BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 84

In the Matter of IDAHO POWER COMPANY, 2023 Integrated Resource Plan.	STAFF OPENING COMMENTS

Contents

Executive Summary 3

Section 1. Load Forecast 8

Section 2. Wind and solar resources 14

Section 3. Coal to Gas Conversion 17

Section 4. WRAP Benefits Modeling 19

Section 5. Wind Qualifying Facilities (QFs) 21

Section 6. Transmission and Market Access 23

Section 7. Wholesale Electricity Prices 25

Section 8. Long-term Storage Pilot 28

Section 9. New Resource: Hydrogen 29

Section 10. Distribution-Connected Storage 30

Section 11. Energy Efficiency (EE) 32

Section 12. Demand Response 35

Conclusion 39

Executive Summary

Context

This document contains Staff's initial comments regarding Idaho Power Company's (IPC, Idaho Power, or the Company) 2023 Integrated Resource Plan (IRP) filed on September 29, 2023. 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 April 25, 2024, and a Staff Report on June 18, 2024. 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.

Resource planning in Idaho Power's 2023 IRP is primarily driven by substantial load growth forecasted for the 20-year planning period. Idaho Power embarks on a variety of new initiatives to expand on supply-side resources and some innovative approaches to utility planning, such as early participation in the Western Regional Adequacy Program (WRAP) as leverage for peak capacity planning. The Company is expanding its transmission network to enable the connection of renewable generation and access to diverse wholesale electricity markets. It is also planning a long-duration storage pilot and new clean energy resources, such as hydrogen. On demand-side management, the Company continues its activities in distribution-connected storage and cost-effective energy efficiency. In addition, it is planning for additional 160 MW of Demand Response (DR) based on a third-party potential study.

Staff's Review

This Executive Summary provides brief outlines of Staff's areas of focus and requests by topic, with references to more detailed analysis in later sections.

- **Load Forecast – Section 1:** Idaho Power used a means of forecasting load in this IRP that is similar to what the Company used for the 2021 IRP. The observed forecasting performance does not appear to warrant the assumption of a 70th percentile as the planning condition for weather variables. In addition, the overestimation of Energy Service Agreement (ESA) customer load raises questions about the reasonableness of relying on these large industrial customers' forecasts. Staff is seeking explanations from the Company on the load forecasting methodologies and the assumptions used for load forecasts of ESA customers.
- **Wind and Solar Resources – Section 2:** The 2023 IRP doubles both the wind and solar capacity envisioned by the 2021 IRP. Due to the expected increasing competition for renewable resources by other utilities, the Company should provide a roadmap of RFPs for procuring the volumes of resources identified in the IRP modeling. Additionally, despite the significant increase in variable energy resources and no notable increase in the capacity of new fast-ramping dispatchable resources since the 2021 IRP, the Company does not articulate or demonstrate the extent to which variable energy resources might impact system reliability. The Company should identify the means and costs of any additional resources required in the long term to provide the ancillary services needed to ensure system resilience. Failure to adequately account for the risks of procurement and integration needs of a high volume of renewable resources may hide extra costs of the preferred portfolio.
- **Coal to Gas Conversion – Section 3:** Idaho Power's 2023 IRP preferred portfolio includes more coal to gas conversions compared to its 2021 IRP. Staff seeks to better understand the need for these conversions, especially for the North Valmy coal plant, given the Company is capacity long throughout the planning period even without the Valmy conversions. Nonetheless, the Company

should consider whether targeted demand side measures could be a cheaper alternative to these conversions. Staff seeks to understand the Company's contingency plans around these conversions. Further, Staff is evaluating the implications for customer rates of Idaho Power's participation in Valmy 1 conversion since the Company exited the plant in 2019.

- **WRAP Benefits Modeling – Section 4:** Staff is generally comfortable with the Company's attempt to model the benefits of the WRAP. While refinements may be feasible in the future, the Company's assumption that it can leverage the WRAP operational program only once per year during the time of greatest need appears to match the intent of WRAP and the Western Power Pool's (WPP) messaging about how the operational program should be used. Staff also notes that in a future IRP, the Company will be required to submit certain WRAP-related information should rules in Docket No. AR 660 be adopted.

- **Wind Qualifying Facilities (QFs) – Section 5:** The Company decided in the 2023 IRP to remain consistent with the base planning assumptions of the 2021 IRP that wind QFs would not renew their contracts with Idaho Power upon expiry of those contracts. Instead, the Company developed a scenario that includes a forecast of future QF development after the Action Plan window. The Company provided some explanations for its decisions, citing no empirical evidence to support assumptions and emphasized the reliability risk of overestimation of wind QFs in the near term, among other factors. While Staff appreciates the Company's reasoning, it recommends that the Company develop in the next IRP Update a reasonable non-zero estimate to modeling wind QF renewal rates in line with PacifiCorp's work stemming from Order No. 22-178.

- **Transmission and Market Access – Section 6:** Following from the last IRP, IPC continues to describe Boardman to Hemmingway (B2H) as a path to access Mid-Columbia (Mid-C) energy markets to the west to meet summer peak, and now adds Phase 1 of Gateway West (GWW) in the 2023 IRP as a means to connect renewable energy from the east. The Company is also exploring potential participation in SWIP-North, providing access to the Desert Southwest market to serve future winter peak needs. Given the timing of contractual obligations of all these transmission projects, Staff seeks to understand the Company's strategy of initiating transmission projects in order to optimize its capability to connect renewable generation, as well as access multiple wholesale markets.

- **Wholesale Electricity Prices – Section 7:** In the 2023 IRP, the accuracy of the wholesale electricity prices Idaho Power modeled in the planning case appear mixed, which is an improvement over the 2021 IRP. The highest prices the Company modeled in the stochastic risk analysis appear too low to reasonably reflect the risk of being short the market. A low-price bias could result in unreliable capacity expansion modeling results that favor transmission and storage resources.

- **Long-term Storage Pilot – Section 8:** Idaho Power's near-term action plan includes exploring a 5 MW multi-day storage pilot between 2024 and 2028. While Staff welcomes the concept of the pilot project, the level of detail in the 2023 IRP is not sufficient for Staff to assess all aspects of the project and provide any recommendation regarding a request for acknowledgement. Staff seeks clarification on the request for acknowledgement of the IRP action item, and whether the Company is seeking acknowledgement of a specific pilot project.

- **New Resource: Hydrogen – Section 9:** Idaho Power included 340 MW of clean hydrogen in the preferred portfolio in 2038. In response to a directive from the Commission in the 2021 IRP to include a reasonable proxy for green hydrogen as a potential resource, the Company used the assumptions provided by the National Renewable Energy Laboratory and took into account current federal legislation for cost offsets when modeling the proxy resource. While Staff is satisfied with IPC's implementation of the Commission directive, Staff encourages IPC to elaborate on considering the option of hydrogen blending in its existing natural gas plants.

- **Distribution-Connected Storage – Section 10:** IPC plans for 80 MW of additional distribution-connected storage, adding to the 11 MW of distribution-connected storage projects installed in the fall of 2023. Staff seeks more understanding on how this type of storage is modeled, especially in relation to the Company's Distribution System Plan. Staff also seeks to understand the lessons learned from the Company's experience with installing 11 MW in four distribution-connected storage projects, scheduled to come online in the first half of 2024. In one of these installations, Staff is interested in the safety aspects following a fire event at Melba substation in October 2023.

- **Energy Efficiency (EE) – Section 11:** The 2023 IRP lost 80 MW of cumulative EE compared to the 2021 IRP. Staff is concerned that the company's bundling of EE measures in the 2023 IRP omitted cost-effective EE during optimization. Additionally, the lack of transparency into the EE measures adopted by ESA customers risks that avoidable costs could be placed onto Idaho Power's remaining customer classes.

- **Demand Response – Section 12:** The peak summer capacity of Idaho Power's existing DR programs – 320 MW – was included in the 2023 IRP model. Though there are no DR-related items in the near-term Action Plan, the model selects an additional 160 MW of DR later in the planning period. The Company used an Idaho Power-specific potential study to inform the modeling of additional DR, which addressed many of Staff's concerns from the 2021 IRP.

Staff includes several requests for additional information for the Company to address in its reply comments (Staff Recommendations). Staff will set forth these recommendations within the sections reviewing the discussed topics and are listed at the end of this document.

Action Plan

Idaho Power's 2023 IRP includes eight near-term (2024-2028) Action Items for which the Company is seeking acknowledgement, as shown in Figure 1.

Figure 1: Action Plan for Regulatory Acknowledgement, reproduced from Table 1.3 in Idaho Power's 2023 IRP

Action Number	Action Description	Year of Completion
1	Continue exploring potential participation in the SWIP-N project	2023–2024
2	Explore a 5 MW long-duration storage pilot project	2024–2028
3	Install cost effective distribution-connected storage	2025–2028
4	Bring B2H online	Summer 2026
5	Convert Valmy units 1 and 2 from coal to natural gas	Summer 2026
6	If economic, acquire up to 1,425 MW of combined wind and solar, or other economic resources	2026–2028
7	Include 14 MW of capacity associated with WRAP	2027
8	Bring the first phase of GWW online (Midpoint–Hemingway #2 500-kV line, Midpoint–Cedar Hill 500-kV line, and Mayfield substation)	2028

As mentioned above, IPC has indicated it intends to file its next IRP in June 2025. As such, Staff will focus on action items that likely need the Commission's input before the next IRP filing, and those which Staff believes will benefit from additional time afforded for analysis, discussion, and stakeholder feedback, namely:

- Explore 5 MW long-duration storage pilot from 2025 to 2028 – see Section 8.
- Install cost effective distribution-connected storage from 2025 to 2028 – see Section 10.
- Acquire 1,425 MW wind and solar, in 2026 through 2028 – see Section 2.
- Convert Valmy units 1 and 2 from coal to natural gas by summer 2026 – see Section 3.

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.

Staff has found no substantive compliance concerns with IPC's 2023 IRP at this time. However, Staff and stakeholders again received an Idaho Power Draft IRP for review with an unreasonably short timeframe from which to develop and share substantive comments. Idaho Power submitted its Draft IRP and provided stakeholder and Staff with five business days to provide comments and ten business days prior to posting the final IRP. While this meets the letter of IRP guideline 2.c, it does not reasonably align with the historical interpretation and use of the guideline and OAR 860-027-0400(2), thus deviating from the intended purpose of the guideline and rule. Ten business days is an inadequate length of time for stakeholders to conduct a review, craft a response, and for the Company to be responsive to feedback. Further, the IRP advisory committee meetings are neither a meaningful substitute for, nor meet the Oregon rules regarding the submission a Draft IRP. This follows the pattern from LC 74 and LC 78.[1]

Staff understands that this is the result of IPC striving to meet filing deadlines with the Idaho Public Utility Commission (IPUC) and has worked with the Company and stakeholders in this IRP to develop a schedule intended to support future alignment of filing requirements across the two commissions. However, Staff appreciated the approach taken by PGE and PAC of proactively requesting a partial waiver of OAR 860-027-0400(2) regarding Draft IRPs. We suggest Idaho Power consider that approach in future IRPs, rather than giving parties only five business days to review and give comments.

Compliance with Past Orders

The Commission's Order acknowledging the 2021 IRP included several action items proposed in Idaho Power's 2021 Action Plan, as well as additional Staff recommendations, as discussed at the December 6, 2022, Special Public Meeting.[2] Staff confirms that Idaho Power has completed all actions, albeit Staff is still evaluating the intended outcome when implementing one recommendation:

- Staff Recommendation 8: Idaho Power was directed to work with stakeholders and demonstrate the impact of extremely high wholesale electricity prices and decreased liquidity on resource

[1] *See* Docket No. LC 74, Staff email to Idaho Power regarding draft IRP, December 27, 2021.
[2] *See* Docket No. LC 78, OPUC Order No. 23-004, January 13, 2023, Appendix A, pp. 39-41.

selection in the 2023 IRP. In addition, Idaho Power was directed to provide insight into volatility and need. Comparing data provided in the 2023 IRP with actual market data, Staff found that the high-end prices the Company modeled are not "extremely" higher than observed prices.

Staff continues to investigate the concerns about whether Recommendation 8 was implemented as required–see Section 7.

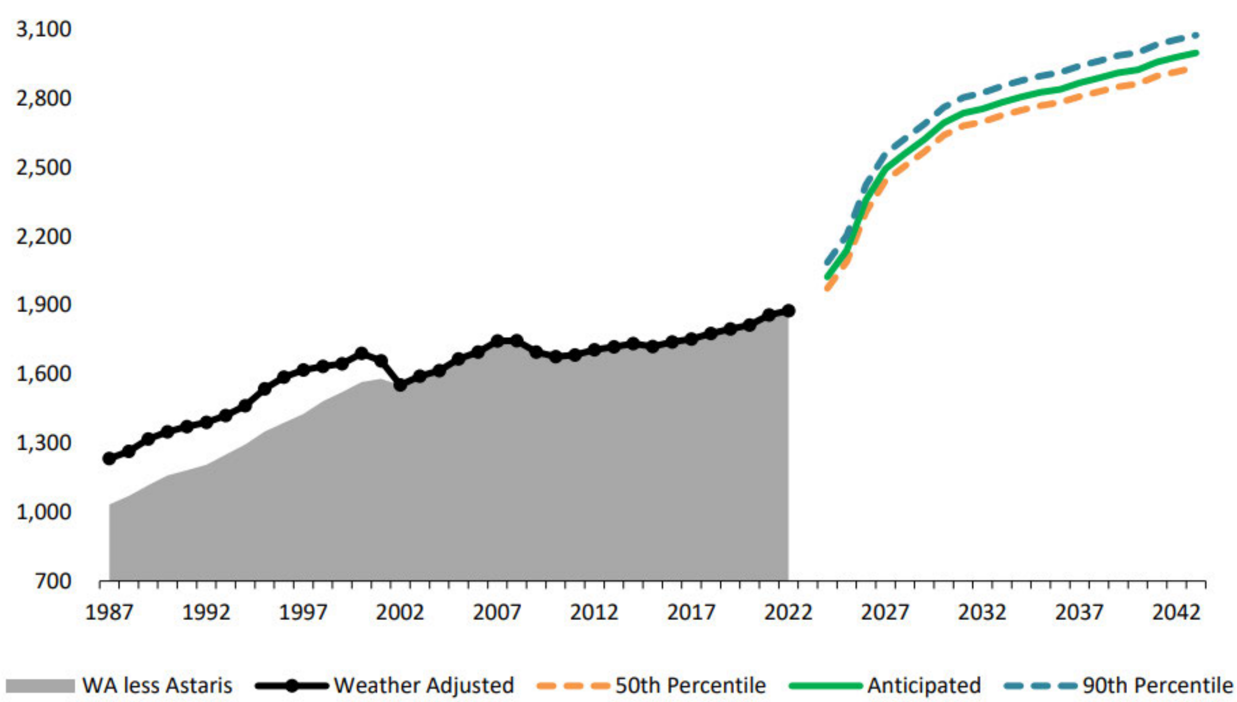
Section 1. Load Forecast

Idaho Power used a similar means of forecasting load in this IRP as the Company used for the 2021 IRP. The observed forecasting performance does not appear to warrant the assumption of a 70th percentile of weather impacts as the planning condition. The overestimation of Energy Service Agreement (ESA) customer load raises questions about the reasonableness of relying on these large industrial customers' forecasts.

Summary of Load Forecast

IPC's forecasted load anticipates growth. The Company forecasts an average annual 2.1 percent growth rate of energy demand during the 20-year planning period.[3]

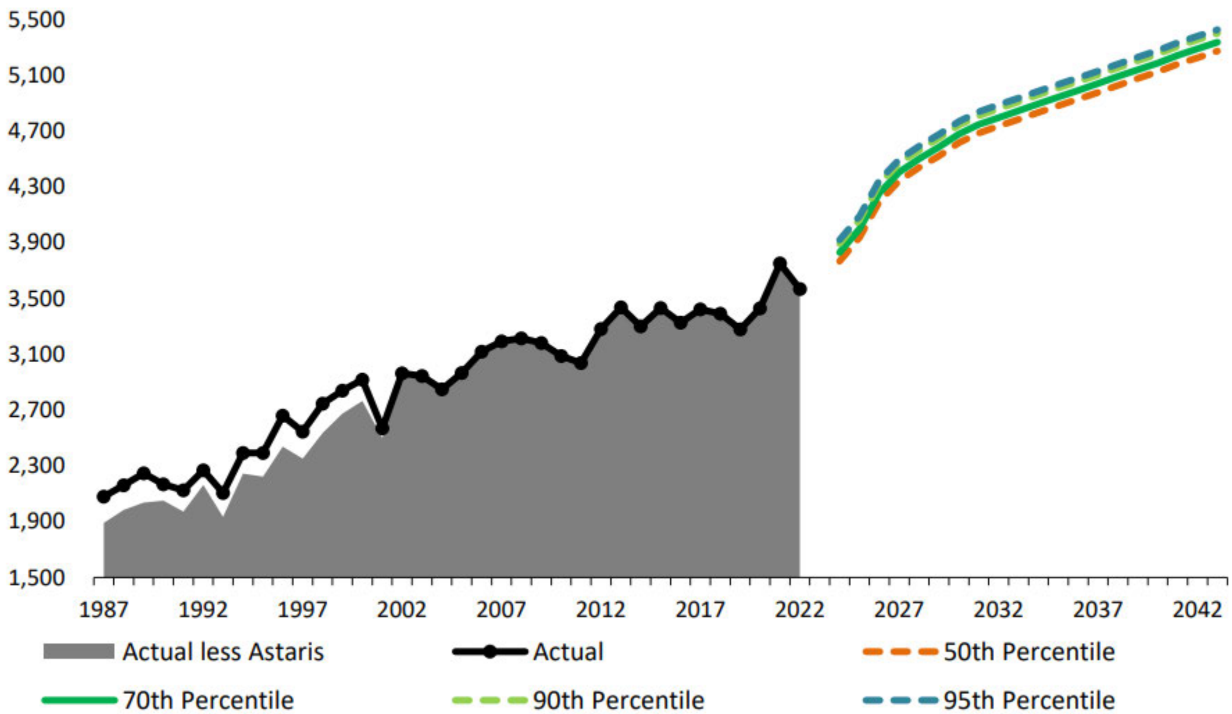
Figure 2: Average Energy Load, Figure 8.1 in the 2023 IRP



Idaho Power forecasts an average 1.8 percent growth rate in peak hour demand.

[3] See Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p 102.

Figure 3: Peak Hour Load, Figure 8.2 in the 2023 IRP



For both energy and peak load, the Company expects a higher growth rate through 2030 than from 2031 to 2043.[4]

Summary of the Company's Load Forecasting Methodology

Idaho Power uses three means of forecasting the load inputs to the Aurora model. First, the Company estimates energy load. Second, the forecasted energy load becomes an independent variable in a peak load forecast for all twelve months of the year. Third, the level of MWh that is forecasted for each hour during the twenty-year planning horizon is derived from a machine learning technique that maps the monthly peak load forecast into a distribution of hourly energy consumption for every hour in that month.

Idaho Power's forecast of energy load is derived from nine regression models. They are:

1. Residential Sales,
2. Residential Customer,
3. Industrial – Manufacturing,
4. Industrial – Services,
5. Commercial – Manufacturing,
6. Commercial – Services,
7. Large Commercial – Manufacturing,
8. Large Commercial – Services, and
9. Irrigation.

[4] See Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p 105.

One model represents a change from the 2021 IRP load forecast, where small commercial load was estimated in one model. Instead, in the 2023 IRP, these nonresidential customers with less than 20 kW of demand capacity are now broken down by manufacturing and services as well. This provides more granularity.

Idaho Power's forecast of energy load also comes directly from large customers. These ESA customers are not included in the industrial regression models. Instead, these customers provide Idaho Power with forecasts that are added to the energy demand from regression analysis.

Idaho Power's forecast of monthly peak demand is derived from twelve regression models, one for each month. In addition to system energy demand as an independent variable, these models also specify the peak average temperature. Some months contain other variables, such as the price of electricity. The Company uses dummy variables for specific times where the model has high error and, in the summer months, a trend variable.

Idaho Power's hourly forecast uses machine learning to distribute load into the unit of time modeled in Aurora. The Company used this technique for the first time in the 2021 IRP. When Staff learned the limited scope of the application of this artificial intelligence, it did not investigate further.[5] In this IRP, Staff would like to increase its understanding of how this final stage of the load forecast works with regard to the quantity of energy. The forecast of load for each hour of the month is derived from the peak demand, but some assumed energy demand would likely need to be distributed from the peak hour. In Appendix A of the 2023 IRP, Idaho Power has a single sentence apparently alluding to this: "To maintain conformance with the historical methodology, the company applies a calibration algorithm to the hourly forecast to both the monthly peak and energy sales within a month as produced by the legacy linear forms the company operates."[6]

Staff Analysis

Staff observes similar modeling issues in this IRP with those that were present in the Company's 2021 IRP. In Staff's review of Idaho Power's 2021 IRP, Staff identified several modeling choices that did not reflect best practices in the use of regression analysis. Those issues were serial correlation in the residential use per customer model, the use of dummy variables without a prior hypothesis to test, having the wrong sign on dummy variables, and a unit root in the industrial services model.[7] Staff was not certain the problems it saw with Idaho Power's 2021 IRP load forecast should be expected to bias the forecast. Staff also found the impact of the regression models to be less impactful, at the margin, to Idaho Power's sudden projection of a near-term capacity deficit relative to the forecast of ESA customers, which Staff found to be insufficiently transparent.[8]

Those modeling anomalies remain present in this IRP and Staff observes another: omitting retail price as an independent variable. Only two of Idaho Power's seven nonresidential energy models include retail price as an independent variable, the two small commercial models. The two industrial models incorporate industrial prices into a ratio with commercial rates, which may not fully capture the elasticity

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[5] *See* Docket No. LC 78, Staff Report for the November 29, 2022 Special Public Meeting (Item No. 1), October 28, 2022, p. 31.

[6] *See* Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, Appendix A, p. 43.

[7] *See* Docket No. LC 78, OPUC Staff, Staff Report, October 28, 2022, pp. 29-33.

[8] *See* Docket No. LC 78, OPUC Staff, Staff Report, October 28, 2022, p. 32.

of demand to increases in industrial rates. Three models, irrigation and the two large commercial models, omit rates entirely. The omission of rates in the large commercial models represents a methodological change from the 2021 IRP where the large commercial manufacturing model used commercial rates and the large commercial services model use a ratio of commercial and industrial rates.

Because Idaho Power has filed a general rate case, this IRP has an opportunity to more closely assess the reasonableness of the forecast of retail prices used to forecast load. The Company should compare the forecast of rates for 2025 with the increase Idaho Power actually seeks for that year.

Comparing the performance of the 2021 IRP load forecast with actual load data, Staff observes relative accuracy, as shown in Figure 4. The Company has consistently overestimated energy demand from ESA customers; however, this was, on average within five percent.

In contrast to the ESA customers' load forecasts, Idaho Power has mostly underestimated energy demand in the regression models.[9]

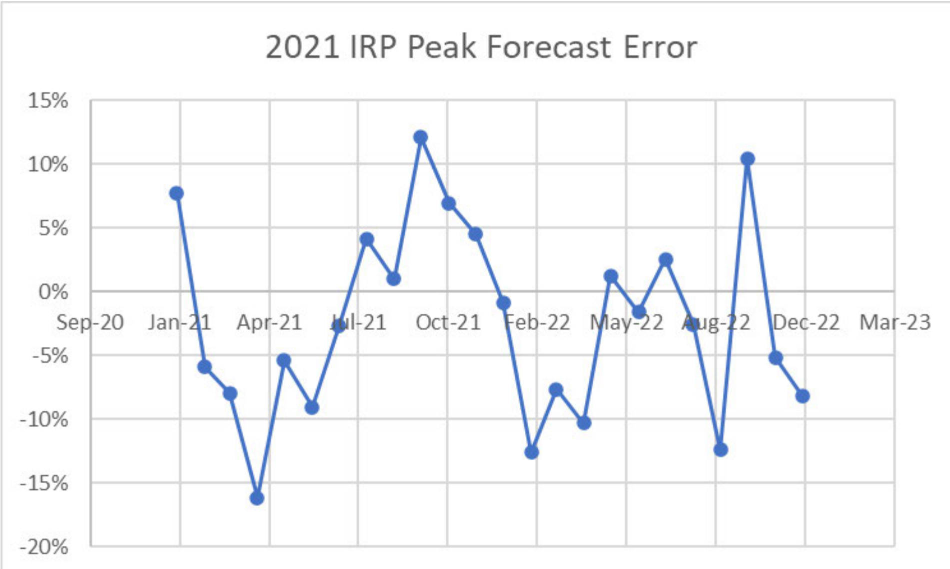
Figure 4: Energy Forecasts from regression models the 2021 IRP

2021 IRP Sales (thousands of MWh)								
Class	**Residential**		**Commercial**		**Irrigation**		**Industrial**	
Year	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**
Projected Billed Sales	5,636	5,710	4,154	4,218	1,970	1,965	2,580	2,623
Actual Non-Weather Adjusted Sales	5,658	6,022	4,166	4,297	2,126	1,950	2,559	2,560
Actual Weather Adjusted Sales	5,622	5,720	4,128	4,216	1,938	1,910	2,559	2,560

And the Company has been underestimating June peak load by an average of approximately five percent. As shown in Figure 5, the 2021 IRP's forecast of peak load appears to be mixed in both directions for the rest of the year.[10]

[9] *See* Docket No. LC 84, Idaho Power, IPC Response to OPUC IR No. 33, December 11, 2023, p. 1.
[10] *See* Docket No. LC 84, Idaho Power, IPC supplemental response to OPUC IR No. 33, January 8, 2024, Attachment 1.

Figure 5: Peak Forecasts from the 2021 IRP



This IRP's method of forecasting load may be sufficiently similar to the prior IRP's load forecast for its performance to inform Staff's assessment of the reasonableness the 2023 IRP's load forecast. Staff does not observe a major net bias in either direction. If the average forecasting error stays around five percent, Staff does not see a material problem or have an expectation for greater accuracy.

Given the prior IRP's load forecasting performance, Staff has three specific concerns with the 2023 IRP's load forecast. First, Idaho Power has adjusted the load forecast from a 50th percentile central tendency of weather data to a 70th percentile by inputting weather-related-data in future years using more adverse weather conditions. This has the impact of increasing the load forecast and could be justified if the Company had historically seen an underestimation in forecast and actual load of that magnitude and was seeking a way to true up its forecasting error. However, the need for a 70th percentile adjustment does not appear justified, because Staff does not find evidence that Idaho Power's load is otherwise reasonably expected to be underestimated by that magnitude. Further, Idaho Power's reason for selecting the 70th percentile is to produce "similar reliability results when compared to the combination of the 50th percentile load forecast and a 0.05 event-days per year Loss of Load Expectation (LOLE) threshold".[11] This has the effect of returning the LOLE to a value that was rejected by both OPUC and IPUC in the prior IRP. Adjusting the load forecast to mimic the resource selection of a 0.05 LOLE is not a valid reason to alter weather data.

While the reason for using the 70th percentile as the anticipated case is not adequately predicated, Staff has remaining questions about how this adjustment is performed. For example, Table 8 in the IRP's Appendix A depicts the anticipated 70th percentile case for commercial load growth.[12] In a meeting with Staff on January 18, 2024, the Company explained that the 70th percentile is derived from weather-related variables. None of Idaho Power's four commercial regression models have a weather-related variable. So, how this forecast was adjusted up from the 50th percentile remains unclear to Staff.

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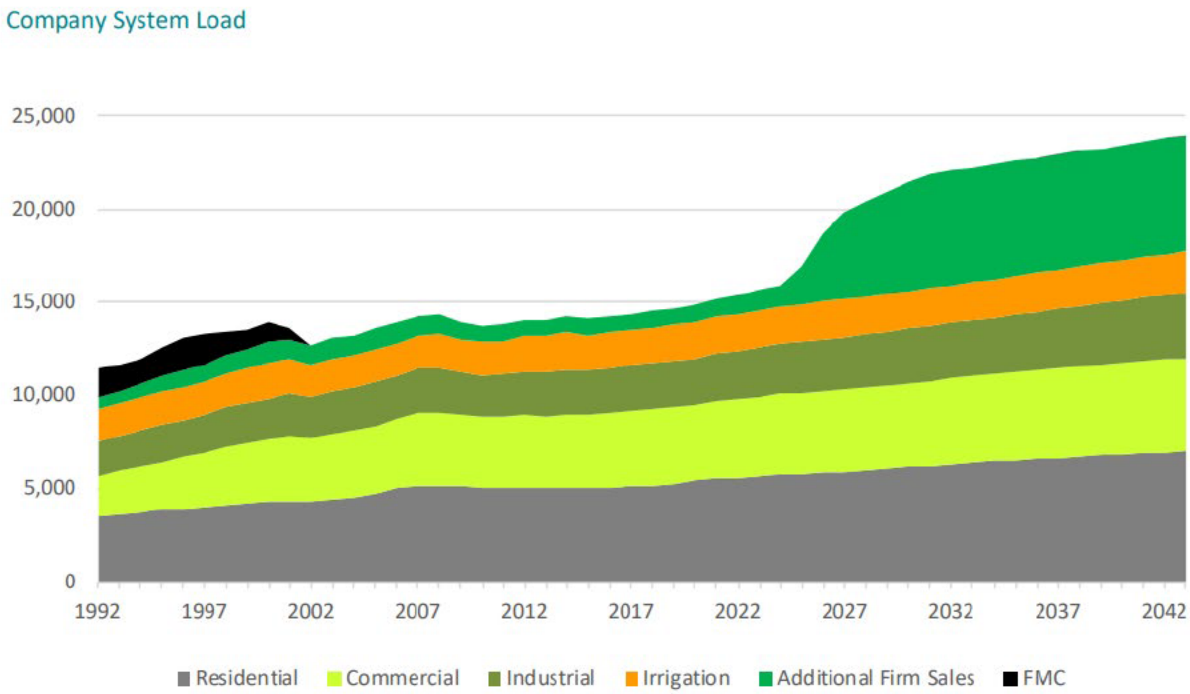
[11] *See* Docket No. LC 84, IPC Response to OPUC IR No. 89, January 9, 2024, p. 1.

[12] *See* Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, Appendix A, p. 24.

Staff's second concern is that, though the regression modeling from the last IRP has proven to be relatively accurate, the primary driver of the Company's near-term energy demand comes from outside those models, the forecasts from ESA customers, as shown in Figure 6.

Figure 6: Composition of system energy load in thousands of MWh, Figure 3 from Idaho Power's 2021 IRP



The 2021 IRP has mostly overestimated load from ESA customers.[13]

Figure 7: Energy Forecasts from ESA customers in the 2021 IRP.

[BEGIN CONFIDENTIAL]

2021 IRP Sales (thousands of MWh)						
Specials	**Micron**		**Simplot Fertilizer**		**INL**	
Year	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**
Projected Billed Sales	[redacted]					
Non-Weather Adjusted Sales						

[END CONFIDENTIAL]

That error, though modest in magnitude, highlights the importance of carefully weighing the reasonableness of these customers' forecasts. Idaho Power takes these customer's own forecasts at face value, believing that these customers are incented to avoid overestimation. Given a track record of overestimation, Idaho Power should explore steps to qualify these customer forecasts. The relative

[13] See Docket No. LC 84, Idaho Power, Response to OPUC IR No. 34, December 12, 2023, p. 1.

consistency of the overestimation raises questions about the incentives for these customers to forecast load accurately, such as what costs these customers now face for their overestimation.

Staff's third concern is Staff's observation of relatively large changes in methodology that Staff sees each time Idaho Power performs a load forecast in recent years. For example, this IRP's regression models use different independent variables than the 2021 IRP specified. Staff has observed similar changes in the load forecast used in UM 2255. This may be an indication of data mining, the *post hoc* selection variables with the highest correlation. This is not a best practice, because it risks chasing random variation. Instead, Idaho Power should filter the selection of variables with an *a priori* theoretical justification for inclusion. The regression model then tests posited hypotheses rather than optimize for highest correlation to avoid the use of spurious statistical relationships and omitting important variables that in one moment in time may not provide the highest fit but whose absence produce a bias.

Recommendation 1: Staff recommends, in Reply Comments, Idaho Power describe how monthly energy demand is derived as an input to the Company's hourly load forecast.

Recommendation 2: Staff recommends, in Reply Comments, the Company explain why retail price is not used as an independent variable for all nonresidential regression models.

Recommendation 3: Staff recommends, in Reply Comments, the Company compare the inputted value of rates for 2025 for the load forecast with the rates Idaho Power seeks in Docket No. UE 426.

Recommendation 4: Staff recommends, in Reply Comments, the Company explain how the anticipated case of a 70th percentile was calculated relative to the 50th percentile.

Recommendation 5: Staff recommends, in Reply Comments, the Company describe the costs borne by ESA customers that overestimated their load in the 2021 IRP.

Section 2. Wind and solar resources

The 2023 IRP doubles both the wind and solar capacity envisioned by the 2021 IRP, but does not discuss the extent to which variable energy resources might impact system reliability or any additional resources required to ensure system resilience. Failure to adequately account for the risks of procurement and integration needs of high volume of renewable resources may hide extra costs to the preferred portfolio.

The 2023 IRP includes 1,800 MW of wind resources to the year 2043, a capacity that is more than double the 2021 IRP additional wind capacity of 700 MW. Similarly, solar resources more than doubled in capacity from 1,405 MW in the 2021 IRP to 3,325 MW in the 2023 IRP, by a difference of 1,920 MW.

Staff would like to know the drivers for this increase in capacity need. Staff is interested in other drivers, such as transmission decisions, in addition to the increased load forecast in the 2023 IRP.

Staff also wants to understand whether there were limits to the amount of solar and wind the model could select. In responding to OPUC IR No. 56 regarding the potential of wind and solar resources, the Company revealed that there are capacity caps on both wind and solar that are generally set to limit run time by the model or are based on reasonable maximums for the availability of the particular resource. For example, wind resources from Idaho are limited to 800 MW, which is the capacity of the transmission line from Wyoming to Idaho, while the limit for Idaho wind is set to a cap of 1800 MW.

Of the 800 MW of wind and 925 MW of solar planned in the near term (2024-2028) in the preferred portfolio,[14] the Company stated that there were no contracted wind projects, 300 MW of contracted solar to come online in 2024-2025, and 525 MW of solar assumed to be contracted for 2027-2028 via the Clean Energy Your Way (CEYW) program.[15] Idaho Power has already procured 300 MW of solar in 2024-2025 and is currently seeking in its 2026 All-Source RFP up to 1,100 MW of variable energy resources from projects achieving a commercial operation date of no later than either June 1, 2026 or June 1, 2027.[16] This means that of the total 1,725 MW of wind and solar capacity required by the IRP in the near term, the combined total of 1,400 MW (300 MW of contracted solar plus the maximum of 1,100 MW of renewables to be procured through the 2026 All-Source RFP for 2026-2027) would mostly cover the need leaving a balance of 325 MW to be procured for 2028. In relation to the near-term Action Plan item for IPC to acquire up to 1,425 MW of combined wind and solar, or other economic resources, Staff would like the Company to clarify how this shortfall would be met, either through the 2026 RFP, future RFPs, or the procurement plan for the CEWY program.

While the near-term needs are expected to be fulfilled, Staff is concerned about the alignment of the procurement process with the projected resources in the IRP for the remaining years in the long term. Given the risk of other utilities competing for the same resources to meet increasing commitments to emission standards, Staff would like the Company to provide a timeline of RFPs that would align with the time frames for delivering the quantities projected in the preferred portfolio for the 20-year planning period.

VERs and System Reliability

For the purpose of having adequate resources to meet demand, system reliability in general refers to the ability of the system to serve the load requirements under varying system conditions.[17] VERs affect system reliability by their intermittent source of energy. Staff would like to understand how IPC plans to maintain reliability of system operations, given the near-term volumes of variable energy resource selected as part of the preferred portfolio. In the 2023 IRP, the Company provided the results of the VER study which shows the regulation reserves required by firm generation to balance the variability of both load and generation.[18] In Table 1, the results of the study shows the amount of set-aside capacity of ramping up and down regulation reserves each month as percentage of load, wind production and solar production. It is evident from the results of the study that in every month of the year requirements for balancing variable generation far outweigh requirements for balancing variability in load. In the most severe cases, regulation reserves representing 87 percent of solar generation is required to be online in the month of November.

[14] See Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, Table 1.1, p. 6.

[15] *See* Docket No. LC 84, Idaho Power, IPC Response to OPUC IR No. 58. The 525 MW of solar resources is assumed to be contracted under Idaho Power's Clean Energy Your Way program (see Idaho Power, 2023 IRP, September 29, 2023, pp. 34-35).

[16] *See* Docket No. UM 2255, Cover letter for Idaho Power 2026 All-Source Request for Proposal, p. 2.

[17] According to NERC, the definition of reliability in terms of the basic aspect of adequacy is "the ability of the electricity system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements". See https://www.nerc.com/AboutNERC/Documents/Terms%20AUG13.pdf – accessed on February 5, 2024.

[18] *See* Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, pp. 122-123.

Table 1: Regulation reserve requirements—percentage of hourly load MW, wind MW, and solar MW[19]

	% of Load	% of Load	% of Wind	% of Wind	% of Solar	% of Solar
Month	LoadUp	LoadDn	WindUp	WindDn	SolarUp	SolarDn
1	8.2%	1.7%	19.6%	19.6%	51.9%	57.6%
2	8.3%	1.6%	15.9%	21.2%	32.1%	39.3%
3	8.3%	1.7%	21.4%	22.1%	59.3%	59.3%
4	8.2%	1.7%	20.3%	26.0%	45.9%	50.6%
5	8.2%	1.6%	25.4%	34.5%	45.6%	53.7%
6	8.1%	1.6%	27.4%	21.7%	43.1%	29.3%
7	8.2%	1.4%	19.4%	22.0%	36.0%	24.6%
8	8.2%	1.5%	18.8%	23.8%	42.5%	31.9%
9	8.5%	1.8%	29.9%	29.9%	42.5%	40.5%
10	8.3%	1.6%	21.0%	31.8%	49.2%	51.4%
11	8.4%	1.8%	18.3%	29.2%	87.8%	71.8%
12	8.1%	1.6%	20.5%	39.3%	65.9%	73.3%

Considering that there has not been a notable increase in the capacity of new fast-ramping dispatchable resources since the 2021 IRP, whether in the form of generation or storage, it is not clear how large the amount of regulation reserves will be needed and whether that amount has been sufficiently allowed for in the model. The Company should demonstrate how it plans to provide the additional flexible resources during times of need in case of cloud cover for solar resources or sudden wind change for wind resources. It is envisaged that these flexible resources may be additional generation capacity with fast ramping capabilities, support from WRAP or fast power transfer from and to wholesale markets accessed via transmission lines.

VERs and System Resilience

System Resilience can be defined in its simplest form and for the purpose of the IRP as the ability of the system to withstand and rapidly recover from disruptions.[20] High volumes of VERs impact system resilience by the supply variability and the means by which it is connected to the power system, as an inverter-based resource, limiting its response to major frequency and voltage changes due to major disruptions.

It is also worth noting that towards the end of the planning period, a system dominated by high volume of inverter-based renewable generation and storage asynchronously connected to the grid will have different characteristics from a traditional system dominated by synchronous generation. In order to preserve system resilience, such transition will require an increased need for ancillary services such as system inertia for maintaining frequency within the prescribed standards, system strength (contribution to fault current) for voltage stability, and black start capability. As such, the Company should identify in

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[19] *See* Docket No. LC 84, Idaho Power, 2023 IRP, December 30, 2021, Table 9.1, p. 123.

[20] The US Department of Energy (DOE) defines Resilience as "the ability of a system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions". See *DOE, Transforming the Nation's Electricity Sector: The Second Installment of the QER | January 2017*, p. 4-3.

its long-term planning the impact of the need for more ancillary services, the appropriate resources by which it will provide these services and the cost of those resources.

Recommendation 6: In Reply Comments, Staff requests that IPC describe all the drivers impacting the capacity needs in the 2023 IRP, and the contribution of each driver on the capacity of planned additional renewable resources.

Recommendation 7: In Reply Comments, Staff requests that IPC provide a timeline of planned RFPs to meet the procurement needs of the 2023 IRP, and the procurement plan for the 325 MW nameplate capacity shortfall in the near-term, either through RFPs or the CEYW program.

Recommendation 8: In Reply Comments, Staff requests that IPC share the reliability studies that determine the extra quantities and costs of the planned regulation reserves required to balance the variability of renewable resources throughout the 20-year planning period.

Recommendation 9: In Reply Comments, Staff requests that IPC share information about the means and costs of providing ancillary services needed to preserve system resilience in the face of high penetration of renewable resources towards the end of the planning period.

Section 3. Coal to Gas Conversion

Idaho Power's 2023 IRP preferred portfolio includes more coal to gas conversions compared to its 2021 IRP. Given the Company's annual capacity length projections for alternative portfolios, Staff seeks to understand the need for these conversions, whether targeted demand side measures could be a cheaper alternative, and the Company's contingency plans around these conversions. Further, since the Company exited Valmy 1 in 2019, Staff is evaluating the implications for customer rates of Idaho Power's participation in Valmy 1 conversion.

Idaho Power proposes to convert Valmy 1 and 2 to natural gas fired plants in 2026. Idaho Power's portfolio analysis identifies the conversions as part of the least-cost least-risk portfolio or the Preferred Portfolio. Alternative portfolios depicting variations in exit dates of these plants and availability of transmission resources, like Boardman to Hemingway (B2H) and Gateway West, have higher costs or net present values of revenue requirement (NPVRR) compared to the Preferred Portfolio. This indicates that coal to gas conversions is selected by the optimization model based on economics. While this is reassuring, Staff has the following concerns related to the Valmy conversions: the role of demand side resources; the Company's relatively long capacity position associated with the portfolios under various Valmy conversion scenarios; various uncertainties around the conversions; and customer rate impacts.

Role of Demand Side Resources

Idaho Power makes significant changes in its portfolio by adding several coal to gas conversions to meet growing demand on its system. Surprisingly, its demand side resources stay largely unresponsive to the increased needs. In fact, the 2023 IRP adds only 360 MW of energy efficiency (EE) resources over the planning period compared to 440 MW of EE selected in its 2021 IRP Preferred Portfolio. Given the projected annual growth rate of 9 percent for its ESA customers, Staff is curious if Idaho Power could consider targeted energy efficiency or demand response programs for these customers and include these measures in its portfolio analysis to evaluate coal to gas conversions, among other resources. The EE issue is discussed in more detail in Section 11.

Capacity Position

Idaho Power's annual capacity position under different cases for Valmy conversion to gas is presented in Table 2 below:[21]

Table 2: Capacity Positions for Valmy Scenarios

Year	July 2026 B2H & Valmy 1 & 2 Gas Conversion		July 2026 B2H & Valmy 2 Gas Conversion		July 2026 B2H & No Valmy Gas Conversion	
2024	11	Length	11	Length	11	Length
2025	3	Length	3	Length	3	Length
2026	224	Length	103	Length	3	Length
2027	284	Length	176	Length	50	Length
2028	211	Length	103	Length	7	Length
2029	126	Length	130	Length	104	Length
2030	134	Length	107	Length	54	Length
2031	131	Length	89	Length	38	Length
2032	157	Length	102	Length	57	Length
2033	137	Length	88	Length	43	Length
2034	126	Length	87	Length	30	Length
2035	117	Length	83	Length	20	Length
2036	108	Length	71	Length	57	Length
2037	111	Length	48	Length	31	Length
2038	45	Length	111	Length	97	Length
2039	54	Length	98	Length	106	Length
2040	62	Length	97	Length	96	Length
2041	56	Length	105	Length	107	Length
2042	49	Length	135	Length	108	Length
2043	57	Length	119	Length	113	Length

Table 2 shows that with B2H coming online in July 2026 and Valmy 1 and 2 gas conversions Idaho Power ends up with substantial excess capacity. The portfolio without the conversions (No Valmy Gas Conversion) also shows capacity length. Staff seeks to understand the usefulness of these conversions in light of Idaho Power's capacity positions in 2026 and onwards.

Staff believes there is a considerable degree of uncertainty related to the gas conversions of Valmy 1 and 2 and seeks more detailed information on the progress and timeline for the completion of this project. The plant would need new equipment (see IPC response to OPUC IR 37) and new pipelines for the delivery of natural gas (IPC response to OPUC IR 36). Idaho Power indicates that new permits and approvals will be needed, and this will be taken up at the Nevada Public Utilities Commission. The

[21] *See* Docket No. LC 84, IPC response to Staff's OPUC IR No. 115, Attachment 1.

Company provides no further details on the specifics of the application and approval status for these permits. Idaho Power will share ownership of the converted plants with NV Energy. However, negotiations between the partners are ongoing and no contracts have been signed to date.[22] Further, Staff is uncertain whether the performance of the gas converted plants will be the same as before. The Company states it will but provides no supporting evidence. [23] Despite these uncertainties, Idaho Power does not anticipate any situation in which the conversion may not take place and therefore does not have a contingency plan. Given all these uncertainties, along with the concerns discussed above, Staff is not sure if the Valmy conversion actions can be considered for Commission acknowledgement in this IRP.

2019 Valmy 1 Exit Rate Impacts

Idaho Power had exited Valmy 1 in 2019, as it was the best economic outcome for its customers according to the Company's 2019 IRP.[24] Staff is not certain what this reversal in action means for Idaho Power's customers who already fully paid towards the revenue requirement associated with Valmy 1 when the Company exited the plant on December 31, 2019. The Company, however, has not given up ownership of Valmy 1[25] and continues to pay a fixed exit fee to the co-owner, NV Energy, that still operates the plant. Staff is uncertain how the exit fee impacts Idaho Power customer rates and what re-participation in Valmy 1 conversion would imply for the exit fee and customer rates.[26]
Based on the above findings, Staff has the following requests for the Company:

Recommendation 10: In Reply Comments, IPC should include a detailed explanation of the need for the Valmy 1 and 2 conversions. The Company should supplement its response with any additional study it may have performed to justify the conversion and continued operation of Valmy 1 and 2 throughout the planning period.

Recommendation11: In Reply Comments, IPC should explain why additional EE and DR resources were not considered as alternatives to Valmy conversion.

Recommendation 12: In Reply Comments, IPC should discuss its evaluation of cost and risks for customers in the event the Valmy conversion does not materialize or if the converted plants become stranded assets. IPC should clearly discuss resource alternatives and cost/risk management strategies if either of the above situations occur.

Recommendation 13: In Reply Comments, IPC should address the rate implications of its continued ownership of Valmy Unit 1, extension of operating lives of both Valmy 1 and 2 beyond 2025, and Idaho Power's re-participation in Valmy Unit 1 in its conversion.

Section 4. WRAP Benefits Modeling

Staff is generally comfortable with the Company's effort to model the benefits of WRAP. While refinements may be necessary in the future, the Company's assumption that it can leverage the WRAP operational program only once per year during the time of greatest need appears to match the intent of WRAP and the WPP's messaging about how the operational program should be used. Staff also notes

[22] *See* Docket No. LC 84, IPC Response to OPUC IR No. 47.
[23] *See* Docket No. LC 84, IPC Response to OPUC IR No. 39.
[24] *See* Docket No. LC 74, Idaho Power Amended 2019 IRP, January 31, 2020, p.125-126.
[25] *See* Docket No. LC 84, IPC Response to OPUC IR No.120.
[26] *See* Docket No. LC 84, IPC Response to OPUC IR No. 119.

that in a future IRP, the Company will be required to submit certain WRAP-related information should rules in Docket No. AR 660 be adopted.

Idaho Power includes 14 MW of capacity benefits associated with its participation in the Western Resource Adequacy Program (WRAP) beginning in 2027.[27] The Company arrives at this number by attempting to quantify the benefit of WRAP's operational program, which allows WRAP participants to request capacity from other WRAP members in times of need. WRAP is currently in its non-binding phase. In practice, this means that its members can voluntarily submit resource adequacy forward showings but face no penalties for failing to meet WRAP's compliance threshold, but they also do not benefit from the operational program's capacity sharing. The Company chose 2027 as the first year of the capacity benefit based on when WRAP is expected to move from its non-binding phase into the binding phase.[28]

The Company chose to model the benefits of WRAP by assessing when it would likely rely on other WRAP members in the operational program and quantifying the avoided capacity of having access to these other members' resources. The Company first conducts a Loss-Of-Load-Probability (LOLP) assessment on six historical test years and identifies the day within each test year with the highest LOLP.[29] The Company then assumes that it would be able to leverage the operational program once per year and would be able to use up to 100 MW of capacity to bring the day with the highest LOLP down to a comparable level to other days within the test year.[30] Idaho Power's method leads to a reduction in perfect capacity needs by 14 MW, a benefit which they assume will begin in 2027. The Company expects to develop a more refined understanding of how often it will leverage the WRAP operational program as it gains operational experience.[31]

Staff would like to commend the Company for attempting to model the benefits of future WRAP participation in this IRP. Staff expects that WRAP participation should lead to decreased resource needs by way of sharing diverse resources from many utilities across a wide geographic area and has recommended that other utilities model the benefits of WRAP participation in other dockets.[32] Like the Company, Staff believes that refinements may be necessary as both the Company and other WRAP participants become familiar with the program. However, as a first step, Staff finds it to be acceptable to model WRAP benefits as only manifesting during one event per year. The WPP has repeatedly expressed that the WRAP operational program is not intended to function as a market, but rather a sharing program in times of extreme need. As such, Staff believes it to be a proper first attempt for the Company to only model WRAP benefits accruing once per year during the most extreme circumstances. Staff is hopeful that more information about the Company's use of the operational program can be used to further inform WRAP benefits once the binding program commences.

Staff would like to conclude these comments by summarizing what is happening in the resource adequacy rulemaking in AR 660 and what this means for a future IRP filing, should the rules ultimately be adopted. In that docket, Staff has recommended that all Oregon-regulated Investor Owned Utilities

[27] *See* Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 8.
[28] *See* Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, Appendix C, p. 92.
[29] *See* Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, Appendix C, p. 91.
[30] Ibid
[31] Ibid.
[32] *See* Docket No. LC 80, Staff's Opening Comments, July 28, 2023, p. 43.

include an informational filing in their IRP that addresses peak load growth, strategies to meet the load, and transmission strategies to meet any Resource Adequacy (RA) needs over a four-year period.[33] Staff also recommends that the utilities include any public program output from the WRAP so that the Company's RA strategies and methods can be placed in a regionwide context. The proposed rule language was made to be flexible enough that the utilities could implement their own RA methodology or update it with newer data or industry best practices that may not perfectly align with WRAP.

Section 5. Wind Qualifying Facilities (QFs)

Like the 2021 IRP, the Company's base planning assumption in the 2023 IRP assumes that wind QFs would not renew their contracts upon expiry. However, the Company developed a scenario that includes a forecast of future QF development after the Action Plan window. The Company cited no empirical evidence to support this approach, but emphasized the reliability risk of overestimation of wind QFs in the near term. While Staff appreciates the Company's reasoning, it recommends that the Company develop a reasonable non-zero estimate to modeling wind QF renewal rates in the next IRP Update.

In the acknowledgement order of the 2021 IRP, the Commission issued two directives to Idaho Power: 1) to revisit the wind QF renewal rate, and 2) develop a reasonable forecast of new QFs beginning in the fifth year of the planning cycle.[34]

With regards to the directive to revisit the QF renewal rate, the Company elected to stay with the 2021 IRP assumption that no wind QFs would renew after contract expiration. In response to questioning this assumption by the Renewable Energy Coalition (in REC IR 3), the Company stated that no wind projects were up for renewal as yet and hence, it did not have any empirical evidence to support any assumption of actual wind QF renewals other than zero. The Company asserted that its decision on the forecast did not preclude the ability of QFs to renew their contracts at any time, and in that case, Idaho Power will update its capacity position at the time. The Company added that informal discussions with several wind QFs over the years revealed that no project indicated definitive and actionable intent to renew their contract under the Public Utility Regulatory Policies Act of 1978 (PURPA).

Further, Staff questioned in OPUC IR No. 61 the extent of the Company's claim in the 2023 IRP that assuming the renewal of four wind projects, with a total installed capacity of 61.5 MW expiring between 2024 and 2028, could distort resource selection in the critical near-term window.[35] The Company responded that the assumption that all wind projects renew would create a reliability risk because it would increase the procurement need and the requirement to fill that need with additional resources in a short time, if no renewals eventuated. On the other hand, if that assumption is not made and some or all wind projects did renew, then there will be less procurement need and Idaho Power can easily decrease the quantity of resource procurement in the near term.

In OPUC IR No. 62, Staff also requested that the Company elaborate on its efforts to negotiate QF wind contract renewals and, in OPUC IR No. 63, the reasons for why a wind QF developer or owner would not renew their contract with Idaho Power if they already made the investment in land and permits and the plant is able to continue operation. In response, the Company explained that it reaches out to all QFs

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[33] *See* Docket No. UM 2143, Staff report for the September 21, 2023 Regular Public Meeting, September 13, 2023.
[34] *See* Order No. 23-004 in Docket No. LC 78, Staff Recommendations 22 and 23, Appendix A, pp. 36-37.
[35] *See* Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 162.

with expiring contracts well in advance of expiry (8-10 months in advance) to allow time to execute a replacement contract, but not longer than a year in advance to ensure the replacement contract contains the most up-to-date avoided cost pricing. The Company also explained that there were many economic or contractual factors that would impact the decision of a QF owner or developer to not pursue a new contract with Idaho Power. One factor to consider is the opportunity for sales to entities other than Idaho Power, which is not an unreasonable assumption.

With regards to the directive to develop a forecast for wind QFs beyond the near-term planning period, the Company explained in the 2023 IRP that due to the size and non-linear nature of wind QF development in the past, it developed a scenario of wind QF forecast with 100 percent renewal rate starting 2028. This scenario assumes a quantity of 23 MW each year by averaging the quantity of new wind QF developments coming online for the past 10 years ending in 2021.

Staff acknowledges the common issue facing all utilities in the state regarding the lack of historical data to be able to calculate reasonable wind QF renewal rates. On the other hand, the uniqueness of the impact of QF renewal rates on different utilities in the state is manifest when taking into account the proportion of the total aggregate nameplate capacity relative to other resource types. For example, Staff sees two different approaches by other utilities, albeit applicable to all QFs and not just wind. PGE followed the same approach of Idaho Power by assuming no renewal after contract end in all study cases of QF sensitivities.[36] In response to Staff's recommendation of recalculating IRP inputs using an assumption of 75 percent for QF renewals, PGE stated that the impact of such a change would be immaterial to the Preferred Portfolio.[37] Conversely and in response to a directive by the Commission in Order No. 22-178,[38] PacifiCorp assumed methodology calculated a 79 percent QF renewal rate upon reaching the expiration date, based on analysis of historical rates.[39]

While Staff appreciates the arguments made by Idaho Power on assuming a zero wind QF renewal rate, Staff first notes the resolution arrived at by the Commission in Order No. 21-184, which commented that modeling of renewals should include some percentage, rather than taking an unrealistic "all or nothing" approach, as a reasonable assumption.[40] Pending the adoption of the guidance on this issue within the UM 2000 Broad Investigation of PURPA,[41] Staff would like to see in the interim the Company develop some percentage estimate with an equal likelihood of under- and over-estimating the actual renewal rate. In developing such estimate, Idaho Power should consider its own approach for non-wind QFs in line with the analysis performed by PacifiCorp in its 2023 IRP to forecast a likely QF contract renewal rate.

Recommendation 14: In the next IRP Update, Staff requests that IPC develops a reasonable non-zero estimate of a wind QF renewal rate that utilizes the approach taken for establishing a non-wind QF in line with the analysis undertaken by PacifiCorp in its 2023 IRP to estimate the QF renewal rate.

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[36] *See* Docket No. LC 80, PGE, 2023 CEP and IRP (Updated), June 30, 2023, p. 133
[37] *See* Docket No. LC 80, PGE's Comments on Staff's Final Memo, January 12, 2024, p. 13
[38] See Order No. 22-178 in Docket No. LC 77, PacifiCorp 2021 IRP, May 23, 2022, p. 14.
[39] *See* Docket No. LC 82, PacifiCorp 2023 IRP Volume II, March 31, 2023, p. 37.
[40] *See* Order No. 21-184 in Docket No. LC 74, Idaho Power 2019 IRP, June 4, 2021, p. 19
[41] *See* Docket No. UM 2000, Staff's Process Proposal and Scope Update, February 24, 2023.

Section 6. Transmission and Market Access

IPC continues to describe B2H as a path to access Mid-C energy markets to the west to meet summer peak, and now adds Phase 1 of Gateway West (GWW) in the 2023 IRP as a means to connect renewable energy from the east while also exploring potential participation in SWIP-North, providing access to the Desert Southwest market to serve future winter peak needs. Staff seeks to understand the Company's transmission strategy for optimizing connections to renewable generation and access to wholesale markets.

Transmission Paths

In the 2023 IRP, Idaho Power outlines its approach of pursuing transmission projects that serve both purposes of accessing wholesale electricity markets and connecting renewables. In the last three IRPs the B2H project has been seen as the pathway for access to Mid-C Northwest market for purchasing energy from the West to meet the Company's summer peak. In the 2023 IRP, Phase 1 of the Gateway West (GWW) transmission project is presented as being driven primarily by the purpose of connecting renewable energy from the East.

Considering each transmission project in its own right is simple to understand if each project serving one purpose is totally isolated from the other serving a different purpose. However, these projects interact if they run along the same transmission pathway and more than one market is involved. Staff seeks to understand how the Company optimizes the use of transfer capacity when considering the cost and timing of construction of transmission segments to connect renewables and trading transmission ownerships rights to access markets at the same time.

Figure 8 shows the east to west transmission path where capacity transfer between Idaho Power and PacifiCorp is taking place on the in-service date of B2H in 2026.[42] In OPUC IR No. 51, Staff sought clarification on the benefits and costs of the asset swap described in the 2023 IRP presentation on October 31, 2023.[43] In response, the Company stated that this exchange, among other exchanges, will cost Idaho Power the reduction of 600 MW of east-to-west transmission ownership and will increase PacifiCorp's east-to-west transmission capacity by 600 MW to avoid wheeling this capacity from PacifiCorp East to PacifiCorp West regions. This exchange will also enable Idaho Power to use 200 MW of bidirectional transmission capacity between the Idaho Power market system (Populus substation) and Four Corners market.

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[42] *See* Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, Figure 7.3, p. 91.
[43] *See* Docket No. LC 84, Idaho Power's 2023 IRP presentation on October 31, 2023, October 26, 2023, slide 13.

Figure 8: Transmission asset swaps between Idaho Power and PacifiCorp

Three years later, in 2029, the Company is anticipating interconnecting additional resources through the same east-to-west pathway by building the Gateway West (GWW) segment of Midpoint to Hemingway of 2000 MW capacity. This segment will give Idaho Power access to a third of this capacity (approximately 667 MW) allowing it to add around 1,000 MW of renewables, assuming not all renewable output of all facilities will be flowing at the same time.

If Idaho Power is getting a new transfer capacity of 667 MW via its share of GWW segment in 2029 to connect 1,000 MW of renewable generation from the east, Staff questions whether that result would have been possible by using the 600 MW capacity that the Company swapped with PacifiCorp in the first place. Now, with Idaho Power possibly gaining access to the Four Corners market earlier in 2026, Staff seeks to understand Idaho Power's broader transmission strategy to optimize connections to renewable generation and access to wholesale markets.

Market Access

Idaho Power's action plan includes potential participation in the SWIP-North transmission capacity giving access to the Desert Southwest market to serve winter peak season needs from 2027. With Idaho Power having access to multiple market hubs, Staff requests the Company to explain how it decides on utilizing transmission paths when having the potential to access diversified markets.

In the IRP presentation on October 31, 2023, the Company demonstrated its goal to be able to access markets hubs that are diverse from the Mid-C hub. The Company explained that in practice, the Aurora model currently considers the entire WECC as a one-market construct having interaction between different nodes with certain limitations. The Company added that it was working with consultants to try to get at the heart of the details in order to improve the modeling to reflect the nature of the different markets. Staff looks forward to any developments around optimizing the choice of markets in the IRP Update and future IRPs.

In response to OPUC IR No. 84, in which Staff asks whether the Company has any plans to purchase wholesale energy from hubs other than Mid-C, the Company explains that transfer capacity is available from market hubs, and that the model resource selection takes into consideration the possibility of market purchases at Mid-C and other hubs. Staff is interested to understand the strategy by which the Company decides to make transfer capacity available to markets.

Recommendation 15: In Reply Comments, Staff requests that IPC explain its strategy for connecting renewable resources along the east-to-west transmission pathway in light of the terms of the asset swap with PacifiCorp in 2026 and the addition of Phase 1 of GWW transmission in 2029.

Recommendation 16: In Reply Comments, Staff requests the Company explain how it makes business decisions on transmission ownership or rights to connect to different markets.

Section 7. Wholesale Electricity Prices

In the 2023 IRP, the accuracy of the wholesale electricity prices Idaho Power modeled in the planning case appear mixed, which is an improvement over the 2021 IRP. However, the highest prices the Company modeled in the stochastic risk analysis appear too low to reasonably reflect the risk of being short the market. A low-price bias could result in unreliable capacity expansion modeling results that favor transmission and storage resources.

Background

In the 2021 IRP, Staff argued that Idaho Power substantially underestimated wholesale electricity prices.[44] This led to Recommendation 8 in Order No. 22-004 where the Commission directs "Idaho Power to work with stakeholders and demonstrate the impact of extremely high wholesale electricity prices and decreased liquidity on resource selection in the 2023 IRP."[45]

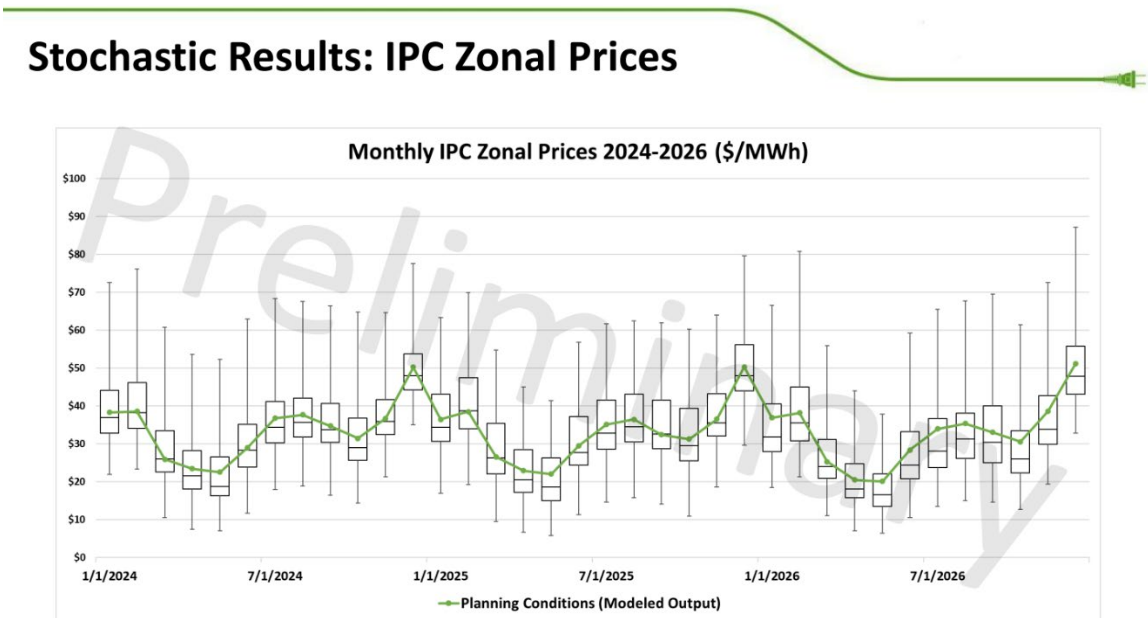
Staff does not hold a belief that prices will be higher. Instead, for modeling purposes, Staff expects to see near-term price forecasts relatively contiguous to observed prices and for the Company to forecast significantly higher prices than we observe today in the stochastic risk analysis. Idaho Power's modeling of wholesale prices should not be optimistic in the planning case. Low prices should bookend higher prices in stochastic risk analysis.

Planning Case Prices

IPC relied on a slide it presented during its August 31, 2023 IRPAC workshop to provide the range of wholesale electricity prices that Idaho Power's model produced.[46] Staff was unable to find further depiction of wholesale electricity prices in the body of the 2023 IRP.

[44] *See* Docket No. LC 78, OPUC Staff, Staff Report, October 28, 2022, pp. 12-14.
[45] *See* Docket No. LC 78, OPUC, Order No. 22-004, January 13, 2023, pp. 12,13.
[46] Idaho Power IRPAC Meeting, *Stochastic Risk Analysis,* August 31, 2023, slide 7.

Figure 9: IPC Zonal Prices Presented at the August 31, 2023 IRPAC Meeting



Looking at this slide, as shown in Figure 9, it appears the highest imaginable average June wholesale electricity price in the next three years will not be much higher than the $44.83 per MWh observed last June, as reported by Platts.[47] Also, the Company's stochastic risk analysis appears to not anticipate the possibility that wholesale electricity prices could average as high as triple digits for a month through 2026.

Staff has sought greater detail through discovery on the wholesale electricity prices Idaho Power has modeled.[48] The Company has been able to provide planning case prices at the hourly level.

The planning case prices in this IRP appear more realistic than what was modeled in the 2021 IRP. Staff compared the highest hourly prices Idaho Power modeled in the 2023 IRP for 2024 with the highest observed hourly prices in the relatively mild market conditions of the past year, where, in contrast to the exceptional low hydro year of 2021, market conditions have been favorable for low wholesale electricity prices in the Pacific Northwest. The highest planning condition hourly price Idaho Power modeled for June 2024 was $61 per MWh.[49] That was an hourly price of the IPC zone, a composite of wholesale electricity prices from markets Idaho Power has access to import. The highest hourly (Mid-C) price modeled under planning conditions for June of last year was $67.27. Both these prices are within a reasonable range of the highest actual hourly price last June: $65.31 on June 8, 2023, during the hour ending at 7 pm.[50]

In making this comparison with Mid-C, Staff notes that the Northwest's bilateral market is modeled as being relatively more expensive than Palo Verde, Idaho Power's largest southern wholesale electricity

[47] Platts. Jun 30 2023 MDFD Megawatt Daily Market Fundamentals Daily.xlsx.
[48] See Docket No. LC 84, OPUC Staff, OPUC IRs 91-95, December 22, 2023, pp. 1,2.
[49] *See* Docket No. LC 84, IPC Response to OPUC IR No. 91, IPC Response to Staff's DR No. 91 – Attachment 1 – IPC Zonal Prices ES.xlsx, sheet titled "June 2024," cell G33079.
[50] Platts. *Megawatt Daily* June 9, 2023, p 18.

market. In the last IRP, the price difference went the other way. In the 2023 IRP Palo Verde hourly prices are, on average, $4.51 cheaper than Mid-C hourly prices.[51] Those are surprising results.

Comparing prices so far this year provides another means of validating Idaho Power's modeling of wholesale electricity prices. For the first eleven days of 2024, market conditions were ripe for seasonally low Mid-C prices. That initial week and a half provides a deferential comparison for planning case prices. The highest hourly price Idaho Power modeled for planning conditions during the month of January 2024 was $61.81 per MWh for the IPC zone and $67.81 for Mid-C, but actual peak hour prices were much higher when planning conditions were present at the start of this year, as shown in Table 3.[52] Well before an ice storm settled into the Northwest on the morning of January 13, 2023, a buyer of power from Mid-C would have a hard time paying so low a price during peak hours.

Table 3: Highest Hourly Mid-C Prices – January 2 - 11, Source: Platts Megawatt Daily

Date	**2nd**	**3rd**	**4th**	**5th**	**8th**	**9th**	**10th**	**11th**
Highest	$65	$80	$90	$80	$115	$225	$87	$130
Hour Ending	6 pm	8 pm	7 pm	1 – 7 pm (Except 5)	6 – 8 pm	8 pm	10 pm	7 pm

Comparing peak hourly prices during planning conditions with the planning condition wholesale electricity prices Idaho Power modeled, Staff sees mixed results. The highest modeled price in June 2024 is congruent with observed hourly prices in June 2023. However, a similar comparison with the first week and a half of this year shows a significant underestimation. Overall, these planning case prices appear to be an improvement in accuracy over the 2021 IRP.

Stochastic Risk Prices

Beyond the planning case prices, Idaho Power's stochastic risk analysis compares wholesale electricity prices that may be too low to reasonably capture market risk associated with the Company's heavy reliance on wholesale electricity prices as a resource. For example, the highest average market price produced by the Company's model for January 2024 is $70.31 per MWh.[53] The highest average observed Mid-C price was $222.91 per MWh.[54] When an ice storm moved into the Northwest on January 13, 2024, Mid-C prices would repeatedly hit the Federal Energy Regulatory Commission's price cap of $1,000 per MWh that weekend. Staff would like to go beyond a comparison of averages and see if the Company's stochastic risk analysis modeled prices like that weekend, though not necessarily on the same days, but whether this IRP's demonstration of extreme market prices considers prices higher than what we observe. However, Idaho Power was not able to provide hourly prices from the stochastic runs.

The low ceiling for average wholesale electricity prices in the Company's 2023 stochastic risk analysis does not appear to Staff to consider the risk from worse market conditions than we already observe. However, Staff recognizes that the comparison of average monthly prices is less insightful than a

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[51] *See* Docket No. LC 84, IPC Response to OPUC IR No. 91, Set 8 DR 91 Hub Prices Supplement ES.xlsx, sheet titled "Mid C v PV", cell E175323.

[52] *See* Docket No. LC 84, IPC Response to OPUC IR No. 91, Set 8 DR 91 Hub Prices Supplement ES.xlsx, sheet titled "January 2024", cell C2.

[53] *See* Docket No. LC 84, IPC Response to OPUC IR No. 92, IPC Response to Staff's DR No. 92 - Attachment 1 - IPC Stochastic Prices.xlsx, Sheet titled "Prices", Cell AI2.

[54] Monthly Mid C Prices ES.xlsx, sheet titled "Blend of Platts Data" cell D8.

comparison of hourly prices. Idaho Power should be validating the reasonableness of the Company's modeling of wholesale electricity prices at the hourly level.

Another perspective to assess the reasonableness of Idaho Power's modeling of wholesale electricity prices is to match the Company's actual market purchases with the 2023 IRP's modeling of market purchases. Idaho Power provided a helpful data set of historical market purchases in response to OPUC IR No. 95. This data set is helpful, because it can narrow the scope of hours used for comparison to the hours Idaho Power is most likely to rely on market purchases.

In addition to comparing market transactions, Idaho Power's recent RFPs for resources may provide another perspective to understand the use of wholesale markets as a generation resource. Bids for firm contracts to purchase power can provide insight on the resource cost of market purchases.

Reasonable Wholesale Price

Having a low-price bias in modeled wholesale electricity prices may bias resource selection. The two resources that rely on market purchases are storage and transmission. Because these are major resources in the Company's preferred portfolio, the reasonableness of this IRP's capacity expansion and production cost modeling may be unreliable if the market risk of this resource is not adequately considered. In reviewing the 2023 IRP, Staff is comparing the prices Idaho Power modeled from multiple perspectives: historical average monthly prices from market data, historical peak hourly prices, Idaho Power's market purchases, and price discovery from the Company's RFPs. While Staff has more analysis to perform before arriving at a conclusion, a comparison of monthly averages already suggests the planning case prices have improved over the 2021 IRP, but the need to demonstrate the impact of extremely higher prices appears to remain a modeling shortfall.

Recommendation 17: Staff recommends, in Reply Comments, the Company provide the modeled hourly wholesale electricity prices for January 2024 from the stochastic run that produced the highest prices for that month.

Recommendation 18: Staff recommends, in Reply Comments, the Company present a comparison of Idaho Power's wholesale electricity purchases in June 2023 and January 2024 with the 2023 IRP's modeling of market purchases during those months in 2024.

Recommendation 19: Staff recommends, in Reply Comments, the Company describe the market purchase bids Idaho Power has received in recent RFPs.

Section 8. Long-term Storage Pilot

Idaho Power's near-term action plan includes exploring a 5 MW multi-day storage pilot between 2024 - 2028, but the description lacks sufficient details necessary for Staff analysis.

While IRP portfolio modeling provides insights into the cost-effectiveness of a resource, Idaho Power aims to learn more about the operational aspects of multi-day storage resources by means of the pilot and use the learning experience in a decision to pursue an additional 200 MW of Long duration storage selected in the Preferred Portfolio.[55] Staff understands that this pilot project is in a research and development stage and, as such, does not discourage the idea of exploring a pilot. However, Staff wants

[55] *See* Docket No. LC 84, IPC Response to OPUC IR No. 75.

to ensure that Idaho Power is not requesting acknowledgement for the actual pilot project at this time, as that would necessitate more details on several aspects of the project, including, but not limited to: description of specific learning objectives, estimates of detailed project costs and value to Idaho Power customers, number of participants, evaluation strategy, and many others. Staff understands that this level of information is not currently available. Staff suggests that Idaho Power look into previous processes and orders (specifically Docket No. UM 2141, Order No. 22-115) from Oregon PUC to provide more details on the anticipated pilot for Staff's evaluation if it seeks acknowledgement for a specific pilot project; this could be in the form of a separate filing for approval of the pilot project.

Recommendation 20: In its Reply Comments, Idaho Power should clarify its acknowledgement request, and if seeking acknowledgement of an actual pilot project, it should provide more details on the Company's activities related to this project including, but not limited to those identified in UM 2141 and Order No. 22-115, as well as a project timeline and status update.

Section 9. New Resource: Hydrogen

Idaho Power included 340 MW of clean hydrogen in the preferred portfolio in 2038. The Company used assumptions provided by the National Renewable Energy Laboratory, and accounted for current federal legislation for cost offsets when modeling the proxy resource. Staff generally see this approach as reasonable and encourages IPC to explore the option of hydrogen blending in its existing natural gas plants.

Idaho Power's preferred portfolio includes 340 MW of clean hydrogen coming online in 2038. Staff appreciates the Company responding to LC 78, Order 23-004, which included:

> *Recommendation 25: Direct Idaho Power to include the most reasonable proxy of green hydrogen as a potential resource in its next IRP, either available for selection in a portfolio or in a sensitivity.*

Idaho Power used a peaking gas SCCT as the reference resource for modeling hydrogen. Staff finds the proxy to be reasonable and consistent with current research on costs and characteristics of hydrogen fueled combustion turbine. IPC's assumptions rely on a National Renewable Energy Laboratory report that uses a 3 percent higher cost for hydrogen combustion turbines compared to a new natural gas turbine.[56] IPC has accounted for federal incentives from the Infrastructure Investment and Jobs Act and the Inflation Reduction Act as cost offsets to the capital cost of building a clean hydrogen burning resource and as a decreased cost of the hydrogen fuel itself. IPC will adjust the cost estimated in the future if the incentives happen to change.[57]

Staff understands that a fully hydrogen fueled turbine is not a commercially available technology at present, however, Staff wonders whether Idaho Power has considered options for hydrogen blending in its currently existing natural gas plants. Staff would like Idaho Power to provide any information available regarding hydrogen blending options in its reply comments.

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[56] *See* Docket No. LC 84, IPC Response to OPUC IR No. 69.
[57] *See* Docket No. LC 84, IPC Response to OPUC IR No. 77.

Recommendation 21: In its Reply Comments, Idaho Power should share any information available on hydrogen blending options in its existing natural gas plants.

Section 10. Distribution-Connected Storage

IPC plans for 80 MW of additional distribution-connected storage, adding to the 11 MW of distribution-connected storage projects installed in the fall of 2023. Staff is seeking more understanding on how this type of storage is modeled, especially in relation to the Company's Distribution System Plan. Staff is also seeking to understand the lessons learned from the Company's experience with installing 11 MW in four distribution-connected storage projects, scheduled to come online in the first half of 2024, including the safety aspects following the fire event at Melba substation in October 2023.

Similar to the 2021 IRP, Idaho Power is making 100 MW of distribution-connected storage available to the Aurora Long Term Capacity Expansion (LTCE) model throughout the 20-year planning period, with an annual average capacity of 5 MW. In the 2023 IRP, the preferred portfolio includes 80 MW (5 MW every year from 2027 to 2042) of cost-effective distribution-connected storage selected to meet system resource needs as well as defer transmission and distribution (T&D) investments.[58] Staff is interested in how this type of technology is modelled and what lessons were learned from the installation of the first 11 MWs of distribution-connected storage projects originally expected to come online by the end of 2023, but is now scheduled to be in service in the first half of 2024.[59]

Modeling

IPC anticipates a locational value of T&D deferral for distribution-connected storage estimated at 10 percent of the utility scale storage cost.[60] In OPUC IR No. 79, Staff sought more information on how T&D deferral and local/system peak shaving benefits are modeled for distribution-connected storage as compared to grid-scale storage. The Company responded that for distribution-connected storage, a block size of one-tenth of grid-scale storage, or 5 MW, and a reduction of 10 percent in cost of grid-scale storage are inputs to the Aurora model.

In response to OPUC IR No. 80 asking about how the costs and benefits are reflected in the IRP modeling, the Company modeled a 10 percent decrease in storage cost compared to centralized storage projects because distribution-based projects provide a distribution deferral benefit. With regards to block size limits, the Company explained that the 5 MW limit per year aligns with the number of actual T&D deferral opportunities the Company has identified in the past, which is confirmed by the four distribution projects installed in 2022 and 2023, totaling 11 MW.[61] The average capacity per year for these four projects is 5.5 MW, which was rounded to 5 MW as an estimate of the block size limit implemented in the model.

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[58] The 5 MW distribution-connected storage resources are included in the 4-hour storage "4 Hr" column of Table 1.1 (page 6) in Idaho Power's 2023 IRP. See Docket No. LC 84, IPC's response to OPUC IR No. 78 that requested the capacity (MW) and energy (MWh) quantities of distribution-connected storage per year selected by the Aurora model in the 20-year IRP planning period.

[59] *See* Docket No. LC 84, IPC Response to OPUC IR No. 82 that requested a progress update on the four distribution-connected storage projects.

[60] *See* Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 58.

[61] *See* Docket No. UM 2196, 2022 Oregon Distribution System Planning Report: Part II, Table 4.2, p. 44 for the Grid Needs Summary for both Oregon and Idaho, filed on August 15, 2022.

Staff is interested in how distribution-connected storage projects might be available for model selections in development of the preferred portfolio. For example, looking beyond the near-term, the DSP for Oregon shows a longer-term grid need by May 2028 at three other substations considered for non-wire solutions.[62] The DSP states that one site was not a good candidate for a non-wire solution and more thorough reviews are needed at the two other sites to determine feasibility. Given that the planned capacity of distribution-connected storage in the IRP is based on a shorter planning time frame (5 to 10 years) compared to the IRP review cycle (20 years), Staff would like to see how the Company plans to align the capacity requirements of the IRP with the inputs from the DSP. However, Staff understands that the capacity limit of 5 MW per year in the model may be adjusted in future IRPs as new information is acquired, as the Company indicated in response to OPUC IR No. 80.

Lessons Learned

The Company's first implementation of targeted grid storage was the installation of 11 MW of batteries at four locations identified in the Company's DSP at Weiser, Filer, Elmore, and Melba substations. This action was in response to the Staff Recommendation 18 in Order No. 23-004, where the Company was to finalize candidate locations for distributed storage projects and implement where possible to defer T&D investments, as identified in the Action Plan. Staff is seeking to understand what lessons were learned from the installation of these projects, including the safety aspects following the fire event at Melba substation on October 2, 2023.[63]

Staff raised OPUC IR No. 82 to request an update and understand the lessons learned from commissioning these first-time installations. The Company explained that the expected in-service date for three of the projects at Weiser, Filer and Elmore has been delayed to February 2024, with the fourth, the Melba substation, being delayed to May 2024, all due to a common design element that needs to be adjusted before commissioning. In addition, energy storage units need to be replaced for the Melba substation after the battery fire that occurred on October 2, 2023. The Company further explained that costs and schedule changes associated with these projects may result in adjustments to modeling assumptions and constraints in future IRPs.

Fire Event

Given the increasing number of explosions or fire-related events related to distribution-connected of batteries around the world, including the battery fire at the Company's Melba substation,[64] Staff seeks to understand how the Company is reflecting safety risks with distribution-connected storage batteries in planning.

Staff raised OPUC IR No. 83 requesting Idaho Power provide the circumstances surrounding the event and all aspects of the safety standards that were in place or were required to be in place to avoid this type of event. The Company declined to share the causes and effects of the fire event citing confidentiality requirements due the event being under investigation. However, the Company committed

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[62] Id, p. 45.

[63] *See* incident report at https://agenda.canyoncounty.id.gov/SupportDoc/GetSupportingDoc?supportDocID=1475, accessed on January 25, 2024.

[64] *See* Electric Power Research Institute (EPRI) BESS Failure Event Database at: https://storagewiki.epri.com/index.php/BESS_Failure_Event_Database, accessed on January 9, 2024.

to provide any final reports from its consultants identifying the cause and origin of the fire at the Melba substation.

Staff requests the Company provide a list of all the safety standards and certifications needed for the design, construction, and operations of distribution-connected storage projects.

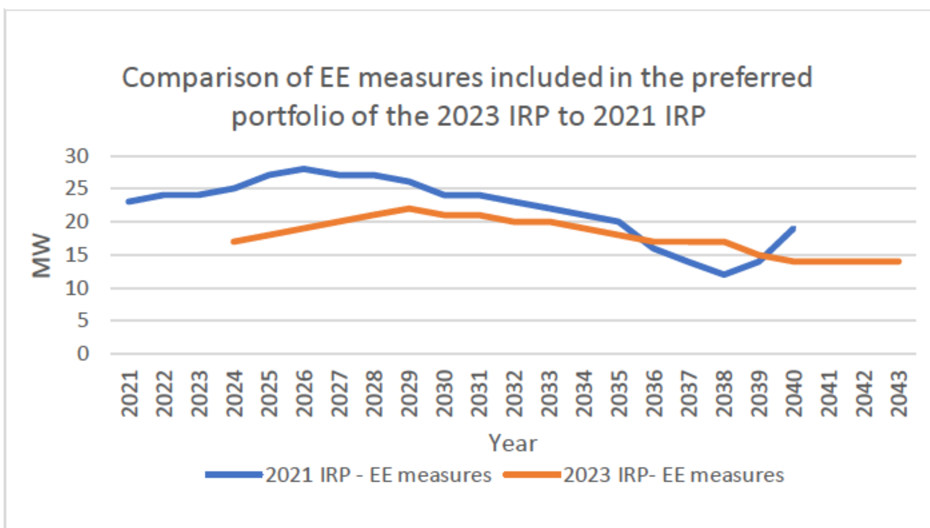
Recommendation 22: In Reply Comments, Staff requests that IPC describe the planning mechanism by which long-term grid needs identified in the DSP inform the capacities planned in the IRP and whether planned capacity limits for distribution-connected storage will need to be adjusted in future IRPs to suit the grid need in the DSP.

Recommendation 23: In Reply Comments, Staff request that the Company provide a comprehensive listing of standards that are adhered to for the design, construction, and operations of all distribution-connected storage projects. The listing should include the standard number, title, description of use, and governing board for the standard, with general reference as to how the content is applied in these projects.

Section 11. Energy Efficiency (EE)

The 2023 IRP lost 80 MW of cumulative EE compared to the 2021 IRP. Staff is concerned that the company's bundling of EE measures in the 2023 IRP omitted cost-effective EE during optimization. Additionally, the lack of transparency into the EE measures adopted by Energy Service Agreement customers risks that avoidable costs could be placed onto Idaho Power's remaining customer classes.

Figure 10: EE Measures 2021 to 2023 Comparison



Staff appreciates Idaho Power Company's ongoing commitment to energy efficiency (EE) programs.[65] Idaho Power's preferred portfolio includes 360 MW of cost-effective EE measures. This includes 95 MW of EE measures acknowledged in the 2021 IRP. The 360 MW represents the achievable economic energy efficiency identified though an EE potential assessment and decremented from the load forecast. The Aurora model did not select any additional EE during optimization. In the 2021 IRP, the preferred portfolio included 440 MW of EE measures.[66] Thus, the 2023 IRP lost 80 MW of cumulative EE compared to the 2021 IRP. In the 2023 IRP's Near-Term Action Plan window (2024-2028) cost-

[65] *See e.g.*, Idaho Power 2023 IRP, Appendix B: DSM Annual Report.

[66] The 2021 IRP Preferred Portfolio included 428 MW of achievable economic EE and 12 MW of technically achievable EE. *See* Docket No. LC 78, Idaho Power Company 2021 IRP, Table 1.1.

effective EE decreases 29 percent compared to the 2021 IRP, for a cumulative loss of 39 MW over the next four years.

Avoided Cost

Idaho Power determined cost-effective EE in the 2023 IRP using the avoided cost data from the Company's 2021 acknowledged IRP in LC 78. In LC 78, Staff observed that IPC's 2021 IRP underestimated the forward market price (FMP).[67] This low FMP estimate results in a low avoided cost in the 2023 IRP.[68] The low avoided cost derived from the 2021 IRP, Idaho Power explained, reduced the cost-effective EE measures in the 2023 IRP compared to the 2021 IRP.[69] Idaho Power recognized the avoided cost lag in informal discussions with Staff but explained that the lag is inherent to their IRP process.[70]

Staff has recently commented on the impact that utilities' market price forecasts have on their avoided cost calculation and, by extension, EE valuation. In LC 80, given the need for PGE to acquire clean generation rather than simply least-cost generation, Staff found PGE had forecasted unreasonably low forward market prices. The resulting avoided cost, Staff concluded, undervalued EE measures in PGE's 2023 IRP.[71] By comparison, in LC 82, Staff observed that elevated and volatile forward market prices for electricity in the next three years were the primary drivers of EE selection in PacifiCorp's 2023 IRP preferred portfolio. There, cumulative EE acquisition between 2024 and 2030 increased by 28 aMW compared to PacifiCorp's 2021 IRP.[72]

Going forward, Staff is curious whether Idaho Power's IRP process may be adjusted to negate or mitigate the avoided cost lag or otherwise use more reasonable FMP forecast in determining avoided cost.[73]

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[67] *In the Matter of IDAHO POWER COMPANY, 2021 Integrated Resource Plan*, Staff Report, Docket No. LC 78 at pages 12-13 (Oct. 28, 2022) ("Persistent high prices in 2022 during a relatively normal hydro year, and the forward price curve show observed market prices that are significantly higher than the 2021 IRP's forecast."); *see also id.* at 16 ("[T]he 2021 IRP's planning condition resembles a sensitivity for low prices. Specifically, observed prices in 2021 and beyond are significantly higher than the stochastic risk analysis scenarios for Mid-C price risk.") (citing *In the Matter of IDAHO POWER COMPANY, 2021 Integrated Resource Plan*, Staff Report, Docket No. LC 78 at page 11 (Sept. 8, 2022)).

[68] Informal discussions with IPC and Staff, January 22, 2024.

[69] *See* Docket No. LC 84, IPC Response to OPUC IR No. 101.

[70] Informal discussions with IPC and Staff, January 22, 2024.

[71] *See* Docket No. LC 80, Portland General Electric 2023 IRP/CEP, Staff Round 1 Comments, July 27, 2023, pages 28-29.

[72] PacifiCorp 2023 Integrated Resource Plan, Docket No. LC 82, Staff Opening Comments at 55 (citing LC 82, PacifiCorp Amended IRP Filing, May 31, 2023, Table D.4. Appendix D, page 116 and Table D.4. PacifiCorp 2021 Integrated Resource Plan. Appendix D. Docket No. LC 77. Page 110).

[73] For example, in Docket No. 1893, the Commission delayed the filing of PacifiCorp and PGE's avoided cost data, from October 15, 2023 to March 1, 2024, so that more recent data could be considered. The Commission found that the October 15 date, which would be based on 2021 IRP data, was not optimal for use in the 2023 IRP given the need for data that reflected the new HB 2021 resource strategies outlined in each utility's 2023 IRP. *See In the Matter of Request for Waiver of OAR 860-030-0011 for Utility Filing of Energy Efficiency Avoided Cost Report*, Docket No. UM 1893, Order No. 23-362 at App. A at 3 (Oct. 6, 2023). Unlike PacifiCorp and PGE, Idaho Power does not file its avoided cost data for approval by the Commission. *See* OAR 860-030-011. Nevertheless, Staff is curious whether a similar change in procedure could ensure that the avoided cost data reflects IPC's resource strategy to meet the significant increase in near-term demand with renewable capacity additions and market purchases.

EE bundles in the portfolio optimization

The Company uses portfolio optimization as a backstop to ensure cost-effective bundles of remaining EE measures are included in the preferred portfolio. In the 2023 IRP, IPC modeled five bundles of technically achievable EE and their costs in Aurora. Aurora did not select any of the five EE bundles. This would suggest that all the cost-effective EE is included in the Preferred Portfolio.

Staff is in the process of reviewing the Company's information request submissions related to these bundling practices. In this initial review, Staff observed that Idaho Power's bundling analysis groups the EE measures by 17 "Sector-Level Cost Bundles." The Company delineates the Sector-Level Cost Bundles by customer class and a range of costs by peak season (winter and summer).[74] During the portfolio optimization; however, the Company only uses five bundles with a wider cost range as shown in Figure 9 (Final Cost Bundles). Additionally, IPC does not delineate the Final Cost Bundles by customer class as it did with the Sector-Level Cost Bundles.

This may be an issue for optimization of cost-effective EE, particularly when looking at the commercial and industrial (C&I) EE measures available. The Final Cost Bundles delineation includes low-cost bundles with extremely low-cost EE measures for C&I customers, including some measures with an LCOE of $0.[75] It appears that the model did not select these low to no cost measures because they were bundled with measures reaching up to $258.18 for the summer low cost bundle and $254.43 for the winter low cost bundle, thus forcing each bundle's LCOE to reach uneconomic costs.[76] Testing key bundles of technically achievable EE may be more insightful. For example, PacifiCorp's 2023 IRP modeling used 27 bundles, including a bundle of only those zero and negative cost EE measures thus ensuring the model would select the zero-cost bundle.

IPC forecasts that the annual system near-term load growth is disproportionately weighted to industrial customers.[77] In this regard, Staff is concerned that mitigating C&I efficiency measures are lost because the bundles are unfairly skewed by more expensive measures. Staff would like to understand the costs and benefits of portfolio runs with more bundles such as these Sector-Level Cost Bundles and a bundle with EE measures with an LCOE of $0.

Figure 9: IPC Savings Weighted Levelized Cost of Energy for Final Cost Bundles

Bundle Costs

Savings Weighted Levelized Cost of Energy ($/MWh) Real Dollars

Bundle	2024	2025	2026	2027	2028	2029	2030	2031
Summer Low	$91	$94	$96	$98	$100	$99	$99	$97
Summer Medium	$336	$334	$333	$330	$326	$321	$316	$310
Summer High	$948	$873	$860	$835	$807	$772	$749	$725
Winter Low	$85	$84	$84	$83	$82	$80	$77	$74
Winter High	$632	$592	$559	$540	$514	$482	$466	$432
Total	**$2,091**	**$1,977**	**$1,933**	**$1,886**	**$1,829**	**$1,754**	**$1,707**	**$1,639**

[74] *See* Docket No. LC 84, IPC response to OPUC IR No. 102 attachment 2.

[75] *See* Docket No. LC 84, IPC response to OPUC IR 102 attachment 2.

[76] IPC 2023 IRP appendix C at 19; IPC response to OPUC IR 102 attachment 2.

[77] IPC 2023 IRP at 100-101.

Energy Service Agreement Customers

ESA customers are Idaho Power's largest customers.[78] These ESA customers comprise the entire forecast category labeled "additional firm load". [79] The Company's tariff requires Idaho Power provide electric service greater than 20 MW under a special contract schedule negotiated between Idaho Power and each ESA.[80] Each ESA customer develops its own energy and peak-demand forecast decremented by EE measures, wherein each customer conducts its own internal cost-effectiveness evaluation.[81] IPC explained that the Company assumes the analyses are cost-effective; however, IPC described having little transparency into the internal analysis or the EE measures the ESA adopts.[82] IPC does not incorporate additional EE measures for these ESA customers into their IRP or EE potential study.[83] Staff is concerned that what is cost-effective for an ESA customer would not be what is cost-effective for IPC and, by extension, ratepayers.

Recommendation 24: Staff recommends, in Reply Comments, the Company provide additional portfolio runs with more EE bundled by cost and customer class, such as the Company's Sector-Level Cost Bundles and a bundle with zero cost EE measures.

Section 12. Demand Response

The peak summer capacity of Idaho Power's existing DR programs – 320 MW – was included in the 2023 IRP model. Though there are no DR-related items in the near-term Action Plan, the model selects an additional 160 MW of DR later in the planning period. The Company used an Idaho Power-specific potential study to inform the modeling of additional DR, and this addressed many of Staff's concerns from the 2021 IRP.

The 2021 IRP preferred portfolio included 300 MW of DR in 2022, which was an estimate of summer capacity of the Company's programs at the time.[84] The model then selected an additional 100 MW, adding 20 MW in 2023, 2025, and 2038 through 2040.[85] The Action Plan included one DR-related item, namely: 2022-2025 - redesign existing DR programs then determine the amount of additional DR necessary to meet the identified need.[86]

In its analysis, Staff examined why the model did not select additional DR, exploring DR costs, the modeling of DR effective load carrying capacity (ELCC), and the appropriateness of the size of blocks of DR made available to the model. Ultimately Staff learned that Idaho Power had been actively planning and conducting a DR potential study specific to the Company's service area, and that the results of this study would serve as a new data source for modeling DR in the next IRP. As such, Staff recommended that:

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[78] Idaho Power's ESA customers include Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); INL; Brisbie, LLC (Meta Platforms, Inc.); and several anticipated new ESA customers. IRP App. A at 33.

[79] IPC 2023 IRP App. A at 33; *see also supra* Section 1, Fig. 4 (Staff's discussion above notes that the primary driver of the Company's near-term energy demand comes from the load forecasts of ESA customers.).

[80] IPC 2023 IRP at 106.

[81] *See* Docket No. LC 84, IPC response to Staff's OPUC IR No. 113.

[82] Informal discussions with IPC and Staff, January 22, 2024.

[83] *See* Docket No. LC 84, IPC response to Staff's OPUC IR No. 113.

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

[85] *See* Docket No. LC 78, Idaho Power, 2021 IRP, December 30, 2021, Table 11.2, p. 152.

[86] *See* Docket No. LC 78, Idaho Power, 2021 IRP, December 30, 2021, p. 167.

> The Company model new DR for the 2023 IRP based on the results of the IPC-specific DR potential study expected to be complete in the fall of 2022. Results should include exploring whether current programs have additional potential, additional kinds of DR programs including pricing programs, and more accurately estimating costs of future programs.[87]

Idaho Power took the first of what Staff understands may be several steps in executing the DR-related action item from the 2021 IRP. In Docket No. ADV 1355 (Advice No. 21-12) the Company proposed, and the Commission approved, changes to Idaho Power's DR programs.[88] The Company's analysis demonstrated these changes improve the ELCC of the DR programs from 17 to 56 percent.[89] The changes represented the termination of the stipulation that guided Idaho Power DR programs since 2013.[90] These changes were being developed and implemented concurrently with the 2021 IRP, making the 2023 IRP the first to fully reflect the updated program parameters in its modeling.

Idaho Power completed the DR potential study, conducted by Applied Energy Group, Inc., as scheduled in 2022.[91] The study was used to inform modeling for the 2023 IRP and includes estimated capacity and 20-year levelized costs for approximately 15 program options, including pricing programs such as time-of-use tariffs.[92] Staff understands that though the study utilizes data and assumptions from the Northwest Power and Conservation Council (NWPCC) 2021 Power Plan, these were updated with service-territory specific information where available.[93]

The 2023 IRP includes 320 MW of DR. Staff understands this amount is based on observed (as opposed to estimated) peak summer capacity from all of the Company's existing programs.[94] The DR potential study identified an additional 180 MW of new DR. The preferred portfolio includes an additional 160 MW of DR, selecting 20 MW in 2029 and in 2033, and selecting 40 MW annually from 2034 through 2036.[95]

Staff Analysis

Staff is pleased to see the completion, and the utilization of the DR potential study in the 2023 IRP. Staff is also glad to see the inclusion of pricing programs, both in the study and as a modeled resource in the

[87] *See* Docket No. LC 78, OPUC Staff, Final Comments, September 8, 2022, Staff Recommendation 2, p. 21.

[88] *See* Docket No. ADV 1355, 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 season, 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 revamp also increased incentives for program participants to offset a potential participation decline resulting from the changes. For a summary see Table 3, p. 6.

[89] *See* Docket No. ADV 1355, Advice No. 21-12, Attachment 2, p. 4.

[90] *See* Order No. 13-482 in Docket No. UM 1653, December 19, 2013.

[91] *See* Idaho Power Company Demand Response Potential Assessment Report, https://docs.idahopower.com/pdfs/EnergyEfficiency/Reports/Idaho%20Power%20DR%20Potential%20Analysis%20Memo.pdf.

[92] *See* Idaho Power Company Demand Response Potential Assessment Report, Figure 3, p. 5 and Figure 4, p. 6.

[93] *See* Idaho Power Company Demand Response Potential Assessment Report, p. 1 and 2. *See* also November 10, 2022 IRPAC meeting, 2022 Idaho Power DR Potential Study – For Reference Only, https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2023/2023IRP_DR-PotentialStudyResults.pdf, slide 12.

[94] *See* Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 70.

[95] *See* Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, Table 11.1, p. 146.

IRP. Staff reviewed the DR Potential Assessment Report and found the study appears to have employed standard practices and approaches.

To model the additional 180 MW of new DR, Staff understands that Idaho Power used the potential study to create five groups of similar DR programs, which were based on similar amounts of capacity, costs, and characteristics. [96] These five groups were then consolidated further into three buckets, which were included in the IRP model as follows:

- 100 MW of existing program expansion at $47/kW-year,
- 60 MW of storage programs at $258/kW-year, and
- 20 MW associated with pricing programs at $88/kW-year.[97]

Staff's initial review suggests that the amount of DR and the costs of that DR made available to the model appear reasonable, and consistent with the potential study.[98]

Staff understands that the model selected the following types of DR as presented in Table 4 below.

Table 4: Model selection of additional DR program

Year	Program Description	MW
2029	Existing program expansion	20
2033	Existing program expansion	20
2034	Existing program expansion	20
	Storage program	20
2035	Existing program expansion	20
	Storage program	20
2036	Existing program expansion	20
	Storage program	20

Staff finds the model's selection of existing program expansion reasonable. However, Staff is interested in better understanding why the model selected additional MW of storage program before selecting pricing program, and if ELCC plays a part in this outcome.

Like in the 2021 IRP, Staff has concerns that the 20 MW size of blocks of DR made available to the model lack granularity and are not representative of growth of the resource in reality. Staff highlights that Idaho Power's own DR potential study forecasts annual growth in 5 to 13 MW increments, as represented in Figure 11 below. Staff discussed this concern with the Company, and Idaho Power expressed openness to a different size increment in the future.

[96] *See* November 10, 2022 IRPAC meeting, Energy Efficiency & Demand Response for the 2022 IRP, https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2023/2023IRP_DRandEE%20Potential.pdf, slide 22.

[97] *See* for amounts Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 71. *See* for costs Idaho Power response to OPUC IR No. 97.

[98] Staff's conclusion that the costs of additional DR is reasonable is based in part on current program costs. Using total costs and maximum potential capacity assumptions results in the following cost calculations: A/C Cool Credit - $30.99 per kW; Flex Peak Program - $23.34 per kW; Irrigation Peak Rewards - $40.97 per kW. *See* 2023 IRP Appendix B: DSM Annual Report.

Figure 11: Incremental increases – less than 20 MW – in the 20-year potential for new DR[99]

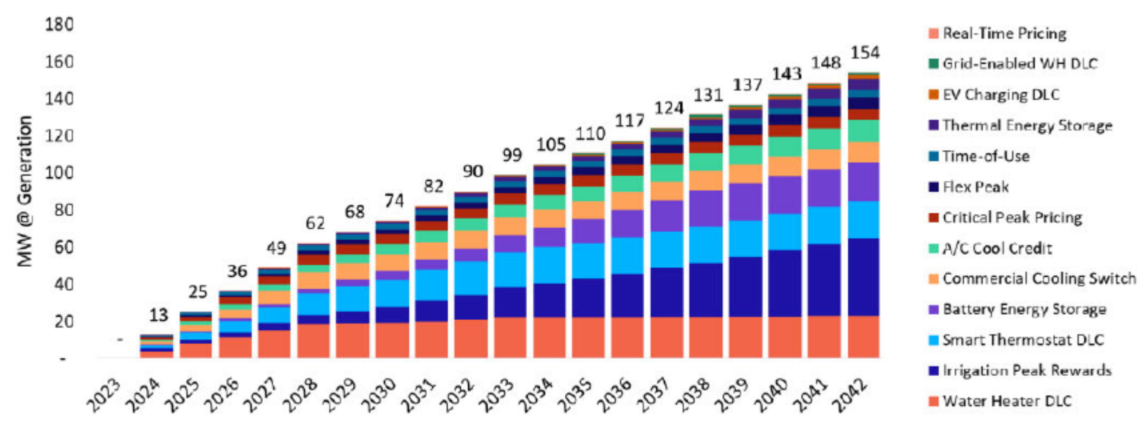

Figure 3 20-Year Demand Response Potential for New Resources by Program Option

Like in the 2021 IRP, Staff has questions about the ELCC of the three buckets of DR as modeled, specifically how it compares to modeling in the 2021 IRP, and how it compares to other resources, for example storage. This is of particular interest given the expected improvement in DR ELCC resulting from the programmatic changes noted previously. To begin to answer these questions Staff requested all code and data used for all ELCC modeling done in the IRP.[100] Staff's initial review suggests that programmatic changes resulting from ADV 1355 (Advice No. 21-12) were accurately modeled in the IRP, and that DR appears to have been modeled reasonably and fairly, vis-à-vis other resources. Staff continues its review of ELCC modeling in the 2023 IRP and may discuss it further in Final Comments.

Staff appreciates that the modeling of DR was grounded in a third-party potential study and finds that the overall transparency of modeling this resource has improved compared to the 2021 IRP. Staff continues to explore this issue and may discuss it further in Final Comments. Based on the above, Staff has the following requests for the Company:

Recommendation 25: Please discuss, in Reply Comments, why the model selected additional MW of storage program priced at $258/kW-year, before selecting pricing program priced at $88/kW-year.

Recommendation 26: Please discuss, in Reply Comments, any benefits or drawbacks the Company sees in making 10 MW (instead of 20 MW) blocks of DR available for the model to select in future IRP modeling exercises. Please also rerun the model using 10 MW blocks or explain why doing so is problematic or misleading.

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[99] *See* Idaho Power Company Demand Response Potential Assessment Report, https://docs.idahopower.com/pdfs/EnergyEfficiency/Reports/Idaho%20Power%20DR%20Potential%20Analysis%20Memo.pdf, Figure 3, p. 5.

[100] *See* Docket No. LC 84, Idaho Power's response to OPUC IR No. 98.

Conclusion

This section concludes Staff's opening comments for Idaho Power's 2023 IRP. Staff welcomes several improvements in the Company's analysis since the 2021 IRP. These comments are composed as constructive feedback to help with the continuous improvement of IPC's resource planning process.

Staff has twenty-six requests for additional information in the Company's reply comments or in the IRP next Update:

Recommendation 1: Staff recommends, in Reply Comments, Idaho Power describe how monthly energy demand is derived as an input to the Company's hourly load forecast.

Recommendation 2: Staff recommends, in Reply Comments, the Company explain why retail price is not used as an independent variable for all nonresidential regression models.

Recommendation 3: Staff recommends, in Reply Comments, the Company compare the inputted value of rates for 2025 for the load forecast with the rates Idaho Power seeks in Docket No. UE 426.

Recommendation 4: Staff recommends, in Reply Comments, the Company explain how the anticipated case of a 70th percentile was calculated relative to the 50th percentile.

Recommendation 5: Staff recommends, in Reply Comments, the Company describe the costs borne by ESA customers that overestimated their load in the 2021 IRP.

Recommendation 6: In Reply Comments, Staff requests that IPC describe all the drivers impacting the capacity needs in the 2023 IRP, and the contribution of each driver on the capacity of planned additional renewable resources.

Recommendation 7: In Reply Comments, Staff requests that IPC provide a timeline of planned RFPs to meet the procurement needs of the 2023 IRP, and the procurement plan for the 325 MW nameplate capacity shortfall in the near-term, either through RFPs or the CEYW program.

Recommendation 8: In Reply Comments, Staff requests that IPC share the reliability studies that determine the extra quantities and costs of the planned regulation reserves required to balance the variability of renewable resources throughout the 20-year planning period.

Recommendation 9: In Reply Comments, Staff requests that IPC share information about the means and costs of providing ancillary services needed to preserve system resilience in the face of high penetration of renewable resources towards the end of the planning period.

Recommendation 10: In Reply Comments, IPC should include a detailed explanation of the need for the Valmy 1 and 2 conversions. The Company should supplement its response with any additional study it may have performed to justify the conversion and continued operation of Valmy 1 and 2 throughout the planning period.

Recommendation 11: In Reply Comments, IPC should explain why additional EE and DR resources were not considered as alternatives to Valmy conversion.

Recommendation 12: In Reply Comments, IPC should discuss its evaluation of cost and risks for customers in the event the Valmy conversion does not materialize or if the converted plants become stranded assets. IPC should clearly discuss resource alternatives and cost/risk management strategies if either of the above situations occur.

Recommendation 13: In Reply Comments, IPC should address the rate implications of its continued ownership of Valmy Unit 1, extension of operating lives of both Valmy 1 and 2 beyond 2025, and Idaho Power's re-participation in Valmy Unit 1 in its conversion.

Recommendation 14: In the next IRP Update, Staff requests that IPC develops a reasonable non-zero estimate of a wind QF renewal rate that utilizes the approach taken for establishing a non-wind QF in line with the analysis undertaken by PacifiCorp in its 2023 IRP to estimate the QF renewal rate.

Recommendation 15: In Reply Comments, Staff requests that IPC explain its strategy for connecting renewable resources along the east-to-west transmission pathway in light of the terms of the asset swap with PacifiCorp in 2026 and the addition of Phase 1 of GWW transmission in 2029.

Recommendation 16: In Reply Comments, Staff requests the Company explain how it makes business decisions on transmission ownership or rights to connect to different markets.

Recommendation 17: Staff recommends, in Reply Comments, the Company provide the modeled hourly wholesale electricity prices for January 2024 from the stochastic run that produced the highest prices for that month.

Recommendation 18: Staff recommends, in Reply Comments, the Company present a comparison of Idaho Power's wholesale electricity purchases in June 2023 and January 2024 with the 2023 IRP's modeling of market purchases during those months in 2024.

Recommendation 19: Staff recommends, in Reply Comments, the Company describe the market purchase bids Idaho Power has received in recent RFPs.

Recommendation 20: In its Reply Comments, Idaho Power should clarify its acknowledgement request, and if seeking acknowledgement of an actual pilot project, it should provide more details on the Company's activities related to this project including, but not limited to those identified in UM 2141 and Order No. 22-115, as well as a project timeline and status update.

Recommendation 21: In its Reply Comments, Idaho Power should share any information available on hydrogen blending options in its existing natural gas plants.

Recommendation 22: In Reply Comments, Staff requests that IPC describe the planning mechanism by which long-term grid needs identified in the DSP inform the capacities planned in the IRP and whether planned capacity limits for distribution-connected storage will need to be adjusted in future IRPs to suit the grid need in the DSP.

Recommendation 23: In Reply Comments, Staff request that the Company provide a comprehensive listing of standards that are adhered to for the design, construction, and operations of all distribution-connected storage projects. The listing should include the standard number, title, description of use and governing board for the standard, with general reference as to how the content is applied in these projects.

Recommendation 24: Staff recommends, in Reply Comments, the Company provide additional portfolio runs with more EE bundled by cost and customer class, such as the Company's Sector-Level Cost Bundles and a bundle with zero cost EE measures.

Recommendation 25: Please discuss, in Reply Comments, why the model selected additional MW of storage program priced at $258/kW-year, before selecting pricing program priced at $88/kW-year.

Recommendation 26: Please discuss, in Reply Comments, any benefits or drawbacks the Company sees in making 10 MW (instead of 20 MW) blocks of DR available for the model to select in future IRP modeling exercises. Please also rerun the model using 10 MW blocks or explain why doing so is problematic or misleading.

This concludes Staff Comments.

Dated this 7 day of February, 2023, at Salem, Oregon.

Kim Herb
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CERTIFICATE OF SERVICE

LC 84

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180 to the following parties or attorneys of parties.

Dated this 20th day of December, 2023 at Salem, Oregon

Kay Barnes

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