participating or had announced plans to participate in the EIM at the start of this study. The BAAs modeled as current participants in the EIM for the BAU Case are listed in the table below.

Table 3: BAA Participants in EIM in BAU Case

Current EIM participants for BAU Case
CAISO
PacifiCorp East (PACE)
PacifiCorp West (PACW)
NV Energy (NVE)
Puget Sound Energy (PSE)
Arizona Public Service (APS)
Portland General Electric (PGE)

2.2.3 WESTERN EIM SIMULATIONS

The EIM cases simulate real-time dispatch with IPC participating in the Western EIM. In each of these cases, intra-hour interchange between IPC and existing EIM participants is allowed up to the assumed transmission transfer limits.

2.3 Key Modeling Assumptions

Three key modeling assumptions are important for understanding the results of this study: (1) sub-hourly dispatch; (2) real-time transmission capability; and (3) hurdle rates.

2.3.1 SUB-HOURLY DISPATCH

In existing operational practice, BAs in the Western Interconnection exchange energy primarily on an hourly basis using hourly or multi-hour schedules, or standardized energy products which include On-Peak, Off-Peak, and Flat energy blocks. These products require long lead times between scheduling the transaction and actual dispatch.[7] Within the hour, each BA resolves imbalances by dispatching generating resources inside its BAA, without the assistance of other BAs. By contrast, the EIM optimizes dispatch of available generating resources in real time across all of the participating BAAs using 15-minute unit commitment and 5-minute dispatch. These sub-hourly processes increase the efficiency of resolving imbalances.

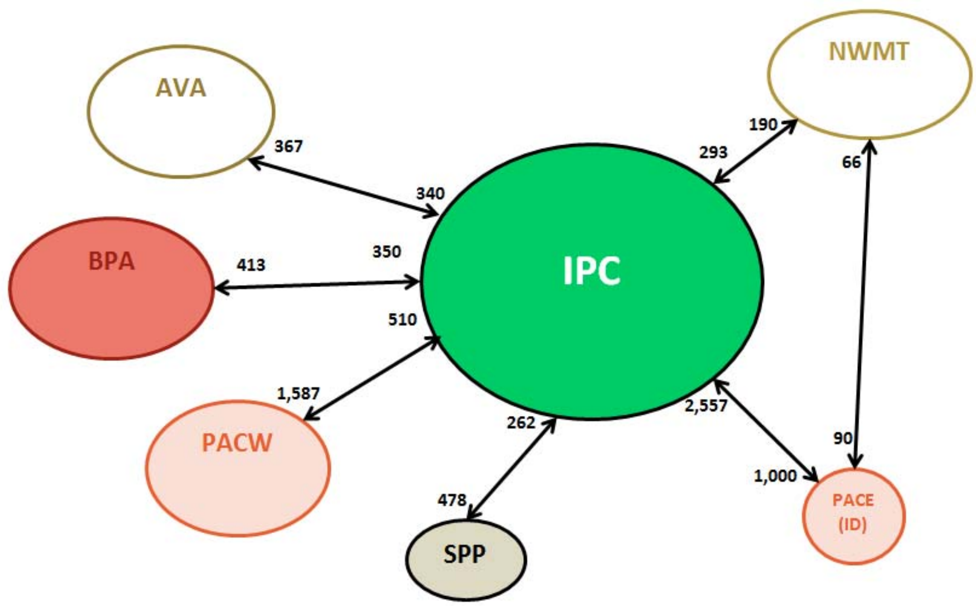
2.3.2 REAL-TIME TRANSMISSION TRANSFER CAPABILITY

Previous studies have indicated that transmission can constrain EIM benefits by limiting the amount of power that can be transferred in real time between participants. This study's transmission topology was built on that of E3's PGE EIM study from 2015 and was updated with the help of IPC transmission experts.

IPC's BAA has direct connections with six other BAAs: AVA, BPA, PACW, PACE, NVE, and NWMT. IPC has significant transfer capability with both PACE and PACW. In the BAU Scenario (without IPC participating) PACE and PACW were assumed to have only 200 MW of east to west dynamic capability between them available for incremental EIM transfers not scheduled in the hour ahead. A zonal depiction of IPC's transmission interconnections is shown in Figure 2.

[7] The Western EIM and AESO are the exceptions.

Figure 2. Real-time Transfer Capabilities with IPC



2.3.3 HURDLE RATES

Within the Western Interconnection's bilateral markets, there are a number of impediments to efficient trade of energy across BAA boundaries. These include:

+ The need, in many cases, for market participants to pay for the fixed costs of the existing transmission system by redirecting or acquiring additional point-to-point transmission service in order to schedule transactions from one BAA to another;
+ The current tariff practice of requiring short-term transactions to provide real power losses for each transmission provider system that is utilized, in some cases resulting in multiple or "pancaked" loss requirements that are added to the fixed costs described above; and

+ Inefficiencies related to having illiquid bulk power and transmission service markets and imperfect information, such as DA block trading products, minimum transaction quantities of 25 MW, and the bilateral nature of transaction origination and clearing.

These real-world barriers to trade are reflected in production cost simulations as “hurdle rates”, which are applied as $/MWh price adders to energy transfers on interfaces between BAAs. Hurdle rates are applied in the DA and HA cases to inhibit power flow over transmission paths that cross BAA boundaries, to represent these inherent inefficiencies and reduce economic energy exchange between BAAs.

The EIM eliminates the barriers listed above during real-time operations by performing security-constrained economic dispatch across the entire EIM footprint, allowing more efficient (i.e., lower cost) dispatch. Our production simulations in PLEXOS capture this effect by removing hurdle rates in real time. Intra-hour exchanges among participants in the EIM are allowed during the real-time simulation cases. The simulation does not allow incremental intra-hour exchanges (beyond the HA schedule) between BAAs that are non-participants in an EIM. The absence of hurdle rates in real time in this analysis is consistent with the FERC-approved CAISO tariff amendment associated with the EIM.

In the DA and HA simulations, hurdle rates are maintained between all BAAs, including between EIM participants. We believe this is a conservative assumption regarding the expected adaptation of DA and HA markets based on information identified by the EIM. In reality, we expect that BAs may adjust their DA and HA scheduled transactions more efficiently over time based on learning the dynamics of the real-time market results. This learning does not imply a shift away from DA and HA scheduling, but rather a more efficient and better informed selection of scheduling levels for any hour based on learning from real-time market participation. To the extent it can be realized, this opportunity for learning and improved DA and HA efficiency is a non-quantified benefit that would be additional to those quantified in this report.

In addition to the hurdle rates described above, charges for CO_2 import fees related to California Assembly Bill (AB) 32 are still applied to energy transfers from BAs outside of California to California BAs. These charges are applied in all cases, including real-time.

For interties among the current EIM participants, hurdle rates were applied to the DA and HA cases, but removed during the real-time case runs for both the BAU and EIM cases.

2.3.4 FLEXIBILITY RESERVE REQUIREMENTS

By pooling load and resource variability across space and time, total variability of the combined net load for participants in the EIM footprint can be reduced, decreasing the amount of flexibility reserves required to ensure reliable operations. This reduces operating costs by:

- requiring fewer thermal generators to be inefficiently committed and operated, and

- decreasing flex reserve requirements placed on hydro resources, enabling them to more efficiently generate energy at times most valuable to their systems.

Units that provide regulating reserves must respond faster than the EIM's 5-minute dispatch interval, so EIM participants are assumed here to receive no regulating reserve diversity savings as a result of participation in the EIM.

While there is currently no uniformly defined requirement for BAs to carry flexibility reserves, all BAs must maintain Area Control Error (ACE) within acceptable NERC-defined limits, which necessitates that BAs hold reserves on generators to respond to within-hour changes in load and variable resource output. These reserve needs will grow under higher renewable penetration scenarios.

Additionally, in December 2014, the CAISO implemented a flexible ramping constraint in the five-minute market optimization to maintain sufficient upward flexibility in the system within the hour.[8] Generators that are chosen to resolve a constraint are compensated at the generation shadow price, which reflects the marginal unit's opportunity cost. Furthermore, the CAISO is in the process of introducing a flexible ramping product, which would allow economic bids to be submitted to procure upward and downward ramping capability.

The CAISO's calculation of flexible ramping constraints for EIM participants is adjusted to reflect diversity of net loads for all participants, subject to transmission constraints. The CAISO determines flexible ramp constraint

[8] See CAISO, 2014, Flexible Ramping Constraint Penalty Price In the Fifteen Minute Market. Available at: http://www.caiso.com/Documents/TechnicalBulletin-FlexibleRampingConstraintPenaltyPrice-FifteenMinuteMarket.pdf. See also CAISO , 2015, Flexible Ramping Products Revised Draft Final Proposal. Available at: https://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.

requirements for the CAISO and each EIM participant based on the aggregate load, wind, and solar resource forecasts and expected variability. By establishing the requirements based on the aggregate load and resource profiles, the benefits of diversity can be reflected in the EIM flexibility reserve requirements. The flexible ramping constraint in the EIM also compensates resources for their contribution to meeting the flexibility constraint.

In the simulations run for this study, flexibility reserves were **not** adjusted to reflect net load diversity in any scenario (BAU and EIM case). This means that the benefits found in this study do not include benefits arising from reductions in flexibility reserves upon joining the EIM. In a previous study, E3 estimated that PGE would receive $0.8 million in *additional* savings due to reduced flexibility reserves from joining the Western EIM.

2.4 Detailed Scenario Assumptions

2.4.1 INPUT DATA

The initial dataset used for this study is the database used in E3's *PGE EIM Comparative Study: Economic Analysis Report*[9], which updated the database from E3's 2014 EIM study for Puget Sound Energy with input from PGE along with representatives from several northwestern BAs. The 2014 PSE database applied PSE- and CAISO-specific updates to the database originally developed for the NWPP Phase 1 EIM analysis.

[9] See E3, 2015, PGE EIM Comparative Study: Economic Analysis Report. Available at: http://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf.

This study for IPC further refined the study database used in the PGE EIM analysis. These refinements are described below in more detail. Utilizing this database allowed this study to reflect the best available information compiled to represent BAAs in the Northwest.

This study made the following key updates to the case:

- **Topology updates**. The 2015 PGE EIM study was used as a starting point for topology data. Major changes include removing a transmission link from SCL to IPC zones because it is a link to SCL-owned hydro generator at Lucky Peak, not the SCL balancing authority area. Additionally, E3 updated the line rating for the link between Northwestern and IPC to reflect the latest WECC path ratings.
- **Gas prices**. Monthly 2020 hub prices came from OTC Global Holding Natural Gas Forwards & Futures (provided by SNL) for selected hubs in the West region.[10] As in the PGE EIM study, these data were translated from hub prices to BA- or plant-specific burner tip prices using the mapping of pipelines, variable transport fees, and other adjustments outlined in the NWPP Phase 1 assessment.
- **Hydro optimization window**. In practice, IPC plans its dispatch of flexible hydro units up to a week in advance to optimize the value of its reservoirs. This flexibility of hydro generation is prominent in the Northwest. Yet modeling hydro as such in PLEXOS runs the risk of unrealistically optimizing hydro dispatch with perfect foresight over a very long time horizon, without reflection of forecast error in identifying when the hydro will most be needed. Therefore, to balance dispatchable hydro units and maintain flexibility, while preventing

[10] Obtained from SNL Financial LC on October 15, 2015

perfect foresight, dispatchable hydro units for this study are optimized with a 24-hour optimization window. In this study, hydro modeling is handled through a series of interactions between simulation stages: monthly hydro energy budgets, which are database inputs, are allocated to each day using PLEXOS's monthly MT simulation based on anticipated load, wind, and solar across the month. Then, the DA and HA simulation stage first optimizes the hydro for each hour based on a DA and HA forecast of hourly load, wind and solar, constrained by the daily generation budget. The RT simulation is permitted to update the hourly hydro schedule across the day to respond to real-time needs within each of the six 10-minute sub-hourly intervals each hour but must maintain the same daily hydro energy total.

+ **Renewable generation updates in California**. Consistent with the PGE EIM study, this analysis has also updated the CAISO renewable resource mix to reflect a higher expected share of solar PV in the 2020 renewable resource portfolio and lower share of wind resources, based on current and planned additions for meeting the state's 33% RPS target by 2020. The resource mix was also adjusted to include additional rooftop PV solar in the CAISO, which was not reflected in the original TEPPC model.

+ **Generation updates in the Northwest**. In order to collect and verify generator data for the PGE EIM study, PGE arranged discussions with experts from several northwestern BAs, including IPC. The data collected from these sessions were integrated in the PGE study database. For this study, IPC reviewed and largely maintained this data, making minor changes to its generator fleet. In the early coal retirement scenario the following units were retired as well: Valmy1, Valmy2, RdGrdnr4, Navajo1, SanJuan2, SanJuan3.

2.4.2 DISPATCH SAVINGS SCENARIOS

The dispatch savings were evaluated under 4 scenarios with different assumptions regarding the current participants in the EIM, the retirement dates of coal plants throughout the west, and the buildout of renewable resources by 2020. The scenarios were developed based on input from IPC staff to highlight changes that IPC believed both plausible to occur and also valuable to explore to test the robustness of EIM savings. Table 4 summarizes the assumptions used for each scenario modeled for calculating sub-hourly benefits.

Because IPC is interested in the benefits of joining the Western EIM[11], this study defines a base scenario that represents a plausible trajectory for the West's operating environment in which IPC joins the Western EIM. This base scenario is subjected to three sensitivities: (1) APS and PGE are assumed to not have joined the EIM by 2020 as planned; (2) Certain coal plants in the West are modeled to retire earlier than planned in the base case; and (3) significant renewable generation is added in California and throughout the West.

[11] In all scenarios but one, CAISO, PAC, NVE, PSE, APS, and PGE are assumed to be already participating in the Western EIM in order to provide the most accurate baseline scenario, given the information available over the course of this study. A single sensitivity scenario models APS and PGE as not having joined the EIM by 2020.

Table 4. Overview of EIM Scenario Assumptions

Scenario	Renewable Energy Target (%)* IPC	CAISO	Other NW BAAs	Coal Capacity in WECC (GW)	BAAs in EIM Case
1. Base	15%	33%	15%	35.0	CAISO, PACW, PACE, NVE, PSE, APS, PGE, IPC
2. No APS or PGE in EIM	15%	33%	15%	35.0	CAISO, PACW, PACE, NVE, PSE, IPC
3. Early Coal Retirements	15%	33%	15%	31.3	CAISO, PACW, PACE, NVE, PSE, APS, PGE, IPC
4. High RPS	20%	40%	20%	35.0	CAISO, PACW, PACE, NVE, PSE, APS, PGE, IPC

*PGE BAA includes non-PGE customers, resulting in a smaller renewable energy share of BAA load than RPS target; CAISO RPS includes renewable energy from out of state imports, does not reflect behind the meter PV generation.

Table 5. Renewable Capacity Added in High RPS Scenario (MW)

Region	Zone	Wind	Solar PV	Geothermal
FAR EAST	IPC		128	
MAGIC	IPC		132	
TREAS	IPC		112	
PG&E_VLY	CAISO	2,489	1,973	
SCE	CAISO	514	1,724	491
SDGE	CAISO	102		
AVA	NW	774		
BPA	NW	1,737	135	
PGE	NW	484		
SMUD	NW	498	616	
TIDC	NW		84	

2.5 Methodology for Attributing Benefits to IPC and Other Participants

To evaluate the benefits yielded by an EIM, we calculated the difference between procurement costs in a business-as-usual case and in an EIM case. There are three components of total procurement costs in our model: hour-ahead net import costs, real-time imbalance costs, and real-time generation costs. First, we define a few terms.

+ Hour-ahead net imports: the hourly difference between imports and exports.

- Locational marginal price (LMP): a given BA's generation shadow price in a certain time period (the cost of generating an additional MWh of electricity).[12]
- Real-time imbalance: the within-hour energy imbalance found in the EIM cases, where trading occurs at 10-minute intervals.
- Average LMP: the imbalance-weighted average of all EIM BAs' LMPs.

Hour-ahead net import costs are calculated as the product of hour-ahead net imports and the locational marginal price, and then summed over all hours in the year. Real-time imbalance cost to a given BA is a 10-minute interval's imbalance multiplied by that interval's average LMP, summed over all 10-minute intervals in the year. Real-time generation costs include the variable costs of energy production modeled in PLEXOS – fuel prices (updated by E3 based on OTC Global Holding Natural Gas Forwards & Futures data provided by SNL), and variable operation and maintenance and unit startup costs (based on the costs characteristics for units in the TEPPC database, but not directly modified for this study).

Total savings associated with an EIM are the difference between the sum of hour-ahead net import costs, real-time imbalance costs, and real-time generation costs in the business-as-usual case and the EIM case. In all scenarios, the hour-ahead simulation is identical for the business-as-usual and the EIM cases, meaning the hour-ahead net import costs can be ignored in the

[12] The minimum LMP used for calculating benefits was set to -$100/MWh, which is the model's penalty price for overgeneration. In overgeneration conditions, renewable resources may be curtailed but also could require replacement costs for renewable energy to fulfill RPS goals in some jurisdictions.

calculation. Table 6 provides an example of benefits parsing that highlights the methodology discussed in this section.

Table 6. Benefits Parsing in the Base Scenario, IPC in Western EIM

Costs (2015$ million)*	Business-as-Usual	Western EIM	EIM Savings vs. BAU
Real-Time Generation and Import Costs	$108.8	$110.1	($1.3)
Real-Time Imbalance Costs (Market Revenues)	($0.1)	($5.9)	$5.8
Total Real-Time Procurement Costs	**$108.7**	**$104.2**	**$4.5**

Note: Individual estimates may not sum to total due to rounding. Positive values in the final column represent cost reductions, or savings in the EIM case relative to the BAU.

3 Results

3.1 Benefits to IPC

Table 7 below presents the simulated annual benefits of IPC participation in the EIM in 2020 under each sensitivity scenario. Each cell in the table represents the incremental benefit to IPC as a result of its participation in the EIM. These savings are each calculated as the reduction in cost compared to the IPC BAU case. Overall, the dispatch cost savings range from $4.1 million in the early coal retirement scenario to $5.1 million in the high RPS scenario. Reduced reserves would provide additional savings in addition to these figures, though reserve reductions were not modeled for this study.

Table 7. Annual Benefits to IPC by Scenario, EIM (2015$ million)

Scenario	Dispatch cost savings to IPC
Base	$4.5
Sensitivity Scenarios	
No APS/PGE in EIM	$4.2
Early Coal Retirement	$4.1
High RPS	$5.1

*Dispatch cost savings for Sensitivity Scenarios are shown as alternatives to the Base case, not cumulative additions. Reserves savings were not modeled.

EIM base scenario savings to IPC were $4.5 million with a decrease in annual real-time procurement costs (real-time generator production cost plus real time imbalance cost of purchases and revenue from sales) from $108.7 million in the BAU case to $104.2 million in the EIM case (a reduction of more than 4%). Section 3.3 goes into more detail for each sensitivity scenario.

3.2 Incremental Benefits to Current EIM Participants

Table 8 below presents the simulated incremental benefits resulting from IPC's EIM participation to the current participants in the EIM. IPC's EIM participation is expected to create $2.2 to $3.1 million in yearly savings to the current EIM participants across all scenarios.

Table 8. Annual Benefits to Current EIM Participants by Scenario (2015$ million)

Scenario	Incremental savings to Existing EIM Participants
Base	$2.9
Sensitivity Scenarios	
No APS/PGE in EIM	$2.2
Early Coal Retirement	$3.0
High RPS	$3.1

*Dispatch cost savings for Sensitivity Scenarios are shown as alternatives to the Base case, not cumulative additions. Reserves savings were not modeled.

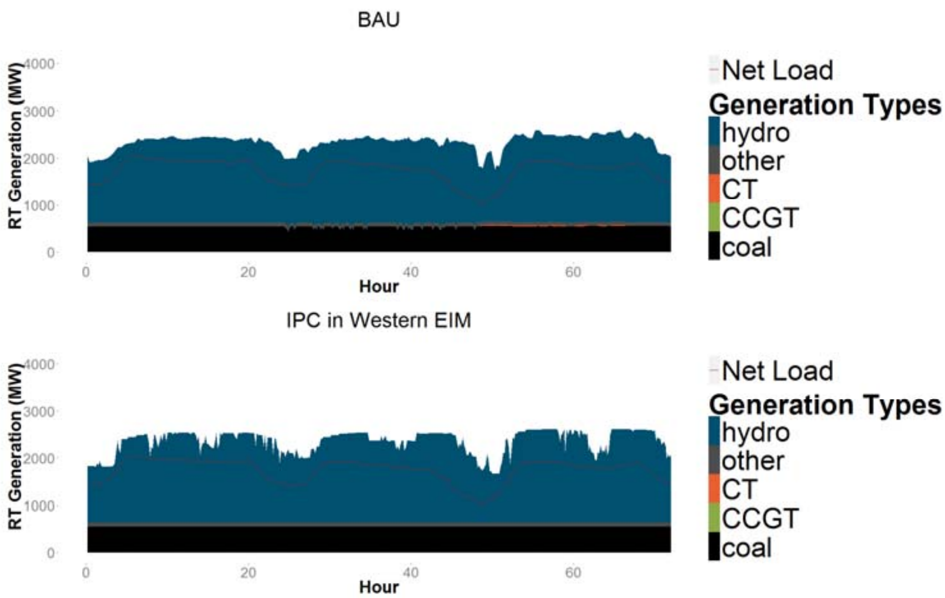
3.3 EIM Results Discussion

3.3.1 BASE SCENARIO

The base scenario brings $4.5 million of savings to IPC, as well as $2.9 million to the existing EIM participants. Various factors underlie EIM participation benefits in the scenarios modeled. In all scenarios, EIM participation enables IPC to export and import with other EIM participants in real time to respond to intra-hour imbalances. As illustrated in Table 6, IPC's real-time generation costs increase in the EIM, while its imbalance costs decrease by a larger amount. This is because, in the EIM, IPC can export its hydro generation extremely flexibly at 5-minute intervals, ramping the units up when LMPs are high and down when prices are low. A second benefit of EIM participation is smoother operation of thermal units; the real-time flexibility of the EIM prevents thermal generators from having to respond to within-hour imbalances (for the most part), decreasing ramping. This flexibility also allows IPC to avoid starting and running its CT generators at times.

The following chart illustrates all the benefits described above, displaying IPC's dispatchable generation in real time over a three-day period in the spring. In the EIM dispatch chart, hydro output is highly variable at the 10-minute level, in striking contrast to the smooth hydro output seen in the BAU case. Thermal generation is perfectly constant in the EIM case, whereas ramping is required in the BAU case. Furthermore, CT units are not used at all in the EIM case, whereas CT units are started and turned off at least four times in the BAU case.

Figure 3. IPC Real-Time Dispatchable Generation, Western EIM, April 28 – May 1



3.3.2 ALTERNATIVE SCENARIOS

Modeling APS and PGE as not in the EIM slightly reduces the size of the total EIM market and has a small downward impact on IPC savings relative to the base case, to $4.2 million.

The scenario with additional retirement of regional coal generators produces savings $0.4 million lower than the savings to IPC in the base scenario ($4.1 million in the early coal retirement case - $4.5 million in the base case). This difference is less than 10% of total savings, and is thus also fairly insignificant, indicating that model results for identified IPC savings are robust to participation and coal resource retirement.

The high RPS scenario brings $5.1 million of savings for IPC, which is $0.6 million higher than the savings in the base scenario. As expected, a higher renewable generation buildout increased savings to IPC, as the EIM allows resources from a wider area to address real-time variability in net load, and creates increased revenue opportunities for IPC's flexible hydro generation in the real-time market.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 68

IDAHO POWER COMPANY

Attachment 2
Valmy Closure Report

December 8, 2017

Attachment 2
Narrative Summary and Results
Supplemental 2019 Valmy Unit 1 Shutdown Analysis

The following document provides a narrative description of the Company's updated 2019 Valmy Unit 1 shutdown analysis. This document begins with a brief description of risk factors considered in the development of the 2015 Integrated Resource Plan ("IRP"), then details changes in these risk factors that have occurred since its completion. The document concludes with a summary of the results of the supplemental Unit 1 shutdown analysis, and the Company's recommendation to utilize a December 2019 Valmy Unit 1 retirement date for development of the 2017 IRP.

A. 2015 IRP Risk Factors and Preferred Portfolio

With respect to the Valmy plant, the preferred portfolio from the Company's 2015 IRP reflected a 2025 shutdown for both Units 1 and 2. This portfolio was selected, in part, to shield the resource plan from the following risk factors:

Public Utilities Regulatory Practices Act of 1978 ("PURPA") Solar Projects

Resource sufficiency modeling in the 2015 IRP reflected 320 megawatts ("MW") of yet-to-be-constructed solar. At the outset of the 2015 IRP process there were 461 MW of PURPA solar projects under contract, which ultimately was reduced to 320 MW following the cancellation of 141 MW that occurred during the development of the IRP. These cancellations demonstrated uncertainty related to the level of capacity under contract that would ultimately be realized.

CO2 emissions regulation under Section 111(d) of the Clean Air Act ("111(d)")

On June 2, 2014, the Environmental Protection Agency ("EPA"), under President Obama's Climate Action Plan, released its proposal to regulate CO_2 emissions from existing power plants under CAA Section 111(d). EPA's proposed Clean Power Plan includes mandatory CO_2 reduction targets for each state designed to achieve nationwide 30-percent CO_2 emission reductions over 2005 levels by 2030.

The final impact of proposed 111(d) regulations was not yet known at the time the 2015 IRP was prepared, creating uncertainty with regard to a number of the Company's generation facilities.

Boardman-to-Hemingway ("B2H") transmission line construction

As discussed further below, the Company was not as advanced in the B2H permitting process during the development of the 2015 IRP as it is in the development of the 2017 IRP, resulting in relatively higher risk in 2015 with respect to the online date of this resource.

Retirement planning for a jointly owned power plant (North Valmy)

Uncertainty existed related to challenges associated with arriving at a retirement date mutually feasible to NV Energy and Idaho Power.

Preferred Portfolio

When modeling portfolios for the 2015 IRP, the first deficit under the 2019 Valmy Unit 1 shutdown scenario was expected to occur in July 2021, including the 320 MW of PURPA solar detailed above. Based on the aforementioned risks and what was known at that time, the Company selected a preferred portfolio that reflected a 2025 shutdown date for both Valmy units. Therefore, when the Company prepared its request for the current application filed in October of 2016 (IPC-E-16-24), it utilized the 2025 shutdown date for both Valmy units to align with the preferred portfolio from its most current IRP.

B. Updated 2017 IRP Risk Factors

As discussed in the Company's initial Response to Staff's Data Request No. 2-i, Idaho Power committed to perform a supplemental analysis to examine the impacts of a 2019 Valmy Unit 1 shutdown scenario utilizing updated assumptions developed for the 2017 IRP. Changes in the risk factors identified in the 2015 IRP are detailed as follows:

PURPA Solar

Uncertainty no longer exists with regard to the PURPA solar contracts that had not yet been built at the time the 2015 IRP was developed. The amount of solar built and available is currently 270 MW, with 20 MW under construction and 9 MW under contract, for total solar capacity of 299 MW.

CO2 emissions regulation under 111(d)

On October 23, 2015, the final Clean Power Plan was published in the Federal Register and the EPA proposed a Federal Implementation Plan.

On February 9, 2016, the U.S. Supreme Court issued orders staying the Clean Power Plan pending resolution of challenges to the rule. On September 27, 2016 the U.S. Court of Appeals for the District of Columbia Circuit heard oral arguments en banc before a panel of ten judges. The en banc review is likely to speed up the overall litigation process; however, timing of the final outcome is difficult to predict. While no details are available at this time, the President Trump administration has publicly stated its intent to scale back the Clean Power Plan.

Operating experience of the Valmy plant since the 2015 IRP reflects its continued utilization as primarily a capacity-providing resource. While still uncertain, emissions restrictions resulting from 111(d) are expected to have greatest impact on baseload energy production from affected resources such as Valmy; therefore, the capacity provided by Valmy is assumed unaffected by 111(d) restrictions. Moreover, as discussed further below, the capacity provided by Valmy Unit 1 is assumed to be replaceable upon retirement by capacity imports across the existing Idaho—Nevada transmission path. Thus, while uncertainty related to 111(d) persists, the Company does not continue to view this uncertainty as precluding December 2019 retirement of Valmy Unit 1.

B2H transmission line construction

The permitting of the B2H transmission line has advanced since the 2015 IRP filing and Idaho Power expects a record of decision on the BLM's Preferred Route in Spring 2017.

Retirement planning for a jointly owned power plant (North Valmy)

Challenges remain in arriving at a mutually feasible retirement date. However, consistent with the action plan from the 2015 IRP, Idaho Power and NV Energy are continuing to work together to synchronize depreciation dates and establish a date to cease Valmy operations.

C. 2017 IRP Supplemental Analysis Study Results

Under updated 2017 IRP assumptions, the first peak-hour capacity deficit occurs in July 2024 if Valmy Unit 1 capacity is removed in December 2019. Since the 2015 IRP, Valmy functions primarily as a capacity-providing resource during periods of high energy demand. For the 2017 IRP, Idaho Power assumes the capacity provided by Valmy is likely to be relatively infrequently needed, and consequently replaceable upon retirement by capacity imports across the existing Idaho—Nevada transmission path. Specifically in regard to Valmy Unit 1, the assumption that its relatively infrequently needed capacity can be replaced by capacity imports across the Idaho—Nevada path effectively nullifies the July 2024 deficit. Consequently, under this assumption, the load and resource balance for the 2017 IRP has no capacity or energy deficits through 2025 with Valmy Unit 1 ceasing operations in 2019.[1]

Idaho Power has also performed analyses related to the impacts of a December 2019 Valmy Unit 1 retirement on fixed costs and variable costs in accordance with assumptions from the 2017 IRP. The results of these analyses are summarized in the tables below; please note, the supporting workpapers and analysis details are provided in Attachments 2 through 7 provided with this supplemental response.

Table 1
Valmy 1 Shutdown Fixed Cost Impact
Modification from December 2025 to December 2019
Present Value of Revenue Requirements
($ millions)

Cost Component	**Incremental Impact**
Accelerated Depreciation	$10.979
Return, Tax, Interest – Existing Investment	($18.636)
Non-Fuel Operations & Maintenance Expense	($19.958)
Run Rate Capital	($4.100)
Return, Tax, Interest – Run Rate Capital	($1.304)
Total	($33.019)

[1] Under assumption the Jim Bridger Units 1 and 2 are operating beyond 2025.

Table 2
Valmy Unit 1 Shutdown Variable Cost Impact
Modification from December 2025 to December 2019
Multiple Gas Price Scenarios
($ thousands)

Year	IRP Planning Case Gas	200% Gas	300% Gas	400% Gas
2020	($19)	($92)	$795	$4,437
2021	($14)	$282	$5,427	$14,974
2022	($37)	$1,647	$6,413	$11,727
2023	($47)	$3,308	$10,736	$17,901
2024	($40)	$4,634	$12,408	$20,351
2025	($35)	$6,335	$14,458	$22,669
Nominal Impact	($192)	$16,114	$50,238	$92,059
NPV Impact	($123)[2]	$9,614	$31,068	$58,174

As detailed in Tables 1 and 2, the Company's quantitative analysis indicates that cost savings are achieved through movement of the Valmy Unit 1 retirement date from December 2025 to December 2019 in all cases ranging from the Planning Case to the 300% Gas case. Only at the 400% Gas case or higher does the variable cost impact exceed the fixed cost benefit of $33.019 million as detailed in Table 1.

D. Conclusion and Recommendation

As discussed above, several of the qualitative risk factors that existed when the 2015 IRP was developed have been mitigated in the two years since its completion. Further, the Company's updated quantitative analysis reflects cost savings related to the 2019 Valmy Unit 1 shutdown without having a material impact on system reliability. Therefore, based on the combination of the qualitative and quantitative factors detailed above, Idaho Power is recommending that the December 2019 retirement of Valmy Unit 1 from the resource stack be used in the planning assumptions for the 2017 IRP. The Company publicly presented this recommendation to the IRP Advisory Committee at the public meeting held on March 9, 2017, and intends to use the 2019 Valmy Unit 1 shutdown assumption throughout the development of the final 2017 IRP.

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[2] Counter intuitively, the analysis of variable cost impact indicates a small benefit (NPV of $123,000) associated with the earlier retirement under the IRP Planning Gas Case. This benefit is viewed as immaterial from a resource planning perspective, with the result effectively interpreted as zero cost impact associated with earlier retirement.

ATTACHMENTS 2.1 – 2.5 ARE CONFIDENTIAL PER PROTECTIVE ORDER 17-292 AND WILL BE PROVIDED SEPARATELY VIA CD

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing documents in Docket LC 68 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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