BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 68

In the Matter of IDAHO POWER COMPANY, 2017 Integrated Resource Plan	Staff's Opening Comments

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Introduction

These are Staff's initial comments and recommendations regarding Idaho Power Company's (Idaho Power or Company) 2017 Integrated Resource Plan (IRP). Staff will continue to review the Company's filed plan, responses to data requests, and parties' comments before filing final comments in this docket on January 18, 2018 and a Staff Report on March 15, 2018. The Staff Report will have Staff's conclusions regarding whether the IRP satisfies the Commission's IRP guidelines and recommendations regarding acknowledgment of Idaho Power's Action Plan. Overall, the Company has been responsive to stakeholder concerns and suggestions. Throughout the comments below, Staff highlights areas of concern in addition to areas Staff found commendable.

IRP Action Plan

In the 2017 IRP, Idaho Power requested acknowledgement for a series of Action Items, listed below:

1. Continue planning for western EIM participation beginning in April 2018.

2. Investigate solar PV contribution to peak and loss-of-load probability analysis.

3. For North Valmy Unit 1, plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2019. Assess import dependability from northern Nevada.

4. For Jim Bridger Units 1 and 2, plan and negotiate with PacifiCorp and regulators to achieve early retirement dates of year-end 2028 for Unit 2 and year-end 2032 for Unit 1.

5. For the Boardman to Hemingway Transmission Line (B2H), conduct ongoing permitting, planning studies, and regulatory filings.

6. Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.

7. Continue to coordinate with PGE to achieve cessation of coal-fired operations by year-end 2020 and the subsequent decommission and demolition of the Boardman coal plant.

8. Conduct ongoing permitting, planning studies, and regulatory filings for Gateway West.

9. Continue the pursuit of cost-effective energy efficiency.
10. Continue stakeholder involvement in CAA Section 111(d) proceedings, or alternative regulations affecting carbon emissions.

11. For North Valmy Unit 2, plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2025.

Primary Concerns

Staff's primary concerns with the IRP focus around three areas:

1) the Boardman to Hemingway (B2H) transmission line;
2) the shutdown dates of North Valmy Units 1 and 2; and,
3) the Company's portfolio design.

The Company has presented two separate Action Items in relation to the B2H. The first is ongoing permitting, and the second is preliminary and general construction. The Company has been pursuing this transmission project for years and has included B2H as part of its Action Plan since the 2009 IRP. However, the 2017 IRP stands out in that the Company filed a cover letter with the IRP on June 30th, notably requesting that "the Commission specifically acknowledge Idaho Power's acquisition of B2H in the Action Plan to satisfy EFSC's "Need" standard under its Least Cost Plan Rule."[1] Staff's comments will share our concerns around B2H as currently presented in this IRP. Staff also raises questions for the Company to address.

In the case of the case of the shutdown of North Valmy Units 1 and 2, Idaho Power did not evaluate multiple retirement dates. Instead, the Company assumed baseline retirement dates of 2019 and 2025, respectively. Despite the fact that the Company did not present analysis on alternative dates, it is requesting acknowledgment for 2019 and 2025 retirement. The 2019 shutdown date is a material deviation from the 2015 IRP Action Plan, where both units were scheduled to retire in 2025. Because the Company did not include an evaluation of the shutdown dates in the 2017 IRP, Staff may be unable to determine whether shutdown in 2019 satisfies the Commission's criteria for acknowledgment. Thus, Staff may not be able to recommend acknowledgment of these Action Items.

Finally, Staff is concerned about the method by which the Company developed the portfolios in this IRP. The Company used a new approach in the 2017 IRP by focusing on two key elements: 1) The Jim Bridger coal plant retirement dates, and 2) testing B2H as a least-cost resource by comparing it to solar PV and natural gas resources. As a result, the Company used a narrow approach to assessing key resource acquisitions. The lack of variety is concerning to Staff, and as a result Staff calls into question the design and selection of the preferred portfolio, P7.
Though these three issues are Staff's main concerns regarding the 2017 IRP, Staff will address other areas of concern throughout its comments in addition to areas of merit. Staff's comments first discuss B2H, followed by the North Valmy shutdown dates, followed by the portfolio development. Staff then discusses Idaho Power's supply side resources, followed by a discussion of demand side resources. Next, Staff discusses Idaho Power's load forecast and natural gas forecast. Finally, Staff discusses

[1] Idaho Power 2017 IRP Initial Application Cover Letter, p. 11. EFSC is Oregon's Energy Facility Siting Council.

miscellaneous analysis, including energy imbalance markets (EIM), Idaho Power's PVRR analysis, economic regulations, and electric vehicles. At the end of these comments is a list of actions and questions.

IRP Guidelines

Oregon utilities file IRPs subject to guidelines in Orders 89-507, 07-002, 07-047,[2] 08-339,[3] and 12-013. In particular, Order 07-047 outlines general guidelines, and Order 08-339 pertains to a utility's treatment of carbon risk in its IRP. Staff is still in the process of reviewing Idaho Power's compliance with the guidelines. In particular, Staff is concerned about how the utility chose to comply with guideline 2c and guideline 8.

Guideline 2c states that there should be a "[d]iscussion of the proposed use and impact on costs and risks of physical and financial hedging." The Company has not clearly presented such an analysis in its 2017 IRP, though Staff will submit discovery and is still in the process of reviewing how the Company complied with this guideline.

An amended version of guideline 8 was adopted by the Commission on June 30, 2008, and it outlines how the utilities should treat carbon risk in their IRPs. Idaho Power also failed to provide this analysis in its 2017 IRP. Staff will submit discovery and is still in the process of reviewing how the Company complied with this guideline.

Throughout its Opening Comments, Staff will address the Company's compliance with Commission guidelines as necessary. Staff will provide a more comprehensive review of the Company's compliance in the Final Comments and the Staff Report.

Boardman to Hemingway Transmission Line

History of the B2H Project

Idaho Power's IRP explains that the Company identified the need for a transmission line to the Pacific Northwest electric market in 2006.[4] Since then the B2H project has been identified as part of Idaho Power's preferred resource portfolio in every Idaho Power IRP since 2009. Currently, the B2H project includes a single-circuit 500 kV transmission line approximately 300 miles long between the proposed Longhorn Station near Boardman, Oregon and the existing Hemingway Substation in southwest Idaho.

While the overall details of the project have not changed much over time, what Idaho Power has requested the Commission to acknowledgement regarding B2H has changed somewhat between recent IRPs. The Company asked for acknowledgment for the construction of B2H in the 2009 and 2011 IRPs. In the 2013 IRP, the Company requested acknowledgment for completion of the line by 2018, but in the 2015 IRP, the Company only requested acknowledgment for permitting, planning studies, and regulatory filings for the B2H project.

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[2] See http://apps.puc.state.or.us/orders/2007ords/07-047.pdf for a complete list of guidelines.
[3] See http://apps.puc.state.or.us/orders/2008ords/08-339.pdf.
[4] LC 68, Idaho Power 2017 IRP, p.61.

In Staff's Final Comments in LC 50 regarding Idaho Power's 2009 IRP, Staff recognized that only recently had utilities in the west proposed and started to build large transmission projects, such as Gateway West and the Southwest Intertie. Few interstate transmission projects have been constructed in the region over the past several decades. In the 2009 IRP, Staff also recognized that the cost components of an interstate transmission project can vary widely, depending on the type of terrain and right-of-way costs.[5] Staff's observations are the same today: there is a dearth of information to benchmark against, and though Idaho Power has made progress on permitting and designing the B2H project, there remain several uncertainties about the project.

Nearly a decade has passed since the Company first asked for acknowledgment of the B2H line in LC 50. At that time, the Company was still in the process of determining several key aspects of the project, including who the partners for the project would be. The proposed B2H completion date for an initial 250 MW was 2015,[6] and the project's estimated capital cost was determined in LC 53 to be $820 million.[7]

In contrast, at this point in time, Bonneville Power Association and PacifiCorp are currently co-participants in the B2H project, the expected completion date of the B2H line is 2024 with 500 MW of capacity, and the project's estimated capital cost is between $1 billion and $1.2 billion.[8]

B2H Analysis in 2017 IRP

Staff does not dispute that ample progress has been made on the B2H project. Staff is aware that Idaho Power recently submitted an Amended Preliminary Application for Site Certificate for the B2H Project to Oregon's Energy Facility Siting Council (EFSC) that was nearly 17,000 pages.[9] However, the history shows that even basic changes to the assumptions underlying the project—such as partners and costs—have changed over time. Regardless of how much progress has been made on advancing B2H, it is still incumbent upon the Company to demonstrate a clear, current case to Staff with a self-contained comprehensive justification regarding the anticipated cost of the project and why the project is needed.

While the Company seems to have accomplished a commendable amount of work in moving the EFSC process forward, this IRP, which seeks acknowledgement to conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project, does not reflect the history and resources dedicated to this project. For example, the IRP does not explicitly state the total projected capital cost of the project or Idaho Power's projected cost share. Staff attained the cost information from a fact

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[5] LC 50 Staff's Final Comments, p. 7.
[6] LC 50, Idaho Power 2009 IRP, p.123.
[7] LC 53, Staff's Initial Comments, p. 2.
[8] Boardman to Hemingway Transmission Factsheet. Accessed at https://www.boardmantohemingway.com/documents/Fact-Sheet_B2H_06-16_PRINT.pdf.
[9] See Docket No. RE 136, Idaho Power 3rd Quarter 2017 Update.

sheet on the B2H website. Further, B2H’s costs, risks, ratepayer benefits, reliability benefits, and resource need for the line do not appear to be adequately covered in the 2017 IRP.

Connectivity benefits of the proposed transmission that cannot be substituted with generation resources or energy efficiency must be better articulated by the Company. Idaho Power should not presume that a participant in the current IRP review process is aware of all analysis or studies that Idaho Power, PacifiCorp, PGE and Bonneville, regional transmission planning entities like WECC, Columbia Grid and Northern Tier Transmission Group have provided over the last decade. The current IRP must, if it is to be a capstone effort, materially inform the current decision-makers and stakeholders.

In the 2017 IRP, the Company is once again asking for acknowledgment for construction of the project. Staff is concerned as to why the Company failed to provide an accessible compendium of relevant milestones, power flow analyses, current interconnection agreements, memorandums of understanding, records of participant decisions, contracts with other companies, line-specific and fully updated electrical and cost assumptions, reliability explanations, benefits of connectivity to blend remote variable renewable generation to markets in Oregon and elsewhere, and other materials that demonstrate to Staff how the project has evolved, how the cost, risk, benefit, reliability, environmental, market, etc. assumptions have changed, and how the project, Oregon ratepayers, and Oregonians in general do and do not benefit from these changes. The Company should demonstrate what data has been updated (such as cost and power flow assumptions) and give both technical and non-technical explanations as to why these data are still relevant today.

Staff has concerns about recommending acknowledgement of the project in the absence of a clear understanding of the current capital costs, construction timelines, operating parameters, project planning assumptions and schedules, and risks associated with B2H.

In summary, since the Company is asking for acknowledgment of conducting preliminary construction activities, acquiring long-lead materials, and constructing the B2H project, there should be a clear and demonstrated case showing the benefits and need for the project. While the Company has provided some of this analysis in its IRP, Staff believes additional information should have been provided. Staff has submitted several discovery requests to obtain some of the basic information necessary to consider B2H, but again, it is incumbent upon the Company, not Staff, to present a persuasive case for B2H as a resource that is part of a portfolio representing the best combination of cost and risk. Staff will continue to evaluate the benefits of the B2H line. Staff looks forward to Idaho Power addressing Staff’s concerns above in the Company’s Reply Comments and other forums.

Resource Need

Idaho Power has identified that there is a need for a transmission line for access to the Pacific Northwest electric market. B2H was identified as a way to meet this resource need in Idaho Power's 2009, 2011, 2013, and 2015 IRPs. In the 2017 IRP, the Company makes the case for B2H on the basis of the following benefits:

- Greater access to the Pacific Northwest electric market to economically serve customers
- Improved system reliability and resiliency
- Reduced capacity limitations on the regional system as demand grows
- Flexibility to integrate renewables and implement advanced market tools like EIM[10]

The Company has explained that the Northern Tier Transmission Group (NTTG) has identified B2H as a regionally significant project that has been referenced in NTTG's biennial regional transmission plans.[11] However, Idaho Power did not provide these studies in an appendix, nor did the Company explain in technical and non-technical terms how B2H is regionally significant. Staff is interested in a more detailed demonstration of regional need.

Apart from the regional need, Staff is concerned that the Company may be using overly conservative assumptions in its energy deficit analysis. Idaho Power provides its average and peak hour energy deficits, respectively, which is included in Staff Attachment A. However, the Company has not clearly presented how it selected 70th-percentile water and 70th-percentile load for its average energy deficit case and 90th-percentile water and 95th-percentile load in its peak hour capacity deficit case. The Company ultimately uses the peak-hour deficit case in its IRP, but because of the limited discussion around this selection, it is not clear what the loss of load expectation (LOLE) around this number is, nor what magnitude and duration of contingencies is addressed. Staff is concerned that this threshold may be overly conservative for planning for resource adequacy, particularly if there is not a thorough explanation of the assumptions.

Traditionally, utilities plan for a "one-in-ten" loss of load expectation standard, meaning that they view themselves to be resource adequate if they expect to have to shed load for cumulatively less than one day over the course of ten years.[12] The Company later indicates that it has performed a capacity planning margin study with this IRP, and its LOLE is indeed roughly one day every ten years. The Company should provide more clarification on how Idaho Power's peak-hour deficit case corresponds with a one-in-ten LOLE, in addition to better characterization of the probability of single and multiple contingencies.

Further, the Company has not clarified what benefits the proposed B2H transmission line would provide in a high impact, low frequency event. For example, when on June 7, 2013, President Obama issued the Presidential Memorandum "Transforming

[10] LC 68, Idaho Power's 2017 IRP, p. 61.
[11] LC 68, Idaho Power's 2017 IRP, p. 61.
[12] See "*Resource Adequacy Requirements: Reliability and Economic Implications*," The Brattle Group, September, 2013, page iii. Available online at https://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf

our Nation's Electric Grid Through Improved Siting, Permitting, and Review," various benefits of the proposed line were articulated by subordinate federal agencies. In furtherance of Executive Order 13604 of March 22, 2012, the Secretaries of Agriculture, Commerce, Defense, Energy, and the Interior, were directly instructed to place this line in service. The Company briefly referenced President Obama's directive in the IRP,[13] but any further detail should not be presumed as common knowledge, nor is it appropriate for Staff to supplement material omissions of the Company. Rather, absent discussion by the Company, Staff must ignore omitted content.

In addition, Staff would like clarification on the Company's assumptions regarding the level of market purchases the Company believes it can rely on for purposes of resource adequacy. On page 95 of the IRP, the Company states, "[a]t times of peak summer load, Idaho Power is using all available transmission capacity (ATC) from the Pacific Northwest. If Idaho Power encountered a significant outage at one of its main generation facilities or a transmission interruption on one of the main import paths, the Company would fail to meet reserve requirement standards."[14]

Notwithstanding the Company's concern regarding the availability of transmission capacity, the Company is relying on market purchases across the Idaho-Nevada path. The IRP states, "[a] baseline assumption in the load and resource balances is the early retirement of Valmy units 1 and 2 in 2019 and 2025, respectively. North Valmy units are assumed to be replaced with market purchases across the Idaho-Nevada path."[15]

The Company has not adequately explained what its assumptions about market purchases are, why it makes those assumptions, and what market resources would or could be connected to different loads across different transmission resources. The Company also has not demonstrated why it assumes that it will fail to meet reserve requirement standards.

In other words, the Company must clearly identify the need for B2H in these scenarios and how it relates to these assumptions. Staff is still seeking clarity on the level of market purchases the Company believes are available to meet reliability needs, and how those market resources would be delivered. Staff further elaborates its concerns around market assumptions below, under the Market Analysis section.

Cost

In a graphic, the Company indicates that the B2H resource is least-cost on a dollars per megawatt-hour basis. Staff provides this graphic as Attachment B.

Since the time of the IRP filing, the Company has indicated that the capacity cost component of the $39/MWh was understated by $6/MWh.[16] Upon further examination of the cost components, Staff believes the energy cost component may be understated

[13] Idaho Power 2017 IRP, p. 61.
[14] Idaho Power 2017 IRP, p. 95.
[15] Idaho Power 2017 IRP, p. 94.
[16] Attachment C, Idaho Power Response to Staff DR No 56, which includes this correction.

and that the cost of the B2H line may be at least $54/MWh. As a result, the B2H line may potentially be more costly than Energy Efficiency ($48/MWh), and only $5/MWh less costly (on an expected basis) than a 2x1 F class combined cycle combustion turbine.

However, on a call with Staff on October 16, 2017, Idaho Power clarified that the graphic is illustrative only, and does not play a part in resource selection. Staff will thus focus on Idaho Power's Aurora files in its review. As discussed in the PVRR Analysis section below, Staff also intends to further explore the method the Company uses to compare other resources to the 55-year lived B2H line.

A fundamental element of IRP planning is to consider other generation resources in lieu of a proposed resource and to articulate the benefits of the proposed resource beyond what alternative generation resources can deliver. Staff is not implying that the incremental benefits of the B2H line have not been explained to former Commissions in former IRPs or other forums in the past. However, it is the Company's burden to inform both lay persons and more technical participants as to the breadth of benefits of B2H with present decision makers in the IRP process given what the Company is requesting in this IRP. Staff feels Idaho Power failed to do so in its filed IRP.

If the Company intends the 2017 IRP is to be a capstone presentation for acknowledgement of the B2H line, the Company must update the information around connectivity, resources, connected markets, and other benefits both in routine and emergency times. The Company should also demonstrate how B2H benefits exceed those of a substitute generation resource *other than the cost component* and mere reference to improved reliability. The Company failed to explain in depth whether and if the B2H line plays a facilitating role in providing the connectivity to make distributed generation, remote renewable generation, and energy efficiency in lieu of thermal generation or other resources.

In addition, Staff is in the process of reviewing the risks and implications around cost overruns for a project of this magnitude. Staff will submit discovery and continue to review these risks. Staff notes that the Company has not presented a clear indication that it has investigated medium-term bilateral contracts. If the Company were to identify significant amounts of energy or capacity available in the markets—through direct communication with potential counterparties—then bilateral contracts should be included as a resource type. Staff is interested in a comparison between such bilateral contracts and the B2H proposal.

Risk

The Company examines risks in its 12 candidate portfolios both quantitatively and qualitatively. Risk factors considered in the quantitative analysis are natural gas price, customer load, and hydroelectric variability. Qualitative risks include the following:

- Hydro—water supply
- Relicensing
- Regulatory
- NOx compliance alternatives

- Permitting/siting
- Regional resource adequacy
- DSM implementation
- Technological obsolescence

In both the qualitative and quantitative analyses, the Company indicates its preferred portfolio is either the least risky or one of the least risky of the group. Attachment D provides the results of the Company's quantitative analysis.[17]

The Commission IRP Guidelines consider "risk" to be the magnitude of potential variability of cost around its expectation.[18] The Guidelines provide this guidance regarding risk:

> To address risk, the plan should include, at a minimum:
> 1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.
> 2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.[19]

Idaho Power's graphic in Attachment D does not clearly define how the B2H portfolios (1, 4, 7, and 10) compare with regard to cost variability to the other portfolios. It would be helpful if the Company could de-mean and re-scale this table for higher clarification of the range of costs.

Finally, the Company seems not to have provided a discussion of proposed use of and impact on costs and risks of physical and financial hedging. In claiming to meet this Guideline, the IRP merely includes the following sentence: "Idaho Power plans for near-term energy and capacity needs in accordance with the *Energy Risk Management Policy* and *Energy Risk Management Standards*."[20] Further, the Company has not explained how its construction bidding process will or will not reduce risk. For example, the Company does not explain whether it intends to install substation equipment itself or how it will vet bidders. Staff has submitted discovery on some of these risks and will continue to review.

Regarding qualitative risks, Staff notes that the Company indicates portfolios that include B2H are the least risky. In considering permitting & siting risk, for example, the Company writes the following:

> Significant challenges are often encountered during permitting and siting for energy resources. While these challenges are not uniform for all resources or for all proposed resource locations, it is nevertheless reasonable to assume all portfolios are exposed to permitting/siting risk, and no portfolio is markedly less

[17] Idaho Power 2017 IRP, p. 116.
[18] For example, a portfolio that costs exactly the same amount in every state of the future would be deemed riskless, regardless of cost.
[19] Oregon Order No. 07-002, p. 6.
[20] Idaho Power 2017 IRP, p. 2.

> exposed than P7; B2H planners have been collaborating with stakeholders for several years on resolving permitting/siting issues, and while challenges remain, much progress has been made.[21]

Staff has submitted a series of data requests on the Boardman to Hemingway project in order to discover more information about the risks of the project. The data requests include questions about potential turnkey contractors, agreements, and contracts with partners. But again, the Company should present a clear and defined case of why the B2H project should be acknowledged and should present the case in an approachable manner.

Market Analysis

Idaho Power focuses its market analysis on the future availability of summer power in the Pacific Northwest. This is because Idaho Power views B2H as a way to bring potentially lower-cost Pacific Northwest power back to Idaho Power's service territory.

Idaho Power relies on reports by the Northwest Power Conservation Council's (NWPCC) Resource Adequacy Advisory Committee's (RACC) resource adequacy report, as well as Bonneville Power Administration's resource adequacy report.[22] Both studies indicate eventual summer resource insufficiency in the Pacific Northwest. However, Idaho Power posits that because winter insufficiencies are larger than summer insufficiencies in both studies, regional reliability needs will cause new generation to be built before Idaho Power is affected.[23]

Staff is interested in analysis showing how the economics of the B2H project will hold up in a situation where additional generation is delayed and summer energy prices are higher than Idaho Power assumes. Such an analysis should be done with a range of potential prices, preferably revealing what the "tipping point" would be to make B2H uneconomic. Here again, the Company fails to clarify whether the proposed transmission line brings lower-cost electricity to Idaho Power from Mid-Columbia in conditions such as a wet spring, or whether the line would provide a conduit to the Mona electrical substation in Utah. In addition, Idaho Power does not provide enough clarification 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. This is again a material omission.

Staff can sympathize with Idaho Power's challenge in synthesizing a large body of planning and explanatory materials into a review that is both current and well-supported by both lay explanations and technical due diligence. However, that is a reasonable burden commensurate with acknowledgment.

Staff reiterates that because few interstate transmission projects have been constructed in the region over the past several decades, it is reasonable to expect a thorough

[21] Idaho Power 2017 IRP, pp. 120-121.
[22] Idaho Power 2017 IRP, pp. 64-66.
[23] Idaho Power 2017 IRP, p. 66.

account of final engineering and cost-effective accumulation of materials and construction with reasonable expectations of recovery of costs. Idaho Power should be ready to demonstrate that this long-studied project is now needed, timely, and part of a portfolio of resources that best benefits Oregon utility ratepayers while minimizing risk for Oregon. Failure to do so must be seen as an indicator that the Boardman to Hemingway transmission line is not yet a timely resource.

Staff awaits the Company's supplemental analysis in discovery, Reply Comments, a Commission workshop, and possibly an additional appendix to the 2017 IRP.

North Valmy

Staff reviewed the Company's assumptions surrounding its North Valmy coal-fired plant and determined that the IRP includes no variation in the analysis regarding the early shutdown of North Valmy Unit 1 in 2019. Instead, North Valmy Unit 1 has an assumed shutdown of 2019 in the Company's baseline case.[24] The Company has provided the 2019 shutdown analysis in response to a discovery request that Staff continues to review.[25] However, Staff remains concerned with the inclusion of a 2019 shutdown in the baseline and lack of comparison to other end-of-life dates.

It is important to note that in the 2015 IRP, Idaho Power's preferred portfolio included retirement of *both* North Valmy Units 1 and 2 in 2025. And, in November 2016, Idaho Power asked the Commission to allow Idaho Power to accelerate the depreciation of both units and to increase rates accordingly.[26] Parties to the dockets stipulated to revising the depreciable life for both Valmy Units 1 and 2 to end in 2025.[27]

Notably, there is no order in Oregon that contemplates North Valmy shut down in 2019. Earlier this year, the Commission stated in its order approving the stipulation in Docket No. UE 316, that, "Idaho Power agrees to continue to evaluate the Valmy retirement dates in its 2017 IRP."[28]

Idaho Power states that "the approved settlement stipulations in both Idaho and Oregon agreed to an early shutdown of year-end 2019 for unit 1 […]." This is incorrect. There has been no stipulation or order in the state of Oregon that approves an early shutdown of Valmy in 2019. Rather, Commission Order No. 17-325 resulted in "shortening the depreciation schedule from 2031 for Unit 1 and 2035 for Unit 2 to 2025 for both units." The Order summarily states that the Company may file rates that correspond to a shorter end-of-life date, but as the stipulation states, "Staff's settlement of the issues in this proceeding does not indicate a waiver of its right to evaluate a proposed change in

[24] Idaho Power 2017 IRP, p. 28.
[25] See Attachment E, Idaho Power Response to Staff DR No 24.
[26] See Docket Nos. UM 1801 and UE 316.
[27] Order Nos. 17-186 (UM 1801) and 17-235 (UE 316).
[28] Order No. 17-235.

the retirement date of Valmy Units 1 and 2 in a future planning or ratemaking proceeding."

Idaho Power's 2017 IRP indicates that there are "favorable economics" associated with the early retirements of Valmy units 1 and 2.[29] Staff does not believe this is verifiable because analysis of both units and multiple dates does not exist in the 2017 IRP. Both units were included as a baseline assumption, so no comparisons were made to other alternatives. Instead, the Company seemed to rely on analysis performed in the 2015 IRP and UE 316. Staff appreciates the Company providing this analysis during discovery, but in Staff's opinion, the 2017 IRP does not fully consider the implications of different end-of-life dates for Valmy.

Ultimately, Staff has no way of determining whether the 2019 and 2025 shutdown dates decision represents the best combination of cost and risk. Idaho Power has not evaluated multiple retirement dates for Valmy Units 1 and 2, and Staff is particularly concerned that the 2019 shutdown date may not be in the best interest of customers.

In addition to this concern, Idaho Power relies on new transmission capacity available on the Idaho-Nevada path (once North Valmy shuts down) and B2H in order to meet peak demand, but the Company does not describe the market or source of the power in significant detail.

Staff requests that the Company include a discussion of the 2019 and 2025 end-of-life analysis in its Reply Comments.

Staff also requests that, in its Reply Comments, the Company provide further information regarding the planned source of the power that will replace the coal plants. Specifically, the Company should provide a breakdown of long-term, short-term, and spot purchases.

Portfolio Development

Staff's primary concerns regarding the Company's portfolio development are intertwined with Staff's concerns about the analysis of B2H, renewable resources (explained further in the Solar Resources section), and Idaho Power's coal plant analysis.

Briefly, Idaho Power prioritized two key components, or "factors," as the basis for comparison in its analysis. These are 1) the treatment of Jim Bridger in the IRP, and 2) B2H as compared to "portfolio elements." For factor 1, the Company analyzed four different approaches to the Jim Bridger Units 1 and 2 retirement dates:

- Install SCR and operate Jim Bridger until the end of the planning period.
- No SCR, but retire Jim Bridger 1 and 2 in 2028 and 2024, respectively.
- No SCR, but retire Jim Bridger 1 and 2 in 2032 and 2028, respectively.
- No SCR, but retire Jim Bridger 1 and 2 in 2022 and 2021, respectively.

[29] Idaho Power 2017 IRP, p. 136.

For factor 2, the Company selected two other "elements" as a basis for comparison to the B2H line, resulting in three key components:

- B2H line.
- The solar PV/reciprocating engine combination.
- Natural gas fired generation.

The resulting combination of portfolios is represented below.

Figure 1 – Factorial Design and Portfolio Elements

Table 8.25 Factorial design applied to portfolios

	Primary Portfolio Element(s)		
Treatment of Jim Bridger Units 1 and 2	**B2H**	**Solar PV/Natural Gas**	**Natural Gas**
Invest in SCR	P1	P2	P3
Retire Unit 1 in 2028 and Unit 2 in 2024	P4	P5	P6
Retire Unit 1 in 2032 and Unit 2 in 2028	P7	P8	P9
Retire Unit 1 in 2022 and Unit 2 in 2021	P10	P11	P12

Of particular concern is that all the portfolios that do not contain B2H—P2, P3, P5, P6, P8, P9, P11, and P12—include natural gas plants. The solar PV/Natural gas portfolios P2, P5, P8, and P11 contain high-cost reciprocating engines that are installed over the course of about 15 years. The natural gas portfolios P3, P6, P9, and P12 contain reciprocating engines in addition to combined cycle combustion turbines (CCCTs).

Staff is very concerned about the about the lack of diversity exhibited in Idaho Power's portfolio design, let alone the scope of concerns surrounding B2H. Staff does not believe that the Company has demonstrated useful comparisons among the portfolios.

The resulting analysis largely compares B2H to natural gas generation, and Staff does not believe this to be appropriate methodology in determining key components of a preferred portfolio. As a basis for comparison, in the 2015 IRP, the Company presented a series of 23 portfolios. In the 2017 IRP, there are 12.[30] The 2015 IRP also contained a base case portfolio against which all others were compared and presented a wider variety of resources, such as ice-based thermal energy storage, additional energy efficiency, battery storage, additional hydro, geothermal, and others.[31]

This is the first year the Company has used the factorial approach, and Staff believes it has proven to be a less robust methodology to craft portfolios. In this IRP, Idaho Power has used high cost reciprocating engines to ensure there is sufficient capacity in each

[30] The higher number of portfolios is partially due to the retirement date analysis of Jim Bridger and North Valmy.
[31] Idaho Power 2015 IRP, Chapter 8.

portfolio that includes a solar resource. However, it is not impractical to pair solar resources with a lower cost resource such as additional hydro and Idaho Power's failure to diversify the portfolios that include a solar resource seriously undermines the usefulness of Idaho Power's analysis.

Staff questions the meaningfulness of the preferred portfolio itself because of the general lack of diversity and robustness of the analysis. Thus, calling P7 the "preferred portfolio" does not provide much depth to the analysis of cost and risk. This, in turn, impacts the qualitative analysis the Company provided in Tables 9.9 and 9.10 of the IRP. Though Staff appreciates that the Company addressed this recommendation, the Company overall has not provided meaningful comparisons among the portfolios due to the lack of variety.

Staff requests that the Company restructure its portfolio development for the 2019 IRP using capacity expansion modeling while also taking into account the analysis presented in the 2015 IRP.

Supply Side Resources

Solar Resources

Staff reviewed Idaho Power's analysis on solar capital costs and levelized cost of energy. Staff is concerned that Idaho Power's assumptions do not adequately take into consideration falling costs of solar technology, which would mean the IRP does not take into account decreasing capital costs over time. The Company used cost information from the Lazard Report, which uses a capital cost of $1,375 per kW for a single-axis tracking system,[32] but that data was out of date by the time of publication. To illustrate how costs are constantly falling, the numbers Idaho Power used from the Lazard report were produced in late 2015 to early 2016. However, by the time the report was published in December 2016 (Q1 2017), the National Renewable Energy Laboratory (NREL) found that the average cost for a utility scale, single-axis tracking solar PV system was $1,110 per kW with a LCOE of $40 to $60 per MWh. This is a difference of $275 in just one year.[33] Staff recognizes the difficulty in predicting future capital costs, so a sensitivity analysis of realistic near-term cost decreases of five, ten, twenty, or twenty-five percent, for example, would provide a more reasonable comparison to other types of energy generation.

Further, every solar PV resource in the planning portfolios is paired with high-cost reciprocating engine turbines of similar capacity. This has an impact on the financial analysis, as evidenced in the Solar Tipping Point Analysis that showed solar PV is not the lowest cost resource even when capital costs are reduced by 100 percent.[34]

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[32] Idaho Power 2017 IRP, p. 36.
[33] NREL U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017; https://www.nrel.gov/docs/fy17osti/68925.pdf
[34] Idaho Power 2017 IRP, p. 118.

Staff recognizes the variable nature of solar PV energy production. However, a majority of the variability can be planned; energy planners know when the sun rises and sets, and have at least hour-ahead forecasting of clouds that could interrupt production.[35] With proper forecasting for readily available resources, fast-ramping gas turbines may not be required. The Company did not analyze the availability of existing resources (gas, hydro, or otherwise) that may be able to ramp up to cover capacity when solar PV shuts down. Instead, the Company paired high-cost reciprocating engine turbines with solar PV in at least three different portfolios.[36]

Assuming that solar PV must be paired with reciprocating engines may not be a realistic or conscientious method of incorporating solar into the IRP. As a result, the exploration of solar PV in the portfolios is not meaningful. Staff believes the Company ought to redesign its Portfolio development to more reasonably simulate renewable and incremental flexible capacity additions reflective of the Company's existing generation and market access. Because the PV resources are paired with high-cost reciprocating engines, Staff is not convinced that these portfolios represent a useful comparison to the preferred portfolio, P7. This holds important implications for portfolio selection and the role of B2H in the IRP. Staff addresses this issue separately.

Jim Bridger

In its order regarding the 2015 IRP, the Commission did not acknowledge the installation of Selective Catalytic Reduction (SCR) technology at Jim Bridger units 3 and 4. Because the installation of the SCR technology was already underway, Staff recommended assessing the installation in a general rate case instead of the IRP. Idaho Power has not had a general rate case since the 2015 IRP, but Staff will review the prudence of that investment when the Company asks to recover it in rates.

Further, in the 2015 IRP, the Commission directed the Company to

- Analyze the impact of Section 111 (d) compliance paths on Idaho Power's liabilities in Valmy and Jim Bridger, with stochastic analysis for each compliance path in the 2017 IRP.
- Calculate the cost to the Company of compliance with these paths, and the impact of these costs on ratepayers.

In the 2015 IRP, the Company considered a retirement date for Jim Bridger Unit 1 in 2023, among other options for Jim Bridger Units 1 and 2. However, in the 2017 IRP, the Company has considered only 2028 and 2032 as retirement dates for Jim Bridger Units 1 and 2. Staff notes that the Company assumed a mass-based approach, and that there has been a number of recent indications that the Clean Power Plan may be repealed. However, the economics of early shutdown dates are also impacted by lower gas prices and SCR investments, which are both independent of the Clean Power Plan.

[35] Photovoltaic and Solar Power Forecasting for Smart Grid Energy Management, CSEE Journal of Power and Energy Systems; http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=7377167
[36] Idaho Power 2017 IRP, pp. 97-107

Staff requests the Company provide an explanation of the reasons for this analytical change and any impact to ratepayers in its Reply Comments.

Energy Storage

Staff is highly concerned about how Idaho Power modeled the costs and benefits of Energy Storage. In Staff's opinion, the total capacity costs noted on page 73 of Appendix C are inflated. Additionally, Idaho Power only seems to have modeled energy storage as a capacity resource. In general, best practices manuals and other studies model energy storage as capable of providing multiple services, and when co-optimized, these services can be provided nearly simultaneously. In fact, in response to a Staff data request, Idaho Power demonstrated an awareness of proper storage modeling.[37] In Docket UM 1751, the Oregon Commission adopted a methodological framework for modeling energy storage. Idaho Power seems not to have employed this methodology in the IRP. The framework adopted by the Commission is not much divorced from the modeling effort undertaken by many of the national leaders in this area such as EPRI, PNNL, US DOE, and DNV GL. Idaho Power seems to have awareness of this as demonstrated in its response to Staff's Data Request 60.[38] The 2017 IRP resource portfolios do not include energy storage as a viable resource. Staff is concerned that Idaho Power may be overpricing it and undervaluing the many services energy storage can provide. Staff is currently exploring how this modeling omission ought to be addressed.

Cloud Seeding

Idaho Power currently operates a cloud seeding program about which Staff has issued discovery requesting quantitative proof of the effectiveness of the program. Additionally, Staff will explore the cost-effectiveness of this program. At present, Staff is skeptical that Idaho Power's cloud seeding program produces enough fuel to justify the expense of the program. A demonstration of net benefits to the ratepayer may be needed.

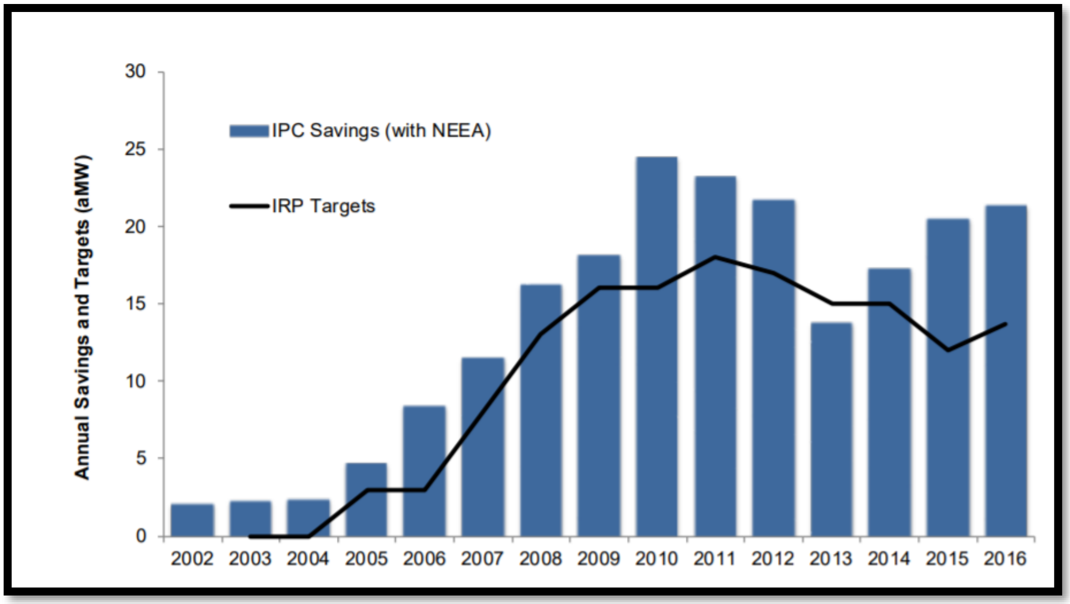
Demand Side Resources

Energy Efficiency

As the graph below demonstrates, Idaho Power has a long history of outperforming its annual IRP savings targets for energy efficiency (EE).[39]

[37] See Attachment F, Idaho Power Response to Staff DR No 60.
[38] See Attachment F.
[39] Reference: Idaho Power 2016 DSM Annual Report, pp. 6-7.

Figure 2 – Comparison of Total Annual Savings to IRP Targets



In 2016, efficiency savings exceeded the Company's IRP savings target by 30 percent and grew 4 percent over 2015.[40] In 2015, Idaho Power's EE savings exceeded its IRP target by 55 percent.[41]

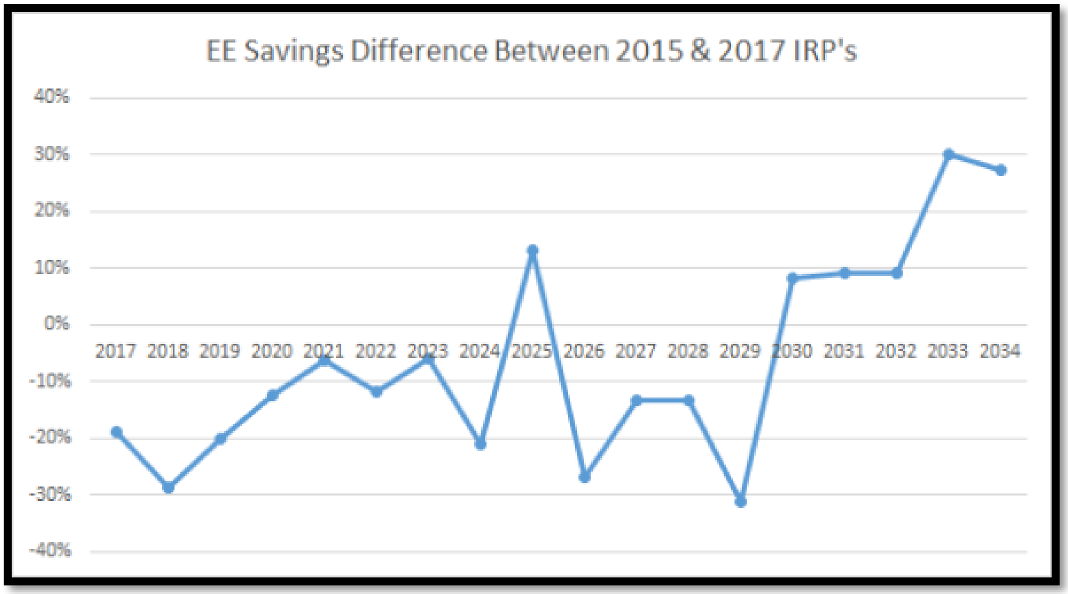
However, the Company projects an approximately 10 percent reduction in cumulative EE savings over the 20 year planning horizon in the 2017 IRP as compared to the 2015 IRP.[42] *Figure 2* captures the extent of the difference on an annual basis. Notably, most of the efficiency decline in this IRP happens early in the 20 year time period of the IRP analysis.

[40] Idaho Power 2016 DSM Annual Report, p. 6.

[41] Analysis of 2015 savings data from Idaho Power 2016 DSM Annual Report, p. 8; and 2015 IRP target found in 2015 Integrated Resource Plan, Appendix C, p. 78.

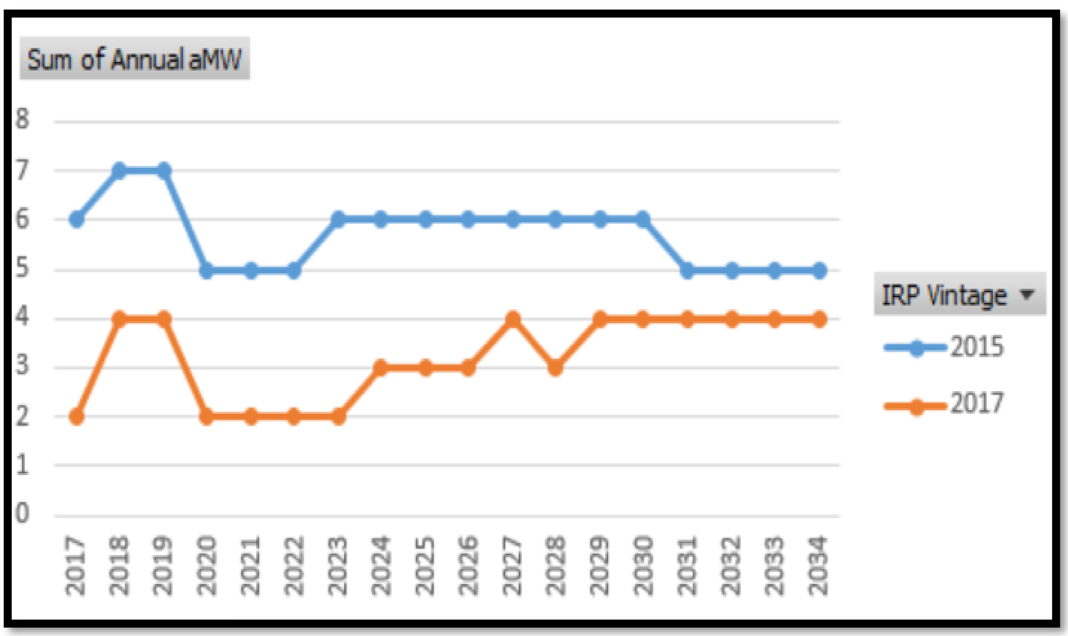
[42] Comparison of efficiency forecasts from the 2017 and 2015 IRP's. See Idaho Power 2017 IRP, Appendix C, p. 67 and 2015 Integrated Resource Plan, Appendix C, p. 78.

Figure 3 – Annual Percent Difference Between 2015 and 2017 IRP Savings



Forecast
The reduction in annual savings targets between the 2015 and 2017 IRPs is most pronounced for the residential sector. As can be seen in Figure 3, the EE IRP targets drop over 50 percent during the 2017 IRP action plan time horizon and in the years leading up to the completion of B2H.

Figure 4 – Residential Savings Forecast Difference, 2015 and 2017 IRPs



Staff understands that there are several pressures on residential savings over time—for example, Federal Standards on lighting, improving building codes, and lower avoided costs. However, the extent of this drop in the near-term raises concerns for Staff regarding modeling decisions and in how avoided costs are constructed for the Company's cost effectiveness analysis.

Modeling Impact Concerns

The IRP is unclear about the reasons for the substantial, near-term decline in EE savings. Staff has concerns about the Company's residential EE forecast. As shown in Figure 3 above, the immediate drop in residential EE is troubling, especially given its contribution to peak-load reduction. Again, Staff understands there are several pressures on residential savings but believes a more in-depth explanation is warranted for the 2017 IRP. For example, the Company has not clearly demonstrated how much of the large forecasted decline in the annual residential savings from 2017 through 2021 is due to changes in the lighting market or some other factor. To this end, the Company should more clearly identify ramp rates around key technologies like heat pumps and how these assumptions changed between the 2015 and 2017 IRPs.

The IRP also lacks clarity about the source of EE forecasting data used in IRP Analysis. This rapid, near-time decline in EE IRP targets has implications across the IRP. Most notably, this cumulative reduction in forecasted savings most likely exacerbates the monthly peak-hour deficit that the Company projects beginning in 2026.[43] However, the extent of this issue is unclear from the data provided and the narrative description in the IRP.

It is unclear what the source is for the EE data being used in the Company's Energy and Peak-Hour Load and Resource Balance analysis. The Company stated that AEG produced a detailed report of EE potential for the IRP, which includes annual peak impacts. [44] Idaho Power also states that the data from this report is used to set IRP targets, but the Company chooses to substitute different data in its load and resource balance analysis and states that the data found in AEG's forecast and IRP targets are actually lower than the EE savings used in the load and resource balance analysis.[45] The Company provides limited insight into this decision and on the data and methodology it deploys for its load and resource balance. The Company ought to provide the source of this data, explain why the product from AEG has to be modified for load and resource analysis, and demonstrate that Idaho Power's analysis captures all cumulative savings.

The Company also has not clarified the extent to which Idaho Power's forecast of EE savings in the 2017 IRP is impacted by modeling decisions around EE retrofit and replacement opportunities. The Company should more clearly explain how it treats EE retrofit opportunities relative to replacement opportunities and whether retrofit opportunities are being shifted out to later in the forecast period as evidenced by the rise in savings in later years of the IRP.

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[43] *See* Idaho Power 2017 IRP, Appendix C, p. 49.

[44] *See* Applied Energy Group's Report, "Idaho Power Company Energy Efficiency Potential Study," April 2017.

[45] *See* Idaho Power 2017 IRP, p. 52.

Avoided Cost Concerns
Avoided costs represent the value of EE to Idaho Power's system, are a key component of cost effectiveness calculations, and are used to determine which EE resources are selected as part of the IRP analysis. Staff appreciates Idaho Power's detailed work to produce differentiated average, forward energy pricing categories for EE avoided costs. However, the Company ought to clarify additional elements of the avoided cost elements. Staff is concerned that the Company may be undervaluing EE and underrepresenting its impact in the IRP analysis.

For forward market prices, the most valuable peak price for EE is Summer On-Peak (SONP), but this energy value is based on the 5-year levelized cost of a new, natural gas-fired, simple-cycle combustion turbine. Staff feels this value may be more properly assigned as a generation deferral value within the context of EE's avoided cost.

With regard to generation deferral value, the Company should clarify the values behind and the application of generation or capacity deferral value. Other utilities apply this value when the utility is resource deficient.

Staff requests that Idaho Power confirm when it is resource deficient and how the generation or capacity deferral value is utilized as part of its EE Avoided Costs in its Reply Comments.

Further, Staff is concerned about Idaho Power's T&D deferral value of $3.76 per kW year for EE. By comparison, the T&D deferral value for Portland General Electric (PGE) and PacifiCorp (PAC) are greater than Idaho Power's T&D deferral value. [46]

	PGE	**PAC**
Transmission	$ 8.59	$ 6.07
Distribution	$25.35	$ 7.79
Total T&D Value (kW/Year)	**$33.94**	**$ 13.86**

It is worth noting that a T&D deferral value generally represents the local cost of deferred maintenance along with deferring investments in any new transmission and distribution assets over the course of the IRP. This is especially critical as Idaho Power *seeks to make a large transmission investment that is operational by 2026.* Staff believes that Idaho Power's methodology is most likely under-representing the value of EE's contribution to deferring T&D investments and should be revamped to align with current practices used by other investor-owned utilities operating in Oregon.

Staff requests that Idaho Power make the following changes to its avoided cost methodology, re-run its cost-effectiveness analysis, and report back on the impact to the amount of EE selected for its IRP forecast (including a revised table 5.3 from page 52 of

[46] *See* Energy Trust, "Electric and Gas Avoided Cost Update for 2018" August 8, 2017.

the IRP) and detail the estimated impact on energy and peak-hour load and resource balance analysis:

- Forward Market Prices: Substitute an average of actual peak prices for the hours covered by SONP.
- Generation Deferral Value: Use the price of $122/kW year for all EE measures with a measure life that extends into the first year Idaho Power is capacity deficient, 2026 per this IRP.
- T&D Deferral Value: Develop a new methodology that more closely resembles the methodology deployed by PGE and/or PAC. This should include projected costs of future T&D investments over the course of the IRP, like B2H, not just those in the three-year 2016 budget.

Demand Response

Staff commends Idaho Power for the impressive work undertaken to acquire nearly 12 percent of peak capacity through demand response. This level of demand response capacity procurement likely places Idaho Power in an elite group of utilities nationwide who have made a commitment to procure substantial levels of demand response capacity. For this work, Idaho Power deserves recognition. This level of commitment to demand response procurement should be seen as an example to Oregon's other regulated utilities that demand response at high penetration levels is feasible, valuable, and reliable. Additionally, as the Northwest Power and Conservation Council (NPCC) has stated in its Seventh Power Plan, demand response is a necessary and real resource, and without its development, the region as a whole will see increased power costs.[47]

With the passage of Senate Bill 1547 in 2015, the Oregon legislature placed additional emphasis on demand response as a preferred resource.[48] Additionally, the Oregon Commission in LC 66 has demonstrated an interest in advancing demand response development.[49] The industry and the types of resources made available to the utility are changing with the advancement of advanced communication and IT networks, consumer products, and end-use resource development. These aspects of the overall discourse and physical network restructuring are an important sign to our utilities that advancements are necessary. An expansive view of defining system resources is emerging, and it is important that our utilities be active in this new discourse and resource development.

Staff has initially reviewed Idaho Power's demand response resource development plans as outlined in its 2017 IRP, and Staff has issued several data requests to Idaho Power to more clearly understand the possibilities for demand response development in Idaho Power's service territory.

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[47] See generally, Northwest Power and Conservation Council's 7th Power Plan, Chapter 14 Demand Response. Available at https://www.nwcouncil.org/media/7149925/7thplanfinal_chap14_dr.pdf.
[48] See Section 19 of Enrolled Senate Bill 1547.
[49] See Commission Order 17-368.

Although Idaho Power should be commended for its current level of procured demand response capacity, Staff does have a few concerns. Such capacity relies on an older technology backbone, and the resource itself may not be currently utilized to the best of its capabilities. Staff is additionally concerned that although Idaho Power's IRP forecasts load growth over the planning period, it does not show commensurate growth of demand response procurement. In fact, Idaho Power's IRP shows stagnation in this area. Staff initially finds this to be troubling. Staff was provided with very little information from Idaho Power regarding the methodology used to determine demand response cost effectiveness. With the passage of Senate Bill 1547, such a methodology holds significant weight. Staff is also concerned that Idaho Power's direct load control program for residential customers may not be utilizing an up-to-date communication and technology infrastructure that can be carried forward into a new and dynamic resource paradigm. Lastly, the Company did not clarify how often it offers its products and what the current demand response resources are.

While Idaho Power's schedules and tariffs note the possibilities for how often and when events will occur, the question of capability can only be answered from actual practice and program design. Staff notes that at times of extreme peak, Idaho Power has successfully deployed its demand response programs, thus demonstrating the value to Idaho Power and its ratepayers during extraordinary system conditions. However, Staff would like to see the Company advance the capabilities of its demand response resources and program in two ways. First, these resources should be capable of being called for more than a select number of events strictly correlated to near-emergency capacity conditions. Second, Idaho Power should be exploring demand response opportunities that have arisen through advancements in technology that increase participation from the residential and commercial sectors. If the forecasted capacity gap is to be met, Idaho Power has an obligation, possibly a requirement, to meet that gap first with energy efficiency and demand response. The current construction of Idaho Power's preferred portfolio does not demonstrate its continued commitment to demand response resource development as much as it demonstrates a commitment to legacy effort and programs.

Forecasts

Load Forecast

Idaho Power prepares separate load forecasts for each of its customer types: residential, commercial, irrigation, industrial-manufacturing, industrial-service, and special contract. The industrial class is split into two types so that different regression covariates may be used. For example, the Company uses explanatory variables related to farm earnings that may be correlated with industrial-manufacturing load. Rather than also separating its customers into weather regions, the Company uses a weighted average weather explanatory variable. The Company also uses economic forecast drivers. As an example, household income is a driver of residential load and agricultural GDP tailored to its service area is a driver of irrigation load.

With increased precision, the Company could likely produce a more accurate expected case. For example, while the Company possesses sub-hourly load data for its commercial customers, its forecasts are produced using yearly load data. The Company should clarify in its Reply Comments why it chooses this approach, and whether it has anything to do with weather as a forecast driver for its commercial forecast. All other Oregon IRP filings postulate a positive relationship between cold weather and increased winter commercial load. This omission is especially important given the direction utility analyses are moving in. Consider Portland General Electric's most recent rate case, where it proposed a weather assumption to better approximate "a persistent warming trend, as experienced in the Pacific Northwest."[50] Because Idaho Power is a summer peaking utility, it is a shortcoming that its forecasting models preclude any explicit impact of commercial air conditioning load.

The Company seems to underestimate the variability in future expected load for at least two reasons. First, large shifts in load are difficult to predict. For example, the Company describes both that customer growth was at a near standstill following the 2008 recession and that the Company assumes non-recession growth rates for the entire forecast period.[51] Clearly, all else equal, the Company's expected case would be over-forecasted if another recession occurs before 2036. As another example, for its 2013 IRP, the Company removed the anticipated special contract load of Hoku Materials. It is possible that the Company could have unanticipated gains or losses of special contract customers before 2036.

Second, the Company's percentile approach is only a rough approximation of probability because the Company looks at each covariate in isolation. Looking at each covariate in isolation is problematic because historically, there have likely been stacked impacts. For example, an abnormally cold summer could also have abnormally high rain, thereby reducing irrigation load in a stacked manner.

Staff believes the Company's use-per-customer forecast could be improved with more granular data. Staff will continue to review the assumptions made in the Company's number of customers forecast and the Company's peak load forecast.

Staff requests that in the next IRP, the Company provide analysis of a no-special-contract-load-growth scenario. Because special contract loads are not forecasted using robust third-party data, it is important to prepare a no-special-contract-load-growth scenario as a comparison case in order to determine whether forecasted special contract load growth is driving resource decisions.

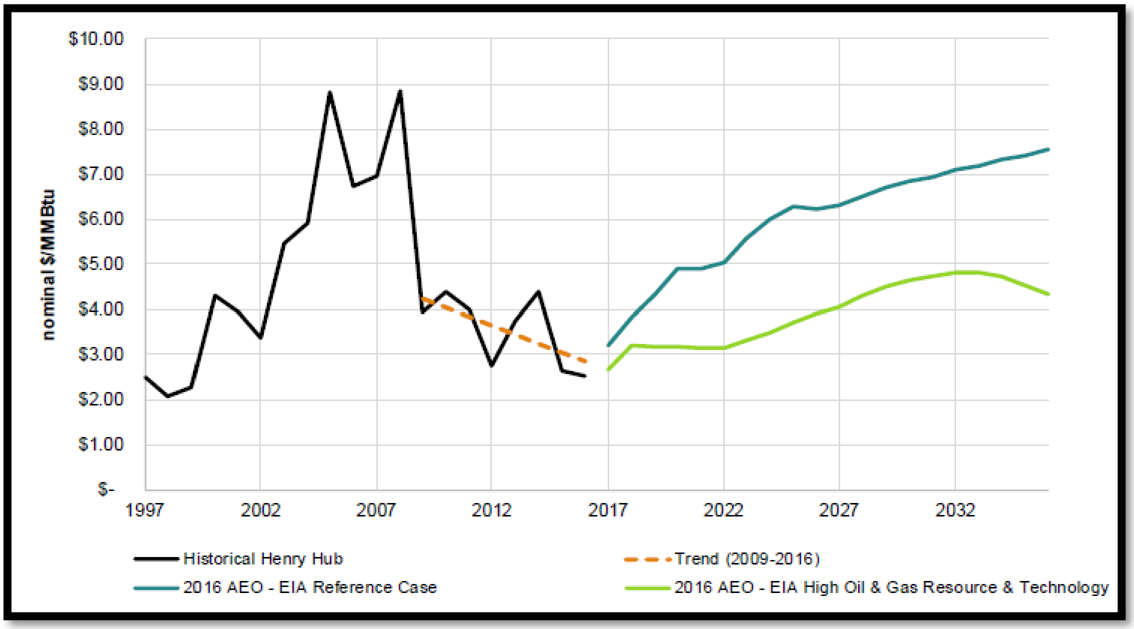
Natural Gas Price Forecast

Idaho Power relies on the 2016 Annual Energy Outlook (AEO) of the U.S. Energy Information Administration (EIA) for its natural gas price forecast. The Company provides the following chart comparing the reference case forecast (blue line) with a forecast under the assumption that oil and gas extraction improves over the reference

[50] See UE 319 PGE/1200, Dammen – Riter/6 in UE 319, lines 21-22.
[51] Idaho Power 2017 IRP, p. 72.

case by 50 percent (green line). The green line is EIA's High Oil & Gas Resource & Technology (EIAHO) case, which Idaho Power uses as its own planning case.

Figure 5 – Henry Hub Natural Gas Spot Price [52]



Idaho Power elects to use the low-price case instead of the reference case as its base case for modeling and analysis of resources

Idaho Power tested various sensitivities[53] and applied stochastic shocks[54] to its gas price analysis to determine a range of outcomes as a result of changing prices. However, Idaho Power's planning case is lower than any of the sensitivities,[55] and most of the stochastic shocks trended above this planning case. This indicates that Idaho Power is largely analyzing upward price risk, and in the case of modeling sensitivities, prices lower than the planning case are not considered at all. When Staff asked why the Company chose a low planning case, Idaho Power stated that "actual natural gas prices have consistently been lower than the Idaho Power IRP Planning Case EIA forecast selected in the past several IRP cycles."[56] In addition, Idaho Power reviewed settled forward contracts through the intercontinental exchange (ICE) and stated that the ICE forecasts were shown to be more accurate than the EIA Planning Case forecast used in the IRP over the past few years. Because the 2016 EIAHO case forecast "closely followed the ICE forward contract prices as compared to the other available EIA forecasts," the EIAHO case forecast was selected because it "seems to be the most likely future."[57]

[52] Idaho Power 2017 IRP, p. 84.
[53] Idaho Power 2017 IRP, p. 112.
[54] Idaho Power 2017 IRP, p. 116.
[55] Idaho Power 2017 IRP, p. 112.
[56] See Attachment G, Idaho Power Response to Staff DR No 32.
[57] See Attachment G.

In other words, Idaho Power seems to have determined that ICE contracts were more accurate predictors of gas prices over the past few IRP cycles and chose an EIA forecast that most closely matched the ICE forecast. During the IRP planning meetings, stakeholders raised concerns over the low gas price forecast, particularly the use of the ICE contracts. Idaho Power seems to have mitigated the concern by choosing an EIA forecast close to the ICE case.

A closer inspection of the EIAHO projection reveals the following assumptions that underlie this case:

> In all cases but the High Oil and Gas Resource Technology case, which assumes substantial improvements in production technology and, U.S. production declines in the 2030s, which slows or reverses projected growth in net energy exports.[58]

These substantial improvements include:

> 50% higher assumed rates of technological improvement that reduce costs and increase productivity in the United States than in the Reference case; and…50% higher technically recoverable undiscovered resources in Alaska and the offshore lower 48 states than in the Reference case. The total unproved technically recoverable resource of crude oil increases to 355 billion barrels, and the natural gas resource increases to 2,812 Tcf as compared with unproved resource estimates of 236 billion barrels of crude oil and 1,986 Tcf of natural gas in the Reference case as of the start of 2015.[59]

Staff does not dispute that gas prices have been consistently trending down in the past few IRP cycles. However, Staff does believe that Idaho Power seems to have used subjective judgment in determining what a likely future was. The Company seems to have utilized a short-term ICE forecast to inform the decision to use the EIAHO projection and as a result based its planning case on that future.

In addition, Staff is concerned about the natural gas planning case as it is inconsistent with the forecast used in its DSM study done by AEG. Staff asked a clarifying data request about the natural gas planning case and the gas price projection used in the DSM (EE) study. The Company clarified that the two of these were not the same. Rather, AEG used the EIA 2016 Annual Energy Outlook ("AEO") Reference Case for the DSM study,[60] and Idaho Power used the EIAHO Case for its planning case.

[58] "EIA's AEO2017 projects the United States as a net energy exporter in most cases." EIA. Retrieved at https://www.eia.gov/pressroom/releases/press443.php.
[59] Assumptions to the Annual Energy Outlook, p. 148. Retrieved at https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf.
[60] See Attachment H, Idaho Power Response to Staff DR No 15.

Staff believes that the Company should have presented a more consistent approach to modeling its IRP and provided a more robust justification for the decision to change its planning case from previous IRPs.

Additional Analysis

Energy Imbalance Market

Staff is still in the process of reviewing the Company's decision to participate in the Energy Imbalance Market (EIM). Idaho Power is scheduled to begin participating in the western EIM in April 2018 and lists this among its Action Items in the Action Plan.

This is the first year the Company has requested acknowledgement for participation in the EIM, but the Company provides no analysis in the IRP about the benefits, costs, risks, or additional details as to how this will relate to its current pool of resources. Staff is also surprised that the Company has not stated the relevance of the EIM to B2H. As Staff explains in the next section, further detail should not be presumed as common knowledge, nor is it appropriate for Staff to supplement material omissions of the Company. Rather, it is incumbent upon the Company to present a case for EIM as a resource in its portfolio.

Staff Requests that the Company provide analysis or documents presenting the benefits of EIM participation and how it might impact the B2H project.

Present Value Revenue Requirement (PVRR) Analysis

The Company considers 12 portfolios, which are combinations of alternatives for the retirement date of the Jim Bridger power plant, various new resource acquisitions, and demand response assumptions. In order to determine which portfolio is least-cost, the Company ranks its portfolios by each portfolio's net present value cost[61] over 20 years. The result of this is included as Attachment I, which indicates portfolio seven (P7)[62] is the least-cost portfolio.[63]

Staff finds this method of ranking portfolios by their 20-year expected cost to be traditional and appropriate, with the possible exception of the B2H transmission line. Because the B2H line has a significantly longer economic life (55 years) than the rest of the resources considered, Staff is concerned that this traditional comparison may cause the B2H line to look more economic than it really is. Staff has engaged with the Company on this matter, and Staff is continuing to investigate the economic lives of the resources.

[61] Supply-side and demand-side cost information is found in Idaho Power's Technical Appendix C to this IRP.
[62] Portfolio seven includes the Boardman to Hemmingway transmission project, a 300 MW combined-cycle combustion turbine, and 180 MW of reciprocating engine generation.
[63] See Attachment I.

Staff notes, however, that this ranking method complies with the Commission's Integrated Resource Plan Guidelines, which in part, state:

> The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.

The Company indicates that it accounts for "end effects" by annualizing the fixed costs of each resource over the entire economic life of the resource.[64] Staff has issued discovery requests to the Company to understand this further.

The Oregon IRP guidelines also provide:

> Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.[65]

Idaho Power's IRP complies with this guideline, as the net present value portfolio cost is equivalent to the PVRR measure the guidelines suggest. Staff does not have any concerns over Idaho Power's PVRR analysis methodology other than an interest in how "end effects" are handled. However, it is important to note that the PVRR results are a product of both how the portfolios were constructed and the resource costs used in the Company's model. Staff addresses these topics separately.

Environmental Regulations

The Idaho Power 2017 IRP has several sections that raise or address many environmental concerns and risks. The Company explicitly discusses the risks of FERC Relicensing for the Hells Canyon Project, Idaho and federal Clean Water Act issues, the US Bureau of Reclamation release of water in the Snake River Basin, possible fuel augmentation through cloud seeding, water lease agreements, and protected species issues such as Bliss Rapids snail. Staff thanks Idaho Power for its attention to and management of these risks, especially as they all directly impact the resource and operation backbone of Idaho Power's system: hydroelectric power. However, Staff 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.

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[64] See Idaho Power 2017 IRP, p. 88 ("For the portfolio cost analysis, resource fixed costs are annualized over the assumed economic life for each resource and are applied only to the years of output within the IRP planning period, **thereby accounting for end effects**.") (Emphasis added).

[65] Order No. 07-002, Guideline 1.c.

Climate models predict that over the coming century the Northwest will experience higher maximum summer temperatures.[66] If this prediction is correct, line losses and peak demand to serve air conditioning load will very likely increase. Idaho Power needs to take these potential effects into account in its planning.

Models also show an increase in the number of forest fires and the length of the forest fire season throughout the Western states.[67] This change may affect transmission lines and transmission corridors that Idaho Power is dependent upon for energy delivery.

Decreased snow pack will affect many aspects of the Northwest hydrological system, all of which may have serious implications for Idaho Power and its customers.[68] A decreased snow pack means increased stream flow seasonal variability and additional endangered species compliance obligations at hydropower units owned by or relied upon by Idaho Power. Decreased stream flows will likely trigger greater reliance on ground water reserves, which may mean greater pumping loads on Idaho Power's system and additional legal risk related to ground water rights. Many times, these ground water pumps are situated on long rural radial distribution lines which can significantly affect line voltage and substation equipment integrity. It is important to remember also that much of agricultural pumping load also makes up a majority of Idaho Power's Demand Response resource. In addition, increased summer heat may cause distribution line sagging in highly urbanized areas, resulting in a drop in distribution reliability indices.

Models also show increased rainfall intensity is possible. An increase in cloud cover will affect lighting demand and intense seasonal rainfall or seasonal rapid snow melt may also lead increased flooding.[69]

These are just a few examples of how climate change could affect the Northwest and Idaho Power. When these changes occur, Idaho Power customers will be forced to adapt, changing how and when they consume electricity. Idaho Power needs to remain aware of these potential impacts on its generation and distribution system and plan

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[66] See USGS, Climate and Land Use Change Research and Development Program, National Climate Change Viewer, Full NEX-DCP30 model, available at, http://www.usgs.gov/climate_landuse/clu_rd/nex-dcp30.asp, See also U.S. National Climate Assessment; See also Intergovernmental Panel on Climate Change, Fifth Assessment Report, See also Intergovernmental Panel on Climate Change, Climate Change 2014: Mitigation of Climate Change.

[67]See The US Forest Service, An Overview available at http://www.fs.fed.us/documents/USFS_An_Overview_0106MJS.pdf; See also USGS, Climate and Land Use Change Research and Development Program, National Climate Change Viewer, Full NEX-DCP30 model, available at, http://www.usgs.gov/climate_landuse/clu_rd/nex-dcp30.asp, See also U.S. National Climate Assessment; See also Intergovernmental Panel on Climate Change, Fifth Assessment Report.

[68] See USGS, Climate and Land Use Change Research and Development Program, National Climate Change Viewer, Full NEX-DCP30 model, available at, http://www.usgs.gov/climate_landuse/clu_rd/nex-dcp30.asp, See also Intergovernmental Panel on Climate Change, Fifth Assessment Report.

[69] See USGS, Climate and Land Use Change Research and Development Program, National Climate Change Viewer, Full NEX-DCP30 model, available at, http://www.usgs.gov/climate_landuse/clu_rd/nex-dcp30.asp, See also Intergovernmental Panel on Climate Change, Fifth Assessment Report.

accordingly, thus recognizing that climate change is a real risk beyond a regulatory risk expressed as a cost of carbon.

Staff believes that Idaho Power has made some positive steps to meet some of the challenges of climate change through resource diversity and plans for de-carbonization of its resource stack. However, Staff believes that climate change adaptation and mitigation requires further steps to limit exposure to costly risks that will affect how Idaho Power delivers energy and services to its ratepayers in the future. Staff also recognizes that at this point in time, Idaho Power does not have a regulatory or legislative mandate that specifically requires Idaho Power to assess or to take action to mitigate or adapt to climate change risks. However, Staff believes it would be in the long-term best interest of Idaho Power and its ratepayers to take initial steps to assess and better understand the risks presented. To this end, Staff is exploring requiring Idaho Power to undertake modeling and related planning efforts to inform future actions that would model and address the real and present risk of climate change. This may be in the form of a new IRP guideline. Such a guideline might direct the utility to identify and model the risks associated with climate change and develop adaption and mitigation measures and plans to meet those risks.

Electric Vehicles

Staff commends Idaho Power's progressive and proactive endeavors to advance the adoption of electric vehicles. Idaho Power's work as a corporation and in collaboration with such entities such as the Idaho National Lab serve as a model and resource for the rest of the Region. It is particularly heartening that a utility with such a diverse territory would undertake effort to advance EV adoption. Staff is currently reviewing Idaho Power EV efforts and will explore recommendations for next steps. Staff is currently interested in aggressive time-of-use adoption by EV owners in Idaho Power's service territory to help manage this new load and mitigate its potential impact on peak demand and by implication peak resource need and development. Additionally, Staff will review Idaho Power's current tariff structure to determine whether it presents a barrier to public charger development.

Conclusion

Staff commends the Company on the work it has done in certain aspects of the IRP, but Staff has concerns about other areas. Most notably, Staff requests that the Company demonstrate a more convincing case as to why the B2H line is needed now, timely, and part of a portfolio of resources that best benefits Oregon utility ratepayers while minimizing risk. In addition, Staff needs to better understand the Company's request to acknowledge the early shut down of a Valmy Unit 1 in 2019 when the Commission did not agree to this date in the Company's latest rate case, UE 316. Finally, Staff's request that its concerns about tthe portfolios against which the preferred portfolio was selected be addressed. Staff does not believe some of the competing portfolios represent a realistic way to meet load and thus fail provide meaningful comparisons to the preferred portfolio and also a true understanding as to why the preferred portfolio is least cost, least risk.

Staff anticipates that in addition to addressing the concerns above, other substantive questions from each section of these comments will be addressed in Idaho Power's Reply Comments. Staff would also ask the Company to address the outstanding issues below in its Reply Comments:

- Discussion of the 2019 and 2025 end-of-life analysis in its Reply Comments.
- An explanation of the reasons for the analytical change around the Jim Bridger plant and any impact this has on ratepayers.
- Information regarding the planned source of the power that will replace the coal plants. Specifically, the Company should provide a breakdown of long-term, short-term, and spot purchases.
- Analysis or documents presenting the benefits of EIM participation and how it might impact the B2H project.
- Confirmation of when Idaho Power is resource deficient and how the generation or capacity deferral value is utilized as part of its EE Avoided Costs.
- Make the changes outlined in the Energy Efficiency section above to its avoided cost methodology, re-run its cost-effectiveness analysis, and report back on the impact to the amount of EE selected for its IRP forecast (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.
- Supplemental analysis of the B2H line, possibly as an appendix to the 2017 IRP.

Staff asks that in the next IRP, Idaho Power:

- Provide analysis of a no-special-contract-load-growth scenario.
- Restructure its portfolio development for the 2019 IRP using capacity expansion modeling while also taking into account the analysis presented in the 2015 IRP.

This concludes Staff's opening comments.

Dated at Salem, Oregon, this 31st day of October, 2017.

Nadine Hanhan
Utility Analyst
Energy Resources and Planning Division

Table 7.4 July monthly average energy deficits (aMW) by Bridger coal future with existing and committed supply- and demand-side resources (70th-percentile water and 70th-percentile load)

Energy Deficits (aMW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Invest in Bridger SCR	0	0	0	0	0	0	0	(9)	(80)	(107)	(173)	(200)	(226)	(256)
Retire Bridger Units 1 & 2 in 2024, 2028	0	0	0	(11)	(41)	(105)	(312)	(346)	(416)	(444)	(509)	(536)	(562)	(592)
Retire Bridger Units 1 & 2 in 2028, 2032	0	0	0	0	0	0	(143)	(177)	(248)	(276)	(509)	(536)	(562)	(592)
Retire Bridger Units 1 & 2 in 2021, 2022	0	(16)	(38)	(180)	(209)	(273)	(312)	(346)	(416)	(444)	(509)	(536)	(562)	(592)

Note: Darker shading indicates increasing deficit values.

Table 7.5 July monthly peak-hour capacity deficits (MW) by Bridger coal future with existing and committed supply- and demand side resources (90th-percentile water and 95th-percentile load)

Capacity Deficits (MW)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Invest in Bridger SCR	0	0	0	(34)	(94)	(159)	(222)	(282)	(346)	(399)	(464)	(521)	(576)	(635)
Retire Bridger Units 1 & 2 in 2024, 2028	0	0	(152)	(210)	(270)	(335)	(573)	(634)	(697)	(750)	(815)	(872)	(921)	(967)
Retire Bridger Units 1 & 2 in 2028, 2032	0	0	0	(34)	(94)	(159)	(397)	(458)	(521)	(574)	(815)	(872)	(921)	(967)
Retire Bridger Units 1 & 2 in 2021, 2022	(213)	(275)	(328)	(386)	(445)	(510)	(573)	(634)	(697)	(750)	(815)	(872)	(921)	(967)

Note: Darker shading indicates increasing deficit values.

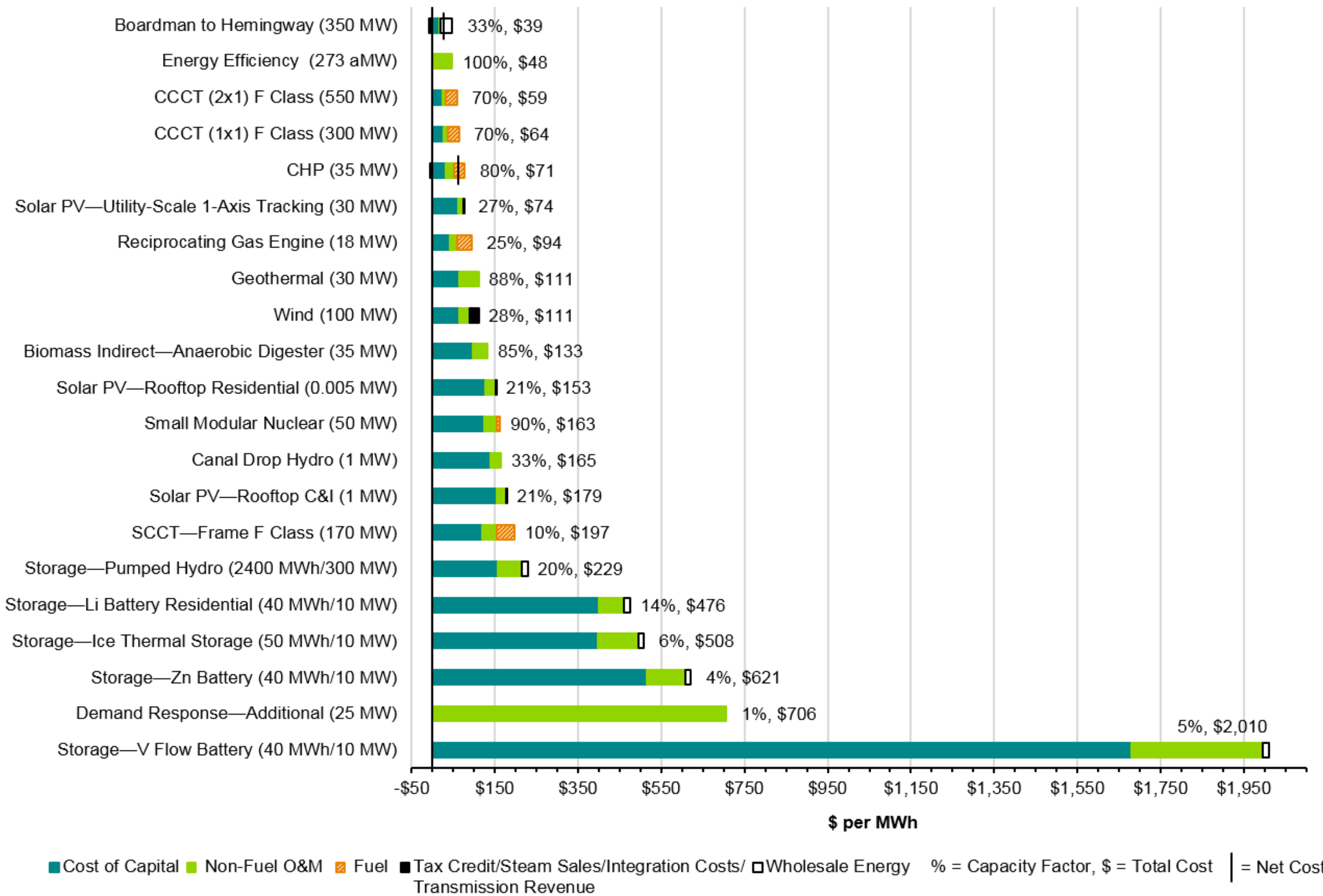

Figure 7.6 LCOE (as stated capacity factors)

<u>STAFF'S DATA REQUEST NO. 56</u>:

See IRP page 89. Please provide the derivation of $39 total cost for Boardman to Hemmingway (350 MW). In your response include all source data, intact formulas, and a list of assumptions made.

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 56</u>:

In preparation of this response, it was discovered that the total cost estimate used the incorrect starting point to arrive at the $39 per megawatt-hour ("MWh") for Boardman to Hemmingway ("B2H"). The correct capital cost should have been $24 (rounded) per MWh from Protected Information Attachment 2, cell H78 on tab "B2H 2017 IRP". The levelized cost of energy ("LCOE") table on page 89 that included the $39 per MWh value incorrectly referenced cell M78, which was the $18 (rounded) per MWh on that tab. Using the correct starting point, the total cost per MWh for B2H should be $46 (rounded) which consists of $23.65 capital, $2.65 operations and maintenance ("O&M") -$8.80 transmission revenue, and $28 wholesale energy. The cost per MWh for each of the resources in Figure 7.6 LCOE is an estimate for comparative purposes and was not used in the valuation of the portfolios. Although this error did not impact the valuation of the portfolios, the Company will submit a letter to the parties' correcting the error in presentation.

Derivation of each of the total cost components is detailed in the following files:

Idaho Power's capital cost estimate for B2H is included as Protected Information Attachment 1 (B2H 2017 IRP Cost Estimate). This information is used in Protected Information Attachment 2 (B2H 2017 Energy 17.51 MWh) and the resulting (rounded) cost of $18 per MWh is calculated within this Excel spreadsheet. As detailed above, the correct capital cost should be $24 (rounded) per MWh found on cell H78.

The derivation of the annual non-fuel O&M cost is provided as Protected Information Attachment 3 (B2H Estimated O&M Costs 2017). This information is used in Protected Information Attachment 2 and the resulting (rounded) $3 per MWh is calculated within this Excel spreadsheet.

The derivation of the additional transmission revenue is provided as Protected Information Attachment 4 (B2H Rev Forecast 2017 IRP). The results of the forecast are used in Protected Information Attachment 2 and the resulting (rounded) -$9 per MWh is calculated within this Excel spreadsheet.

The derivation of the wholesale energy cost $28 per MWh was provided by a forecast from AURORA and is included as Attachment 5.

Attachments 1 through 4 produced in response to this Request are protected information and will be provided in accordance with Protective Order No. 17-292.

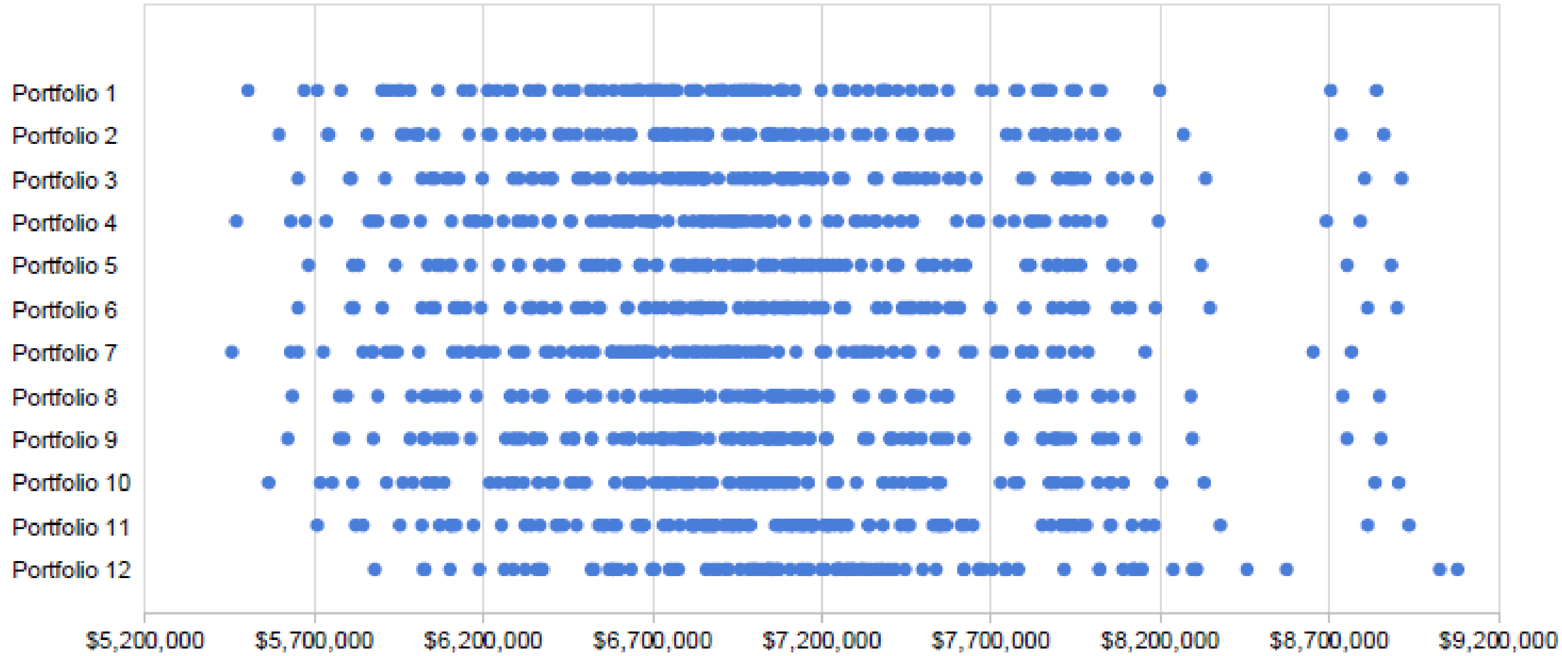

Figure 9.5 Portfolio stochastic analysis, total portfolio cost, NPV years 2017–2036 ($ x 1,000)

August 24, 2017

Subject: Docket No. LC 68 – 2017 Integrated Resource Plan ("IRP")
Idaho Power Company's Responses to the Public Utility Commission of Oregon Staff's ("Staff") Data Request Nos. 1-34

STAFF'S DATA REQUEST NO. 24:

See page 82 of the IRP.

a. Staff struggles to understand the statement made about coal plants being dispatched less frequently, but the load-resource balance is being projected at the same monthly average energy output (see first paragraph). Please explain.

b. What are the "customer economic benefits" from North Valmy that informed the decision for an early retirement date of 2019? How will customer rates be impacted as a result of the early depreciation schedule?

c. What are the impacts on economic benefits with less coal generation being dispatched?

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 24:

a. A load and resource balance is created for each portfolio. This initial view contains the net dependable capacity typical for each resource, including coal. This net dependable capacity view demonstrates the resource adequacy for each portfolio and helps Idaho Power determine when other resources would need to be added for system reliability. The statement regarding monthly average energy output on page 82 is referencing net dependable capacity within the context of the load and resource balance.

In the second step, each portfolio is run in AURORA. The AURORA model provides an hourly market simulation for each portfolio, dispatching resources economically against a gas forecast and market prices. In this step, the model is choosing the hourly dispatch of each plant, within established parameters. Due to low gas prices and the impacts of renewable technology, the coal plants have dispatched less frequently than in years past. The statement regarding less frequent dispatch is referencing the projected dispatch as determined by AURORA.

b. Attached is the supplemental Valmy Unit 1 analysis performed by Idaho Power in line with the 2017 IRP and updated Valmy capital and operations and maintenance budgets. The supplemental analysis, which was provided to the Public Utility Commission of Oregon ("Commission") as part of the Company's request to accelerate the Valmy end-of-life in Docket No. UE 316, describes the customer economic benefits of a Unit 1 2019 end-of-life. The supplemental analysis is provided as Attachment 1 and the supporting workpapers are provided as protected information Attachments 2 through 6, the following table provides a description of the information contained in each attachment:

No.	Filename	Description
1	Analysis Summary Results	Narrative of assumptions, changes in risk factors, analysis results, and final recommendation.
2	Confidential Fixed Cost Impact	Detailed calculation of fixed cost impacts presented in Table 1 of Attachment 1.
3	Confidential AURORA Base Gas	AURORA output in support of variable cost impacts under base gas scenario as detailed in Table 2 of Attachment 1.
4	Confidential AURORA 200 Percent Gas	Same as Attachment 3, but reflecting 200 percent gas scenario.
5	Confidential AURORA 300 Percent Gas	Same as Attachment 3, but reflecting 300 percent gas scenario.
6	Confidential AURORA 400 Percent Gas	Same as Attachment 3, but reflecting 400 percent gas scenario.

The Company's request in Docket No. UE 316, which was filed on November 2, 2016, prior to the supplemental analysis, included recovery of the accelerated depreciation for all existing Valmy plant investments associated with a 2025 shutdown, a return on undepreciated capital investments, and decommissioning costs. In Order No. 17-235, effective July 1, 2017, the Commission approved a revenue requirement increase of $1,056,800, or 1.91 percent, associated with a 2025 end-of-life for both Valmy units. Any rate impacts associated with the 2019 Unit 1 end-of-life will be determined in a future rate proceeding.

c. The impact on economic benefits to the portfolios of lower coal generation is lower fuel usage and a lower power supply cost for the portfolio. When a resource is displaced by a lower-cost resource or market purchase, the power supply cost is lower, resulting in economic benefits to customers. Alternatively, when high market prices in excess of the dispatch price of a resource exist and there is available capacity to enable off-system sales, the profit from these sales will reduce power supply costs.

Attachments 2-6 produced in response to this Request contain protected information and will be provided in accordance with General Protective Order No. 17-292.

September 26, 2017

Subject: Docket No. LC 68 – 2017 Integrated Resource Plan ("IRP")
Idaho Power Company's Responses to the Public Utility Commission of Oregon Staff's ("Staff") Data Request Nos. 58-69

STAFF'S DATA REQUEST NO. 60:

Explain Idaho Power's familiarity with energy storage valuation and the concept of co-optimization. Has Idaho Power piloted any energy storage projects? Is Idaho Power aware of US DOE efforts to model energy storage system values?

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 60:

Idaho Power has performed energy storage valuations using the concept of co-optimization. In 2015, the Company developed a draft proposal to participate in an Energy Storage Demonstration Pilot, Request for Grant Application 330-1186-15 (ODOE-15-013). In this effort, Idaho Power considered three different values of the application: asset deferral, voltage support, and resilience for the Jordan Valley, Oregon community. Ultimately, Idaho Power did not submit the application after concluding that this application was not a cost-effective alternative as described in the letter sent to the Oregon Department of Energy ("ODOE") included as an attachment to this response. Idaho Power is currently considering implementing a more cost-effective energy storage system at the same Jordan Valley, Oregon location for asset deferral as described in the *2017 Smart Grid Report*.[1]

Additionally, Idaho Power is aware of the U.S. Department of Energy's efforts to model energy storage systems and is familiar with the Pacific Northwest National Laboratory (PNNL) and the National Renewable Energy Laboratory (NREL) reports and tools developed to model energy storage system values. The Company is also a member of Electric Power Research Institute ("EPRI") Program 94: Energy Storage and Distributed Generation. EPRI Program 94 explores the following as it relates to energy storage and distributed generation: technologies, analyzing methods for cost and benefit, developing integration methods, as well as, testing and evaluating product solutions in lab and field environments. The Company continues to examine the Idaho Power system for cost-effective applications of energy storage systems.

[1] Draft *2017 Smart Grid Report* can be found at: https://www.idahopower.com/pdfs/AboutUs/CompanyInformation/SmartGrid/2017SmartGridReport_DRAFT.pdf

<u>STAFF'S DATA REQUEST NO. 32</u>:

See page 112 of the IRP, Figure 9.1. Staff understand this graph to reflect that the Company has chosen the lowest of all gas price scenarios as the planning case, with price sensitivities only being tested above the planning case. Is this correct? Why has the Company chosen to use low gas prices in its planning case scenario? Is this the same gas price assumptions the Company used for its energy efficiency analysis (DSM Report)?

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 32</u>:

No. The natural gas price forecast sensitivities shown in Figure 9.1 are based on the 2016 EIA High Oil and Gas Resource and Technology ("EIAHO") case forecast (depicted as the "Planning Case" in Figure 9.1). The graph in Figure 9.1 displays the resulting natural gas prices based on the EIAHO Planning Case forecast over a range of upward price sensitivities. The objective of the gas price sensitivities analysis was to test the performance of each portfolio over a possible range of higher priced futures, which helps effectively test the key resource decisions of coal unit retirement and the B2H transmission project evaluated in the 2017 IRP.

The natural gas forecast was discussed at the September 2016 and March 2017 IRPAC meetings. Following those discussions, it was determined that testing sensitivities lower than the EIAHO Planning Case forecast was not informative to the resource portfolios being evaluated.

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. The IRP Planning Case natural gas price is based on an EIA forecast. Upon a detailed a review of Intercontinental Exchange ("ICE") settled forward contracts, ICE was shown 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.

The 2016 EIAHO case natural gas forecast was not used in the energy efficiency analysis used in Appendix B of the 2017 IRP. Please see the Company's response to Staff's Data Request No. 15 for more information regarding the gas forecast utilized for the DSM potential study.

<u>STAFF'S DATA REQUEST NO. 15</u>:

What data did Idaho Power use for gas prices in its energy efficiency analysis? What data did the Company use for gas prices in its load-resource balance analysis?

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 15</u>:

For the 2017 IRP process, Idaho Power contracted with a third-party consultant, AEG, to produce an Energy Efficiency Potential Study. The Company provided AEG the preliminary DSM alternate costs based on the 2015 IRP preferred portfolio updating the 2017 load forecast and the gas forecast using the EIA 2016 Annual Energy Outlook ("AEO") Reference Case.

The final DSM alternate costs published in the 2017 IRP Appendix C: Technical Report are based on the 2017 IRP preferred portfolio using the 2017 IRP planning case natural gas price forecast, which is based on the EIA 2016 AEO High Oil and Gas Resource and Technology Case.

The load and resource balance analysis is strictly an assessment of resource adequacy and does not factor in resource operating costs (i.e., fuel).

Table 9.3 2017 IRP Portfolios, NPV years 2017–2036 ($ x 1,000)

Portfolio Details				Variable Costs			New Resource Fixed Costs			Bridger	Summary		
Portfolio Index (1)	Portfolio Description (2)	B2H (3)	Bridger Capacity Retirement (4)	Operating (AURORA) (5)	Rank (6)	Relative Difference (7)	Portfolio Fixed Costs (8)	Rank (9)	Relative Difference (10)	Bridger Fixed Costs (11)	Total Fixed + Variable Costs (12) = (5) + (8) + (11)	Lowest Cost Rank (13)	Lowest Cost Relative Difference (14)
P1	SCR invest, B2H, recips	✓		$5,782,181	10	$252,923	$91,266	1	–	$527,249	$6,400,696	4	$64,925
P2	SCR invest, DR, recips, solar			$5,670,820	4	$141,562	$299,436	5	$208,169	$527,249	$6,497,505	6	$161,733
P3	SCR invest, DR, recips, CCCT			$5,731,938	8	$202,679	$271,669	4	$180,403	$527,249	$6,530,856	9	$195,084
P4	Bridger retire in 24 & 28, B2H, recips	✓	✓	$5,796,035	11	$266,777	$207,739	2	$116,473	$334,909	$6,338,683	2	$2,912
P5	Bridger retire in 24 & 28, DR, recips, solar		✓	$5,577,721	2	$48,463	$653,937	10	$562,671	$334,909	$6,566,567	10	$230,796
P6	Bridger retire in 24 & 28, DR, recips, CCCT		✓	$5,729,526	7	$200,267	$443,808	8	$352,541	$334,909	$6,508,242	8	$172,470
P7	Bridger retire in 28 & 32, B2H, recips, CCCT	✓	✓	$5,755,589	9	$226,331	$214,229	3	$122,963	$365,952	$6,335,771	1	–
P8	Bridger retire in 28 & 32, DR, recips, solar, CCCT		✓	$5,654,210	3	$124,951	$483,362	9	$392,096	$365,952	$6,503,524	7	$167,753
P9	Bridger retire in 28 & 32, DR, recips, CCCT		✓	$5,701,053	6	$171,794	$415,995	7	$324,729	$365,952	$6,483,000	5	$147,229
P10	Bridger retire in 21 & 22, B2H, recips	✓	✓	$5,807,951	12	$278,693	$309,227	6	$217,961	$283,328	$6,400,507	3	$64,736
P11	Bridger retire in 21 & 22, DR, recips, solar		✓	$5,529,258	1	–	$767,183	12	$675,917	$283,328	$6,579,769	11	$243,998
P12	Bridger retire in 21 & 22, DR, recips, CCCT		✓	$5,689,172	5	$159,914	$699,009	11	$607,743	$283,328	$6,671,510	12	$335,739

Under the planning case natural gas price, P7 has a total fixed and variable 20-year NPV cost of $6,335,771,000 and a lowest cost rank of 1.