BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 68

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

Table of Contents

Introduction

The following are Staff's Final Comments concerning Idaho Power Company's ("Idaho Power" or "Company") 2017 Integrated Resource Plan (IRP). Staff remains appreciative of the work done by Idaho Power and the other stakeholders involved in this IRP. Stakeholder input and Idaho Power's Reply Comments has been substantive and helpful in clarifying several outstanding issues.

In these Final Comments Staff discusses several things, including the Company's Action Items, some of Staff's recommendations regarding acknowledgment of these items, the 2017 IRP Update, and the 2019 IRP. Staff will provide its final recommendations regarding all items in Idaho Power's Action Plan in its Staff Report after reviewing the Company's Final Comments due on February 16, 2018.

Overall, Staff found the Company's Reply Comments informative. In particular, Staff appreciates the Company's response to Staff's questions with respect to the Boardman to Hemingway (B2H) transmission project. The Company created an additional appendix to its IRP—Appendix D: B2H Supplement to the 2017 IRP. Staff commends the Company on a thorough response to Staff's request.

The first topic addressed in Staff Final Comments is the B2H transmission project. Though Appendix D answered many of Staff's questions regarding the project, some questions remain, especially around the cost of the project and the commitment of co-participants.

Second, Staff discusses its concerns regarding the Energy Imbalance Market (EIM) Action Item, which Staff will recommend removing as an Action Item. This is followed by a discussion on Idaho Power's planned coal retirements. Staff will ultimately recommend acknowledgment of the 2019 Valmy Unit 1 closure but not the Jim Bridger Action Item.

Staff then discusses issues related to energy efficiency (EE) and demand response; Staff includes recommendations for the Company's Final Comments on each of these topics.

The rest of Staff's comments focus on general concerns with the IRP. Staff reviews the Company's response to the Company's load forecasting and makes recommendations for the 2019 IRP. Following this discussion, Staff comments on the Company's exceedance assumptions, followed by hedging, in which Staff also includes recommendations for the next IRP and IRP Update.

Staff then continues with a discussion on the Portfolio Design of the IRP and Staff's recommendation that a new methodology be explored in the IRP Update. Staff believes the current methodology is a step backward from the 2015 IRP and that by the next IRP, the Company should adopt a different approach to creating portfolios that includes a more transparent vetting process.

The next comments focus on a discussion on renewable costs and natural gas price forecasts. Staff recommends using more conservative natural gas prices in the next IRP. Finally, Staff discusses concerns around Idaho Power's treatment of climate change in the IRP. Staff recognizes that the Company's portfolios complied with the federal policy anticipated at the time the IRP was drafted, but for the next IRP, Staff recommends a different approach due to changes at the national level.

Idaho Power Action Plan Overview

In the 2017 IRP Idaho Power requested acknowledgement for a series of Action Items. The Action Items have not changed over the course of the IRP acknowledgment process. The Action Items are 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.

Staff Comments on Action Plan Items

Introduction to B2H

In Opening Comments, Staff identified several concerns related to the proposed B2H transmission line. First, Staff noted that Idaho Power had identified both a need for transmission capacity but also a resource deficiency need within its planning horizon. In particular, Staff identified Idaho Power's peak capacity need starting in 2026.[1] Staff recognized—largely due to sources outside of the IRP and through discovery—that the Company seemed to have accomplished a significant amount of work in moving the project along. However, these accomplishments were only briefly summarized in the IRP. This was a surprising omission in this capstone IRP where the Company specifically requests acknowledgment for construction to satisfy the Energy Facility Siting Council (EFSC) need requirement. Furthermore, little was explained regarding the need for the line. This was concerning since the Company relied so heavily on B2H as a resource in its portfolio design.

In its comments, Staff stated that the Company should demonstrate how B2H benefits exceed those of a substitute generation resource beyond its reference to improved reliability. Because Staff felt that the Company failed to explain in depth the benefits, need, and role of the line, Staff requested that the Company address Staff's concerns in Reply Comments.

In response to Staff's request for additional information, the Company produced Appendix D: B2H Supplement. This appendix includes a thorough account of the history, timeline, reliability and capacity needs, public participation, benefits, costs and risks of the project. In particular, Staff appreciates the Company's description of project activities and the history of public engagement, including with landowners and responses to community concerns. Again, Staff is appreciative of the Company for its response to Staff in delivering Appendix D on such short notice.

[1] Staff's Opening Comments, p. 6 and Attachment A.

Cost of B2H

Arguably the most significant factor leading to B2H's inclusion in the Preferred Portfolio is its lower cost relative to other resources. Accordingly, Staff analyzed Idaho Power's assumptions regarding costs of B2H. In Opening Comments, Staff raised several concerns about the cost of the line. In particular, Staff was concerned about the potential cost overruns and lack of clarity in the Company's cost comparisons among the resources it vetted for use in the portfolios. Among these resources were energy efficiency, Combined Cycle Combustion Turbines (CCCT), Single-Cycle Combustion Turbines (SCCT), and others that can be found in Attachment B in Staff's Opening Comments. Other parties such as STOP B2H also raised concerns around cost overruns and stated that the Company should incorporate them in analysis.[2]

Staff also indicated in Opening Comments that it would further review the Company's files related to costs. Staff also submitted discovery on the impact of "end effects" on the analysis.

The Company explained through a data response that its statement on "end effects" referred to the reality that most new resources added to a portfolio will have some useful life after the 20-year IRP study period. To address this issue, the Company allocated new resource costs over the entire life of the resource but only measured the costs of all the resources within the 20-year study period. The Company provided an example, which Staff has included as Attachment 1 in these Final Comments.

Staff is still concerned, however, with the assumptions regarding the variable costs of B2H, which the Company provided through discovery and lists in Table 9.3 of the IRP as AURORA operating costs. When Idaho Power forecasts prices for market purchases, it uses the AURORA software. The natural gas price input for the portfolio analysis was the Energy Information Administration's (EIA) High Oil and Gas Resource and Technology Case (EIAHO) for 2016. The EIAHO results in a low natural gas prices over the planning horizon.[3]

Staff is concerned about how Idaho Power's use of the EIAHO gas price scenario as an input affects the economics of B2H.[4,5] Staff understands that in Appendix D, the Company stated that "the B2H portfolios' capacity costs are so low that capacity

[2] Stop B2H Opening Comments, p. 13.
[3] Renewable Energy Coalition Comments, pp. 3-4 (Explaining the EIA High Oil and Gas Resource Technology case results in gas prices staying under $5/MMTbu for the entire IRP planning period. In contrast, the "Reference" case, which REC describes as "a business-as-usual estimate given known market, demographic, and technological trends[,]" results in gas prices that gradually increase to $7.50/MMTbu over the 20-year planning period. The EIA Low Oil and Gas Resource Technology case, which is the other end of the spectrum from the EIAHO, results in projected gas prices up to $15/MMTbu over the planning period. In both the 2013 and 2015 IRPs, Idaho Power used the Reference case, rather than the lower High Oil and Gas Resource Technology case for its natural gas price.)
[4] Idaho Power 2017 IRP, p. 11.
[5] Idaho Power IRP Appendix D, p. 11.

installation savings far outweigh the additional energy costs."[6] Staff also notes that the Company stated that it used a series of conservative assumptions around transmission revenues.[7] However, Staff requests that the Company address Staff's concern regarding the use of the EIAHO in greater depth in its Final Comments and demonstrate in a clearer fashion, with numerical examples, the interaction between variable and fixed costs in determining the lowest-cost rank of Portfolio P7. For capital costs, Idaho Power produced the following table in its Reply Comments:

Table 1: Idaho Power's Capital Cost in $/kW for Selected Resources [8]

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

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

Staff notes that, when utilizing 500 MW of average capacity, B2H results in a $/kW capital cost of about 62 percent of the next lowest-cost resource. Staff and the Commission remain concerned about underestimation of costs related to a project of this magnitude, particularly in light of Staff's questions about the commitment of Idaho Power's partners. **Staff also notes that the functions of a transmission line and a reciprocating engine are fundamentally different.** Staff recognizes that the Company mitigates the concern of cost overrun by applying a 20 percent contingency rate to its capital cost analysis.[9] Staff believes this to be an appropriate measure at this stage of planning. Staff also finds that the Company's revenue assumptions for this transmission investment could be considered appropriate for the IRP's NPVRR analysis.

It is important to note that the Company has attained greater levels of certainty with respect to project assumptions since the 2015 IRP. Most notably, the Bureau of Land Management (BLM) issued a Record of Decision (ROD) that included the BLM Preferred Pathway for the line. This is an important milestone that adds greater certainty to project particulars and consequently the cost of the project. Should the Commission acknowledge the construction of B2H, Staff expects the Company to update the estimated cost of the project in the 2017 IRP Update now that the ROD has been issued.

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[6] Idaho Power IRP Appendix D, p. 8.
[7] Idaho Power IRP Appendix D, p. 40.
[8] Idaho Power Company's Reply Comments, p. 23.
[9] Idaho Power IRP Appendix D, p. 2.

It is also important to note that Idaho Power has 60 days to file a Notice of Completion, which triggers negotiations for the B2H project. As of writing these comments, Staff is unaware of any such move by Idaho Power. Staff would view this as a crucial milestone to the B2H project and expects the Company to provide an update on this issue in its Final Comments if the Company is seeking Commission acknowledgment.

In further considering capital costs, according to Idaho Power, the calculation for the project construction cost utilizes BPA's standard tower and conductor design for 500-kV lines.[10] However, Idaho Power's cost calculations are based on shorter service life assumptions. Idaho Power's transmission plant average service life span is 55 years as demonstrated in *Table 1* above. Staff has previously determined that a transmission plant's average service life span is 60-65 years, based on whether the proposed rates are sufficient to recover utilities' total costs.[11]

In general, the shorter an asset's depreciable life, the higher the near-term impact on electric rates. A short depreciable life will have a significant impact on electric rates and make (1) the annual depreciation expense much higher in the Revenue Requirement, and (2) the electric rate subsequently increase. For example, changing Idaho Power's assumptions of service life by using OPUC authorized service lives, the estimated Annual Depreciation Expense (fixed cost) could be lowered by 18 percent. *See Table 2* Below.

Table 2: Fixed Costs Using Staff's Depreciable Lives

	Idaho Power	**Idaho Power**	**OPUC**	**OPUC**	**OPUC Depreciation**
Resource Type	**Depreciation**	**Depreciable**	**Depreciation**	**Depreciable**	**Exp Decrease**
	$Exp/IPC year	**Life/year**	**$ Exp/PUC year**	**Life/year**	**$ / year**
$1.2b B2H Transmission line	$23,120,314	55 years	$19,563,343	65	-$3,556,971
CCCT (1x1) F Class (300 MW)		30 years		40 & 45	
SCCT – Frame F Class (170 MW)		30 years		40 & 45	
Reciprocating Gas Engine		30 years		40 & 45	
Solar PV – Utility Scale 1-Axis		25 years		20	
Total $	$23,120,314		$19,563,343		-$3,556,971
% change					**-15.4%**

[10] Idaho Power Appendix D: B2H Supplement, p. 39.
[11] *See* Order No. 17-186, Order No. 13-347, and Order No. 17-365.

In summary, annualized net depreciation expenses due to the change of "Depreciable Life" for a $1.2 billion transmission line from 55 years to 65 years will decrease by $3.56 million per year, and the total fixed assets depreciation expense in *Table 1* will decrease by over 15 percent.

B2H Justification

Strengths [12]

In reading through Appendix D, Staff identified the following strengths in the project and analysis:

- Increases grid reliability and flexibility for Idaho Power customers.
- Potentially allows intermittent resources in Oregon and Washington to avoid curtailment and connect to areas where thermal generation can be replaced with zero-carbon generation.
- Offers greater access to Northwest markets to bring potentially low-cost energy to Idaho Power customers.
- Planned Idaho Power asset swaps may address concerns about wheeling costs raised by parties in this proceeding.
- Idaho Power has stated that it will take prudent steps to ensure that contractors have adequate guarantees for line construction and quality.
- B2H mitigates fire and terrorist risk by connecting additional capacity to Oregon, increasing Oregon resilience to a variety of weather and human-caused events.
- Generally considered more reliable than generation, with transmission having forced outage rates of 1 percent vs. 7-10 percent for non-variable generation resources.
- Bureau of Land Management (BLM) has issued a Record of Decision (ROD), which is a significant milestone in B2H development.

Upon reviewing the Company's materials and cited third-party materials such as the NTTG Regional Transmission Plan, Staff believes that the Company has done its due

[12] Staff also notes a series of regional benefits that are not Oregon-specific or specific to Idaho Power customers and recognized by third parties, such as 1) Increasing regional grid capacity, stability, reliability, and resiliency, in addition to transmission constraint relief. For example, when other generation resources are unavailable, i.e., when another utility has turbine shaft failure, B2H would increase Oregon utility operation flexibility and connectivity to potentially lower-cost replacement resources, reducing cost and risk for Oregon ratepayers; 2) The Western Electricity Coordinating Council (WECC), Columbia Grid, and the Northern Tier Transmission Group (NTTG), have found B2H to be a critical transmission resource; 3) Reducing Loss of Load Probability (LOLP) according to the Northwest Power and Conservation Council (NWPCC); 4) Increasing the ability for EIM and any future ISO to dispatch the lowest-cost generation to the Pacific Northwest; and 5) Has been recognized by both the Obama and Trump administrations as critical infrastructure necessary for clean energy and American jobs.

diligence regarding the need for the project. More specifically, Idaho Power has demonstrated a transmission capacity constraint need for the line, and has provided sufficient information to eliminate concerns about whether the project is needed for reliability and resiliency.

Weaknesses

Despite the Company's need and strengths of the project, there remain several areas where Staff requires additional certainty. The Company has remained largely silent on the future participation of other line proponents and owners, namely the Bonneville Power Association (BPA) and PacifiCorp. The Company is essentially asking the Commission to acknowledge this project as a major resource acquisition akin to a large thermal generation plant, with unique cost overrun risk, and in which it is not the majority owner of the proposed asset. With the exception of a permitting agreement and a terminated Memorandum of Understanding (MOU), Idaho Power has not demonstrated the commitment of the other parties to building this resource and thus the likelihood that the project will actually proceed.[13]

In Docket No. LC 67 regarding PacifiCorp's 2017 IRP, Staff requested that PacifiCorp explain its commitment to the B2H line as it is listed as the majority owner of the transmission capacity: 55 percent of B2H overall and 81 percent of B2H's east-to-west transmission.[14] PacifiCorp did not give a definite answer regarding its commitment to B2H. Instead PacifiCorp stated that it would remain party to the permitting phase only, and that it was still evaluating the economic justification for its investment in B2H. For these reasons, PacifiCorp did not include B2H a resource in its recent IRP, despite the fact the transmission project is slated to come online in next ten years.[15] Staff recognizes that Idaho Power has stated that it will not move forward with the line if its partners drop out.[16] (Idaho Power has also stated that an additional party has expressed interest in being a partner.)[17] The Memorandum of Understanding filed between the parties had a termination date of nearly four years ago. In total, Idaho Power has not allayed Staff's concerns around the commitment of B2H's majority owners to pay for the construction of the actual project. Staff believes the uncertainty around this commitment is still not fully captured as a risk in this IRP.

Staff also notes that the analysis is silent on Idaho Power's rights to utilize direct wheeling. Idaho Power has planned for bypassing wheeling costs through an asset swap with BPA, but this is not entirely certain. Idaho Power has provided no evidence that BPA would allow for such an arrangement. Also, even though Idaho Power has

[13] Notably, Commissioner Bloom indicated at the November 7 workshop, that he would like to see more certainty as to the commitment of the partners.
[14] For information on ownership percentages of B2H, please see Idaho 2017 IRP, June 2017, p. 62, Table 6.2.
[15] *See* Attachment 2; PacifiCorp's October 5, 2017 response to Staff's Data Request # 75.
[16] Idaho Power Company's Reply Comments, p. 6.
[17] Idaho Power Company's Reply Comments, p. 58.

estimated the cost of the line at $1-1.2 billion, Staff has yet to see Idaho Power filing any information in this IRP of agreement from the partners on the cost of the line.

In its Opening Comments, Staff requested that the Company discuss both benefits to the region and Oregon. While the Company has done a thorough job of describing a variety of benefits to the Pacific Northwest, this is less so for Oregon specifically. The Company should provide a clearer exploration in its Final Comments on why Oregon and other ratepayers of Idaho Power are better off with B2H. Closely related to this issue is the role of B2H in Energy Gateway, which the Company has included as part of its Action Items. While Idaho Power's 2017 IRP does not specifically label B2H as part of Energy Gateway (it would appear to be considered a separate project), PacifiCorp's IRP labels B2H as Segment H of its Energy Gateway project.[18] It would be beneficial for the Company to provide clarification in its Final Comments on the role of B2H in Energy Gateway, or lack thereof. Particularly helpful would be the Company's summary of a scenario of Energy Gateway without Boardman to Hemingway—how would Oregon ratepayers benefit in such a scenario?

Furthermore, if the construction of B2H is acknowledged and consequently satisfies the EFSC need requirement, this does not guarantee that an IOU co-participant of the B2H project will automatically gain acknowledgement or approval. Any Idaho Power co-participant regulated by the Oregon Public Utility Commission must demonstrate its own thorough and independent IRP analysis with a demonstrated record of B2H serving as the least-cost, least-risk resource for its system. Acknowledgement for Idaho Power does not guarantee acknowledgment for PacifiCorp.

Recommendation
Staff is unsure at this point if it can recommend B2H for acknowledgement unless the following information is provided by the Company in its final comments:

- An update on the Notice of Completion
- The role of the EIAHO gas price forecast on the variable costs of B2H
- More specification on Oregon ratepayer-specific benefits
- Clarification on the relationships among other co-participants and potential use of the line, i.e., the likelihood of participation and the likelihood the other partners will rely on asset swaps instead of forcing the Company to pay wheeling charges.
- Clarification of the role of B2H in Energy Gateway.

[18] LC 67 – PacifiCorp's 2016 IRP, p. 274.

EIM

In its Opening Comments, Staff noted that Idaho Power requested acknowledgment of EIM participation but provided no analysis in the IRP about the benefits, costs, risks, or details of EIM or how it will relate to its current pool of resources and B2H. Staff asked the Company to provide this analysis in its Reply Comments. The Company responded by noting that Staff had requested this same analysis during its review of Idaho Power's 2015 IRP and that the Company had argued EIM participation "should not be evaluated within the context of an IRP" because it is not a long-term resource.[19] Idaho Power notes that Staff subsequently dropped this request for analysis in its Staff Report. The Company also explains that it included EIM in its 2017 IRP Action Plan for "informational purposes" only.[20]

Staff notes that Idaho Power's EIM participation begins in April 2018, less than four months away. Though the Company did include its February 2016 Energy Imbalance Market Analysis as an attachment to Final Comments, because the Company has declared that EIM is not a long-term resource and included it in its Action Plan for informational purposes only, Staff recommends that the Company remove the EIM Action Item from its Action Plan.

Recommendation
Staff recommends that the Company remove the EIM Action Item from its Action Plan.

North Valmy

In Opening Comments, Staff noted that Idaho Power had not followed the Commission's direction in Commission Order No. 17-235 "to continue to evaluate the Valmy retirement dates in its 2017 IRP." Staff also noted that the 2019 shutdown date of Valmy Unit 1 had not been fully described or vetted. In response, Idaho Power provided all of the analysis performed to support a 2019 shutdown date as opposed to a 2025 shutdown for Valmy Unit 1. The analysis included both quantitative and qualitative portions.

The qualitative analysis identifies three risk factors considered by Idaho Power when arriving at the 2025 shutdown date used in the 2015 IRP and how circumstances with respect to these risk factors had changed.[21] The quantitative analysis compares Idaho Power's estimates of fixed cost savings to its estimates of incremental cost increases resulting from a shutdown. Noticeably, when looking at the variable cost impact using Idaho Power's base assumption, the model shows no increase to variable cost.

[19] Idaho Power Company's Reply Comments, p. 41.
[20] Idaho Power Company's Reply Comments, p. 41.
[21] Idaho Power Company's Reply Comments, p. 52.

Idaho Power reports that the risks leading to the 2025 Unit 1 Valmy retirement date in the 2015 IRP were (1) the possible failure of PURPA solar projects to come online; (2) uncertainties surrounding development of the B2H line; and (3) the feasibility of arriving at a mutually agreeable retirement date with Valmy co-owner, NV Energy.

Idaho Power's report that 270 MW of solar has come online and its discussion of the milestones reached with respect to B2H support the change in retirement of Valmy Unit 1 from 2025 to 2019. However, more detail is needed regarding the feasibility of agreeing to a 2019 retirement date with NV Energy. NV Energy received acknowledgement of early retirement of Valmy units 1 & 2 in its 2013 IRP.[22] There is no discussion as to why the companies have not reached agreement on the retirement dates. The Company should explain in its Final Comments why it is reasonable to believe an agreement will be reached in the next two years.

In Reply Comments, the Company reports that closing Valmy Unit 1 in 2019 rather than 2025 results in a decrease to variable power costs in its IRP planning case.[23] However, Staff notes that Valmy is projected to provide roughly 500,000 MWh of energy in Idaho Power's 2018 APCU.[24]

As Idaho Power implies by noting that the decrease to variable power costs is "counter-intuitive,"[25] relying on a non-dispatchable resource (solar capacity) and market purchases to replace a resource that has "primarily functioned as a capacity resource during periods of high energy demand," would likely result in an increase in variable power costs.[26] The logic being, periods of high demand normally would coincide with periods of high market prices. In simple terms, the Company would have purchased the 500,000 MWhs of power from the market in its most recent APCU if it were cheaper than running Valmy.[27] These counterintuitive results are concerning to Staff. The Company should address this in its Final Comments.

Finally, Staff is concerned with the intergenerational equity of rate impact on customers from an early retirement of Valmy. While these concerns can best be addressed in a subsequent rate filing in which the Company seeks recovery of these costs, Staff requests some explanation as part of the IRP.

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[22] Application of Sierra Pacific Power Company d/b/a/ NV Energy for Approval of New and Revised Depreciation Rates for its Electric and Common Accounts, Docket No. 13-06004, Doc. ID 34333 at 46 (Jan. 29, 2014).
[23] Idaho Power Company's Reply Comments, p. 55.
[24] UE 333 Idaho Power/100, Blackwell/10.
[25] Idaho Power Company's Reply Comments, p. 55, n. 113.
[26] Idaho Power Company's Reply Comments, p. 53.
[27] Staff notes that O&M expenses are split based on total plant operations at Valmy and not solely based on Idaho Power's dispatch decisions, which may complicate this assumption.

Recommendation
Staff will recommend acknowledgement of the early closure date for Valmy, but in Idaho Power's Final Comments, the Company should explain why it is reasonable to believe an agreement will be reached in the next two years over the closure of Valmy, address Staff's variable costs concerns, and address Staff's concerns around intergenerational equity of the rate impacts from an early Valmy retirement.

Jim Bridger

Idaho Power asks the Commission to acknowledge Idaho Power's Action Item to "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." In Staff's Opening Comments, Staff inquired as to the reasoning for using 2028 and 2032 as retirement dates for Bridger Units 1 and 2 in the Company's preferred portfolio. Idaho Power's Reply Comments explained that the 2028 and 2032 retirement dates were considered because Idaho Power's operating partner, PacifiCorp, used those dates in the preferred portfolio in its 2017 IRP.[28]

Staff is concerned that the Company has not shown these retirement dates are the least-cost, least-risk option, yet asks for acknowledgement of these dates in its IRP. Staff finds several issues with the Company's request for acknowledgement of 2028 and 2032 retirement dates for Jim Bridger 1 and 2. First, Staff continues to be concerned about the portfolio design in the IRP. Idaho Power's IRP compares 12 portfolios, broken into four groups based on Bridger Units 1 and 2 retirement date scenarios. One scenario includes installation of SCR technology and operation through 2036. The other three scenarios retire the units early without installing SCRs: [29]

1. Invest in SCRs and operate through 2036
2. Retire Unit 1 in 2028 and Unit 2 in 2024
3. Retire Unit 1 in 2032 and Unit 2 in 2028

Retire Unit 1 in 2022 and Unit 2 in 2021
Each portfolio includes various capacity additions over the planning time horizon. In their Opening Comments, Staff and Sierra Club expressed concern about the lack of transparent analysis behind portfolio design, and suggested the Company perform capacity expansion modeling.[30, 31] As Staff states above, the Company replied to criticism of its portfolio design, stating that, "[b]y limiting the resources to only the most

[28] Docket No. LC 67 Pacific Power 2017 Integrated Resource Plan.
[29] Idaho Power 2017 Integrated Resource Plan, p. 107.
[30] Staff's Opening comments, p. 14.
[31] Sierra Club Opening Comments.

cost-effective options, the Company was able to limit the variables influencing the SCR and B2H resource evaluation." [32] However, Staff continues to have some concerns about this hand-selection method as described in the Portfolio Design section below. A review of Portfolio 4 can help to illustrate:

P4

Table 8.7 P4 timeline

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2026	B2H	500, 200 (Apr–Sep, Oct–Mar transfer capacity)	500
2029	Reciprocating engines	72	72
2030	Reciprocating engines	72	72
2031	Reciprocating engines	54	54
2032	Reciprocating engines	54	54
2033	Reciprocating engines	72	72
2034	Reciprocating engines	54	54
2035	Reciprocating engines	54	54
2036	Reciprocating engines	36	36
	Total	**968**	**968**

[33]

Could the Company have optimized Portfolio 4 by including other resources instead of only B2H and 468 MW of reciprocating engines? The portfolio design of the 2017 IRP does not answer these questions.

More importantly, Staff's second concern with Idaho Power's request to acknowledge actions related to the closure of Jim Bridger relates to the joint ownership of Jim Bridger by PacifiCorp and Idaho Power. Idaho Power relies largely on PacifiCorp's IRP as the reason for choosing these retirement dates. However, as Staff points out in its Final Comments to PacifiCorp's 2016 IRP, additional analysis could have identified more transparency for stakeholders and could have further optimized PacifiCorp's system costs.[34] A more robust analysis from Idaho Power could uncover a different set of lower-cost retirement dates for Jim Bridger. If analysis proves an earlier or later set of retirement dates to be a lower-cost solution, then pursuing that lower-cost option would seem rational and prudent.

PacifiCorp does not appear highly invested in specific retirement dates for Jim Bridger and notes that retirement date selection in its IRP should not be considered a firm

[32] Idaho Power Company's Reply Comment, p. 45.
[33] Idaho Power Company 2017 Integrated Resource Plan, p. 101.
[34] Docket No. LC 67 Staff's Final Comments re: PacifiCorp's 2017 IRP, p. 30.

commitment to retire units at specific times. Instead, PacifiCorp intends the selected retirement dates to provide a range of Regional Haze compliance paths for evaluation:

> Individual unit outcomes under any Regional Haze compliance case will ultimately be determined by ongoing rulemaking, results of litigation, and future negotiations with state and federal agencies, partner plant owners, and other vested stakeholders. While the Regional Haze case definitions represent a range of strategic paths to be evaluated, no individual unit commitments are being made at this time.[35]

PacifiCorp further elaborates on why the coal unit retirement dates in its Regional Haze Cases were chosen in a response to a data request from Sierra Club:

> The regional haze scenarios were developed to reflect a range of plausible compliance alternatives with a graduated path to reduce emissions and provide relative cost information between cases. The overall intent was to provide a bookended set of information that reflects the balance between emission reductions and potential cost impact on customers while also meeting customers load and resource needs.[36]

PacifiCorp is not attached to these retirement dates. Idaho Power's request for acknowledgement of these dates is surprising given that no specific dates for Jim Bridger were included in PacifiCorp's Action Plan and given that PacifiCorp intends to rearrange retirement dates as necessary to respond to regulators and stakeholders.

Unlike with the case of the Valmy Unit 1 2019 closure in which costs were more thoroughly vetted in a separate filing and subsequently submitted in discovery for this IRP, Staff does not find sufficient evidence supporting 2028 and 2032 as the least-cost retirement dates for Jim Bridger 1 and 2. Optimal retirement could either be earlier or later than these dates.

Finally, as acknowledged by Sierra Club and Idaho Power, the 2017 IRP analysis is based on an assumption that the current trend of increasing coal prices in recent years will not continue.[37,38] This assumption is not adequately supported in Idaho Power's IRP or Reply Comments. The Company's Reply Comments state that coal prices are increasing because of decreasing coal generation and increasing mining costs. The Company explains, "[t]hese increases are not forecasted to continue at the present pace," but provides no support for this statement.[39] Given that factors out of the

[35] PacifiCorp 2017 Integrated Resource Plan, p. 171.
[36] Att. A; PacifiCorp's response to Sierra Club Data Request 1.1 in LC 67.
[37] Sierra Club Reply Comments, p. 26.
[38] Idaho Power Company's Reply Comments, p. 16.
[39] Idaho Power Company's Reply Comments, p. 16.

Company's control are part of the reason for coal price increases in recent years, the Company should provide the reasoning or analysis supporting its claim that the trend of increasing coal prices will change in the near future.

Recommendation
Staff recommends that Idaho Power pursue the Jim Bridger retirement plan that is most cost-effective. Rather than acknowledging Idaho Power's plan to negotiate 2028 and 2032 retirement dates for Bridger, Idaho Power should work with its operating partner PacifiCorp to identify and pursue the most cost-effective retirement dates for these units. Additionally, Staff recommends that Idaho Power provide support for a change in the trend of coal costs in its Final Reply Comments.

Energy Efficiency & Avoided Cost Analysis

Staff's Opening Comments on energy efficiency (EE) identified two main points of concern. These concerns centered on how the Company (a) developed and/or utilized some of the elements in its EE avoided cost methodology, and (b) how Idaho Power modeled EE.

Idaho Power's responses to Staff's concerns about the Company's avoided cost methodology answered Staff's three main questions relating to this concern. First, Idaho Power demonstrated that switching the source of EE's peak value in its avoided cost methodology may result in a slightly negative impact on the total amount of EE in this IRP.[40] Currently the Company uses the levelized cost of a Simple Cycle Combustion Turbine (SCCT) to a represent peak power prices. Staff suggested Idaho Power use actual peak power prices. The Company conducted additional analysis using on-peak values from their modeling software and demonstrated a drop in the total amount of EE. Staff generally agrees with the results and believes any questions regarding this aspect of Idaho Power's methodology can be addressed as part of the Company's 2017 IRP Update and in workshops leading up to the next IRP.

Second, Idaho Power demonstrated in its Reply Comments that its current approach to determine generation deferral value best benefits EE. Staff appreciates the clarification on how this avoided cost value seems to be applied to all EE at all times. Lastly, Idaho Power responded to Staff's concern that the Company's Transmission and Distribution (T&D) deferral values used for EE avoided costs were rather low. Comparatively, Idaho Power's T&D deferral values for EE are much lower than both PGE and PAC:[41]

[40] *See* Idaho Power Company's Reply Comments, p. 72.
[41] Staff's Opening Comments, p. 20.

Table 3 – T&D deferral values

	PGE	PAC	Idaho Power
Total T&D Value (per kW/Year)	$33.94	$13.86	$3.76

Given the forecasted pace of growth in Idaho Power's territory **and** the fact that Idaho Power is planning to complete a major transmission investment by 2026, Staff is skeptical of the T&D deferral value of EE in this IRP. Idaho Power has offered to work with PGE and PAC in order to update the Idaho Power methodology and values used for T&D deferral in its next IRP. [42]

While Idaho Power's proposal may ameliorate Staff's concern regarding avoided cost modeling in future IRPs, it will not impact the energy and capacity analysis used in this IRP. Staff expected that Idaho Power could update its T&D methodology as part of its Reply Comments, but this did not prove to be the case. Staff will recommend that by the 2017 IRP update, Idaho Power fully update its T&D deferral value for EE and re-run its key analysis in the IRP. This should help inform any ongoing discussions about energy and capacity needs for the Company and for any large, planned investments, such as B2H.

Idaho Power has not yet satisfactorily addressed Staff's concern regarding EE modeling. The Company's Reply Comments provided no further analysis and/or understanding as to why the forecast for EE between the past two IRPs dropped, especially in the first few years of the forecast. Idaho Power's Reply Comments did address questions raised by Staff regarding the data sources used for its forecast of EE. However, Staff sought a more in-depth description behind the large and near-term reduction in cumulative EE savings in this IRP—especially in the Residential sector—as compared to the last IRP. Again, here are Staff's graphs that attempt to visually capture the difference in EE savings between the 2015 and 2017 IRPs:

[42] Idaho Power Company's Reply Comments, p. 75.

Figure 1 – Annual Percent Difference Between 2015 and 2017 IRP Savings

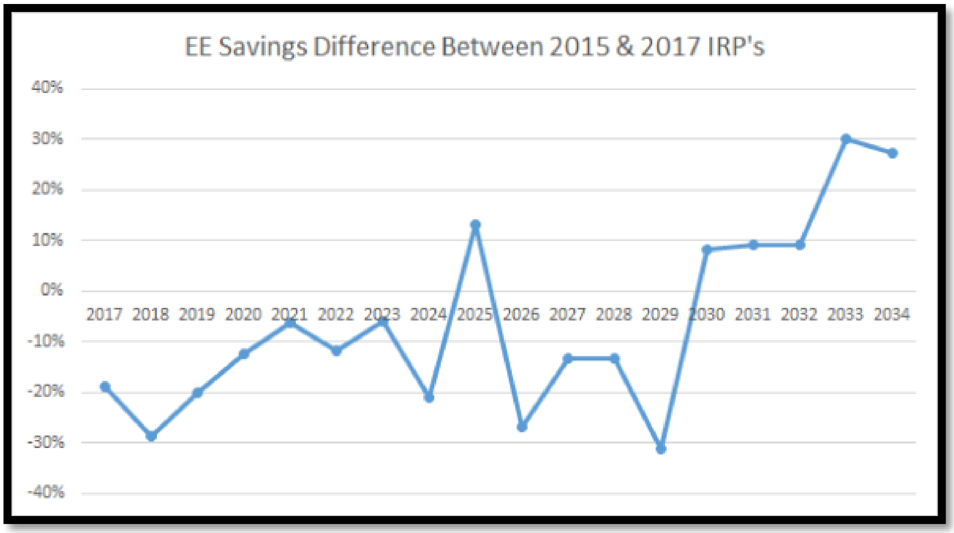
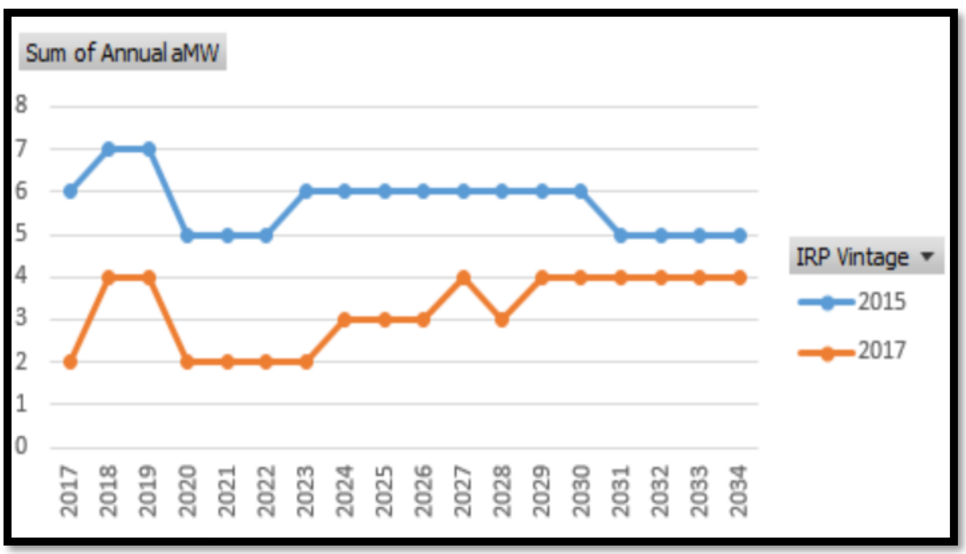


Figure 2 – Residential Savings Forecast Difference, 2015 and 2017 IRP's



Staff also sought clarification as to how Idaho Power forecasts EE technology adoption rates (e.g., ramp rates) and how its forecast treats retrofit vs. replacement opportunities, as both impact EE forecasts. Both of these factors impact forecasted models of future EE savings.

In short, Idaho Power's Reply Comments did not offer a meaningful explanation for Staff regarding observed differences in EE savings between IRPs. The Reply Comments also did not address Staff's questions regarding forecasting methodology in general. As a result, Staff does not believe the Company's response in Reply Comments is sufficient. Unless the Company can adequately address Staff's questions in Final Comments, Staff may not recommend acknowledgment of its EE action item.

Four stakeholders provided comments on EE. Sierra Club expressed several concerns about the declining forecast of EE found in this IRP. Staff agrees with Sierra Club and, as stated above, believes the Company should better clarify the reasons behind the forecasted drop in savings found in this IRP. While Staff does not recommend using previous estimated forecasts of EE savings as suggested by Sierra Club, Staff does share the concern that the level of EE found in this IRP may be too low and needs a more convincing explanation of the drop in EE savings between this IRP and the past IRP. A possible adjustment to the EE IRP forecast may be necessary, with emphasis on the near-term drop in savings in the residential sector.

STOP B2H made two claims regarding EE: (a) Idaho Power has not added new EE programs, and (b) the Company has not achieved as much EE as possible or as much as other utilities. Staff is unclear as to the source of STOP B2H's claim regarding Idaho Power not adding new programs. It appears to Staff that Idaho Power has generally done well in adding EE programs, measures, and services. Staff would need to conduct further analysis to substantiate B2H's claims.

The Renewable Energy Coalition's comments included Idaho Power's responses to information requests related to EE and gas forecast prices but included no discussion of EE. Finally, Gail Carbiener noted that EE has always been underestimated in the preferred portfolios.

Recommendation

Staff plans to recommend acknowledgement of Idaho Power's EE action item if the Company includes in its Final Comments: (a) a more transparent explanation for the decrease in savings, especially in the near-term, between the past two IRPs, and (b) a description, with examples, of how the Company makes modeling decisions regarding technology adoption rates and how it treats retrofit vs. replacement opportunities. If Idaho Power chooses to address these issues in Final Comments, Staff would also recommend that Idaho Power update the T&D deferral value methodology and data by the next IRP.

General IRP Comments

Demand Response

Staff's Opening Comments on Demand Response (DR) raised two overarching points of concern. These concerns were related to (a) the current DR resources, activities, program design, and potential for capacity growth of DR, and (b) Idaho Power's DR forecasting and prioritization in the IRP.

Idaho Power's Reply Comments addressed Staff's concerns about the state of the infrastructure supporting DR programs, cost-effectiveness methodology, and how the existing programs are designed and managed. Staff also agrees with Idaho Power's assertions that its current DR programs are effective at reducing a sizeable amount of its capacity.[43] However, the Company fails to address Staff's questions as to what is behind the stagnating levels of DR in the IRP forecast.

Staff noted in its initial comments that despite an IRP that forecasts consistent, overall load growth, the IRP itself shows no commensurate growth in DR procurement. Effectively, the amount of DR appears to be held flat into the future. This was counterintuitive to Staff given the Company's past success, existing programs, and new program potential given advances in communication and control technology.

Further, this raises prioritization questions. Does the preferred portfolio reflect SB 1547's direction to acquire EE first and DR second prior to new generation resources?[44] Idaho Power's Reply Comments do not answer this question.

Recommendation
Staff recommends acknowledging Idaho Power's DR action item once the Company clarifies (1) why its currently commendable levels of DR are not projected to grow in the IRP despite forecasted load growth, and (2) what activities the Company plans to undertake to address this stagnation of DR procurement. If Company produces an updated DR forecast, the Company should ensure it is properly reflected throughout its IRP analysis.

Load Forecast

In Opening Comments, Staff expressed several concerns regarding the variability in iIdaho Power's load forecast and believed that the Company could likely produce an improved expected case for load growth by using more granular data like sub-hourly load data for its commercial customers as opposed to yearly load data. Staff requested

[43] *See* Idaho Power Company's Reply Comments, p. 76.
[44] *See* SB 1547 (2016), subsection 19, p. 12.

that the Company clarify why it chose this approach and whether it has anything to do with weather. Staff expressed concerns about the Company's use of non-recession growth rates and asked that in the next IRP, the Company provide analysis of a no-special contract-load-growth scenario.

In its Reply Comments, the Company corrected Staff by noting that it uses monthly data rather than yearly data in its IRP analysis. Idaho Power noted, however, that it only possesses daily data for the past four years and does not possess interval data for all of its customers. Staff believes that as the Company garners more granular information over the years, it should work to incorporate greater granularity into its load forecasts.

Staff also points to its discussion on climate, which is below. The Company stated that it "has not—and does not—make predictions specific to changes in the scale and timing of hydrologic effects or any other aspect of the Company due to future climate variability."[45] Idaho Power also states that "in the irrigation space, the probabilities of weather occurrences with these parameters are appropriately reflected in the distribution of the outcomes."[46] Staff does not believe this to be a satisfactory response. In addition to hydro resources, Staff also anticipates climate change to have an impact on load forecasting.

Recommendation
Staff recommends that Idaho Power prepare more detailed forecasts for its next IRP. Idaho Power's current forecast is useful to capture broad trends that affect load. However, a more detailed forecast can provide the Company additional insight into the causes of load growth. As an example, Idaho Power might find which region or industry new commercial customers are likely to come from. Additionally, improvements in load forecasting for the next IRP should more explicitly account for the risk and uncertainty associated with climate change.

LOLE and Exceedance

In Opening Comments, Staff expressed concerns regarding the Company's exceedance assumptions for peak planning and loss of load expectation (LOLE) assumptions. In particular, Staff asked for clarity on how Idaho Power's peak-hour deficit case (at 90 percent exceedance and 95 percent load) corresponds with LOLE. The Company responded by clarifying that the two are not related. Rather, the peak-hour deficit case the Company uses in planning conservatively assumes that "water inflows to the Brownlee Reservoir…are assumed to be in the bottom 10 percent of likely conditions." This corresponds with "90% exceedance." Coupled with that is the conservative assumption that load will be in the top 5 percent of expected monthly peak-hour events. This corresponds with "95th percentile load." Idaho Power explains that these peak-hour

[45] Idaho Power Company's Reply Comments, p. 85.
[46] Idaho Power Company's Reply Comments, p. 80.

deficit scenarios are unrelated to loss of load probability (LOLP) presented in the IRP.[47] The Company has also agreed to using the methodology developed in UM 1719 in the 2019 IRP, which differs from the existing methodology in that it performs an evaluation of capacity contribution of renewable resources by utilizing all hours of the year as opposed to the 150 high-load hours Idaho Power traditionally uses. Staff notes that the Company has included this as an Action Item in its Action Plan and appreciates it doing so.

Staff also recognizes that the Company has been conducting its capacity deficit analysis the same way since the early 2000's[48] and that this analysis was inspired by high market prices in the summer of 2001.[49] Staff believes it may be time to revisit these conservative peak-hour assumptions in the 2019 IRP as nearly 20 years have passed since the "new" methodology has been adopted. Initial questions Staff has about the Company's methodology are:

- What is the correlation between stream flows and peak load? For instance, if the peak load is in the summer and the 10 percent flow level isn't reached until later in the year, is 90 percent exceedance appropriate?
- Historically, how often has inflow been at 90% exceedance, and when did this happen? From the Company's Reply Comments, the Company adopted these conservative assumptions to account for high market prices after the summer of 2001 but does not clarify whether this is due to low inflow conditions or whether it was possibly due to the energy crisis of 2000-2001.
- What is the worst inflow actually recorded?
- Since Idaho Power continues to prepare hydro forecasts for 50th percentile exceedance, and since there are differences between capacity needs as demonstrated in IRP Appendix C, is there some kind of "trigger point" analysis the Company has done to determine when a new resource is needed?
- Has Idaho done sensitivity studies around the 90% exceedance rate (like 80 percent, or 95 percent) to see the delta?

Recommendation
Staff recommends that the questions posed above on exceedance be addressed in the Company's next IRP.

[47] LOLP is the probability of a loss of load event, whereas the LOLE is an accumulation of each loss of load event. The two are related measurements of system reliability.
[48] Idaho Power Company's Reply Comments, p. 13.
[49] Idaho Power Company's Reply Comments, p. 11.

Hedging

In Opening Comments, Staff expressed concern that the Company did not discuss the proposed use of and impact on costs and risks of physical and financial hedging as contemplated by the IRP guidelines.[50] In its Reply Comments, the Company merely references its Risk Management Policy and explains that its financial and physical hedging takes place in a "near-term time frame." The Company says little else related to hedging. Staff believes the Company's approach is not sufficient moving forward.

Recommendation

Staff believes Idaho Power should explore this topic further in its IRP Update in preparation for the next IRP. Idaho Power should include a discussion of the proposed use and impact on costs and risks of physical and financial hedging on resource portfolios.

Portfolio Design

In Opening Comments, Staff expressed its concerns about the lack of diversity exhibited in Idaho Power's portfolio design analysis structure and how the portfolios were constructed overall. Idaho Power's analysis utilized a "factorial design approach" that compared B2H to natural gas sources with utility solar as key components of each portfolio. Overall, Staff had questions around the Company's analysis.

Sierra Club also criticized the lack of diversity of resources in the portfolio analysis, in addition to the factorial design. Sierra Club maintained that the analysis was flawed because it did not consider a full range of resources, ultimately distorting the transparency of the analysis. Sierra Club also maintained that, though the Company attempted to control the results of the analysis by selecting few resources, this "manual" approach (as opposed to using more complex optimization software) ultimately failed to account for the changes occurring within a series rows or columns of portfolios that ultimately do not allow for a uniform comparison.[51]

In its Reply Comments, the Company defended its portfolio analysis structure. Staff notes several key responses by the Company:

1) The Company stated that it initially did utilize the AURORA model's Long-Term Optimization ("LTO") run, which does not incorporate transmission, but does iterate through multiple generation resource build-outs to minimize the WECC power supply cost.[52] The LTO run did not select any new resources in the 20-year planning period, but Idaho Power was unsatisfied with the reliability of the

[50] See Order No. 07-002, Guideline 1.C Bullet 2, Subsection 2, page 6, "utilities are to include, at a minimum, "[d]iscussion of the proposed use and impact on costs and risks of physical and financial hedging."
[51] Sierra Club Opening Comments, pp. 4 and 5.
[52] Idaho Power Company's Reply Comments, p. 45.

results, so the Company determined to perform the factorial design approach instead.[53]

2) Idaho Power clarified that the portfolio analysis was purposely focused to guide the Company's business judgments and ultimately "limited to only the most cost-effective resources."[54] As a result, many of the resources that did not make the cut during IRP development were not included at all in any portfolio of the IRP.[55]

The points made by the Company above raise transparency concerns in addition to the diversity concerns of the portfolio analysis. Staff does not believe that Idaho Power's current approach to portfolio development constitutes best practices. However, while not ideal, the portfolio analysis in this IRP was sufficient to determine that the preferred portfolio P7 was the best combination of least-cost, least-risk, out of the twelve analyzed. This was especially true due to two factors: First, the NPVRR analysis initially supplied by the Company found in Chapter 9 of the 2017 IRP. This analysis showed that under normal operating parameters, all of the portfolios with B2H ranked highest. Second, the Company's issuance of the new Appendix D after Staff's Opening Comments that were critical of Idaho Power's lack of information on B2H provided much more extensive analysis of the merits and benefits of B2H relative to other resources and provided more convincing information that a least-cost, least-risk portfolio was being selected in this IRP process.

Finally, the Company stated in its Reply Comments that it is amenable to considering more diverse portfolio selections and also capacity expansion modeling in the 2019 IRP planning cycle.[56] Staff believes the Company should do so, and it should begin by making proposals for IRP enhancements in its 2017 IRP Update. The Company should include a more diverse set of portfolios and resources and include an improved and more transparent selection process.

Recommendation:
For the 2017 IRP Update, the Company must propose an enhanced IRP portfolio selection methodology.

Renewable costs

Staff reviewed Idaho Power's analysis on solar photovoltaic (PV) capital costs and levelized cost of energy. Staff was concerned that Idaho Power's assumptions do not take into consideration falling costs of solar PV technology and do not accurately reflect current or future costs of solar PV systems.[57] Staff also requested portfolio analysis for

[53] Idaho Power Company's Reply Comments, p. 45.
[54] Idaho Power Company's Reply Comments, p. 45.
[55] Idaho Power Company's Reply Comments, p. 45.
[56] LC 68, Idaho Power 2017 IRP Reply Comments p. 44.
[57] Idaho Power 2017 IRP, p. 36.

solar PV without corresponding reciprocating engine capacity. Finally, Staff was not satisfied with the Company's solar tipping point analysis, and asked for a more granular analysis. [58]

The Company's Reply Comments updated solar cost data from the November 2017 Lazard report. The Company's analysis reflects a decrease in cost from $1,375/kW to $1,228/kW.[59] The Company also performed another solar tipping point analysis that shows a stand-alone single-axis solar PV system would be more cost effective than (1) a CCCT when capital cost decline over 35 percent, (2) reciprocating engines after capital costs decline 65 to 70 percent, and (3) B2H after a 90 percent decrease.[60]

Staff is satisfied that the Company's Reply Comments have addressed Staff's concerns with respect to these costs.

Natural Gas Price Forecasts

Staff, Sierra Club, and Renewable Energy Coalition all expressed concerns with the Company's use of EIA's low gas price scenario to forecast fuel prices in its IRP.[61] This was also an issue of concern among many stakeholders at the Company's IRPAC meetings and was also addressed in the Idaho Public Utilities Commission Comments filed in Idaho.[62]

In summary, most parties expressed concern that the Company's fuel price forecast was too low. The Company broke from the approach it took in its 2013 and 2015 IRPs of using the EIA "Reference" case.[63] For its 2017 IRP, Idaho Power's base case was essentially the bottom tier of projected gas prices. Using low gas prices not only has implications for energy efficiency acquisition, but as Staff expressed above, the economics of other resources such as B2H. Moreover, Staff noted its concern that the Company appeared to have determined that ICE contracts were more accurate predictors of gas prices over the past few IRP cycles and decided to choose an EIA forecast based on that judgement. Staff expressed concern that this approach is too subjective.

The Company confirmed Staff's worry in its Reply Comments:

> A detailed review of the Intercontinental Exchange ("ICE") settled forward contracts demonstrated ICE to be a more accurate indicator than the EIA Planning Case forecast used in the IRP over the past few years. Comparing

[58] Idaho Power 2017 IRP, p. 118.
[59] Idaho Power Company's Reply Comments, p. 47.
[60] Idaho Power Company's Reply Comments, p. 48.
[61] Sierra Club's Opening Comments, p. 30; Staff's Opening Comments, p. 23; Renewable Energy Coalition Opening Comments.
[62] CASE NO. IPC-E.17.11, IPUC Staff Comments, p. 6.
[63] Idaho Power Company's Reply Comments, p. 81.

> 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*.[64]

The Company proceeded to produce a graphic that shows the ICE forward contract prices following the EIA low gas price forecast more closely than the other EIA gas price forecasts. The Company thus appears to have used intuition in extrapolating an accurate choice based on recent market trends rather than using the standard conservative approach of the EIA base case scenario. Staff reiterates that it does not dispute that gas prices have decreased over time, but the IRP is a planning document. The EIA Reference case prices have accounted for these lower prices over the years, and choosing among the lowest possible forecasts for gas prices does not exemplify best practices in resource planning. Selecting the EIAHO case may have biased the results of the IRP and adds to Staff's concerns with the Portfolio Design of the 2017 IRP. This approach by the Company also contradicts Idaho Power's usual practice of planning for conservative scenarios (such as using 90 percent exceedance and 95 percent peak conditions). A low gas price case can be considered too optimistic and does not constitute conservative, least-cost planning. This allows Idaho Power to plan for gas-friendly resources, thereby shifting the risk of higher gas prices onto customers. [65]

Recommendation
Staff is unconvinced by Idaho Power's justification for such a low gas price forecast. Staff recommends that in the next IRP, it revert back to a more conservative gas price forecast.

Environmental Regulations

Staff's initial comments on Environmental Regulations revolved around one central concern: climate change. Staff believes that the IRP does not address the real and present risks related to climate change. Staff raised several concerns about the risk and uncertainties associated with climate change not explicitly captured in this IRP. These include:

- Increasing line losses
- Increasing summer peak
- Risk of more forest fires
- Decreased snow pack

[64] Idaho Power Company's Reply Comments, p. 81 (Emphasis added).
[65] IPUC Commission made several similar arguments. See http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1711/staff/20171127COMMENTS.PDF.

- Increased pumping of ground water

The Company responded that it does not make predictions related to climate change. However, Idaho Power noted that its stochastic analysis does take into account the potential portfolio impacts of climate change when variables, such as hydro, take on values different from their planning-case levels. Staff also notes that the coal unit modeling considered the Clean Power Plan CO2 emissions limits and complied with the state mass-based approach.

Climate models predict that over the coming century the Northwest will experience higher maximum summer temperatures.[66] A 2015 report issued by the Oregon Climate Change Resource Institute projects that climate change will, at a minimum, change the availability of hydro resources and increase summer peaks.[67] This projection is particularly significant for Idaho Power because nearly 40 percent of Idaho Power's generation comes from hydro resources. Since Idaho Power's system relies so heavily on hydropower, the Company must choose a different approach to addressing climate risk in its IRP in 2019. The Company must demonstrate some creativity in capturing the systemic risk and uncertainty posed by climate change to the customers of Idaho Power.

The Company did not include carbon risk analysis as outlined in revised IRP Guideline 8, which requires a base case carbon risk scenario in addition to alternative carbon portfolios.[68] Staff recognizes the Company attempted to plan consistently with what was expected to be federal policy at the time and modeled a mass-based approach to the Clean Power Plan. As a result of the anticipated sunset of the Clean Power Plan, the Company must find other ways to address the risks and uncertainties related to climate change in its next IRP.

Recommendation
Commission a report for the next IRP to assess the risks and uncertainties associated with climate change to Idaho Power and its customers.

Conclusion and Recommendations

The three most significant issues of concern noted in Staff's Opening Comments were the B2H project, the Valmy Unit 1 2019 shutdown, and the Company's portfolio design. Staff intends to recommend acknowledgement of the 2019 Valmy Unit 1 closure. Staff

[66] Staffs Opening Comments, p. 28.
[67] *See* LC 66 PGE IRP, Appendix E, "Climate Change Projections in PGE's Service Territory," from the Oregon Climate Change Resource Institute, Nov. 2015, p. 388.
[68] Order No. 08-339.

requires additional information with respect to B2H in Idaho Power's Final Comments, and Staff anticipates that the Company will restructure its portfolio design in the 2019 IRP. In addition to these issues, Staff highlighted other areas of concern regarding energy efficiency and avoided costs, natural gas price assumptions, environmental regulation, load forecasting, and others.   Finally, for reasons discussed in these comments, Staff does not intend recommend acknowledgment of the Bridger Action Item for 2028 and 2032 retirement dates.

For Final Comments, Staff requests that Idaho Power:

- Provide an update on the Notice of Completion that was supposed to have been filed within 60 days of the ROD
- Clarify the impact of the EIAHO gas price forecast on the variable costs of B2H

  Identify any Oregon-specific and Oregon ratepayer-specific benefits of B2H
- Clarify the agreements between co-participants regarding B2H, their status with respect to B2H, and their use of B2H
- Clarify the role of B2H in Energy Gateway
- Provide certainty regarding the Company's intention with respect to the EIM Action Item by removing it from the Company's Action Plan
- Explain why it is reasonable that an agreement be reached in the next two years over the closure of Valmy, address Staff's variable cost concerns, and address concerns around intergenerational equity
- Provide support for a change in the trend of coal costs
- Explain the decrease in projected EE savings, especially in the near-term, compared to savings projected in the past two IRPs
- Describe, with examples, how the Company makes modeling decisions regarding technology adoption rates and how it treats retrofit vs. replacement opportunities
- Address whether and how it considered Staff's recommendation to change forecasted rate of EE based on any adjustments
- Clarify why Idaho Power's currently commendable levels of DR are not projected to grow in the IRP
- Clarify what activities the Company plans to undertake to address the stagnation of DR procurement

For the 2017 IRP Update:

- Propose an enhanced IRP portfolio selection methodology
- Detail the steps the Company is taking to ensure the next IRP more holistically addresses the risks and uncertainties presented by climate change to Idaho Power and its customers
- Discuss the proposed use and impact on costs and risks of physical and financial hedging on resource portfolios

For the 2019 IRP:

- Work with its operating partner PacifiCorp to identify and pursue the most cost-effective retirement dates for Bridger Units 1 and 2
- Provide more detailed load forecasts. As an example, Idaho Power might attempt to identify from which region or industry new commercial customers are likely to come from. As another example, Idaho Power could more precisely predict whether new commercial customers will have summer cooling needs, winter heating needs, or neither
- Explore a renewed exceedance methodology
- Revert back to a more conservative gas price forecast
- Commission a report for the next IRP to assess the risks and uncertainties associated with climate change to Idaho Power and its customers.

This concludes Staff's final comments.

Dated at Salem, Oregon, this 18th day of January, 2018.

Nadine Hanhan
Senior Utility Analyst
Energy Resources and Planning Division

October 19, 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. 98-102

STAFF'S DATA REQUEST NO. 102:

Please see page 88 of the IRP. The final sentence reads "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."

a. Please describe the "end effects" referenced here, and discuss how the procedure described above accounts for them.

b. Please provide a simple example.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 102:

a. The term "end effects" in this statement relates to the end of the 20-year term of the study and the timing of resource additions. At the end of the study term, most new resources added to a portfolio will have some useful life remaining. Accounting for the study period "end effects" means the new resource addition costs are allocated over the entire life of the resource and only the costs attributed to the study period are used in the portfolio evaluation. This treatment matches the costs with the associated benefits of new resources to the study period.

b. The example below is from Attachment 6, New Resources Fixed Cost Tables, tab "Fixed Cost Streams- by Resource," provided with Idaho Power's response to Sierra Club's Data Request No. 1-2. The numbers represent the fixed costs included in Portfolio 7 for the B2H resource. The annual cost of $21,356,306 results in a total cost of $234,919,361 for the IRP planning period 2026-2036. Because the annualized cost calculation is based on each individual resource's useful life, this methodology enables resources with differing lives to be fairly compared over the planning horizon. Therefore, the end effects, or costs associated with resource additions that exist beyond the study period, are properly accounted for.

Portfolio 7: B2H_CCCT_Recips	
	2026
	Boardman to Heming
	350
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	
2025	
2026	21,356,306
2027	21,356,306
2028	21,356,306
2029	21,356,306
2030	21,356,306
2031	21,356,306
2032	21,356,306
2033	21,356,306
2034	21,356,306
2035	21,356,306
2036	21,356,306
Remaining Costs	1,937,613,997

OPUC Data Request 75

Regarding the Boardman-to-Hemmingway transmission project:

(a) In Idaho Power's Integrated Resource Plan filing (LC 68) PacifiCorp is listed as being the majority owner of the transmission capacity for the proposed Boardman-to-Hemmingway (B2H) transmission line. Specifically, PacifiCorp owns 55% of the total capacity, and 81% of the proposed project's east-to-west transmission capacity. The project's anticipated completion date is 2027. PacifiCorp's IRP (LC 67) states that construction of this transmission capacity is beyond the scope of acknowledgement of this IRP (Pg. 57). Given that it falls within the 20 year planning horizon and Guideline 1c calls for consideration of all costs with a reasonable likelihood of being included in rates over the long-term, why has PacifiCorp chosen to defer providing this analysis?

(b) What is the proposed cost of PacifiCorp's portion of B2H? Please indicate whether-or-not the cost of adding of B2H is included in the NPVRR of the portfolios in this IRP? If not, what is the estimated cost impact to each portfolio?

(c) Please provide the analysis supporting the Company's need for its share of this transmission project.

(d) Given the slated generation retirements in the region and in PacifiCorp's fleet, what resources does PacifiCorp plan to bring from Hemmingway into Boardman (east to west)? How will this change as retirements occur? Would this improve access to any renewable resources, such as wind from Montana or wind from the 2017R RFP?

(e) How does PacifiCorp's east-to-west capacity of B2H (~818 MW) improve 2017R RFP potential wind projects' abilities to serve load in Oregon and Washington? To what extent will the capacity of B2H improve the economics of all generation assets in the eastern portion of PacifiCorp's territory?

(f) Given the 818 MW of east-to-west transmission capacity from the completed B2H transmission project, what increase in access to FOTs does PacifiCorp anticipate to serve Oregon load?

Response to OPUC Data Request 75

(a) At this time, PacifiCorp is a party to the permitting phase of the project only. The parties have not yet entered into the contract that will govern the construction phase of the project. Before moving to the construction agreement phase as outlined in the permitting agreement PacifiCorp will further evaluate need and economic justification. Therefore, the project is not included in the 2017 Integrated Resource Plan (IRP) analysis. As stated in the permit funding agreement between Idaho Power

Company (IPC), Bonneville Power Administration (BPA), and PacifiCorp (the Funders), IPC has 60 days following publication of the United States (U.S.) Bureau of Land Management (BLM) Record of Decision (ROD) to issue a notice that triggers the commencement of the negotiation period. The Funders have up to two 180-day negotiation periods (360 days total) to negotiate one or more definitive development and construction agreements.

The current forecasted costs for PacifiCorp's portion to secure the ROD and the required Oregon permits for the Boardman to Hemingway project is approximately $85 million. This includes all payments to IPC based on their September 2017 forecast, as well as PacifiCorp's forecasted overheads. PacifiCorp has not included the cost of adding the Boardman to Hemingway project in the 2017 IRP modeling for the reasons described above.

(b) This analysis has not been done. The Boardman to Hemingway project supports the full achievable capacity of the Energy Gateway projects by providing a strategic transmission tie between the Pacific Northwest and the Intermountain West regions. The cost impact to each portfolio has not been analyzed. Please refer to the Company's response to subpart (a) above.

(c) Since the project is not included in PacifiCorp's 2017 IRP, the Company has not performed this analysis.

(d) Please refer to the Company's response to subpart (a) above.

(e) Please refer to the Company's response to subpart (a) above.