BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 78

In the Matter of IDAHO POWER COMPANY, 2021 Integrated Resource Plan	OPENING COMMENTS

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Introduction

These are Staff's initial comments regarding Idaho Power Company's (IPC, Idaho Power, or the Company) 2021 Integrated Resource Plan (IRP). Staff will continue to review the Company's filed plan, responses to information requests, and stakeholders' comments before filing final comments in this docket on September 8, 2022 and a Staff Report on October 25, 2022. 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.

Staff's Initial Comments focus on questions and concerns about the Company's IRP modeling choices and associated impacts, greenhouse gas emissions, and compliance. In this first stage of our review of IPC's 2021 IRP, Staff focused on the following initial concerns and questions:

- IRP Modeling changes: Concerns about the use of unvetted modeling methodologies and assumptions derived during the creation of the 2021 IRP, from which resulted a rapid succession of procurement efforts and changes to PURPA avoided costs.
- Load Forecast: Questions about the expected load increase.
- Demand Response: Questions and concerns about the assumed impacts of changes to the Company's DR program and how DR was modeled.
- Transmission: Questions about Boardman to Hemmingway project economics and general questions about access to wholesale markets via other transmission projects.
- Modeling investment cost: Questions about whether Idaho Power's modeling fully captures the relative costs of the investments the Company is considering.
- Emissions: Emission forecasts do not capture emissions attributable to market purchases.

Staff has identified several areas for which Staff would like additional information and analysis before making its final recommendations in this docket. Staff includes several requests for additional information for the Company to address in its reply comments (Staff Request for Company Reply Comments). Staff also has one recommendation for the Company to address at the first Commission workshop on August 18, 2022 (Staff Recommendation). While both are requests for information, the difference between the requests for the Company's reply comments and the Staff recommendation is that the recommendation involves a timely action item to put Idaho Power in compliance with a prior Commission order. Staff will set forth these requests and the recommendation in the comments below.

Background

Idaho Power's last IRP was reviewed in Docket No. LC 74. Initially filed on June 28, 2019, the 2019 IRP process was suspended and the plan was amended twice by the Company to correct modeling errors it encountered while implementing a new modeling approach and to update modeling to reflect changes to the ownership of the proposed Boardman to Hemingway (B2H) transmission line.[1] The final version of the last IRP, referred to as the Second Amended 2019 IRP, was filed on October 2, 2020, and acknowledged on June 4, 2021, through Order No. 21-184.

Compliance

IRP Guideline Compliance

The rules for integrated resource planning by electric companies in Oregon are found at OAR 860-027-0400, and the guidelines are prescribed in Order Nos. 07-002, 07-047, and 08-399. In addition, Commission orders regarding previous IRPs may include specific actions the utility must take in connection with future IRPs.

Compliance with Past Orders

The Commission's order acknowledging the Second Amended 2019 IRP contained several action items.[2] Staff has confirmed that Idaho Power has completed all but one. The action item yet to be completed is the requirement to "[p]resent to Commissioners the impact of COVID-19 on load."[3] IPC has not done this. Staff includes a recommendation regarding this requirement in its discussion of IPC's load forecast below, which is to present on this topic at the LC 78 workshop on August 18, 2022.[4]

IRP Modeling

Staff appreciates the work on the part of the Company to continually improve its IRP modeling using advanced modeling tools. Staff recognizes that implementation of new modeling tools

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[1] *See* Docket No. LC 74, Idaho Power, *Idaho Power Company's 2019 Integrated Resource Plan ("IRP") – Procedural Schedule*, July 19, 2019, p. 1;
See Docket No. LC 74, Idaho Power, *Motion to Suspend the Procedural Schedule*, July 1, 2020, p. 1.

[2] *See* Docket No. LC 74, OPUC Order No. 21-184, June 4, 2021, Appendix A, p. 1-5.

[3] *See* Docket No. LC 74, OPUC, Order No. 21-184, June 4, 2021, Appendix A, p. 4.

[4] *See* Docket No. LC 78, Idaho Power, Reply to OPUC IR 104, June 15, 2022, p. 1.

can be challenging and that it is not uncommon to encounter errors or for modeling to produce results that are substantially different from previous modeling efforts. This can make it challenging to assess modeling results and changes from past IRPs. While Staff believes Idaho Power's current modeling appears to be an improvement from the Company's past modeling, Staff continues to review assumptions and drivers of the changes present in this IRP.

Staff notes that modeling changes have had significant impacts on Idaho Power's integrated resource planning results in recent months. These changes have left Staff with some concerns regarding the validity of Idaho Power's modeling, and thus, Staff has focused very keenly on modeling in this IRP.

An immediate action item for IPC following the Commission's acknowledgement of the Second Amended 2019 IRP was to: "Conduct focused economic and system reliability analysis on timing of exit from Valmy Unit 2."[5] In LC 74, Staff recommended the Commission not acknowledge a Valmy exit in 2022 due to shortcomings it noted in Idaho Power's analysis, which Staff believed lacked sufficient analysis of near-term reliability issues. Instead, Staff recommended the Company retain the planned LC 68 exit of 2025.[6] Renewable Northwest (RNW) and the Citizens' Utility Board (CUB) both recommended the Commission acknowledge the Company's plan to exit Valmy 2 in 2022. The Commission chose to acknowledge the 2022 exit.[7] Two months later, Idaho Power released its *Valmy Unit 2 Exit Analysis*, concluding: "The current results of the resource alternative analyses support an exit from operations of Valmy Unit 2 in 2025."[8] The primary drivers of the Company's conclusion were a revised load resource balance informed by new modeling that found IPC resource deficient in 2021 and congestion on third-party transmission lines south of Valmy that prevent the Company from securing firm market purchases.[9]

The economics and reliability analysis conducted by the Company on its generation resources led to more than a cancelation of Valmy 2's 2022 exit. In addition to triggering an 'up to 80' MW request for proposal (RFP) on June 30, 2021, for resources in 2023, on December 9, 2021, Idaho Power filed a request to waive competitive bidding rules (CBR) for the procurement of these new resources that were not in the Second Amended 2019 IRP and gave notice of additional procurement through 2025 in what the Company called the 2022 all source RFP.[10] In

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[5] *See* Docket No. LC 74, OPUC, Order No. 21-184, June 4, 2021, p. 9.
[6] *See* Docket No. LC 74, OPUC Staff, *Staff Report*, March 5, 2021, p. 24.
[7] *See* Docket No. LC 74, OPUC, Order No. 21-184, June 4, 2021, p. 9.
[8] *See* Docket No. LC 74, Idaho Power, *Valmy Unit 2 Exit Analysis*, August 4, 2021, p. 16.
[9] *See* Docket No. LC 74, Idaho Power, *Valmy Unit 2 Exit Analysis*, August 4, 2021, pp. 5-11.
[10] *See* Docket No. UM 2210, Idaho Power, *Application for Waiver of Competitive Bidding Rules*, December 9, 2021, pp. 2, 13.

Docket No. UM 2210, Staff sought to understand the events leading up to the deficiency and the need for rapid procurement outside the CBRs. In the Staff Report for the March 8, 2021 Public Meeting on UM 2210, Staff articulated the sequence of events as it understood them. Staff captures that history below:

> In May 2021, Idaho Power announced that the Company's near-term capacity position was worse than the Company's Second Amended 2019 IRP had indicated. Improved modeling using revised assumptions pointed to Idaho Power facing a capacity shortfall of an additional 101 MW in 2023, which would widen until the Boardman-to-Hemmingway transmission came on-line in 2026. This new capacity shortfall would occur despite the 2021 all sources request for proposal (RFP), which was issued on June 30, 2021, and sought to acquire [up to 80] MW of new resources by [2023].
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> The Company's May announcement to the IRPAC of a sudden capacity shortfall came almost immediately following the Oregon Commission's acknowledgement of their 2019 IRP in April 2021 and the Idaho Commission's acknowledgement in March of 2021. Idaho Power filed to update its PURPA Avoided Cost values with the numbers from their acknowledged IRPs – with a capacity sufficiency period until 2028 – and then shortly after announced their capacity shortfall had moved up five years to 2023 and added over 101 MW of new resource.

Figure 1: Table 1 from UM 2210 Filing

Table 1: Peak-Hour Load and Resource Balance	2023	2024	2025
	23-Jul	**24-Jul**	**25-Jul**
Surplus / Deficit (MW)	**-101**	**-186**	**-311**

> This marked deterioration of Idaho's summer capacity position in 2023 through 2025 is due largely to three overarching factors. First, the market availability of transmission from the south of their territory dropped after the 2020 heat waves, limiting the Company's ability to import power during the summer peak. Second, Idaho Power, in preparation for the next Idaho Power IRP (LC 78), made changes to how their IRP model (Aurora, the capacity expansion software the Company

used) approached forecasting peak (net vs. maximum demand) and for planning reserve margins. Third, the Company continues to experience very high load growth. Other factors, such as Demand Response timing availability and the postponement of the Jackpot solar project, also played a role.[11]

The repeated suspension of the 2019 IRP and the substantial discontinuity between sequential IRP modeling results demonstrate a need for increased scrutiny of this IRP's modeling and the Action Plan items associated with it. Staff will not respond to all modeling performed by IPC and reviewed by Staff to date but will focus on modeling components around which substantial changes were noted or around which Staff has concerns or questions.

Load Forecast

Load growth is a significant driver of Idaho Power's assertion that the Company faces an immediate capacity deficit and thus a need for near term investments, but as filed, the 2021 IRP has insufficient information to test the validity of the Company's load forecast. Idaho Power's responses to information requests on the load forecasts for the Company's customer classes had insufficient information to independently reproduce the 2021 IRP's published results. Staff continues to have questions and concerns regarding the Company's load forecast assumptions and methods.

Idaho Power projects the Company's overall system load to compound at an annual growth rate of 1.4 percent from 2021 to 2040.[12] This represents a 40 percent increase from the last IRP.[13] From the qualitative description of Idaho Power's expectation of load growth, the economic assumptions driving the anticipated growth in energy sales may be overestimating

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[11] *See* Docket No. UM 2210, Idaho Power, Initial Application for Waiver, December 9, 2021, p. 6;
While this new deficit was officially confirmed in May 2021 as part of the completed Valmy Unit 2 reliability and economic impact analysis, per Information Request #7 in UM 2210, Idaho Power had known of this deficit since early 2021. In February and April 2021 Idaho Power had shared this information with its IRP Advisory Council;
The 2019 IRP was not acknowledged until April 2021 due to two pauses in the IRP process for Idaho Power to ensure modeling was done accurately. New, amended updates to the 2019 IRP were issued June 1, 2021, and October 10, 2021;
Idaho Power, *Idaho Power's Resource Adequacy*, May 13, 2021, slide 16;
See Docket No. UM 2210, OPUC Staff, *Staff Report*, March 1, 2022, pp. 3-4;
Idaho Power received a waiver to the competitive bidding rules to execute the Jackpot Solar PPA on April 4, 2019, because the Company represented it as a time-limited opportunity of unique value in LC 68, Notice of Exception (860.089-0100) https://edocs.puc.state.or.us/efdocs/HNA/lc68hna163119.pdf. This 120 MW project is now delayed and will not meet its December 2022 online date, over 3 years after receiving the exception.
[12] *See* Docket No. LC 74, Idaho Power, 2021 IRP, December 30, 2021, p. 92.
[13] *See* Docket No. LC 74, Idaho Power, Second Amended 2019 IRP, October 2, 2020, p. 80.

growth in the planning period, especially in the near-term. The load forecast is based in part on the assumption that there will be continued improvement in the service area economy and increased economic growth for industrial customers. The largest shares of industrial customers are made up of customers in the food manufacturing, dairy, and construction-related sectors. While these sectors have recovered from the pandemic-induced recession, there are broader trends that may affect the growth of these sectors. For example, dairy production is generally declining which in the long run may impact Idaho Power's industrial dairy customers energy demands. Furthermore, the 2021 IRP appears to generally overestimate the forecasted near-term strength of the economy. Several indicators signal another economic downturn in the United States which may not be reflected in the anticipated economic scenario used for the load forecast: from consumer outlook to the *Wall Street Journal* survey of economists.[14] One solution for uncertainty in demand is to treat it as a sensitivity with a high, planning, and low load growth scenario. Staff wonders if Idaho Power's load forecast represents the upper bound from a range of scenarios. Staff would like to better understand how Idaho Power's load forecast avoids extrapolating the growth rate of a recent economic recovery for the entire 20-year planning horizon.

A large part of the growth in load comes from what the 2021 IRP calls "additional firm load." This category is made up of large power customers that receive service under a special-contract schedule. These customers include Micron Technology, Simplot Fertilizer, and Idaho National Laboratory. The 2021 IRP forecasts a steep increase in additional firm load of around 24 percent per year in the first nine years, going from 108 aMW in 2021 to 345 aMW in 2030.[15] Because this additional firm load is expected to remain at that 2030 level until 2040, the Company explains this customer class will have an average growth rate of 6.3 percent per year over the planning period.[16] However, neither the text of the 2021 IRP's Appendix A nor the Company's response to OPUC IR 49 offer sufficient detail to show why an annual growth rate of 24 percent can be reasonably expected through 2030.

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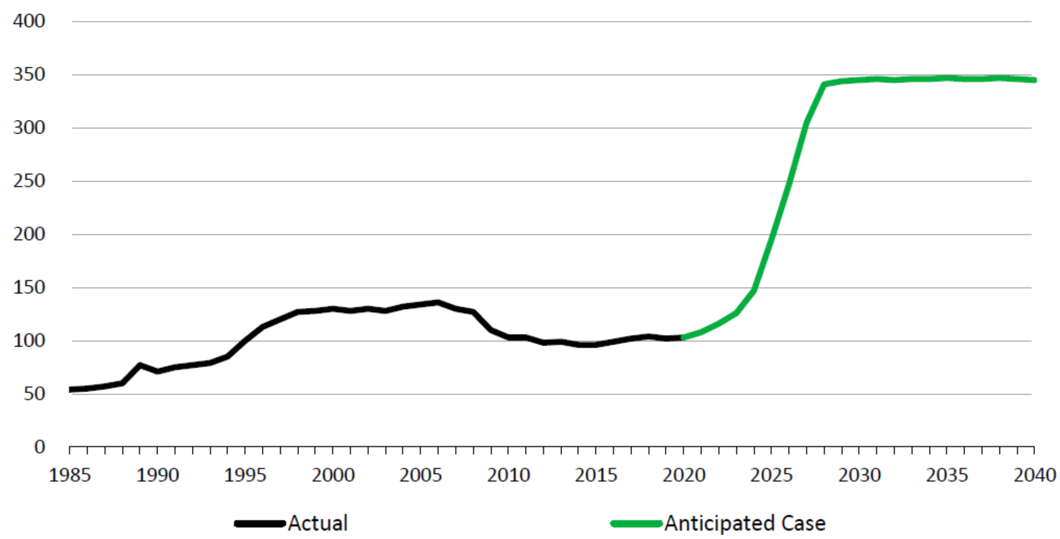
[14] Torchinsky, Rina. *Consumers' Economic Outlook Worsens,* The Wall Street Journal, June 29, 2022, p. A2; Torry, Harriet and DeBarros, Anthony. *Economists Say Recession Is Likelier* The Wall Street Journal, June 21, 2022, p. A2.

[15] *See* Docket No. LC 78, Idaho Power, Appendix A, December 30, 2021, p. 57.

[16] *See* Docket No. LC 78, Idaho Power, 2021 IRP, December 30, 2021, p. 92.

Figure 2: 2021 IRP Appendix A Figure 19 Forecast Additional Firm Load (aMW)



Furthermore, Idaho Power only has one large load special contract application filed for IPUC approval for a 20 MW data center facility.[17] That alone does not explain the forecasted 237 MW increase in additional firm load. In the IRP, Idaho Power describes that it expects several large power customers to come online including Lamb Weston, ASIC, and True West Beef, but no additional special contracts have been filed with the Idaho Public Utility Commission or OPUC.

Regarding the residential load forecast, Idaho Power anticipates an increase from 644 aMW in 2021 to 743 aMW in 2040, an average annual compound growth rate of 0.8 percent.[18] Staff notes that Idaho Power's time series data only goes back to 2011.[19] Staff believes this regression model should be tested against longer time periods. Staff would like to better understand why only one decade was used for historical residential customer data and why the same reasoning does not also apply to the industrial regression model where the time series data goes back to 1991.

Staff found that the 2021 IRP's Appendix A does not contain a thorough description of the methods used to forecast load. In OPUC IR 49, Staff requested the code and data used to the run Idaho Power's estimations for each customer class. The Company responded:

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[17] Microsoft Word - Brisbie - Application - 12-22-21 (002).docx (idaho.gov) Microsoft Word - Brisbie - Application - 12-22-21 (002).docx (idaho.gov).

[18] *See* Docket No. LC 78, Idaho Power, Appendix A, December 30, 2021, p. 18.

[19] *See* Docket No. LC 78, Idaho Power, Attachment 1 – Response to Staff IR No. 49_2021 IRP Resi model output.xlsx, sheet titled "Data" cell A2.

> The source data for Idaho Power's forecasting models/techniques are maintained in an Oracle OLAP database. The source code for data derivation and extraction is proprietary Oracle language (DML). The regression modeling for the primary class forecasts is developed in Itron's MetrixND, via proprietary source code. Derivative data inputs are available in Excel and included as attachments 1-7 to this request.
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> In meeting the full scope of this request, Idaho Power suggests that that Staff observe the operation of the development of the forecast in these platforms through an on-site visit to the Company. Idaho Power would welcome such an opportunity to review its forecasting techniques in detail.[20]

Staff will meet with Idaho Power to go over the load forecast in more detail. The attachments 1 through 7 in the Company's response do not provide sufficient information on how the future values of the independent variables were derived or on the estimator used in the regression models. For example, the P value of the Ljung-Box Statistic in Attachment 1 rejects the null hypothesis that Idaho Power's data is independently distributed in the regression model for residential customers, but the Company's response does not show how this problem of autocorrelation was overcome. Staff does not currently have enough information to either question or confirm the soundness of the Company's load forecast but looks forward to working with Idaho Power to get the additional detail needed to make a recommendation.

As noted in the section above on Compliance with Past Orders, the Commission ordered the Company to: "Present to Commissioners the impact of COVID-19 on load."[21] IPC has not done that.[22] Staff recommends the Company present on this topic at the LC 78 workshop on August 18, 2022, to meet this requirement.

Staff Request for Company Reply Comments 1: Describe where Idaho Power's load forecast belongs within a range of load forecast assumptions.

Staff Request for Company Reply Comments 2: Explain how the problem of Autocorrelation was resolved in Idaho Power's regression model for residential customers.

Staff Request for Company Reply Comments 3: Explain why the data for the residential regression model only goes back to 2011 and why the same reasoning in the Company's

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[20] See Docket No. LC 78, Idaho Power, Response to OPUC IR 49, June 9, 2022, p. 1.
[21] *See* Docket No. LC 74, OPUC, Order No. 21-184, June 4, 2021, Appendix A, p. 4.
[22] *See* Docket No. LC 78, Idaho Power, Reply to OPUC IR 104, June 15, 2022, p. 1.

reply does not apply to the regression models with longer time periods of historical data.

Staff Request for Company Reply Comments 4: Explain how the future values of the independent variables in Idaho Power's regression models are derived.

Staff Request for Company Reply Comments 5: Explain the specific basis for each large industrial customer's growth in the additional firm load customer class.

Staff Request for Company Reply Comments 6: Explain how Idaho power's load forecast avoids extrapolating the growth rate of a recent economic recovery for the entire 20-year planning horizon.

Staff Recommendation 1: Make a presentation to the Commission on the impact of Covid on load at the August 18, 2022, workshop.

Effective Load Carrying Capability (ELCC)

Idaho Power changed the method of calculating the capacity contribution of variable energy resources from the last IRP. In the Second Amended 2019 IRP, the Company calculated solar contribution to peak using the 8,760-based method developed by the National Renewable Energy Laboratory (NREL).[23] For wind energy, Idaho Power used a capacity factor in the last IRP.[24] In the 2021 IRP, Idaho Power has adopted a risk-based method called ELCC to evaluate the capacity contribution of the Company's existing resources and expected future resources that vary in generation. The Company has expanded its application to evaluate the contribution to peak of solar, wind, demand response, storage, and solar plus storage.[25] IPC's application of this method evaluated a resource's ability to reduce loss of load expectation (LOLE), which is mostly impacted by a limited number of highest risk hours, rather than only analyzing a resource's average ability to meet peak load.[26] This new approach still inherently has a focus on peak hours, but an hour's risk is not exclusively defined by demand. By assessing ELCC as an impact on LOLE, the Company is measuring a resource's ability to meet Idaho Power's net peak, the combination of high demand with supply constraints.

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[23] *See* Docket No. LC 74, Idaho Power, Second Amended 2019 IRP, October 2, 2020, pp. 54-56.
[24] *See* Docket No. LC 74, Idaho Power, Second Amended 2019 IRP, October 2, 2020, p. 59.
[25] *See* Docket No. LC 78, Idaho Power, Appendix C, December 30, 2021, pp. 97-99.
[26] Advice No. 21-12 filed in OPUC Docket No. ADV 1355, p. 3.

In changing the method for calculating capacity contribution, Idaho Power's ELCCs appear on the low end of assumed capacity contributions that Staff has seen elsewhere. For example, the Company assumes an ELCC of 11.2 percent for wind. This falls between the last IRP's assumption of 5 percent for peak hour planning and annual average capacity factors of 35 percent for projects sited in Idaho and 45 percent for projects sited in Wyoming.[27] Idaho Power considers procuring wind sited in both Idaho and Wyoming but uses only one ELCC for both, raising questions about granularity. In PacifiCorp's 2021 IRP, both sources of wind energy are separately estimated for capacity contribution, and PacifiCorp found higher percentages for both: 33 percent for Idaho and 30 percent for Wyoming.[28] PacifiCorp used NREL's capacity factor method (CF Method). The ELCC method Idaho Power used, which compares the impact on LOLE of a perfect resource with the estimated resource, may inherently produce lower estimates of ELCC. If so, Staff would like to understand whether that improves resource planning. A study by E3 and Puget Sound Energy's (PSE) 2021 IRP appear to have used the same method that Idaho Power now uses but found higher ELCCs for wind energy as well.[29] Estimating ELCC is very specific to a utility's own risk profile and does not necessarily mean Idaho Power has underestimated wind ELCC. PSE's ELCC for Wyoming wind is for the winter, for example, which may not be comparable to the impact of the same resource on Idaho Power's LOLE in the summer. Staff would like to better understand why Idaho Power is finding lower ELCCs and plans to closely review the Company's modeling in MATLAB.

Demand Response (DR)

Staff has many questions about how DR has been treated in this IRP, most of which are related to understanding why the preferred portfolio fails to maximize all potential DR. The Company uses a Northwest Power and Conservation Council (NWPCC) assessment of achievable potential DR for the region to determine the DR potential for IPC's service area. Based on NWPCC's assessment, Idaho Power estimated 584 MW of DR potential in the Company's service area.[30] Excluding the 300 MW of existing capacity represented by existing programs, this leaves 284 MW of additional capacity.

Idaho Power's preferred portfolio includes 300 MW of DR in 2022, which the Company notes represents a reduction from the previously assumed 380 MW of existing capacity due to an

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[27] *See* Docket No. LC 78, Idaho Power, Second Amended 2019 IRP, October 2, 2020, p. 59.
[28] *See* Docket No. LC 77, PacifiCorp, 2021 IRP, September 1, 2021, p. 220.
[29] E3. *Resource Adequacy in the Pacific Northwest*, March 2019, p. 55;
PSE. 2021 IRP, April 1, 2021, pp. 7-28.
[30] *See* Docket No. LC 78, Idaho Power, 2021 IRP, December 30, 2021, p. 69.

adjustment to account for an expected decrease in realization rates from the implementation of new program parameters.[31] After accounting for existing DR, the preferred portfolio includes the selection of only 100 MW of new DR over the planning horizon, leaving 184 MW undeveloped.

Staff seeks to understand the factors impacting DR selection. In particular, Staff would like to understand whether IPC's assumed:

- DR costs are too high;
- DR capacity is too low;
- Declining capacity contribution for future DR is consistent with the Company's modeling of other resources.

DR Cost Assumptions

IPC continues to assume DR remains a very low-cost resource. The Company's modeling assumes a two-tiered cost, where the first tranche of new capacity is priced at $51 per kW-year, and the second tranche is priced at $82 per kW-year.[32] Both costs represent substantial savings from the cost of a simple cycle combustion turbine (SCCT), which the PUC widely uses as the proxy least-cost supply side capacity resource. Staff's initial impression is that the cost assumptions appear reasonable and that the preferred portfolio's failure to maximize all potential DR is not likely due to unreasonably high DR cost assumptions.

DR Assumed Capacity

In the 2021 IRP, Idaho Power reduces the assumed nameplate capacity of existing DR compared both to the last IRP and recent advice filings and, as noted above, adopted a new method to measure the capacity contribution of DR applying an ELCC to what was previously considered a dispatchable resource. In the first version of the 2019 IRP, DR provided 380 MW of nameplate capacity.[33] In the Second Amended 2019 IRP, DR provided 390 MW of nameplate capacity.[34] In Advice No. 21-12, filed about a month before the Company filed the 2021 IRP, Idaho Power

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[31] *See* Docket No. LC 78, Idaho Power,2021 IRP, December 30, 2022 p. 152.
[32] *See* Docket No. LC 78, Idaho Power, Response to OPUC IR 95, June 10, 2022, Attachment – Response to Staff Request No. 95_DR Model inputs, sheet titled "TSG Fixed O&M", cells C3 and D3.
[33] *See* Docket No. LC 78, Idaho Power, 2021 IRP, December 30, 2021, p. 68.
[34] *See* Docket No. LC 74, Idaho Power, Second Amended 2019 IRP, October 2, 2020, p. 64.

dropped the additional 10 MW and returned to the original 2019 IRP's 380 MW.[35] The 2021 IRP reduced it further to 300 MW.

Table 1: Changes to DR Capacity

Filing	Nameplate Capacity	Capacity Contribution
2019 IRP	380 MW	100%
Second Amended 2019 IRP	390 MW	100%
Advice No. 21-12	380 MW	17%
2021 IRP	300 MW	56%

In preparing the 2021 IRP, the Company found a larger difference between the nameplate capacity of existing DR and the actual capacity contribution of existing DR when the ELCC method was applied. The use of ELCC reduced Idaho Power's estimation of the capacity contribution of the Company's DR. In ADV 1355, IPC showed the Company's DR programs to have an ELCC of approximately 17 percent.[36] This was a significant reduction from the last IRP's capacity contribution of 100 percent.[37]

Idaho Power believes the ELCC of its existing DR can be raised through program changes. As a result, the Company proposed, and the Commission approved, changes to Idaho Power's DR programs in Advice No. 21-12. These changes better aligned the Company's DR program parameters with the highest-risk loss-of-load-probability hours by extending the summer program season to September 15, shifted the start and end times in which events can be called to later in the evening, and increased the maximum number of event hours that can be called in a week. The Company's analysis demonstrated these changes improve the ELCC of the DR programs from 17 to 56 percent.[38] This revamp also increased incentives for program participants to offset a potential participation decline resulting from the changes. Yet the Company assumes there will still likely be a drop in DR program participation due to survey research on program participants. As a result, the 2021 IRP assumes the nameplate capacity of existing DR to be 300 MW.[39]

However, the observed nameplate capacity of DR in 2022 has already proven to be higher than 300 MW. Increased enrollment enabled IPC to go into its current peak season with at least 323

[35] *See* Docket No. ADV 1355, Idaho Power, Advice No. 21-12, November 24, 2021, p. 3.
[36] Advice No. 21-12 filed in OPUC Docket No. ADV 1355, Attachment 2, p. 3.
[37] See Docket No. LC 74, Idaho Power, Second Amended 2019 IRP, October 4, 2020, p. 27.
[38] Advice No. 21-12 filed in OPUC Docket No. ADV 1355, Attachment 2, p. 4.
[39] 2021 IRP, p. 69.

MW of DR capacity.[40] Staff finds the Company's initial forecast reasonable from the perspective of the information available in 2021, but Staff believes the observed capacity of the Company's DR programs in 2022 should replace the 2021 assumptions to update the nameplate capacity of DR in IPC's modeling.

Staff would like to better understand how DR capacity is calculated. Staff would like Idaho Power to provide the characteristics of DR considered in the calculation of nameplate capacity and ELCC, the degree to which each characteristic impacts the capacity total, and the basis for the Company's decision to assign the specific value given to each characteristic.[41]

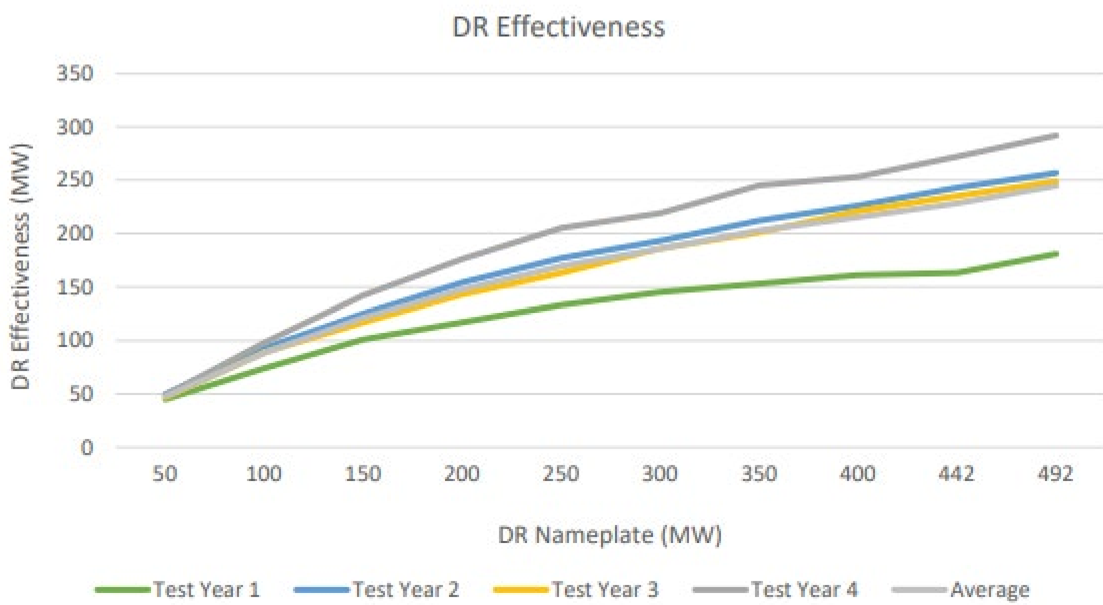
Staff is concerned that the way DR is being modeled is affecting its utilization and would like to better understand how DR is made available for selection in Aurora. Idaho Power uses Aurora's forced outage rate function to manually enter when DR is available. Most hours have a forced outage rate of 100 percent, preventing DR from selection. That makes sense for hours outside the DR programs' windows for calling events. Many hours for which DR events can be called have a forced outage rate of 100 percent as well, which, as the Company explained to Staff at a meeting on June 13, 2022, is to account for the limited number of events that can be called. Staff would like to better understand how the Company chose the hours that represent available DR.

DR's Declining Capacity Contribution

On June 13, 2022, Staff met with the Company to discuss questions about DR, including changes to DR's ELCC. Idaho Power explained that additional DR resource do not continue to present an ELCC of approximately 56 percent but rather can be expected to have a declining ELCC per 20 MW increment. Staff understands Chart 1 from page 4 of Attachment 2 to the Company's Advice No. 21-12 filing to have illustrated this concept of diminishing marginal ELCC as a decline in effectiveness. Chart 1 shows flattening curves where the effectiveness of DR does not increase at the same rate as nameplate capacity.

[40] *See* Docket No. LC 78, Idaho Power, Company response to OPUC IR 94, June 10, 2022, p. 1.
[41] *See* Docket No. LC 78, Idaho Power, Appendix C, December 30, 2021, p. 99.

Chart 1: DR Effectiveness vs DR Nameplate Capacity



Staff would like to better understand the calculation behind the Company's DR ELCC and how this calculation compares to other, similar resources, such as storage. Staff would like to understand whether the varied ELCC of different tranches of potential DR is an outcome of the IRP modeling exercise or based on exogenous characteristics assigned to the 20 MW increments of new DR. Further, if the varied ELCC is an outcome of the IRP modeling exercise, Staff would like to know whether Idaho Power has observed a similar outcome with other resources. For example, is the ELCC of a storage resource also varied and declining in a stair-step fashion?

Aurora was allowed to select DR from potential future capacity in 20 MW blocks.[42] This constraint was not applied to the last IRP when Idaho Power made DR available for selection in the model at 5 MW increments.[43] Staff would like to understand why the size of a block was increased 400 percent from the last IRP and what impact this change has had on DR's selection in the Preferred Portfolio.

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[42] *See* Docket No. LC 78, Idaho Power, 2021 IRP, December 30, 2021 p. 69.

[43] *See* Docket No. LC 74, Idaho Power, Second Amended 2019 IRP, October 2, 2020, p. 64.

Staff Request for Company Reply Comments 7: Provide the observed nameplate capacity and ELCC of the Company's DR programs in the current peak season of 2022.

Staff Request for Company Reply Comments 8: Provide the characteristics of DR considered in the calculations of DR nameplate capacity and ELCC, the degree to which each characteristic impacts the capacity total, and provide the basis for the Company's decision to assign a specific value for each characteristic.

Staff Request for Company Reply Comments 9: Explain whether the varied ELCC of different tranches of potential DR is an outcome of the IRP modeling exercise or based on exogenous characteristics assigned to the 20 MW increments of new DR. If the varied ELCC is an outcome of the IRP modeling exercise, Staff requests the Company confirm whether Idaho Power has observed a similar outcome with other resources. For example, is the ELCC of a storage resource varied, declining in a stair-step fashion? If the varied ELCC is based on exogenous characteristics assigned to the 20 MW increments of DR, Staff requests IPC list those characteristics, the value that each characteristic impacts ELCC, and provide the basis for the Company's decision to assign the value given to each characteristic.

Staff Request for Company Reply Comments 10: Explain why the size of a new DR block was increased 400 percent from 5 MW in the last IRP.

Staff Request for Company Reply Comments 11: Explain how the hours when DR was given a forced outage rate less than 100 percent were chosen.

Resource Economics

Wholesale Electricity Prices

The expected wholesale electricity price is an important variable. A downward bias on wholesale electricity prices may bias the selection of storage and transmission resources.

IPC's wholesale electricity price forecasts appear low. The Company's forecast is endogenously produced from Idaho Power's Aurora modeling. Because the 2021 IRP forecasts prices that are now historical, the Company's forecast for 2021 can be compared with historical prices. IPC's modeling of wholesale prices significantly undershot observed Mid-Columbia (Mid-C) prices in 2021. Some of this can be explained by 2021 being a low hydro year. The Company did model higher wholesale prices than the planning assumptions. Staff would like to see how accurate those prices are compared to Mid-C prices in 2021 to see if the underestimation persists.

Aurora produces wholesale price forecasts based on expected resources in the WECC. Staff would like to better understand those assumptions about future regional resource availability. A key aspect of this is the assumption of what the buildout of storage will be. Idaho Power expects an arbitrage opportunity to make storage resources more economic. This means the Company expects to store energy at low prices, on average negative prices, and then discharge the energy when power costs are much higher. A heavy storage buildout in the WECC may smooth out peak and off-peak wholesale prices in a way that denies Idaho Power the arbitrage opportunity the Company seeks to exploit.

Idaho Power's Aurora-based wholesale price forecast for Mid-C prices is significantly lower than the prices the Company is using to set PURPA prices in UM 1730 where Idaho Power uses observed forward prices from the Intercontinental Exchange. In the Company's 2022 avoided cost update for Schedule 85, IPC put forth an *off-peak* price of $50.64 per MWh in 2022 which is 189 percent higher than the $17.52 per MWh the 2021 IRP assumes for an average Mid-C price in 2022.[44] Mid-C is a liquid trading market with many sophisticated traders converging prices toward greater market efficiency. Staff would like to understand what insight Idaho Power's Aurora modeling of wholesale energy prices has to offer over current forward market prices.

Staff Request for Company Reply Comments 12: Compare the 2021 IRP's Mid-C forecast under low hydro conditions in 2021 with observed 2021 prices.

Staff Request for Company Reply Comments 13: Describe the basis for the 2021 IRP's forecast of WECC resources and their associated availability.

Staff Request for Company Reply Comments 14: Graph the 2021 IRP's wholesale price forecasts for Mid-C and Palo Verde with the latest forward price curves of these markets and explain how and why Idaho Power's Aurora modeling is more reasonable than observed market prices.

Combined Cycle Combustion Turbine (CCCT)

Staff finds all the assumed costs for a CCCT plant to be reasonable except the initial capital cost. The fixed O&M, variable O&M, and escalation rates are congruent with contemporary research, but IPC used the capital cost of its 2012 investment in the Langley Gulch plant as a proxy, which was compounded to a 2021 cost at an annual rate of 12.5 percent using the cost of spare parts

[44] *See* Docket No. UM 1730, Idaho Power, 2022 Annual May Update of Avoided Cost Rates – Schedule 85, April 26, 2022, p 3.
See Docket No. LC 78, Idaho Power, Reply to OPUC IR 43, June 3, 2022, p 1.

as an escalation proxy and then marked up an additional 20 percent "to account for hydrogen fuel blending."[45] This approach produced a capital cost of $1,656 per kW, which is 59 percent higher than the National Renewable Energy Laboratory's (NREL) estimate in its Annual Technology Baseline (ATB).[46] Lazard estimates a capital cost range of $700 - $1,300 per kW. Idaho Power's estimate is thus 27 percent over the top range of Lazard's research on combined cycle plants.

Staff Request for Company Reply Comments 15: Explain why Idaho Power's method of estimating the capital cost of a combined cycle combustion turbine is more reasonable that citing contemporary research from either NREL or Lazard as the Company does for other resources.

Battery Storage

Of the potential future-supply side resources that Idaho Power describes in the 2021 IRP's Chapter 10, the Company includes one combination of a variable energy resource packaged with storage. This resource pairs solar with 4-hour lithium-ion batteries at a 1:1 ratio.[47] The IRP should model other pairing ratios. Resource options with a lower ratio of battery storage on a solar site might have otherwise been selected. Staff believes the Company should add these additional resource options for modeling.

Idaho Power's assumed capital cost for utility scale four-hour lithium-ion batteries looks low. The Company took the bottom range of NREL's 2020 estimate ($1,118 per kW) for 2021 and averaged it with a quote of $1100 per kW IPC received from a developer in 2021. In its 2022 ATB, NREL reports a historical cost of $1,475 per kW for 2021, which is 28 percent higher than what the Company assumed for that calendar year. Given the supply risk of rare earth metals to construct batteries and competition with auto manufacturers' use of the same materials to scale up production of electric vehicles, Staff believes that IPC's near-term battery prices may be optimistically low. Since the Company based the battery capital cost assumption in part on a quote from a developer, Staff would like the Company to provide additional support and justification for its choice of battery storage costs by sharing the capital costs found in bids Idaho Power is seeing from its current RFPs.

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[45] *See* Docket No. LC 78, Idaho Power, Reply to Staff OPUC IR 42, LCOC Capacity Cost Files 2021, sheet titled "Cost Input + Op Assumptions", cell F5.
[46] NREL. ATB, 2022, sheet titled "Natural Gas_FE", cell N84.
[47] *See* Docket No. LC 78, Idaho Power, 2021 IRP, December 30, 2021, p 147.

Staff Request for Company Reply Comments 16: Explain why only a 1:1 ratio was used for storage sited with solar.

Staff Request for Company Reply Comments 17: Provide the capital costs from battery storage bids Idaho Power has received in its current RFPs.

Transmission

IPC's transmission planning in the 2021 IRP has four changes over the previous IRP. First, Idaho Power is experiencing congestion on third-party transmission lines, blocking access to market hubs, to which the Company responded with a more conservative estimate of IPC's capacity for imports with a reduction in its determination of overall transmission availability to wholesale markets from 900 MW in the 2019 IRP to 710 MW in the 2021 IRP.[48] Second, the Boardman to Hemmingway (B2H) project ownership share of Idaho Power has increased from 21 percent to around 45 percent. This comes with the addition of a transmission service obligation across southern Idaho for BPA's customers through a Network Integration Transmission Service Agreements (NITSA) with BPA under Idaho Power's Open Access Transmission Tariff (OATT). Third, Idaho Power has agreed to some asset swaps and upgrades of existing transmission lines as part of the terms of the B2H ownership agreement. Fourth, the Southwest Intertie Transmission Project-North (SWIP-North) was added in the 2021 IRP, albeit this project was not considered for inclusion in the preferred portfolio due to uncertainty of project viability and available partners.[49] Staff's opening comments focus on the impact of changes to B2H ownership, asset swaps, and other transmission projects that might relieve access to wholesale markets without investing in SWIP-North.

Boardman to Hemmingway (B2H)

The Company's analysis continues to show that inclusion of B2H in the preferred portfolio is more cost effective compared to the best portfolio that did not include the B2H project. The difference in cost was calculated as $265.5 million,[50] which represents an increase of 3.3 percent of the cost of the preferred portfolio.[51]

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[48] See Docket No. LC 78, Idaho Power, response to OPUC IR 75, June 10, 2022 which shows the transmission paths and MW quantities available on individual paths.
[49] *See* Docket No. LC 78, Idaho Power, 2021 IRP, December 30, 2021, p. 88.
[50] Ibid. p 81.
[51] Ibid. p 130.

The Commission's acknowledgement order in Idaho Power's last IRP, Order No. 21-184, discussed Idaho Power's plans to acquire the BPA ownership share, and that BPA would purchase access of B2H through the Idaho Power's OATT. The Order also mentioned that the Company had agreed that its 2021 IRP would include modeling of the B2H partnership costs and risks. The Commission expected Idaho Power to closely analyze whether expanding its ownership share from 21 percent and relying on OATT revenues to offset its additional costs was truly comparable to joint ownership, in terms of risks and financial impacts. In addition, where differences might exist, the Commission expected Idaho Power to explain how those risks were mitigated or considered in its analyses.[52]

Despite the recommendations and expectations, the 2021 IRP did not have detailed analysis of the cost of B2H before and after the ownership change to give Staff the ability to compare the financial impacts and risks to customers. The 2021 IRP simply states that "for the 2021 IRP, Idaho Power modeled B2H assuming the company has a 45% ownership interest and is providing transmission service to BPA, with BPA transmission wheeling payments acting as a cost-offset to the overall B2H project costs."[53]

Staff submitted two information requests to Idaho Power (OPUC IR 4 and OPUC IR 5) requesting sensitivity analysis to consider the partnership risks of different levels of ownership, up to 100 percent Idaho Power ownership, and calculating the near-term and long-term cost impacts on ratepayers. The Company's response was that all portfolios were modeled only as per the non-binding term sheet Idaho Power agreed to with PacifiCorp and BPA. All robustness tests assumed the same 45.45 percent level of ownership by Idaho Power.[54]

Given the non-binding nature of the B2H term sheet, ownership structure may remain unsettled. Studying a 100 percent ownership arrangement would look at the risk that PacifiCorp might seek the same deal as BPA, namely, to let Idaho Power assume the hazards of ownership and instead pay IPC the OATT. But Idaho Power did not perform this analysis. Staff would like the Company to describe how likely it is that this scenario might emerge.

To understand how BPA's transmission service payments to Idaho Power would offset the Company's higher costs from a higher percentage of ownership, Staff submitted OPUC IR 82 to provide a breakdown of the net present value of all costs and payments. Idaho Power's response to OPUC IR 82 provides annual estimates for the incremental revenue requirement due to the increase in the B2H ownership share and lists the projected BPA payments. Those

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[52] *See* Docket No. LC 74, OPUC, Order No. 21-184, June 4, 2021, p. 16.
[53] *See* Docket No. LC 78, Idaho Power, Appendix D, February 16, 2022, p. 62.
[54] Ibid. p. 6.

annual revenue streams confirm that projected revenues can offset the increased costs as stated in the application. However, those annual revenue numbers are hardcoded, making them difficult to assess. Staff would like to understand the assumptions behind those annual revenue estimates. For example, Staff would like to understand how the projected BPA revenues were calculated, what the assumed load that BPA will serve is, and the projected payments under the assumed Network Integration Transmission Service Agreement. Staff seeks to understand whether there are additional revenues that IPC could receive from the use of the 182 MW of east to west capacity.

The non-binding B2H term sheet also contains asset swaps and upgrades that may themselves have a net cost. The asset swaps include purchasing 200 MW of bidirectional transmission capacity between Populus and Four Corners from PacifiCorp, the sale of Idaho Power's assets in southern Idaho to PacifiCorp, the swapping of point-to-point contracts across southern Idaho with PacifiCorp, the upgrade of the Borah West path, and an upgrade of the Midpoint-Hemingway line. If these swaps and upgrades present a net cost to customers, and are necessary for the B2H project, that net cost should be included in the total cost for B2H. However, if these swaps and upgrades are not necessary for the B2H project, each of these projects should be weighed on their own merits. A portfolio that just contains construction of the B2H line should stand alone as a portfolio to compare with selection of the associated asset swaps and upgrades in the term sheet. Staff would like to see how the NPVRR of the preferred portfolio would change without these additional transmission projects.

Staff was interested in understanding whether federal funds have been pursued to support the costs associated with B2H and submitted OPUC IR 1 on this topic. In Idaho Power's response, Staff learned that the Company has not sought federal grant funding for B2H.[55] The November 2021 Infrastructure Investment and Jobs Act specified funding for transmission, which IPC may qualify for. This includes $5 billion in direct funding, a $2.5 billion revolving loan in the Transmission Facilitation Program, and $3 billion in the Smart Grid Investment Matching Grant Program. Staff would like to understand why Idaho Power has not sought external funding.

Access to Wholesale Markets

The 2021 IRP describes how capacity outside Idaho Power's transmission system has become congested, but the Company does not provide a comprehensive analysis of how that may change due to other new transmission projects planned outside the Company's balancing area. For example, the 2021 IRP's transmission map on Figure 8 of Appendix D does not include the

[55] *See* Docket No. LC 78, Idaho Power, Response to OPUC IR 1, April 27, 2022, p. 1.

recently approved NVE Greenlink project. This is a significant regional transmission project that could improve Idaho Power's access to southern markets through NVE and affect the Company's evaluation of SWIP-North. Staff would like Idaho Power to describe the impact the Greenlink project could have on relieving the congestion south of Valmy. Staff would also like Idaho Power to list transmission projects outside and immediately adjacent to the Company's balancing area that may provide new opportunities for firm transmission from market hubs to IPC's customers, most notably Greenlink.

Staff Request for Company Reply Comments 18: Describe the probability Idaho Power's ownership share of B2H will increase again.

Staff Request for Company Reply Comments 19: Describe the assumptions behind the projected revenue estimates from BPA's use of B2H.

Staff Request for Company Reply Comments 20: Describe how necessary each asset swap and upgrade mentioned in the 2021 IRP's Appendix D pages 6 – 9 is to the engineering of B2H.

Staff Request for Company Reply Comments 21: Itemize the cost of each asset swap and upgrade mentioned in the 2021 IRP's Appendix D pages 6 – 9.

Staff Request for Company Reply Comments 22: Explain why Idaho Power has not sought external funding for B2H.

Staff Request for Company Reply Comments 23: List transmission projects outside IPC's balancing area that may provide new opportunities for firm transmission from market hubs to the Company's customers, most notably Greenlink.

Portfolio Modeling

Twenty-year Limit to Costs

Staff is investigating whether Idaho Power's use of 20 years of levelized costs in the IRP modeling is excluding any costs, distorting the cost impacts of resource decisions, or creating bias toward capital investments. In reply to OPUC IR 97, the Company states: "The net present value revenue requirements presented in Table 10.3 of the 2021 IRP are levelized costs but only reflect those levelized costs during the 20-year planning horizon." Staff is concerned that this does not adequately capture investment costs that occur beyond the 20-year planning horizon and as such might bias capital expenditures with long depreciation schedules against other resource alternatives. For example, as an asset with a 55-year economic life, Idaho Power's approach removes $83 - $112 million from the NPVRR of B2H, depending on the assumed cost contingency.[56] Part of this comes from only capturing 20 years of depreciation, O&M, property tax, insurance, and mitigation expense. Another part may come from the levelization. By estimating an average annual cost, the rate of return customers must pay the Company for the capital expenditure may be lowered in the 20-years of levelized costs that are considered, but the return on capital is, in reality, highest for the Company in the first 20 years. Staff would like to better understand how the levelization was performed and what the Company expects this 20-year time constraint on cost consideration to improve for Idaho Power's resource planning, compared to including the full lifecycle costs of each investment.

Staff Request for Company Reply Comments 24: Explain how costs have been levelized into an annual number.

Staff Request for Company Reply Comments 25: Explain how the 20-year constraint on costs improves Idaho Power's resource planning compared to including the full net present value of the lifecycle cost of each investment made during the 20-year planning horizon.

Future Qualifying Facilities (QFs)

Idaho Power assumes no growth in PURPA resources when choosing to include only signed contracts in resource planning. Staff finds this to be an unreasonable assumption, particularly when the construction of B2H can be expected to increase opportunities for QFs to interconnect. The Company is concerned that the inclusion of future QFs can mask system resource needs.[57] However, Staff believes that excluding QFs can have the effect of overestimating system resource needs. Idaho Power could balance these two concerns by assuming no growth in QFs in the first four years and then apply a forecast of future QF development informed by past QF activity and expanded transmission beginning in the fifth year of planning. This is akin to how Staff has recommended PacifiCorp handle QF renewals.[58]

Staff Request for Company Reply Comments 26: Comment on whether assuming zero growth in QFs beyond signed contracts in the first four years and adding a reasonable

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[56] *See* Docket No. LC 78, Idaho Power, Attachment – Response to Staff IR No. 90_B2H NPV.xlsx, June 16, 2022, Cells F9 and X9.
[57] *See* Docket No. LC 78, Idaho Power, Reply to Staff OPUC IR 8, May 27, 2022, p. 1.
[58] *See* Docket No. LC 77, OPUC Staff, Staff Report, February 11, 2022, pp. 38, 39.

forecast of future QF resources starting in the fifth year of the planning horizon adequately balances near-term risk with longer-term planning accuracy.

Resource Retirement

At a meeting with the Company on June 13, 2022, Idaho Power revealed to Staff that only coal plants are considered for retirement by Aurora. These included only existing coal resources. If a coal plant is selected for gas conversion, it then is no longer a coal plant and becomes excluded from consideration for early retirement. At a minimum, this results in an unequal treatment of different resources. Staff believes that all resources should be considered for retirement during the 20-year planning horizon.

Further, Staff has concerns about the consistency of how decommissioning costs are considered. The only decommissioning costs that Idaho Power models are those for "existing resources that have undetermined retirement dates within the planning window."[59] All existing resources should have assumed decommission costs to model a possible retirement and all new resources should have decommission costs factored into the NPVRR of the investment.

Staff Request for Company Reply Comments 27: Explain how the limitation on resource retirement selection improves Idaho Power's resource planning.

Staff Request for Company Reply Comments 28: Describe the decommissioning costs Idaho Power is seeing in bids for the Company's current RFPs.

Reliability

In the Second Amended 2019 IRP, Idaho Power found all the portfolios that the Company modeled to have a LOLE of 0.01 days per year.[60] This significantly overshot the last IRP's reliability standard of 0.1 days per year. (The lower the number the more reliable the portfolio). In the 2021 IRP, Idaho Power has raised the reliability standard to a LOLE of .05 days per year, but the new portfolios have higher LOLEs than the last IRP, meaning they are less reliable with a higher expectation of a loss of load.[61]

Idaho Power found only one portfolio to meet the Company's least-risk standard, and it is not the preferred portfolio. The only portfolio that has no years in the planning horizon in which

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[59] *See* Docket No. LC 78, Idaho Power, Reply to OPUC IR 91, June 9, 2022, p. 1.
[60] *See* Docket No. LC 74, Idaho Power, Second Amended 2019 IRP, October 2, 2020, p. 61.
[61] *See* Docket No. LC 78, Idaho Power, 2021 IRP, December 30, 2021, p. 117.

the LOLE is greater than 0.05 is the portfolio that builds SWIP-North in 2025.[62] All the other portfolios that the Company presents, including IPC's preferred portfolio, fail to meet this least-risk metric. Staff finds this unusual for a utility to consider portfolios that have higher loss of load expectations than the Company's minimum standard, especially when the preferred portfolio is one of them.

To compare portfolios with different levels of unreliability, the capital cost of a SCCT is imposed proportional to the amount of generation needed to get the portfolio's LOLE under 0.05. This cost proxy does not cover the full cost of meeting this unserved load with a gas peaker plant. Staff would like to understand why Idaho Power is having this portfolio construction challenge and why the Company's modeling did not select a resource in these years of high LOLE for a more accurate economic comparison.

Staff Request for Company Reply Comments 29: Describe the factors that are making the construction of portfolios that meet Idaho Power's reliability standard a challenge.

Staff Request for Company Reply Comments 30: Explain how Idaho Power plans to avoid a loss of load in 2037 with IPC's preferred portfolio and how the expected cost of this solution differs from the capital cost of a SCCT plant.

Aurora

In the Company's response to OPUC IR 39, Idaho Power provided the archived Aurora files used in the 2021 IRP. The focus of Staff's review in these opening comments has been on the inputs. After reaching a conclusion as to which assumptions would be most reasonable, Staff will work with the Company to explore if changing these assumptions produces different outputs.

Climate Risk Report, Emissions, & Clean Energy Goals

Staff appreciates the Company's expanded and distinct discussion about climate change mitigation, adaptation, and climate-related risks. The Company's response is in line with the Climate Change Risk Report recommended by Staff and approved by the Commission in Order No. 21-184, as it includes the Company's process for identifying, assessing, and managing climate-related risks and how it integrates these risks into its overall risk management. This chapter included descriptions of how the Company ensures awareness of climate science, potential impacts to operations, and how the Company modeled climate risk in the 2021 IRP.

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[62] *See* Docket No. LC 74, Idaho Power, Appendix C, December 30, 2021, p 100.

Risk Identification and Management

Staff is pleased to see the expanded descriptions and modeling of various climate-related risks and risk management strategies, including weather-related risk, wildfire risk, water and hydropower generation risk, and policy risk.

The Company explains that it expects that "[c]hanges in legislation, regulation, and government policy may have a material adverse effect on Idaho Power's business in the future."[63] It specifies that these include, but are not limited to "…tax reform, utility regulation, carbon-reduction initiatives, infrastructure renewal programs, environmental regulation, and modifications to accounting and public company reporting requirements." Staff believes it is important to understand the details of each of these risks, how they impact the company and potentially customers, and how the company is responding to and planning for these risks. Staff would like the Company to provide this additional detail in its reply comments.

Staff Request for Company Reply Comments 31: Describe in detail the climate policy risks for which the Company plans and any details regarding the nature of its policy risk planning, including but not limited to those regarding modifications to accounting and public company reporting requirement.

Emissions

The emissions from an electric company's planned generation mix have little direct impact on the selection of the preferred portfolio beyond the inclusion of a policy risk sensitivity to ensure the potential for a future price on carbon is considered, but an IRP also serves as a public document that stakeholders and policymakers can access to learn what the Company's planned emissions are. For this reason, Staff carefully reviews the accuracy of emissions projections and the efficacy of the Company's zero emissions by 2045 goal.

Historical Emissions

The 2021 IRP presents a trend of reduced emission intensity and total emissions since 2003, but since 2017, CO^2 emission intensity increased from 633 to 837 lbs/MWh CO^2 and total emissions increased from 4,323,146 to 5,355,098 tons CO^2.[64] The Company indicates that these increases are the result of low water supply, increased demand for electricity, and market conditions. Staff would like to better understand how market conditions resulted in an increase in emission

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[63] *See* Docket No. LC 78, Idaho Power, 2021 IRP, December 30, 2021, p. 33.

[64] Ibid., p. 28.

intensity and how the Company intends to address emission intensity impacts of low water supply and market conditions.

Staff Request for Company Reply Comments 32: Describe how market conditions led to a recent increase in emission intensity.

Staff Request for Company Reply Comments 33: Explain how Idaho Power intends to address emission intensity from low water supply and market conditions.

Future Emissions

The Company modeled various emission reduction targets (100% by 2035 and 100% by 2045), as requested by Staff. However, despite the Company's 100% by 2045 goal, the emissions associated with the preferred portfolio does not meet that target. The Company stated that the 2021 IRP "…reflects a clean mix of generation and transmission resources that ensures reliable, affordable energy using technologies available today."[65] But the company goes on to say that achieving its 100 percent clean energy goal requires technological advances and reductions in cost, as such the 2021 IRP does not reflect what it will take to meet its 100 percent by 2045 clean energy goal.

The Company cites an emission reduction report on its website.[66] The website includes a "Shareholder Proposal – Website Emissions Report REVISED 2-26-22" document that includes emission reduction targets with a table entitled "Medium-Term Targets" showing continued emissions through 2040.[67] The table shows emissions bottoming out at 1,746,092 in 2030, but then increasing and remaining at about 1.9 million short tons CO^2 per year through 2040.

Staff notes that while the Company is not subject to HB 2021, Idaho Power did model a portfolio with more aggressive targets that Staff believes could approximate the emissions targets of HB 2021, namely its 100% Clean by 2035 Scenario.[68] The Company explains that it was difficult for the modeling to produce a portfolio that met these emission targets and maintain reliability, and that this scenario was higher cost. Staff would like to know what the LOLE was for that portfolio.

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[65] *See* Docket No. LC 78, Idaho Power, 2021 IRP, December 30, 2021, p. 27.

[66] https://www.idahopower.com/energy-environment/energy/energy-sources/our-path-away-from-coal/
https://www.idahopower.com/energy-environment/energy/energy-sources/our-path-away-from-coal/.

[67] https://docs.idahopower.com/pdfs/AboutUs/EnergySources/emissions-reduction-report.pdf
https://docs.idahopower.com/pdfs/AboutUs/EnergySources/emissions-reduction-report.pdf.

[68] https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2021.

The 2021 IRP includes estimates of CO^2 emissions for its portfolios and Idaho Power has responded to Staff's request for more granular data by providing monthly emissions data. However, Staff issued information requests requesting hourly dispatch and emissions data, as well as load duration curves that estimate 8,760 hourly operations costs and emissions. To date, the Company has stated it is only able to provide monthly data. Staff continues to work with the Company to see if there are ways to access more granular emissions and cost information. Staff would like Idaho Power to describe how it can improve both the accuracy of its emissions forecast and the consistency of its emissions forecast with the Company's statements about its own emissions goals.

Further, the Company's emissions forecast is somewhat inaccurate since it does not include emissions from market purchases. Staff finds that the inclusion of an emissions estimate for market purchases consistent with the BPA emissions rate for unspecified market power would improve the emissions forecast and make it more comparable to that of other utilities in the region that report emissions consistent with HB 2021. In a meeting with Idaho Power on June 16, 2022, the Company said it could estimate an even more accurate forecast of future emissions from market purchases than using the BPA's unspecified market mix. Staff would like to see both estimates for comparison.

Staff Request for Company Reply Comments 34: Provide the LOLE for the 100% Clean by 2035 portfolio.

Staff Request for Company Reply Comments 35: Provide an updated emissions forecast for planning conditions that includes emissions from market purchases, one with the standard BPA unspecified mix method and another with Idaho Power's most reasonable estimate of the future emissions intensity of market purchases.

Staff Request for Company Reply Comments 36: Provide an emissions forecast for 2021 using the 2021 IRP's conditions that reflect what was observed that year, such as low hydro conditions.

Communicating the Company's Clean Energy Goal

Staff encourages the Company to make its external messaging on emissions consistent with Idaho Power's actual resource planning. The Company claims to have a goal to provide 100 percent clean energy by 2045, yet the Company's preferred portfolio is not expected reach this goal by 2045, and it is relatively far from doing so. The preferred portfolio reduces emissions only 41 percent from 2021 to 2040.

Staff Request for Company Reply Comments 37: Explain what probability the Company expects to meet its goal of reaching 100 percent clean energy by 2045.

Conclusion

This concludes Staff's opening comments for Idaho Power's 2021 IRP. We welcome several improvements in the Company's analysis since the 2019 IRP. These comments are composed as constructive criticism to help improve IPC's resource planning further.

Staff has one recommendation, that Idaho Power make a presentation to the Commission on the impact of Covid on load at the August 18, 2022 workshop, and Staff has thirty-seven requests for additional information in the Company's reply comments:

1. Describe where Idaho Power's load forecast belongs within a range of load forecast assumptions.
2. Explain how the problem of Autocorrelation was resolved in Idaho Power's regression model for residential customers.
3. Explain why the data for the residential regression model only goes back to 2011 and why the same reasoning in the Company's reply does not apply to the regression models with longer time periods of historical data.
4. Explain how the future values of the independent variables in Idaho Power's regression models are derived.
5. Explain the specific basis for each large industrial customer's growth in the additional firm load customer class.
6. Explain how Idaho power's load forecast avoids extrapolating the growth rate of a recent economic recovery for the entire 20-year planning horizon.
7. Provide the observed nameplate capacity and ELCC of the Company's DR programs in the current peak season of 2022.
8. Provide the characteristics of DR considered in the calculations of DR nameplate capacity and ELCC, the degree to which each characteristic impacts the capacity total and provide the basis for the Company's decision to assign a specific value for each characteristic.
9. Explain whether the varied ELCC of different tranches of potential DR is an outcome of the IRP modeling exercise or based on exogenous characteristics assigned to the 20 MW increments of new DR. If the varied ELCC is an outcome of the IRP modeling exercise, Staff requests the Company confirm whether Idaho Power has observed a similar

outcome with other resources. For example, is the ELCC of a storage resource varied, declining in a stair-step fashion? If the varied ELCC is based on exogenous characteristics assigned to the 20 MW increments of DR, Staff requests IPC list those characteristics, the value that each characteristic impacts ELCC, and provide the basis for the Company's decision to assign the value given to each characteristic.

10. Explain why the size of a new DR block was increased 400 percent from 5 MW in the last IRP.
11. Explain how the hours when DR was given a forced outage rate less than 100 percent were chosen.
12. Compare the 2021 IRP's Mid-C forecast under low hydro conditions in 2021 with observed 2021 prices.
13. Describe the basis for the 2021 IRP's forecast of WECC resources and their associated availability.
14. Graph the 2021 IRP's wholesale price forecasts for Mid-C and Palo Verde with the latest forward price curves of these markets and explain how and why Idaho Power's Aurora modeling is more reasonable than observed market prices.
15. Explain why Idaho Power's method of estimating the capital cost of a combined cycle combustion turbine is more reasonable that citing contemporary research from either NREL or Lazard as the Company does for other resources.
16. Explain why only a 1:1 ratio was used for storage sited with solar.
17. Provide the capital costs from battery storage bids Idaho Power has received in its current RFPs.
18. Describe the probability Idaho Power's ownership share of B2H will increase again.
19. Describe the assumptions behind the projected revenue estimates from BPA's use of B2H.
20. Describe how necessary each asset swap and upgrade mentioned in the 2021 IRP's Appendix D pages 6 – 9 is to the engineering of B2H.
21. Itemize the cost of each asset swap and upgrade mentioned in the 2021 IRP's Appendix D pages 6 – 9.
22. Explain why Idaho Power has not sought external funding for B2H.
23. List transmission projects outside IPC's balancing area that may provide new opportunities for firm transmission from market hubs to the Company's customers, most notably Greenlink.
24. Explain how costs have been levelized into an annual number.
25. Explain how the 20-year constraint on costs improves Idaho Power's resource planning compared to including the full net present value of the lifecycle cost of each investment made during the 20-year planning horizon.

26. Comment on whether assuming zero growth in QFs beyond signed contracts in the first four years and adding a reasonable forecast of future QF resources starting in the fifth year of the planning horizon adequately balances near-term risk with longer-term planning accuracy.
27. Explain how the limitation on resource retirement selection improves Idaho Power's resource planning.
28. Describe the decommissioning costs Idaho Power is seeing in bids for the Company's current RFPs.
29. Describe the factors that are making the construction of portfolios that meet Idaho Power's reliability standard a challenge.
30. Explain how Idaho Power plans to avoid a loss of load in 2037 with IPC's preferred portfolio and how the expected cost of this solution differs from the capital cost of a SCCT plant.
31. Describe in detail the climate policy risks for which the Company plans and any details regarding the nature of its policy risk planning, including but not limited to those regarding modifications to accounting and public company reporting requirement.
32. Describe how market conditions led to a recent increase in emission intensity.
33. Explain how Idaho Power intends to address emission intensity from low water supply and market conditions.
34. Provide the LOLE for the 100% Clean by 2035 portfolio.
35. Provide an updated emissions forecast for planning conditions that includes emissions from market purchases, one with the standard BPA unspecified mix method and another with Idaho Power's most reasonable estimate of the future emissions intensity of market purchases.
36. Provide an emissions forecast for 2021 using the 2021 IRP's conditions that reflect what was observed that year, such as low hydro conditions.
37. Explain what probability the Company expects to meet its goal of reaching 100 percent clean energy by 2045.

Dated at Salem, Oregon, this 7th of July, 2022.

Eric Shierman

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Eric Shierman

Senior Utility Analyst

Energy Resources and Planning Division

Appendix A

Discovery

Topic or Keyword: **Transmission**

STAFF'S INFORMATION REQUEST NO. 1:

Has the Company applied for any federal guarantees, funding, grants, or other monies or cost share to apply to any transmission projects at issue in the IRP? If so:

a. For which projects has Idaho Power applied for grants or funding?

b. What were the grant amounts Idaho Power applied for?

c. What funds or other support has the Company been approved to receive?

d. Please provide any grant or federal funding applications, and a narrative indicating the status of the application.

e. Please provide any responses, including acceptances or rejections, from federal entities for federal funding.

f. If the Company has not applied for any potential federal funding, please explain why not. If not, please identify any barriers or obstacles encountered in applying.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S INFORMATION REQUEST NO. 1

No.

a. N/A

b. N/A

c. N/A

d. N/A

e. N/A

f. The Company has not identified any opportunities that are applicable to the B2H, or Gateway West projects. The Company will continue to monitor for potential cost-saving opportunities.

Topic or Keyword: Demand Response

STAFF'S DATA REQUEST NO. 94:

Please provide current enrollment data for the A/C Cool Credit program, the Flex Peak Program, and the Irrigation Peak Rewards Program. Please provide the current number of participants enrolled in each program, including any relevant differentiating characteristics such as participant type, and the current nameplate capacity of each program.

a. If enrollment is still ongoing, please provide the date that enrollment will close for each program.
b. Please provide the number of participants enrolled in each program, and the resulting nameplate capacity of each program, for the same date in 2021.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 94:

a. Marketing and enrollment in the A/C Cool Credit program is ongoing with no plans to close. Enrollment is expected to close by June 14th each spring for both the Flex Peak and Irrigation Peak Rewards programs.

b. See table below:

	June 15, 2021	June 15, 2021	June 3, 2022	June 3, 2022
Program	Enrolled Customers	Estimated Maximum Program Capacity (MW) (Generation Level)	Enrolled Customers	Estimated Maximum Program Capacity (MW) (Generation Level)
A/C Cool Credit	21,106	29.5	19,118	26.8
Flex Peak	139	36	146	29.5
Irrigation Peak Rewards	2,235	319.5	2,040	266.6