BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 84

In the Matter of IDAHO POWER COMPANY, 2023 Integrated Resource Plan.	Staff Final Comments

Table of Contents

Executive Summary

This document includes Staff's final comments on Idaho Power Company's (IPC, Idaho Power, or the Company) 2023 IRP filed on September 29, 2023. It is preceded by, and reflects issues raised in Staff's Opening Comments, other Parties' opening comments, Idaho Power's Reply Comments, and continued engagement with the Company. Staff appreciates Idaho Power's IRP team for its continued engagement with Staff during this review.

Staff recognizes that Idaho Power is managing its long-term resource planning in a time of uncertainty due to load growth, technological advances, and changing market conditions. In the face of the challenges of increasing demand for clean energy coupled with a mandate for reliability and affordability, the Company has endeavored to present a least-cost, least-risk Preferred Portfolio in the 2023 IRP. However, for the purpose of further refining the resource planning process, Staff includes a number of recommendations and expectations for Idaho Power to consider when preparing the next and future IRPs.

In a recent letter filed by the Company,[1] Idaho Power informed the Commission that the online date of the Boardman to Hemingway (B2H) transmission line is delayed from July 2026 to November 2026 due to pending approvals from several federal and state government agencies. Staff can confirm that Staff's Final Comments would not change because of this delay due to the large cost difference between the Preferred Portfolio with B2H in-service in July 2026 and the no B2H portfolio. The relatively low additional cost of the delayed November 2026 in-service date compared to the July 2026 in-service date does not alter the portfolio selection in the IRP process and the portfolio with B2H online in November 2026 becomes the Preferred Portfolio in this document.

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

Section 1 – Valmy Coal to Gas Conversion: Idaho Power seeks acknowledgment of the conversion of Valmy units 1 and 2 from coal to natural gas in the Summer of 2026. The Company has demonstrated in its IRP portfolio analysis that the conversion of the North Valmy plant from coal to gas fueled generators is a cost effective and low risk resource for its customers. Staff, however, notes a lack of clarity around contingency plans in the event the conversions are delayed and the extent to which the converted plants will be used and balance other renewables on the system. Staff recommends that the Commission acknowledge IPC's action item regarding conversion of Valmy 1 and 2 in 2026 and provides direction regarding additional analysis around the conversion as needed.

Section 2 – Wind and Solar Resources: Idaho Power seeks acknowledgment of acquiring up to 1,425 MW of combined wind and solar in 2026-2028. The Company focused on fulfilling its procurement needs for the projected wind and solar resources in the Preferred Portfolio in the near-term (2024-2028) through multiple RFPs. However, it is not clear whether Idaho Power has a plan in place for the RFPs necessary for procuring the quantities projected in the Preferred Portfolio in the longer term. While Staff

[1] See Docket No. LC 84, Idaho Power 2023 IRP, Idaho Power's Update Boardman to Hemingway Timing, April 19, 2024.

recommends that the Commission acknowledge IPC's acquisition of up to 1,425 MW of combined wind and solar in 2026-2028, it also expects IPC to articulate its longer-term procurement plan in the next IRP.

Section 3 – Transmission: Idaho Power seeks acknowledgment to bring Phase 1 of Gateway West (GWW) online by 2028, as a means to connect more renewable energy from the east. The addition of GWW Phase 1 will enable the connection of 1000 MW of renewable resources and the saving of more than $500 million to the cost of the Preferred Portfolio due to avoiding the addition of gas facilities near load centers to meet the capacity need. Staff supports the acknowledgement of bringing the first phase of GWW online by 2028.

Section 4 – Market Access: Idaho Power seeks acknowledgment to continue exploring the Company's potential participation in the SWIP-North project to access more than 1,000 MW of capacity from the Desert Southwest market in 2024. A final decision by Idaho Power on this project would possibly alter the dynamics of resource selection in the Preferred Portfolio. Prior to the public meeting scheduled for the Commission's decision on this IRP and subject to the Company signing firm agreements, Staff recommends that the Company update the Commission with the latest developments in the SWIP-North project and any impacts on this IRP. Staff recommends the acknowledgement to continue exploring potential participation in the SWIP-N project in 2024 with Staff's condition.

Section 5 – Distribution-Connected Storage: Idaho Power seeks acknowledgment to install cost effective distribution-connected storage in 2025-2028. Idaho Power's first implementation of distribution-connected storage is expected to be the installation of 11 MW of batteries at four locations with expected in-service dates in 2024. Staff notes its concerns regarding the fire event at one of these projects at Melba substation and the implications on implementation changes and cost of future distribution-connected storage projects as a result of the fire. At this time, Staff recommends the Commission acknowledge Idaho Power's proposed action to install cost effective distribution-connected storage in 2025-2028, with expectations for the next IRP.

Section 6 – Long Duration Storage Pilot: Idaho Power is seeking acknowledgement to explore the idea of a long duration storage pilot in 2024-2028. Staff is supportive of Idaho Power's plan to evaluate whether such a pilot program is feasible and of value. Staff recommends that the Commission acknowledge Idaho Power's proposed action to explore a 5 MW long-duration storage pilot project in 2024-2028.

Section 7 – Wind Qualifying Facilities (QFs): In the 2023 IRP, the Company assumed an unrealistic zero wind QF renewal rate in base planning. Assuming that no wind QFs will renew will result in the utility likely overestimating its resource needs and over-procuring resources. Idaho Power should develop a reasonable non-zero estimate of a wind QF renewal rate in the next IRP, in line with the analysis undertaken by PacifiCorp in its 2023 IRP to estimate the QF renewal rate, and until such a rate is established, it should adopt a wind QF renewal rate of 75 percent.

Section 8 – Load Forecast: Staff finds the Company's overall forecast of system load from prior IRPs to be relatively accurate, suggesting that this IRP's forecast may not be too far off either; however, Staff is concerned that the Company has selected independent variables without proper hypothesis testing. Also, the Company uses a lower probability (70th percentile) as the expected load forecast. Staff finds the 50th percentile as the planning case load forecast to be more reasonable.

Section 9 – Wholesale Electricity Prices: Idaho Power endogenously models wholesale electricity prices to forecast them for Idaho Power's balancing area. Staff finds the Company's accuracy of forecasting wholesale electricity prices in the IRP to be an improvement over the 2021 IRP in the planning case. However, the observed prices in January 2024 are still significantly higher than the Company's worst-case stochastic run predicted for that month.

Section 10 – Energy Efficiency: The 2023 IRP lost 80 MW of cumulative cost-effective energy efficiency (EE) measures decremented from the load forecast, as compared to the 2021 IRP. Additionally, no EE bundles were selected by the Aurora model in the Preferred Portfolio. Staff is concerned that the methodology of calculating avoided cost is causing the EE measures to be disadvantaged in planning. In the 2025 IRP and future IRPs, the energy efficiency avoided cost calculation methodology should rely on the most recently "filed" rather than the most recently "acknowledged" IRP in its energy efficiency program planning.

Section 11 – Demand Response (DR): The 2023 IRP model included the peak summer capacity of Idaho Power's existing DR programs, 320 MW, and selected 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 in this IRP, and this approach addressed many of Staff's concerns from the 2021 IRP. Though there are no DR-related items in the near-term Action Plan**,** Staff raised two issues in Opening Comments and Idaho Power responded satisfactorily to both. Staff appreciates the Company's invitation to provide input on the second issue – DR block sizes made available to the model – in the 2025 IRP model, and thus formally notes here an expectation to engage Staff and stakeholders on this topic in developing the next IRP.

Action Plan

Idaho Power's 2023 IRP Near-Term Action Plan (2024-2028) includes eight actions for which the Company is seeking acknowledgement by the Commission.[2] Table 1 shows a list of the eight action items, year of completion, Staff's recommendation, and the location in this document where further discussion on each action item can be found.

Table 1: Idaho Power 2023 IRP Action Items for Regulatory Acknowledgement and Staff's Recommendation

Action Item	Action Description	Year of Completion	Staff's Recommendation	Further Discussion
1	Continue exploring potential participation in the SWIP-North project	2023–2024	Acknowledge	Section 4
2	Explore a 5 MW long-duration storage pilot project	2024–2028	Acknowledge	Section 6
3	Install cost effective distribution-connected storage	2025–2028	Acknowledge with condition	Section 5
4	Bring B2H online	Summer 2026	Not Acknowledge	Executive Summary

[2] See Docket No. LC 84, Idaho Power 2023 IRP, September 29, 2023, p 8.

Action Item	Action Description	Year of Completion	Staff's Recommendation	Further Discussion
5	Convert Valmy units 1 and 2 from coal to natural gas	Summer 2026	Acknowledge	Section 1
6	If economic, acquire up to 1,425 MW of combined wind and solar, or other economic resources	2026–2028	Acknowledge	Section 2
7	Include 14 MW of capacity associated with WRAP	2027	Acknowledge	Executive Summary
8	Bring the first phase of GWW online (Midpoint–Hemingway #2 500-kV line, Midpoint–Cedar Hill 500-kV line, and Mayfield substation)	2028	Acknowledge	Section 3

As shown in Table 1, Staff is recommending acknowledgement for all action items, apart from action item 4, which is to bring B2H online by Summer 2026. Staff makes this recommendation because the procurement of B2H project is already underway after the acknowledgement of its construction in action item 8 in the 2021 IRP.

Action item 7 is not discussed in this document, as Staff already concluded in Opening Comments that it is generally comfortable with the Company's effort to model 14 MW of capacity benefits associated with its participation in the Western Resource Adequacy Program (WRAP) beginning in 2027.

Section 1. Valmy Coal to Gas Conversion

Idaho Power seeks acknowledgment of the conversion of Valmy units 1 and 2 from coal to natural gas in the Summer of 2026. The Company has demonstrated in its IRP portfolio analysis that the conversion of the North Valmy plant from coal to gas fueled generators is a cost effective and low risk resource for its customers. Staff, however, notes a lack of clarity around contingency plans in the event the conversions are delayed and the extent to which the converted plants will be used and balance other renewables on the system. Staff recommends that the Commission acknowledge IPC's action item regarding conversion of Valmy 1 and 2 in 2026 and provide direction regarding additional analysis around the conversion as needed.

Valmy Conversion – Need and Usage

Staff sought a better understanding of the need for the gas conversions of the Valmy plants as well as the risks of the converted units. Idaho Power explained that the coal plant conversions are among the least-cost, least-risk resource options to address the growing need on its system and amidst uncertainties associated with emerging technologies. Idaho Power further described the various uses of the converted plant in terms of adding resource diversity and supporting intermittent generation.

Regarding operating the converted plant, Idaho Power explains that it plans to use the converted gas plants to serve its baseload as well as contribute towards peak needs. In response to information requests (IRs) from Staff, Idaho Power provided information on projected capacity factors and capacity contributions of the converted units for the planning period as well as historical data of the same units pre-conversion.[3] After reviewing the data, Staff concludes that Valmy gas units will continue to operate as the coal units to serve baseload; however, Staff is not convinced about their role in addressing system peak.

Renewable Northwest (RNW) expressed reliability concerns if the Valmy conversions were to function as peaking resources. The Company modeled the new coal-to-gas converted thermal units as dispatchable resources to support system reliability in the Reliability and Capacity Assessment Tool (RCAT).[4] RNW pointed out potential reliability risks, especially if the newly-converted units are used as peaking resources when the risk of correlated, weather-related outages is highest.[5] RNW requested that IPC share the monthly outage table by which the dispatchable gas resources are modeled, particularly for baseload and peaking gas units.

In Reply Comments, Idaho Power argues that, unlike exits from coal units, the four additional (Bridger 1 and 2 and Valmy 1 and 2) coal-to-gas conversions result in a considerable increase in the amount of flexible dispatchable capacity to balance increased variable energy resource penetration, if needed. The Company did not provide additional data supporting its claims on the flexibility of the converted units.

Staff Analysis and Conclusions

Staff reviewed the projected capacity factors for the converted Valmy units and compared it with the historical capacity factors for the coal units as provided by Idaho Power in response to Staff information requests. Idaho Power has also confirmed that the gas units will remain the same in terms of usage and performance as the coal units.[6] Staff finds support for the usage of converted Valmy plant to support the Company's baseload.

Despite Idaho Power's claim that Valmy 1 and 2 converted units will provide flexible dispatchable capacity, Staff is not convinced that they will. Staff agrees with RNW that greater visibility into capacity contribution evaluation of these thermal resources is warranted. Therefore, Staff expects that in its next IRP the Company provide the hourly totals for the Valmy units either peaking or baseload and compare the same for Simple-Cycle Combustion Turbine (SCCT), Combined-Cycle Combustion Turbine (CCCT), and four/eight-hour batteries. This data would provide Staff and RNW a better understanding of the operation of the converted gas units and how they compare with other resources and historical capacity data for the same units.

Valmy – Delayed Conversion Risk

Staff expressed concern that there are risks of delays in the gas plants coming online due to the absence of a contract between Idaho Power and NV Energy regarding the gas conversions, or more detailed information on the conversions including gas supply and pipeline contracts. Idaho Power explains that because the Valmy units are existing plants, they have minor permit requirements to effectuate the

[3] See IPC Response to Staff IR Nos. 132 and 133.

[4] See Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, Appendix C, pp. 90-91.

[5] See Docket No. LC 84, Idaho Power 2023 IRP, Renewable Northwest's Opening Comments, February 7, 2024, pp. 3-4.

[6] See Docket No. LC 84, IPC response to Staff IR No. 39.

conversions, that the units would be less impacted by supply chain disruptions, and the plant location enables access to multiple gas lines to hedge against fuel price volatility.[7]

Staff Analysis and Conclusions

Staff understands that there are reasons to believe that the conversions will be complete by the projected date of 2026 but that project delays are not unusual (as seen in the B2H online date being delayed) and the Company should evaluate impacts of potential delays and have a contingency plan to address it. Therefore, Staff expects that Idaho Power evaluate an alternative portfolio with delayed Valmy conversion in its next IRP in the event it experiences any delay in the conversion schedule.

Valmy Conversion and Air Pollution

Idaho Power proposes to participate in the conversion of both Valmy Unit 1, which it had exited in 2019, and Valmy Unit 2 with NV Energy, which is the 50 percent owner of the plant. In Opening Comments Staff expressed a general concern around the shift from coal exits to gas conversions in IPC's 2023 IRP relative to its previous IRPs, implying a shift towards more emitting resources in its portfolio compared to both 2019 and 2021 resource plans.

RNW expressed similar concerns regarding the increase in the number of gas conversions in Idaho Power's IRP and noted that Idaho Power did not address the resulting nitrogen oxides (NO_X) and sulfur dioxide (SO_2) emissions and local air pollution from the converted plants. RNW recommends IPC evaluate an alternative portfolio in its next IRP with a 2030 exit date from all coal operations and without the gas conversion of Valmy 2 and Bridger 3 and 4 units. RNW notes that the alternative portfolio would provide a more robust analysis of coal plant conversions and a clear understanding of the emissions impacts.

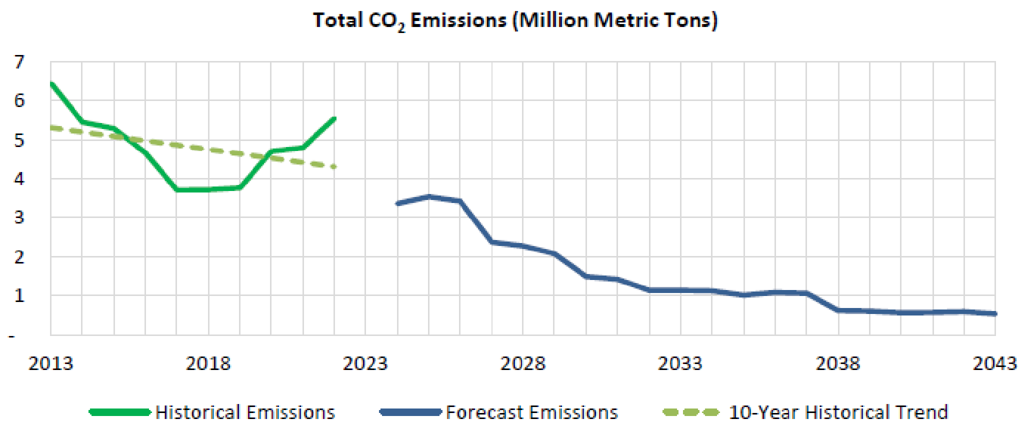
Staff Analysis and Conclusions

Idaho Power stated in its IRP and in its Reply Comments that it should still be on track to reduce carbon emissions in future years. While Figure 1[8] from Idaho Power's 2023 IRP shows a declining trajectory for carbon emissions over the planning period **–** indicating that the Company is going to achieve reduction in carbon emissions with gas conversions and renewables added to its portfolio – Staff is interested to see in the next IRP how the near-term gap between actual and forecasted emissions is bridged.

[7] See Docket No. LC 84, Idaho Power 2023 IRP, Idaho Power's Reply Comments, March 7, 2024, p. 22.
[8] Reproduced from Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, Table 1.4, p. 14.

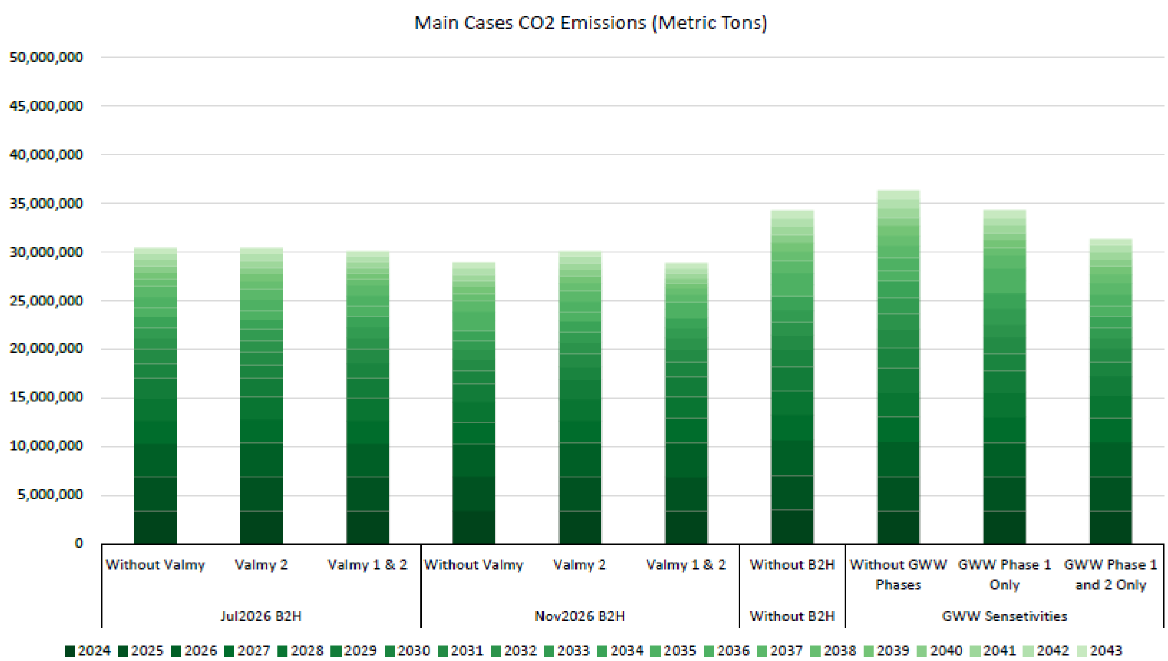
Figure 1: Idaho Power historical and forecasted CO_2 emissions

Table 1.4 Historical and forecasted emissions



Idaho Power also provides estimates of carbon emissions for selected portfolios with and without Valmy 1 and 2 conversions. Figure 2 shows that the portfolios with Valmy 1 and 2 conversions for both the July 2026 B2H and November 2026 B2H online dates have lower emissions over the planning period compared to portfolios without Valmy conversion.[9]

Figure 2: Idaho Power estimated portfolio emissions from 2024 to 2043



[9] Figure reproduced from Docket No. LC 84, Idaho Power, 2023 IRP, Figure 10.1, p. 139.

Staff believes these estimates to be reasonable as natural gas replaces coal and as more renewables are added to the system. Idaho Power, however, does not address air pollution from NO_x and SO_2 emissions from the converted gas plants or the impact on local communities of the localized increase in GHG emissions, as pointed out by RNW.

Staff realizes that IPC's current cost-benefit analysis does not account for costs related to air pollution from non-carbon pollutants and resulting impacts on local communities. Generally speaking, both SO_2 and NO_X emissions are much lower for natural gas plants compared to coal plants. For instance, a study showed that in 2010 in the U.S. power sector that, "(c)ompared with natural gas units, coal-fired units produced over 90 times as much sulfur dioxide, twice as much carbon dioxide and over five times as much nitrogen oxides per unit of electricity, largely because coal contains more sulfur and carbon than natural gas".[10] Nonetheless Staff believes air pollution and local impacts are important considerations if the Company plans on continuing using fossil fuel generation resources. In the absence of clear Commission guidelines on the treatment of non-carbon pollutants and localized impacts of GHG emissions in IRPs, Staff expects that Idaho Power provide cost estimates of SO_2 and NO_X emissions related to the converted plant, in its advisory council meetings in future.

Valmy Conversion Action Item

Based on Idaho Power's portfolio analysis, Staff believes that Idaho Power has demonstrated the Valmy gas conversion to be an economic and low risk option for its customers. Hence, Staff recommends that the Commission acknowledge IPC's action item regarding conversion of Valmy 1 and 2 in 2026, as Action Item 5 in Table 1.

Draft Recommendation 1: Acknowledge Idaho Power's proposed action to convert Valmy Units 1 and 2 to natural gas in 2026.

Expectation 1: In its next IRP, Idaho Power must evaluate two alternative portfolios to address risks associated with coal to gas conversions:

I. ***Exit all coal plants in 2030 without Valmy and Bridger 3 and 4 conversions.***
II. ***Delay Valmy conversion with a November 2026 online date for B2H.***

Expectation 2: In the next IRP, the company should provide workpapers for the projected number of hours for both baseload and peaking operation of the Valmy coal-to-gas converted units, and the corresponding hours for CCCT, SCCT, 4-hour and 8-hour batteries, in the Preferred Portfolio.

Expectation 3: In the next IRP, as suggested by RNW, IPC should evaluate an alternative portfolio with a 2030 exit date from all coal operations and without the gas conversion of Valmy and Bridger 3 and 4 units for a better understanding of emissions implications of continued use of fossil fuel generation.

Expectation 4: In the lead up to the 2025 IRP, Idaho Power should provide cost estimates of SO_2 and NO_X emissions related to the converted plant, in its advisory IRPAC meetings.

[10] U.S. Government Accountability Office 2012 Report titled *Air Emissions and Electricity Generation at U.S. Power Plants*, May 18, 2012.

Section 2. Wind and Solar Resources

Idaho Power seeks acknowledgment of acquiring up to 1,425 MW of combined wind and solar in 2026-2028. The Company focused on fulfilling its procurement needs for the projected wind and solar resources in the Preferred Portfolio in the near-term (2024-2028) through multiple RFPs. However, it is not clear whether Idaho Power has a plan in place to run the RFPs necessary for procuring the quantities projected in the Preferred Portfolio in the longer term. While Staff recommends that the Commission acknowledge IPC's acquisition of up to 1,425 MW of combined wind and solar in 2026-2028, it also expects IPC to articulate its longer-term procurement plan in the next IRP.

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, a difference of 1,920 MW. This increase in capacity poses challenges in terms of the alignment of procurement activities with acknowledged IRPs and planning for adequate time and resources to review RFPs. In addition, Staff needs to understand the implications in this IRP of this increase of variable energy resources (VERs) on maintaining system reliability and resilience.

Longer-term Procurement Planning

In Opening Comments, Staff requested the Company 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. In Reply Comments, the Company focused on how its near-term procurement needs would be met through multiple RFPs currently underway.[11] However, the Company failed to elaborate on its plan to fulfil its longer-term energy and capacity needs identified in the 2023 IRP.

Staff's Analysis and Conclusions

Staff recognizes the challenges facing Idaho Power regarding the urgency of procuring resources to meet the robust load growth facing the Company throughout the 20-year planning period and the Company's own goal to provide 100 percent clean energy by 2045. Staff notes two challenges with the current procurement process: 1) maintaining alignment with an acknowledged IRP, and 2) ensuring adequate time for Staff, stakeholders, and the Independent Evaluator to review RFPs. The supposedly sequential process from identification of a resource need in an acknowledged IRP to resource acquisition via a competitive RFP process is being challenged by a host of new issues. While Oregon's IRP and RFP processes are designed to protect ratepayers by ensuring that the resource needs and eventual procurement volumes are aligned with an IRP vetted by Staff and stakeholders, such an approach is becoming increasingly difficult in a rapidly changing environment.

Staff welcomes opportunities and ideas for flexibility in Oregon's RFP process. Staff would note that the Commission has undertaken an IRP/RFP redesign to better support the energy transition. The redesign process should conclude in 2025. In the next IRP, Staff requests Idaho Power include a roadmap of

[11] In Docket No. LC 84, Idaho Power 2023 IRP, Idaho Power's Reply Comments, March 7, 2024, pp. 14-15, Idaho Power explained that it would fulfil its procurement needs in 2024-2028 via multiple RFPs, including the 2022 RFP (for 2024/2025 resources), 2026-2027 RFP, and recently announced 2028 RFP.

procurement activities meeting the needs represented in the action plan window,[12] while discussing plans for the acquisition of long-lead time resources that reflects the Commission's redesign of Oregon's RFP process.

System Reliability and Resilience

System Reliability

In Opening Comments, Staff remarked that there had been no notable increase in the capacity of new fast-ramping dispatchable resources in the 2023 IRP to balance the variability of renewables. Staff also commented that it was unclear how much regulation reserves provided by flexible resources would be needed and whether it had been accounted for in the Aurora model.

In Reply Comments, Idaho Power argues that, unlike exits from coal units, the four additional coal-to-gas conversions result in a considerable increase in the amount of flexible dispatchable capacity. The Company states that this flexible capacity has been accounted for in the model because the Aurora model has the regulation reserves as a constraint. This means that the model sees the signal to add flexible dispatchable resources to balance increased variable energy resource penetration, as needed.

In response to Staff IR 134 inquiring about the capacity and flexibility attributes of the converted units, the Company responded with a table of the model results of the total starts and total run hours for each of the Valmy converted units for every year in the 20-year planning period. The Company summarized the results to indicate that each converted gas unit is expected to average about 20 occurrences of starts-from-cold per year and running roughly one week at a time. Once online, the gas units will likely provide flexible capacity between their nameplate and minimum output, based on their capacity factors and run hours.

Staff's Analysis and Conclusions

Staff finds that the data for the Valmy converted gas units show similar performance characteristics to the same units running on coal pre-conversion. This finding is confirmed by the Company in response to Staff IR 39 where the Company states that it expects the unit characteristics and performance of the gas conversions for both Bridger and Valmy to remain similar to their characteristics and performance under coal operations.

In response to Staff IR 135 requesting a comparison of the ramping constraints of the converted Valmy units to a SCCT at all modes of operation, the Company provided the information in Table 2.

[12] As an example, Idaho Power could look to the filing made by PGE in Docket No. UM 2274 in which PGE identified the energy and capacity needs in the Action Plan windows through 2030, assumed a typical timeline for RFPs and aligned the procurement process with the IRP filing schedule. See PGE's July 17, 2023 filing in UM 2274: PGE's Planning and Procurement Forecast pursuant to Order No. 23-146, https://edocs.puc.state.or.us/efdocs/HAD/um2274had162126.pdf.

Table 2: Valmy (260 MW) ramp rates – table reproduced from IPC's response to Staff IR 135

Characteristic	Valmy Gas	SCCT
Cold Start time	1 Day	1 hour
Minimum up time	5 days	2 hours
Minimum down time	1 Day	1 hour
Minimum generation	20%	50%
Ramp Rate % (Nameplate Capacity/Minute)	1.7%	8.4%

With regards to regulation reserves, Staff concludes from Table 2 that for peaking and regulation reserve purposes there are significant differences between the characteristics of the Valmy and SCCT units. Although there is more headroom for the converted gas units' output to move upwards from minimum load once online, the converted units start time and ramping rate are significantly lower than those of SCCTs. To get a better picture of the flexibility of the converted units, Staff expects that the Company provide in the next IRP the projected running hours of the converted gas units for regulation reserves and how they compare with SCCT or 4-hour batteries.

<u>System Resilience</u>

In Opening Comments, Staff raised the issue of how having high penetration of Variable Energy Resources (VERs), represented in the high volumes of wind and solar resources, may impact system resilience.[13] Staff was concerned 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.

In Reply Comments, the Company explained that only regulation reserves are modeled as an ancillary service in the IRP, but not the other types of ancillary services to preserve system resilience that Staff mentioned, such as frequency response, system strength, voltage stability and black start capability. However, the Company elaborated that it actively conducts studies to make sure the system remains stable and has enough frequency response capabilities through Idaho Power's compliance with the North American Electric Reliability Corporation (NERC) requirements.

Staff's Analysis and Conclusions

As the penetration of renewables increases towards the end years of the renewable dominated portfolios, it is unknown if the costs for ancillary services required for system resilience are significant enough to impact the overall portfolio cost. Staff is concerned that, in the future, system stability issues may require altering the model's resource selection or adding extra resources to the portfolio. In future IRPs, Staff expects the Company to provide a description of how modeling co-optimized ancillary services in developing the preferred portfolio and to the extent it had any impact on portfolio costs. Additionally, Staff expects the next IRP to detail how participation in regional market organization is impacting planning for reliable, least-cost, least-risk operations.

[13] See Docket No. LC 84, Idaho Power 2023 IRP, Staff's Opening Comments, February 7, 2024, pp. 16-17.

Wind and Solar Resources Action Item

Based on the information provided by Idaho Power on the near-term procurement of wind and solar resources and the balancing of such resources in the short and long term, Staff recommends that the Commission acknowledge IPC's acquisition of up to 1,425 MW of combined wind and solar, as Action Item 6 in Table 1.

Draft Recommendation 2: In the next IRP, the Company should elaborate on its anticipated cadence of RFPs and identify the future IRPs to which expected RFPs will be connected.

Expectation 5: In the next IRP, the company should provide workpapers for the projected number of hours for regulation reserves operation of the Valmy coal-to-gas converted units, and the corresponding hours for SCCT, 4-hour and 8-hour batteries, in the Preferred Portfolio.

Expectation 6: In future IRPs, the Company should include the constraints related to system resilience in portfolio modeling if the estimated cost of ancillary services to preserve system resilience will be significant enough to warrant such inclusion.

Draft Recommendation 3: Acknowledge Idaho Power's proposed action to acquire up to 1,425 MW of combined wind and solar in 2026-2028.

Section 3. Transmission

Idaho Power seeks acknowledgment to bring Phase 1 of Gateway West (GWW) online by 2028, as a means to connect more renewable energy from the east. The addition of GWW Phase 1 will enable the connection of 1000 MW of renewable resources and the saving of more than $500 million to the cost of the Preferred Portfolio due to avoiding the addition of gas facilities near load centers to meet the capacity need. Staff supports the acknowledgement of bringing the first phase of GWW online by 2028.

In the 2023 IRP, the Company explains that the construction of Gateway West (GWW) transmission relieves Idaho Power's constrained transmission system between the Magic Valley and the Treasure Valley, where the two Idaho Power load centers are located.[14] In order to add new resources east of the Treasure Valley, the addition of GWW relieves two primary transmission constraints: the transmission capacity between the Magic Valley and the Treasure Valley (Midpoint West), and the transmission capacity between the Mountain Home area and the Treasure Valley (Boise East), as shown in Figure 1.[15]

---

[14] See Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 91.

[15] Reproduced from figure provided in Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 93.

Figure 3: Gateway West map–Magic Valley to Treasure Valley segments 8, 9, and 10

Gateway West Phase I consists of two segments. The first segment (segment 8) is a new Midpoint–Hemingway #2 500kV line from the Midpoint substation near Shoshone, Idaho to Hemingway substation near Melba, Idaho (red line in Figure 3). This segment will require the construction of a new Mayfield substation southeast Boise, where the new 500 kV line and associated new resources into the Treasure Valley 230-kV system. The second segment (segment 10) is a new Midpoint–Cedar Hill 500-kV line from Midpoint substation to a future Cedar Hill substation (blue line in Figure 3). This segment will connect to the future PacifiCorp's Populus–Cedar Hill 500-kV segment to enable PacifiCorp to use its capacity gained via participation in the Midpoint–Hemingway #2 500-kV line.

Segment 8 will increase the Midpoint West and Boise East path capabilities by approximately 2,000 MW and is expected to in-service by the end of 2028. As Idaho Power has a one-third permitting interest in this segment, with PacifiCorp having the remaining majority interest, Idaho Power's capacity in this segment is anticipated to be 667 MW. The Company states that only 1,725 MW of incremental wind and solar can be connected to the existing grid without GWW, while the GWW Phase 1 addition will enable an additional 1,000 MW of wind and solar resources.[16] The Company's assumption of GWW enabling of 1,000 MW of new resources in the Aurora model, which is above the 667 MW planned capacity, is due to new diverse resources not likely to be at maximum output at the same time. To further support this assumption, the Company states that there is an opportunity to use other methods, such as remedial action schemes or dynamic line ratings, to further optimize transmission flow and resource interconnections.

In Opening Comments, Staff questioned whether it would have been possible for Idaho Power to use the 600 MW of upgraded and exchanged east-to-west capacity that the Company transferred to PacifiCorp to connect more renewable generation from the east and possibly delaying the need for GWW. In Reply

[16] See Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 93.

Comments, the Company explained that the 600 MW additional capacity from east to west would not be possible without the increased flow B2H enables.[17] In addition, PacifiCorp's joint participation in B2H required its increased ownership across southern Idaho to access its B2H capacity, which necessitated the upgrade and asset exchange to PacifiCorp.

The Company also added that originally, as reflected in the 2022 B2H term sheet and the 2021 IRP analysis, it was assumed PacifiCorp would not renew its transmission rights across the Idaho System after B2H comes online and the gaining of 600 MW of transmission ownership rights through the B2H asset swap.[18] This assumption has since changed when PacifiCorp refined its business case and decided to retain its existing 510 MW Open Access Transmission Tariff (OATT) access across Idaho Power system after the completion of B2H. The Company added that "with this change, capacity will not be made available to Idaho Power's renewable generation, which necessitates an upgrade of Midpoint West and Boise East transmission capacity, as implemented in the first phase of GWW".

Staff's Analysis and Conclusions

In the 2021 IRP, Idaho Power did not include the construction of GWW in the preferred portfolio. However, during Staff's discussions with the Company, Idaho Power's staff revealed that the model was on the verge of needing extra resources to meet demand that would require the triggering of GWW transmission. With the significant load growth forecasted in the 2023 IRP, the Company included the construction of three phases of GWW transmission to alleviate transmission constraints and allow additional renewable resources to meet capacity needs, as seen in the Preferred Portfolio.[19]

Staff understands that the Company is taking the opportunity of leveraging tax credits to invest in a large number of wind and solar resources. Portfolio analysis shows that the Company's investment in Phase I of GWW will enable the acquisition of these new resources and, hence, will provide the least-cost solution in the Preferred Portfolio. The alternative is a more expensive portfolio having new gas facilities near load centers. This alternative is demonstrated in the "Without GWW Phases" portfolio where the portfolio cost is more than $500 million more than the cost of the Preferred Portfolio.[20]

Staff sees a large benefit from the GWW transmission project to the Company being able to 'unlock' a total potential of 4,000 MW of renewable capacity in the long term in resource planning.[21] With a phased approach to constructing the overall project in segments and gaining federal permitting for each segment, the Company has the flexibility of enabling portions of the project to relieve constraints at different parts of the GWW transmission system only when needed. An added benefit of GWW is that the interconnection of new renewable generation to meet load growth supports the CO_2 emission reduction target that the Company is pursuing. Figure 2 in the Valmy Conversion section of this document demonstrates the estimated reduction in portfolio emissions over the planning period in the

[17] Docket No. LC 84, Idaho Power 2023 IRP, Idaho Power's Reply Comments, March 7, 2024, p. 29.
[18] Ibid.
[19] Id, Table 1.1, p. 6.
[20] See Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 136 for comparison of portfolio costs and Appendix C, p. 48 for details of resources in the "Without GWW Segments" portfolio.
[21] ID, p. 91.

2023 IRP for the scenarios of adding one, two, or three phases of GWW compared to cases without any GWW phases.[22]

Given the joint ownership of the GWW transmission project between PacifiCorp and Idaho Power, Staff sees some risk in the possibility of both parties not agreeing on the need and timing of construction of the different segments of the project. Staff considers that this risk is likely to be minimal if both co-participants continue to coordinate transmission planning regionally. Staff is monitoring the activities and timing of joint transmission projects in the IRPs of both Companies to ensure that coordination helps maximize the benefits to customers.

With regards to PacifiCorp's change in business decision to retain the 510 MW of OATT across the Idaho system after B2H is online, Staff needs more information to understand impact of the contractual changes on the timing and cost of GWW Phase I. Hence, Staff is unable to speak to the role that this change will play in the decision to bring GWW online by 2028. Considering that the 510 MW would not meet the large capacity needs forecasted by Idaho Power post 2028 in the 2023 IRP, Staff does not see the change by PacifiCorp as material. However, Staff thinks that this topic will be worth revisiting in the cost recovery docket along with the materialization of GHG reduction benefits from GWW bringing more renewables online.

Gateway West Action Item

Based on the information provided by Idaho Power and Staff's analysis of the benefits and risks, Staff is satisfied that the addition of GWW Phase 1 by 2028 is the least-cost, least-risk option to enable the connection of 1000 MW of renewable resources to be connected in 2029-2030.[23] As such, Staff supports the acknowledgement of bringing the first phase of GWW online by 2028, as Action Item 8 in Table 1.

Draft Recommendation 4: Acknowledge Idaho Power's proposed action to bring the first phase of GWW online in 2028.

Section 4. Market Access

Idaho Power seeks acknowledgment to continue exploring the Company's potential participation in the SWIP-North project to access more than 1,000 MW of capacity from the Desert Southwest market in 2024. A decision by Idaho Power to pursue this project would possibly alter the dynamics of resource selection in the Preferred Portfolio. Prior to the public meeting scheduled for the Commission's decision on this IRP and subject to the Company signing firm agreements, Staff recommends that the Company update the Commission with the latest developments in the SWIP-North project and any impacts on this IRP.

In the 2023 IRP, Idaho Power reduces its modeled transmission winter capacity from 330 MW to 100 MW from 2029 onwards. This reduction is due to the Pacific Northwest region facing tighter resources to meet its obligations during the peak winter season.[24] Given winter wholesale energy market depth

[22] Figure reproduced from Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, Figure 10.1, p. 139.

[23] IPC's projection of additional renewable resources in the Preferred Portfolio is 400 MW of wind in 2029, 100 MW of wind in 2030 and 500 MW of solar in 2030, as shown in Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, Table 1.1, p. 8.

[24] *See* discussion on transmission planning in Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p. 82.

concerns from the Pacific Northwest, the Company addressed the increased demand in winter and the lack of market diversity in two ways.

First, as part of the broader B2H transaction, an asset exchange between Idaho Power and PacifiCorp will enable Idaho Power to acquire 200 MW of bidirectional transmission capacity between the Idaho Power system (Populus substation) and Four Corners, through Mona, Utah. At the same time of B2H coming online, the Company explains the connection to the Four Corners hub, with a presence of eight market entities,[25] would enable connectivity to regions rich in solar and wind potential.

Second, Idaho Power's Action Plan includes potential participation in the Southwest Intertie Project-North (SWIP-North) transmission capacity, providing access to the Desert Southwest market to serve winter peak season needs starting in 2027, by creating a south-to-north capacity of more than 1,000 MW.

In Opening Comments, Staff requested the Company explain how it made business decisions for ownership or rights along transmission paths to access different markets. In Reply Comments, regarding business decisions on transmission ownership or rights,[26] the Company explained that portfolio costing in the Aurora model, with and without the transmission assets, is primarily what determines the Company's choices of transmission. With growing winter season energy needs and the tightening of market conditions in the Pacific Northwest, the Company decided to look for opportunities to diversify market connections by increasing transmission capability from the Desert Southwest market and reduce winter season reliance on the Pacific Northwest.[27]

Staff's Analysis and Conclusions

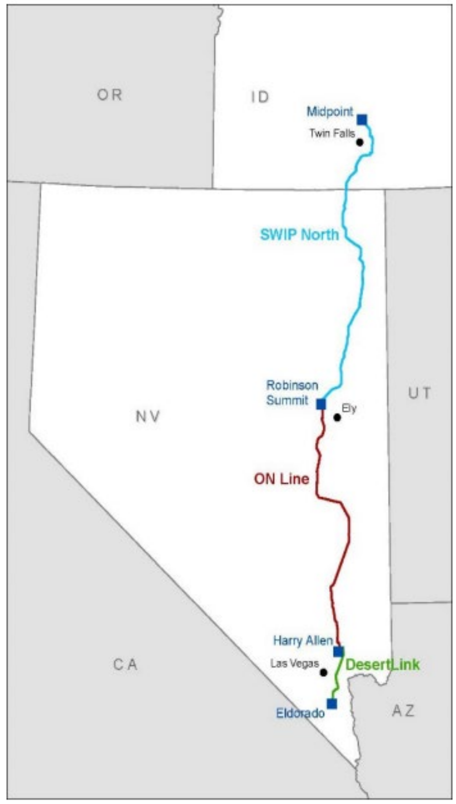
The Company presented the 2023 IRP by underscoring the importance of flexibility and adaptability in resource planning as a necessary theme to inform decisions as more information becomes known before the next planning cycle. One of the possible developments to inform decisions by the Company in this planning cycle is Idaho Power's potential involvement in the SWIP-North project.

The addition of the 500 kV 285 mile-long SWIP-North transmission line enables connection to the in-service One Nevada 500-kV Line (ON Line) in Nevada. Both lines make up the combined SWIP, which provides paths to the Desert Southwest wholesale market hubs, as shown in Figure 5. The addition of the SWIP-N connection has an approved path rating of up to 1,117.5 MW of north-to-south capacity and 1,072.5 MW of south-to-north capacity between Midpoint, Idaho on the Idaho Power system and Harry Allen, Nevada in the Southwest Electric Region.

---

[25] The eight entities having transmission connectivity include Arizona Public Service; Salt River Project; Tri State G&T; Western Area Power Administration; Xcel Energy; Public Service New Mexico; Tucson Electric Power Company; and PacifiCorp (see Table 7.6 in Idaho Power, 2023 IRP, September 29, 2023, p. 86).
[26] *See* Docket No. LC 84, Idaho Power 2023 IRP, Idaho Power's Reply Comments, March 7, 2024, p. 31.
[27] Ibid.

Figure 4 Proposed SWIP-North Transmission Project[28]



The Desert Southwest region has a diverse seasonal load profile compared to Idaho Power and the Pacific Northwest, where the gap between the winter and summer peaks is forecasted to be about 1300 MW. This gap indicates potential for excess capacity in the winter season to help meet Idaho Power's future winter demand. While Idaho Power is interested in the South-to-North power transfer direction, the California Independent System Operator (CAISO) is interested in the North-to-South direction to access the Idaho wind power potential.

Staff sees the participation in the Desert Southwest market via SWIP-North as a positive step towards diversification of accessing markets. The SWIP-North connection provides a resource that can serve Idaho Power at peak times in a region with a diverse seasonal load profile and where other utilities in the southwest do not experience high demand in winter. As the Desert Southwest is rich in natural resources, especially solar,[29] the connection would increase the Company's ability to integrate renewable resources. Other benefits to customers could be increased revenue from off-system sales when resource marginal costs are low and market prices are high.

According to the analysis performed by the Company in the 2023 IRP and the sensitivity analysis in the 2021 IRP, the SWIP-N shows potential cost savings providing a 500 MW resource equivalent capacity, from the Desert Southwest, in the winter months beginning in 2027. The SWIP-North Project's cost is

[28] Figure sourced from the "2022-2023 Transmission Planning Process: SWIP North, Stakeholder Meeting" presentation by California ISO on November 07, 2023, slide 5 at https://www.caiso.com/InitiativeDocuments/Presentation-2022-2023-Transmission-Planning-Process-Nov-7-2023.pdf, accessed on April 16, 2024.

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

estimated to be $1,090 Million, with CAISO being responsible for 77.2 percent and Idaho Power being responsible for 22.8 percent of the overall project cost.[30]

Staff finds that the sharing by CAISO and IPC of power needs and project cost of the SWIP-North project is an encouraging sign for a viable option to access Desert Southwest markets. Staff also understands that the Company is still in the exploration phase of negotiating with third parties the participation in the SWIP-North transmission project. As such and subject to the Company signing firm agreements, Staff recommends that the Company update the Commission with the latest developments with the SWIP-North project and how the outcomes of this project could alter the selection of the Preferred Portfolio in the 2023 IRP.

SWIP-North Action Item

Based on the information available so far on the cost effectiveness of the SWIP-North project and the benefits of market diversification, Staff recommends the acknowledgement of the Action Item to continue exploring potential participation in the SWIP-N project, as Action Item 1 in Table 1.

Draft Recommendation 5: Prior to the public meeting scheduled for the Commission's decision on the 2023 IRP and subject to the Company firm agreements, the Company will update the Commission in a workshop with the latest developments in the SWIP-North project and how the outcomes could alter the selection of the Preferred Portfolio in the 2023 IRP.

Draft Recommendation 6: Acknowledge Idaho Power's proposed action to continue exploring potential participation in the SWIP-North project in 2023-2024.

Section 5. Distribution-Connected Storage

Idaho Power seeks acknowledgment to install cost effective distribution-connected storage in 2025-2028. Idaho Power's first implementation of distribution-connected storage is expected to be the installation of 11 MW of batteries at four locations with expected in-service dates in 2024. However, Staff is particularly concerned about the fire event at one of these projects at Melba substation and the implications on implementation changes and cost of future distribution-connected storage projects as a result of the fire.

The Company's Preferred Portfolio includes the installation of distribution-connected storage projects on a large scale in the planning period, totaling 80 MW in capacity. A maximum of 5 MW of 4-Hour storage capacity is planned for each year from 2027 to 2042. In the 2023 IRP Action Plan, the Company is seeking to install cost-effective distribution connected storage from 2025 to 2028. This installation is planned on the heels of four distribution-connected storage projects totaling 11 MW currently being built inside Idaho Power substations.

In response to Staff IR 82 inquiring about a progress update on these projects, the Company responded stating that all four sites experienced in-service delays due to a common design element that was adjusted and needed to be implemented before commissioning could be completed. Three of those projects experienced delays of 11 months or more and had an expected in-service date of February 2024. The fourth project, at Melba substation, experienced a fire event on October 2, 2023,

[30] See California SO 2022-2023 Transmission Plan – Draft Addendum 1, December 6, 2023, p. 4, accessed at https://www.caiso.com/InitiativeDocuments/Addendum-1-Draft-2022-2023-Transmission-Plan.pdf on April 16, 2024.

which delayed the expected in-service date further to May 2024. The Company explained it would be using tracked data for installation costs and deviations from project schedules to inform adjustments to modeling assumptions and constraints in future IRPs. Upon a request from Staff on an update, IPC replied that the expected in-service dates for Elmore, Filer, and Weiser projects will be delayed to June or July 2024 primarily due to damage sustained on transformer bushings during cable testing, while the Melba project is delayed to August 2024 due to the replacement of battery units after the fire event on October 2, 2023.[31]

Staff requested information about the causes and effects of the fire event at the Melba station and the associated impacts to the public in terms of safety, cost, and disruption to power supply.[32] Further in Opening Comments, Staff requested the Company provide a list of all the safety standards and certifications needed for the design, construction, and operations of distribution-connected storage projects.

In response to Staff IR 83, IPC objected to the request on the basis that this information is the subject of ongoing confidential negotiations with the battery supplier and is related to Idaho Power's possible claims in potential future litigation. In Reply Comments, the Company explained that distribution-connected storage projects are constructed within the perimeter of existing substations and, thus, follow the general standards applicable to all substation design, construction, and operations. However, the Company declined to provide more information about the fire event as the circumstances of the fire and the determination of cause are subject to a legal finding.[33]

Staff's Analysis and Conclusions

Distribution-connected storage projects represent a new type of resource, which is planned to be implemented on a larger scale in the future. For this reason, Staff seeks more understanding of the impact of safety considerations on future planning for this type of resource.

While Staff recognizes that this topic is sensitive for the Company, the critical nature of batteries to planning and the energy transition itself requires some openness. It is important that in the next IRP the Company share information with Staff regarding lessons learned about the incorporation of best-practices in battery project construction, commissioning, and operations to mitigate operational risks. That said, Staff expects the Company's next filing to address two questions, at a minimum:

1. What changes, as a result of the fire event, have been adopted by the Company when implementing distribution-connected storage going forward?
2. How do these changes impact the cost when planning for future distribution-connected storage projects?

Distribution-connected Storage Action Item

Based on the information gathered so far, Staff makes a draft recommendation to acknowledge the installation of cost-effective distribution-connected storage, as Action Item 3 in Table 1.

[31] Email by Idaho Power to Staff on April 23, 2024, in response to Staff email on April 22, 2024.
[32] *See* LC 84, Staff IR 83 to Idaho Power.
[33] See Docket No. LC 84, Idaho Power, Reply Comments, March 7, 2024, p. 43.

Draft Recommendation 7: ***Acknowledge Idaho Power's proposed action to install cost effective distribution-connected storage in 2025-2028.***

Expectation 7: In the next IRP, the Company must share information with Staff about lessons learned regarding the incorporation of best-practices in battery project construction, commissioning, and operations to mitigate operational risks.

Section 6. Long Duration Storage Pilot

Idaho Power is seeking acknowledgement to explore the creation of a long duration storage pilot in 2024-2028*. Staff is supportive of Idaho Power's plan to evaluate whether such a pilot program is feasible and of value.*

In Opening Comments, Staff asked Idaho Power to clarify its acknowledgement request for the long duration storage pilot. In the case that the Company is seeking acknowledgement of an actual pilot program, it should provide more details on the activities related to this project. Details must include, but are not limited to, those identified in UM 2141 and Order No. 22-115, as well as a project timeline and status update.

Idaho Power expressed that it would move forward with evaluating whether a pilot was feasible once it receives acknowledgement for its proposal to explore a potential pilot as described in its Action Plan, and that details of the pilot will be filed in a different docket.

Staff notes that this action item is not directly connected to Idaho Power's portfolio analysis in this IRP and was not presented as a resource option that Staff could analyze. The addition of 200 MW of 100-hr storage in the preferred portfolio in the year 2038 is not dependent on the learnings from the pilot study proposal.[34] Idaho Power indicated that if the pilot project is pursued, the Company would gain experience in optimally dispatching a small-scale long duration storage resource before adding such resources to the system. It would also gain first-hand experience in understanding various operational characteristics of such a resource. Therefore, the learnings from the pilot could potentially help in future IRP modeling refinements for this type of resource.[35]

Long Duration Storage Action Item

Staff sees value in having more information prior to committing to an emerging resource, though believes that there could be alternatives to pursuing a pilot for this purpose. Staff is therefore interested in learning more about the purpose, costs, benefits, feasibility, and usefulness of a long duration storage pilot compared to using portfolio modeling as a learning tool as well as expected learning outcomes and applications should Idaho Power plan to move forward with the project. Staff suggests Idaho Power use the guidance provided in PUC Order No. 22-115, Appendix A, as it explores a potential pilot project for long duration storage. Staff recommends that the Commission acknowledge Idaho Power's plan to explore a long duration pilot project, as presented in the Action Plan, as Action Item 2 in Table 1. RNW has also expressed support for this action item.

[34] See IPC Response to Staff IR No. 141

[35] See IPC Response to Staff IR No. 139.

Draft Recommendation 8: Acknowledge Idaho Power's proposed action to explore a 5 MW long-duration storage pilot project in 2024-2028.

Section 7. Wind Qualifying Facilities (QFs)

In the 2023 IRP, the Company assumed an unrealistic zero wind QF renewal rate in base planning. Assuming that no wind QFs will renew will result in the utility likely overestimating its resource needs and over procuring resources, Idaho Power should develop a reasonable non-zero estimate of a wind QF renewal rate in the next IRP, in line with the analysis undertaken by PacifiCorp in its 2023 IRP to estimate the QF renewal rate, and until such a rate is established, it should adopt a wind QF renewal rate of 75 percent.

The Company's base planning assumption in the 2023 IRP assumes that wind QFs would not renew their contracts upon expiry. This assumption is consistent with the assumption made in the 2021 IRP, where the Company states that it "cannot predict the level of future PURPA development; therefore, only signed contracts are accounted for in Idaho Power's resource planning process".[36] In Opening Comments, Staff expressed concerns about a zero wind QF renewal rate and recommended that Idaho Power look to PacifiCorp's methodology to develop a renewal rate for all QFs, regardless of resource type, in the next IRP Update. Staff expects that the Company will report its new methodology in the next IRP if the Company does not file an IRP Update.

In its opening comments,[37] REC communicated that it does not support Idaho Power's planning assumption that no wind QFs will renew after contract expiration. REC argues that because wind QFs are likely to renew, Idaho Power is overestimating its resource needs and will likely over procure resources, which is not a least-cost approach to resource planning.

REC also raised another issue that it brought up before in Docket No. LC 74 about compensating QFs for capacity value. REC says that while QFs were being compensated for their capacity value prior to renewal, renewed QFs are being denied any compensation once they renew although still providing the same value to Idaho Power's system.[38] Although REC acknowledged that the Commission does not address QF avoided cost pricing in the IRP process, it states that the assumptions made in the IRP often flow directly into the avoided costs.

In conclusion, REC recommended that the Commission direct Idaho Power to update its Preferred Portfolio with planning assumptions based on a wind QF renewal percentage of 85 percent, a percentage based on REC's discussions with current wind QF operators.[39]

In Reply Comments, Idaho Power defends its position that its analysis regarding QFs is reasonable. However, the Company acknowledges Staff's suggestion that Idaho Power should look to PacifiCorp's methodology to develop a renewal rate for all QFs, regardless of resource type, rather than differentiating between resource type as the Company has done in the past. Idaho Power agreed to

---

[36] See Docket LC 78, Idaho Power 2021 IRP, December 30, 2021, p. 47.
[37] See Docket No. LC 84, Idaho Power 2023 IRP, Renewable Energy Coalition's Opening Comments, February 7, 2024, p. 1.
[38] Id, at p.4.
[39] Id, at p. 19.

considering PacifiCorp's methodology, or other similar methodologies, to develop QF renewal assumptions in the next IRP.

With regards to REC's comments, the Company disagrees with REC and argues that it has followed empirical analysis and has had informal discussions with several wind QFs over the past few years to understand QF development. The Company says it did not have sufficient time to rerun the modeling analysis and update its Preferred Portfolio as REC has recommended. Similar to its suggestion to Staff, it agreed to work with stakeholders in future IRPs to negotiate reasonable QF-related assumptions.

Staff's Analysis and Conclusions

Staff agrees with REC that a zero-renewal rate is unacceptable. However, from a practical point of view, an immediate reworking of the Preferred Portfolio may not be the best means to resolve this issue. According to the Company's IRP schedule, the 2025 IRP is only a year away (scheduled to be filed in June 2025) and the modelling work for the next IRP is just starting. The data of the status of wind projects show that there is one project (10.5 MW) expiring in September 2025 and another project (9 MW) expiring in February 2026. Prior to the time the 2025 IRP is filed by the end of June 2025, and according to the Company's policy of reaching out to all QFs with expiring contracts 8-10 months in advance, the renewal status will be known for the first project, and possibly for the second project. Staff finds it would be more efficient for Idaho Power to work with Staff and Stakeholders on a non-zero wind QF renewal rate in the lead up to the 2025 IRP, and also verify its assumptions against the outcome of actual renewal decisions at the same time.

In the interim, Staff recommends that Idaho Power follow a similar Commission directive to PGE in Docket No. LC 80 and utilize an assumption of 75 percent for wind QF renewal rate until a non-zero renewal rate is derived by a methodology accepted by the Commission.[40] This recommendation follows an approach similar to PacifiCorp's approach and assumes a 75 percent renewal rate, which has been vetted and approved in other venues.[41] As an interim solution for IPC, a 75 percent renewal rate provides a reasonable approach based on empirical evidence with an equal likelihood of under and overestimating the actual renewal rate, resulting in more accurate avoided cost pricing.

With regard to the issue raised by REC that the value of capacity provided by renewed QFs is not adequately reflected in avoided costs, Staff reaffirms its position on this issue as presented in Docket No. LC 74.[42] Staff reiterates that this issue is "out of place" in the IRP docket and will be addressed in Staff's general investigation into avoided cost methodology in the Docket No. UM 2000. Through Order No. 21-184 in Docket No. LC 74, the Commission agreed with Staff that IRP acknowledgment decisions should not directly address avoided cost methodology nor make avoided cost pricing determinations. The Commission further stated that capacity valuation and its impact on PURPA avoided cost methodology should be addressed in other Commission dockets, including but not limited to UM 2000 and UM 2011.[43]

---

[40] *See* Docket No. LC 80, PDE 2023 IRP and CEP, Staff Report for the January 18, 2024 Special Public Meeting, December 14, 2024, pp. 24-25.

[41] *See* Docket No. LC 82, PacifiCorp 2023 IRP and Clean Energy Plan, PacifiCorp's Amended 2023 IRP, May 31, 2023, Appendix B, p.39.

[42] *See* Order No. 21-184 in Docket No. LC 74, Idaho Power 2019 IRP, June 4, 2021, pp. 19-20.

Draft Recommendation 9: Prior to portfolio optimization for the next IRP, the Company must work with Staff and Stakeholders to determine and employ a non-zero renewal rate for all QFs in line with PacifiCorp's estimation methodology, or other similar methodologies, to be adopted in the 2025 IRP.

Draft Recommendation 10: Idaho Power should assume a 75 percent wind QF renewal rate pending a non-zero renewal rate determination via a methodology accepted by the Commission in the next IRP.

Section 8. Load Forecast

Staff finds the Company's overall forecast of system load from prior IRPs to be relatively accurate, suggesting that this IRP's forecast may not be too far off either; however, Staff is concerned that the Company has selected independent variables without proper hypothesis testing. Also, the Company uses a lower probability (70th percentile) as the expected load forecast. Staff finds the 50th percentile as the planning case load forecast to be more reasonable.

Staff has identified methodological concerns in Idaho Power's load forecast since the previous two IRPs. In LC 74, Staff observed serial correlation and non-stationarity in several of the Company's econometric models.[44] In LC 78, Staff observed the same methodological problems from LC 74 while simultaneously getting a better understanding of potential improvements.[45]

Staff sought to review the data behind Idaho Power's 2023 IRP load forecast after the Company presented results through an Integrated Resource Plan Advisory Council (IRPAC) meeting. Idaho Power declined to provide this data before filing the IRP.[46] This prevented any meaningful feedback from Staff on the load forecast before this IRP was filed.

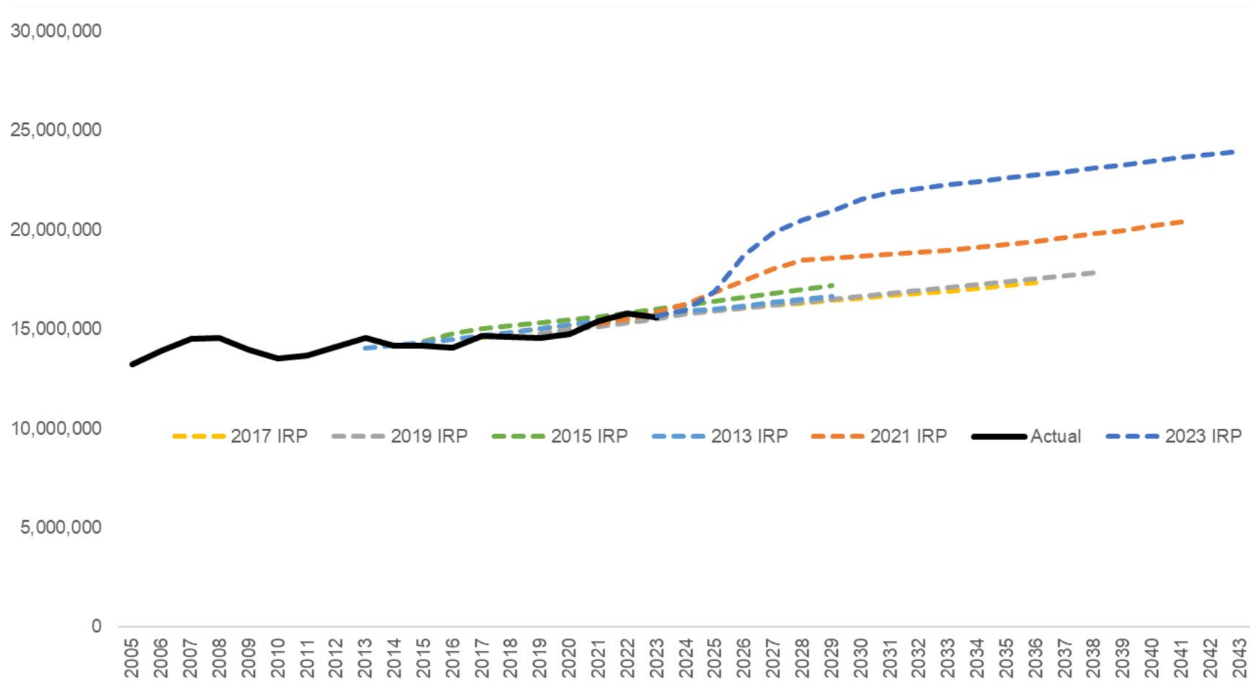
Forecasting Performance

The primary means by which Staff has been determining the reasonableness of Idaho Power's load forecast is to test the Company's forecasting performance. In LC 74 and LC 78, Staff compared forecasting results with different model specifications that were nested within the data the Company provided. Staff found no material changes from these alternatives to Idaho Power's econometric models, which is to say, despite Staff's concerns about flawed modeling approaches, the outcomes of the alternative modeling Staff compared did not appear to produce a material change. Idaho Power is currently seeking revisions to the Company's rates in Docket No. UE 426, which provides Staff an opportunity in this proceeding to compare a parallel load forecast. The forecast energy demand for 2024 is essentially the same for both dockets. This offers some sense of robustness. Since an electric company's incentives for a load forecast are different in a rate case than an IRP, the similarity in forecasts helps rule out the possibility these forecasts have been intentionally constructed to achieve a bias outcome.

Staff has also tested Idaho Power's forecasting performance by comparing past forecasts to observed load. Since the 2013 IRP, each successive load forecast for all retail customers has been relatively accurate, slightly overestimating load in the prior decade and slightly underestimating total system load in recent years, as shown in .

[44] *See* Docket No. LC 74, OPUC Staff, Staff Report, March 5, 2021, pp. 36, 37.
[45] *See* Docket No. LC 78, OPUC Staff, Staff Report, October 28, 2022, pp. 31, 32.
[46] Email from Idaho Power to OPUC Staff, May 9, 2023.

Figure 5: Total System Energy Load, in MWh



As shown in and , this accuracy masks a consistent overestimation of commercial and industrial load, both in the econometric models and special contract customers, which are derived from regression analysis and outside customers, respectively. Underestimation of residential and irrigation load has been balancing out that overestimation.

Figure 6: Commercial and Industrial Energy Load Without Special Contract Customers in MWh

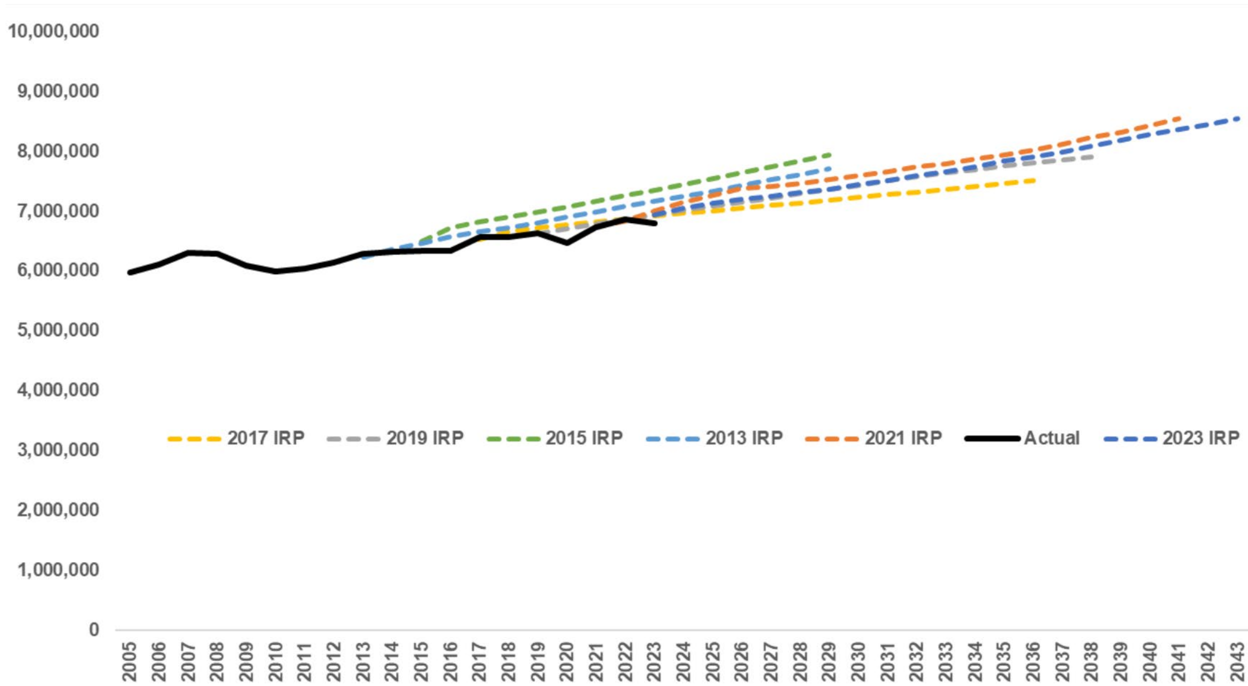
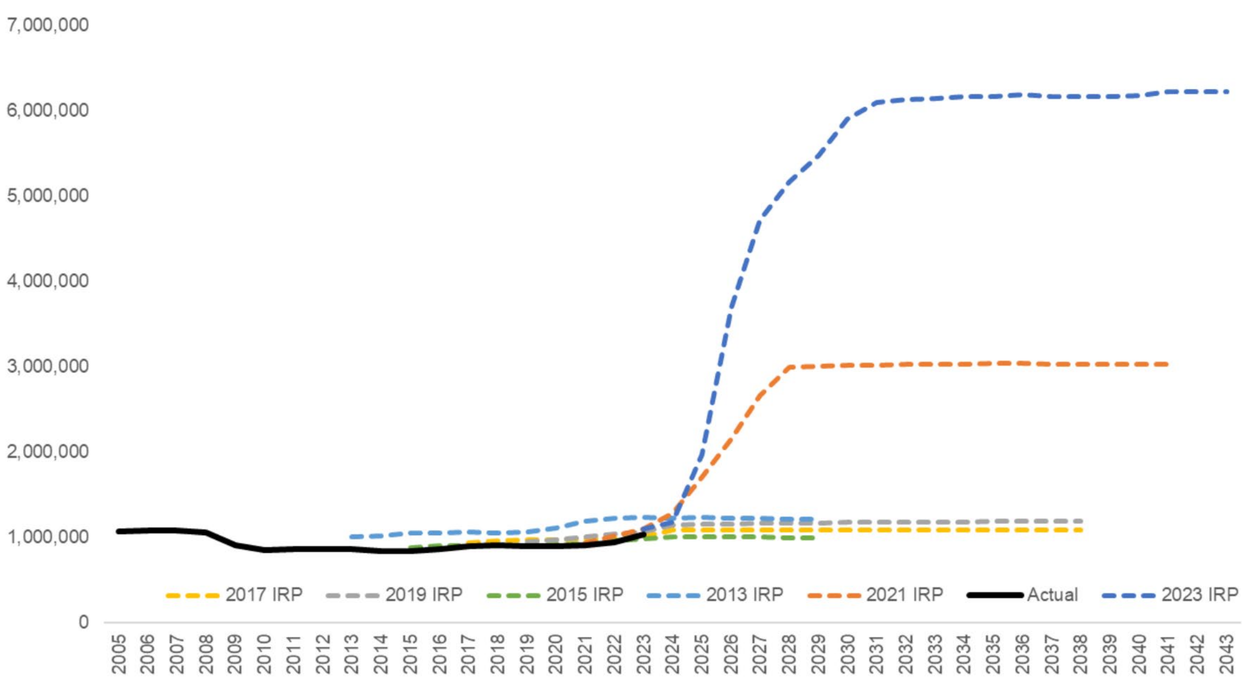


Figure 7: Special Contract Customer Energy Load in MWh



The accuracy of Idaho Power's forecast of system load may become compromised if the near-term growth of special contract load does not materialize. This may increase the magnitude of overestimation beyond what the occasional underestimation of residential and irrigation load can balance. Idaho Power is ultimately responsible for the reasonableness of these special contract customers' load forecast and should be prepared to provide oversight to avoid the over-procurement of resources.

Staff finds IPC's forecasting performance indicates the residential, commercial, industrial, and special contract customer forecasts' accuracy may have room for improvement, but Staff does not see a consistent bias in a single direction for overall system load. Instead, the forecasting error of different customer classes has been canceling itself out.

Post Hoc Variable Selection

During conversations before the filing of the 2023 IRP, and in information requests in this proceeding, IPC stated that the method for forecasting has not changed between the 2021 and 2023 IRP.[47] However, Staff identified several methodological changes such as suppressing the constant and including different independent variables.

Further, Idaho Power's load forecast continues to use of *post hoc* analysis to select predictive variables. In Opening Comments, Staff loosely referred to this as data mining.[48] More common terms for this are P-hacking or data dredging, which prioritize finding statistically significant results at the expense of theoretical rigor or a well-formed method to test a hypothesis. Traditional regression analysis tests a specific, limited set of hypotheses, including a necessary *a priori* expectation of what the sign or magnitude of the variable will be. Otherwise, the model might be built upon spurious correlations that could indicate relationships between variables that do not truly exist.

In Reply Comments, Idaho Power stated that "Idaho Power understands the nature of Staff's concern; however, the Company does, in fact, select variables *a priori*."[49] Staff followed up with an information request for documentation of the hypothesis testing the Company performed, asking for the *a priori* justification for each variable included in the Company's econometric modeling. Idaho Power did not provide any *a priori* justification. Instead, the Company stated: "Please see the Company's Response to Staff's Data Request No. 30 and the associated attachments for the requested information. All coefficients listed in the workpapers are of expected sign. Statistical significance serves as the *a priori* justification of its explanation of historical variance of the dependent variable of each model."[50]

Instead of providing documentation of hypothesis testing, the Company described a *post hoc* method of selecting the variables. OPUC IR 30 contains regression *output*, which is *post hoc* information. The statistical significance found in a t-test is only the sufficient condition for an independent variable to have a statistically significant impact on a dependent variable. The necessary condition is that an *a priori* theoretical justification for including the variable was present before the regression analysis was performed, including the expected sign implied by the theory. If the regression results show the wrong sign, as the COVID 19 variable did in the last IRP's residential model, the scientific interpretation is that the variable is statistically insignificant, regardless of the P-value of the t-test.[51] This is important because, the *a priori* justification for including a variable in a model filters regression models from

[47] *See* Docket No. LC 84, Idaho Power, Reply to OPUC IR 32, December 11, 2023, p 1.
[48] *See* Docket No. LC 84, OPUC Staff, Opening Comments, February 7, 2024, p 14.
[49] *See* Docket No. LC 84, Idaho Power, Reply Comments, March 7, 2024, p. 6.
[50] *See* Docket No. LC 84, Idaho Power, Response to OPUC IR 142, April 1, 2024, p. 1.

picking up random, temporary correlations. Skipping this step means cherry picking correlations, thus increasing the likelihood of selecting spurious statistical relationships.

Further, Idaho Power's unusually frequent and random changes in model specifications is not necessarily justified by having high variation in industrial load. In Reply Comments, the Company explained the instability of its model specifications as the result of high variation in manufacturing load, pointing to Idaho Power's manufacturing sector load having a coefficient of variance (COV) of 28 percent (later revised down to 21 percent in discovery).[52] A COV of 28 percent indicates low volatility. COV measures variance on a scale of 0 to 1. With 1 (100 percent) being the highest range of variance. Even if Idaho Power's load had a high COV, that would never be a reason to skip hypothesis testing. Reasonable changes in a regression model should be grounded in a theoretical predication and require a direct comparison of the alternative specification with the prior one. Staff sees no evidence Idaho Power is following this best practice.

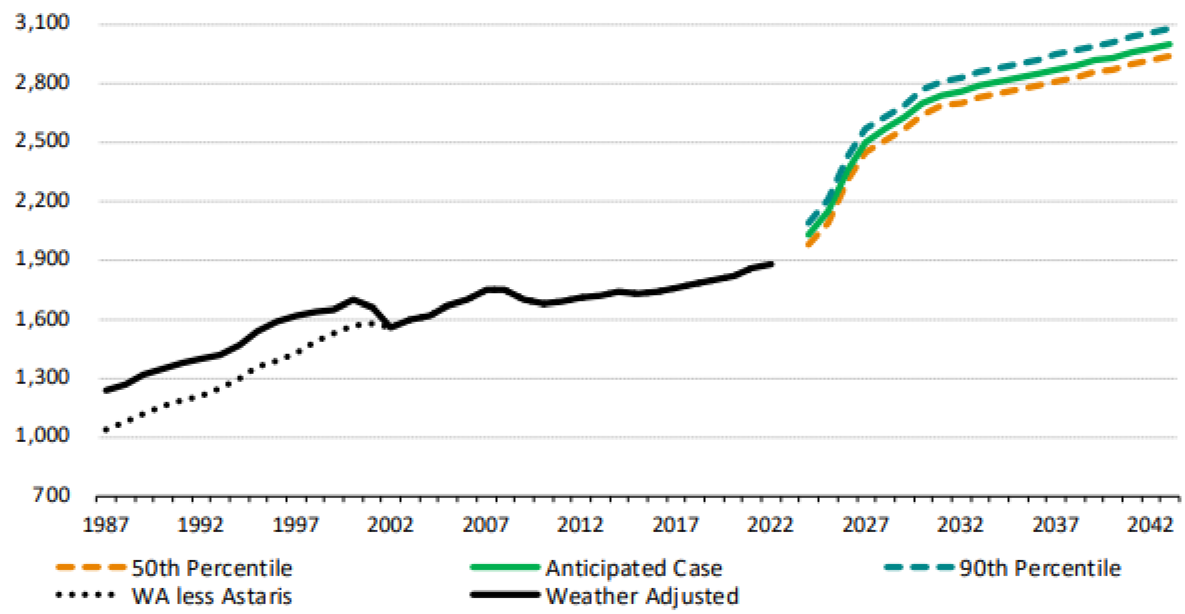
70th Percentile

Staff finds Idaho Power's use of the 70th percentile (P70) load forecast unreasonable. The Company's reason for using a lower probability load than the standard 50th percentile is that it mimics the resource adequacy (RA) of a loss of load expectation (LOLE) of 0.05, which is higher than the Commission's standard LOLE of 0.1.[53] The Idaho Public Utilities Commission (IPUC) has also found this to be unreasonable.[54]

Reaching this conclusion does not necessarily mean Staff has a specific Action Item to recommend non-acknowledgement. Staff is not certain what specific resources selected from a P70 load forecast would not be selected from using a P50. Staff notes that the spread between the P70 and P50 forecasts is relatively narrow compared to the underlying drivers of load growth.

[52] *See* Docket No. LC 84, Idaho Power, Response to OPUC IR 148, April 1, 2024, p. 1.
[53] *See* Docket No. LC 84, Idaho Power, Response to OPUC IR 89, January 9, 2024, p 1.
[54] *See* Idaho Public Utilities Commission, Case Number IPC-E-23-23, Comments of the Commission Staff, February 15, 2024, pp. 18-19.

Figure 8: Idaho Power's Load Forecast Scenarios[55]



The growth in special contract customer load provides a greater impact on resource need. However, using a lower probability forecast is inherently problematic, even with a relatively small upward bias. So, instead of making a recommendation for a Commission action, Staff documents the expectation for Idaho Power to use a P50 load forecast as the expected case in future IRPs.

Special Contract Customers

In Opening Comments, Staff noted its observation regarding the overestimation of load by special contract customers that the Company incorporates into the IRP's system load forecast at face value. In Reply Comments, the Company stated: "Idaho Power assesses these individual load forecasts for reasonableness and refines as necessary. The Company does not, as Staff incorrectly claims, take these customers 'own forecasts at face value."[56]

Staff followed up on this assessment of special contract customer load through discovery. The Company's response states: "For any existing Special Contracts that have expansion plans or new Special Contracts, the Company does not assume more accurate power requirement needs than the Special Contract representative."[57] The assessment the Company does perform is that if the special contract customer predicts a steady state of load, Idaho Power will track the historical load of this customer to confirm the load growth will be flat during the planning period.

Knowing special contract customers have been overestimating their load, given the Company's response to OPUC IR 154 showing a historical overestimation going back twenty years, reducing the overestimation of these load forecasts' growth is the responsibility of Idaho Power.[58] These customers face no penalty for overestimation. Padding their forecasts with extra capacity, however improbable, just

[55] See Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, Appendix A, Figure 1, p. 8.
[56] See Docket No. LC 84, Idaho Power, Reply Comments, March 7, 2024, p. 11.
[57] See Docket No. LC 84, Idaho Power, Reply Comments, April 1, 2024, p. 1.
[58] See Docket No. LC 84, Idaho Power, Response to OPUC IR 154, April 1, 2024, Figure 6, p 4.

in case it will be needed may place risk on other customers that an overestimation can become greater than five percent. Given the near-term growth now included in this forecast, the magnitude of the risk has increased. Staff expects the Company to consider steps to provide oversight for special contract customers' forecasting of load growth.

Conclusion

In this proceeding, Staff advanced our understanding of Idaho Power's method of forecasting load. The Company appears to be selecting variables based on *post hoc* analysis which is not a best practice. However, Staff does not have a specific alternative set of models to compare the Company's forecast with.

Staff finds the use of a P70 forecast unreasonable. The higher probability P50 should be used instead.

Staff finds load growth for special contract customers to have been overestimated for the past five IRPs. The magnitude of the overestimation from the last IRP has been reasonable, but the size of the near-term growth may magnify the risk that this magnitude of the overestimation will grow and lead to over-procurement of resources.

Expectation 8: In the next IRP, Idaho Power should document and share the a priori reasons for all econometric model specification.

Expectation 9: In the next IRP, Idaho Power should use the 50th percentile for the expected case load forecast in future IRPs.

Expectation 10: In the next IRP, the Company should consider and demonstrate the steps taken to provide oversight for special contract customers' forecasting of load growth.

Section 9. Wholesale Electricity Prices

Idaho Power endogenously models wholesale electricity prices to forecast them for Idaho Power's balancing area. Staff finds the Company's accuracy of forecasting wholesale electricity prices in the IRP to be an improvement over the 2021 IRP in the planning case. However, the observed prices in January 2024 are still significantly higher than the worst-case stochastic run predicted for that month.

Improvement from the last IRP

In this proceeding, Staff's review of Idaho Power's wholesale electricity price modeling has been an attempt to better understand how the Company is comparing wholesale electricity purchases as a resource. Idaho Power appears to have taken steps to improve the accuracy of modeled wholesale electricity prices. The 2021 IRP's modeled prices were at a greater fraction of observed prices than in the 2021 IRP.[59]

Comparing Monthly Average Prices

Staff does not expect an electric company to have a perfect forecast of Mid-C prices. Validation of Idaho Power's modeling just needs to show the price expectations are not too far off. In Opening Comments, Staff compared the average historical Mid-Columbia (Mid-C) day-ahead price in June 2023 with the

[59] See Docket No. LC 78, OPUC Staff, Opening Comments, July 7, 2021, p 19.

average planning-case Mid-C price Idaho Power modeled in June 2024. Staff chose this month for comparison because the Company often sees its system peak towards the end of June. Staff found Idaho Power's modeled Mid-C prices to be within a reasonable range of last year's prices.

As shown in Table 3, comparing observed prices in the early months of 2024, the first year of Idaho Power's planning horizon, with modeled average Mid-C prices, February and March of this year offer better months for comparing average planning condition prices than January. By the end of January, relative planning conditions appear to have returned.

Table 3: Comparing Idaho Power 2023 IRP's Average Planning Case Mid-C Prices with Actuals[60]

	February 2024	March 2024
2023 IRP	$42.97	$31.31
Historic[61]	$47.25	$35.78

Though the modeled prices show an underestimation, Staff finds this to be a reasonable amount of error. This is a significant improvement in accuracy over the last IRP.

While average Mid-C prices in January 2024 were inappropriate for comparison with Idaho Power's planning case prices, the extremely high prices observed in the first month of this year, the first month of Idaho Power's 20-year planning horizon, tests the reasonableness of the ceiling of average prices that the Company modeled through stochastic risk analysis. The average historic Mid-C price for January 2024 was $222.91 per MWh.[62] The highest average price Idaho Power's stochastic risk analysis could conceive happening that month was only $70.31 per MWh.[63] While the Company provided Staff a Mid-C price for the planning case model run, the stochastic run prices provided in response to OPUC IR 92 blend Mid-C with Palo Verde. We know Palo Verde prices were relatively lower during the Martin Luther King weekend that saw the Mid-C prices at sustained extremes, but that price difference also put upward pressure on the Palo Verde hub and likely constrained transmission. To better understand how vulnerable Idaho Power was to extreme Mid-C prices in January 2024 Staff analyzed Idaho Power's actual market purchases.

Comparing Market Purchases

While the comparison of modeled monthly average wholesale electricity prices to historic prices provides one means to validate the reasonableness of Idaho Power's modeling of these markets, as a resource to other resources, comparing actual market purchases by Idaho Power provides a more direct insight into how this resource is used and priced. The average price for the market may be different than the average price Idaho Power pays for power.

---

[60] Set 8 DR 91 Hub Prices Supplement ES.xlsx, sheet titled "Hourly Prices" cells G4:H4.

[61] Plats. Feb 29 2024 MDFD Megawatt Daily Market Fundamentals Daily.xlsx; Plats. Mar 29 2024 MDFD Megawatt Daily Market Fundamentals Daily.xlsx.

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

[63] 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.

For example, in January 2024 **[BEGIN CONFIDENTIAL]** [redacted]

[END CONFIDENTIAL]

Staff does not know how Idaho Power's modeling of the simulated market purchases may depart from the modeling of average market prices. Idaho Power is not able to provide the modeled market purchases, the simulated transaction where the IRP's model meets capacity need by purchasing power rather than selecting resources. Staff wonders if that is a data output option Aurora can perform. Such a comparison with observed transactions would improve understanding of these market purchases as a resource.

Similarly, Idaho Power is not able to provide data on the modeled market purchases to recharge storage resources. These purchases are aggregated with other purchases. This too, will be an important aspect of the Company's modeling to compare with observed power costs for storage resources. Staff expects Idaho Power to seek greater insight on the hourly distribution and average price of simulated market purchases in the next IRP.

Comparing Hourly Prices

The Commission directed Staff to go beyond average modeled wholesale prices and compare wholesale

[64] IPC Response to Staff's DR No. 164 - CONFIDENTIAL Attachment 1 - Market Purchases ES, sheet titled "January 2024," cell B2.

electricity prices at the hourly level.[65] Even if wholesale prices trend down on average, the prices during the system critical hours when Idaho Power needs to purchase power the most may rise.

In Opening Comments, Staff compared the high hourly prices with the hourly prices Idaho Power modeled under planning conditions, in these Final Comments, Staff can make the same comparison for February and March.

Table 4: Highest Hourly Price Modeled vs Observed

	February 2024	March 2024
2023 IRP[66]	$73.62	$71.82
Historic[67]	$93.25	$90.25

As shown in Table 4, Staff finds Idaho Power's modeling of hourly Mid-C prices in the planning case relatively reasonable. This shows a slight underestimation that is proportional to the improvement in accuracy in average prices from the last IRP.

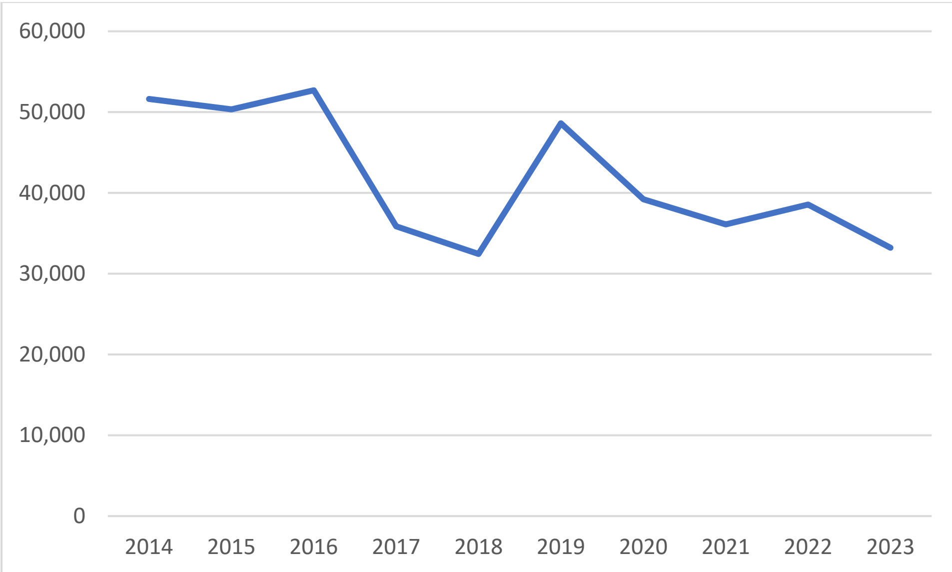
Staff cannot make the same comparison for the highest hourly prices from Idaho Power's stochastic risk analysis. The Company is unable to provide this data. Staff's understanding is that Aurora tracks this data as output, and it can be saved after running the model. Staff expects Idaho Power to preserve hourly wholesale electricity price data from the stochastic production cost runs in the next IRP.

Declining Mid-C liquidity

The declining liquidity of the Mid-C market may be impacting Mid-C prices in a way that Idaho Power's modeling does not capture. Since the Energy Imbalance Market (EIM) was created, the number of transactions for Mid-C power has been declining, as shown in Figure 10.[68]

[65] See Docket No. LC 78, OPUC, Order No. 23-004, January 13, 2023, p 12.
[66] See Docket No. LC 84, Idaho Power, Company response to OPUC IR 91 Supplement, January 19, 2024.
[67] Plats. Megawatt Daily February 6, 2024, p 18; Plats. Megawatt Daily March 7, 2024, p 18.
[68] https://www.eia.gov/electricity/wholesale/.

Figure 10: Peak Hour Mid-C Average Daily Trading Volume in MWh



This may be the result of generation supply migrating from the bilateral Mid-C market to the EIM and adversely impact Idaho Power. The EIM is available only to buyers that go into the hour balanced, that is to say, a buyer in the EIM market can only need to purchase resource due to variance in expected load or expected generation. A buyer cannot lean on the EIM as a resource. Idaho Power is following a strategy to be short the market.[69] For example, the Company meets 151 MW of capacity in 2024 with long-term market contracts.[70] The Company would not be able to meet a known capacity deficit in that way from the EIM. This may deny the Company access to some WECC resources for purchase if sellers prefer to wait for transactions through the EIM or Energy Day-Ahead Market (EDAM).

Idaho Power does not capture this problem in Aurora. Therefore, Idaho Power may be overestimating the supply of resources in Mid-C.

Expectation 11: In the next IRP, the Company should preserve and be prepared to provide hourly wholesale electricity price data from the stochastic risk analysis.

Expectation 12: Idaho Power should investigate the possibility that migration of power sellers to balancing markets may cause Aurora to overestimate resources available for purchase by Idaho Power and report its findings in the next IRP.

Section 10. Energy Efficiency

The 2023 IRP lost 80 MW of cumulative cost-effective energy efficiency (EE) measures decremented from the load forecast, as compared to the 2021 IRP. Additionally, no EE bundles were selected by the Aurora model in the Preferred Portfolio. Staff is concerned that the methodology of calculating avoided costs is causing the EE measures to be disadvantaged. In the 2025 IRP and future IRPs, the Company's energy efficiency avoided cost calculation methodology should rely on the most recently "filed" rather than the

[69] See Docket No. LC 84, Idaho Power, 2023 IRP, September 29, 2023, p 55.
[70] See Docket No. LC 84, Idaho Power, Response to OPUC IR 84, January 5, 2024, p 1.

most recently "acknowledged" IRP. The Company should provide the necessary data to IRPAC members for effective review and feedback on the new methodology before its implementation in the filed IRP.

Avoided costs

Idaho Power determined cost-effective Energy Efficiency (EE) quantities (MWs) in the 2023 IRP using the avoided cost data from the Company's 2021 acknowledged IRP in LC 78.[71] As Staff concluded in Opening Comments, IPC's 2021 IRP has lower overall forecasted market prices compared to the more accurate prices in the 2023 IRP.[72] A low forecasted market price estimate results in a low avoided cost in the 2023 IRP.

In the Opening Comments, Staff brought up the issue of the negative effect of a low avoided cost on determining quantities of cost-effective EE. In informal discussions with Staff, IPC recognized the avoided cost lag but explained that the lag is inherent to their IRP process. Staff suggested that the IRP process in the next IRP be adjusted to negate or mitigate the avoided cost lag. However, Staff did not make any recommendations regarding this suggestion in its Opening Comments.

Staff did not get a written response to Staff's suggestion of amending the input to the avoided cost calculation. In response to requests by Idaho PUC Staff's Comments[73] and production request No. 52 from Idaho PUC Staff,[74] IPC confirmed that it is adopting a new methodology to mitigate the effect of a 'stale' avoided cost calculation on the determination of cost-effective EE measures. In following this new methodology, IPC will be changing the avoided cost calculation methodology from relying on the most recently "acknowledged" to the most recently "filed" Integrated Resource Plan (IRP) avoided costs in its energy efficiency program planning for 2024 and beyond. As such, the 2025 IRP will have a new methodology to reduce the 'lag' in avoided cost values.

Staff's Analysis and Conclusions

As the change in the avoided cost calculation methodology adopted by IPC will rely on more up-to-date and accurate forecasted market prices, Staff expects this change in avoided cost methodology to be implemented in the 2025 IRP. Staff believes that this change will require that the company shares the necessary market data to be vetted by members of the IRPAC meetings.

EE measure bundles

IPC's current EE bundling methodology uses five cost bundles: summer low, summer medium, summer high, winter low, and winter high. In this process, as the Company explains in Reply Comments in response to Staff Recommendation 24, several thousand measures are screened for cost effectiveness using DSM avoided costs from the prior IRP. The resulting cost-effective measures are used to reduce the load forecast, while the left-over measures are consolidated into 17 groups split by load-shape, sector, and costs. These costs are simplified again into the final five bundles grouped by cost ranges and load shapes. The Company adds that the decision to use five bundles is intended to strike a balance between granularity of inputs, while treating EE as a resource that is compatible within the model.

---

[71] *See* Docket No. LC 84, IPC Response to Staff IR 130.
[72] See Docket No. LC 84, Idaho Power 2023 IRP, Staff Opening Comments, p. 33.
[73] See Idaho Public Utilities Commission, Case Number IPC-E-23-23, Company Reply Comments, February 29, 2024.
[74] Provided by Idaho Power to Oregon Public Utility Commission by email on March 11, 2024.

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 in the Preferred Portfolio. In effect, no EE bundles were selected by the Aurora model in the Preferred Portfolio, which means that all the cost-effective EE is included only in the form of reduced load.

Staff has concerns about a couple of issues regarding bundling. One is that bundles are configured by season and by cost and not broken out by customer class/sector. This has the effect that low to no cost Commercial and Industrial (C&I) measures were not selected by the model because they were bundled with high-cost measures, such as measures reaching up to $258.18/MWh for the summer low-cost model bundle.[75] The other issue is that bundles appear to be configured such that low-cost measures – Levelized Cost of Energy (LCOE) of zero dollars – that are technically achievable are not getting selected by the model as cost effective.

In Recommendation 24 of Opening Comments, Staff requested that 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. In Reply Comments, the Company argued that the bundling method does not disproportionately impact C&I measures and demonstrated that of the total EE potential available, the C&I sectors contain a significant amount that were selected in the Achievable Economic screen.[76]

With regards to the zero-cost measures, the Company responded that only eight measures of near-zero cost were found among 2,164 measures evaluated. Grouping these eight measures together, as suggested by Staff, would result in a bundle with peak summer savings of only approximately 31 kW, which is a too small of an amount for reasonable inclusion in the modeling process.

Nevertheless, the Company stated in its Reply Comments that it was open to changes in its framework and had previously increased the number of bundles from four to five in its most recent EE potential study, after gathering feedback from its advisory groups. Given that the process of rerunning the model for Staff's proposed analysis would take a considerable time in this IRP, the Company invited Staff to raise this issue in the IRPAC process prior to the IRP filing in order to have an opportunity to weigh in on changes and developments with respect to EE in the 2025 IRP.

Staff's Analysis and Conclusions

Given the explanation given by IPC, Staff would like to see in the 2025 IRP the outcome of additional portfolio runs with 'low-cost' bundles to ascertain that the bundling process is not biased towards high-cost EE measures.

Draft Recommendation 11: In the 2025 IRP and future IRPs, IPC should change the avoided cost calculation methodology to rely on the most recently "filed" rather than the most recently "acknowledged" IRP in its energy efficiency program planning. This change will require the Company to provide the necessary data to members of the IRPAC meetings so they are able to effectively review and provide feedback on the new methodology before it is implemented in the filed IRP.

[75] See Docket No. LC 84, IPC 2023 IRP, Appendix C, p. 19; IPC response to Staff IR 102 Attachment 2.
[76] *See* Docket No. LC 84, Idaho Power, Reply Comments, March 7, 2024, pp. 44-45.

Expectation 13: In the lead up to the 2025 IRP, the Company should work with and provide workpapers to Staff that explore the costs and benefits of portfolio runs with more 'low-cost' bundles, such as bundles of measures costing below $30/MWh.

Section 11. Demand Response (DR)

The 2023 IRP model included the peak summer capacity of Idaho Power's existing DR programs, 320 MW, and selected 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 in this IRP, and this approach addressed many of Staff's concerns from the 2021 IRP. Though there are no DR-related items in the near-term Action Plan, Staff raised two issues in Opening Comments. Idaho Power responded satisfactorily to both. Staff appreciates the Company's invitation to provide input on the second issue – DR block sizes made available to the model – in the 2025 IRP model, and thus formally notes here an expectation to engage Staff and stakeholders on this topic in developing the next IRP.

In Opening Comments Staff had two recommendations regarding demand response. Recommendation 25 was for the Company to discuss, in Reply Comments, why the model selected additional MW of more expensive ($258/kW-year) storage program DR, before selecting cheaper ($88/kW-year) pricing program DR.

In Reply Comments, the Company noted that cost is not the only metric the model considers in determining resource selection, and that resource availability and flexibility are also important metrics. The Company noted the storage program is dispatchable, and so characterized it as dynamic with respect to availability and flexibility. Idaho Power noted the pricing program has a two-season fixed schedule with two time of-use blocks, and so characterized it as static with respect to availability and flexibility. The Company explained that the dynamic nature of a storage program allows for better economic dispatch that can outweigh a cost penalty, whereas a more static pricing program cannot. Staff is satisfied with this response, especially considering that the model does not select the storage program for another 10 years, during which costs are likely to change considerably.

Staff's second recommendation, number 26, was for the Company to discuss, in Reply Comments, any benefits or drawbacks to making small blocks of DR (10 MW instead of 20 MW) available for the model to select in future IRPs, as well as a request to rerun the model using 10 MW blocks, or explain why doing so is problematic.

In Reply Comments, the Company stated it does not see any meaningful benefits to modeling 10 MW blocks of DR, and that 20 MW blocks do not hinder the selection of DR, as evidenced by the model's selection of 160 MW of the 180 MW of available DR in the Preferred Portfolio. The Company identified longer model run-time as the notable drawback to modeling smaller DR blocks.

Idaho Power also stated that the time required to change the model to use 10 MW blocks, test functionality, run the models, and analyze and validate the results is significant and unfeasible to complete within the given time frame. The Company instead welcomed Staff's input on DR block sizes during the development of the 2025 IRP.

Staff is satisfied with this response. Further, Staff appreciates the Company's invitation, and looks forward to contributing to this topic. As such, Staff formally notes here the following expectation:

Expectation 14: Idaho Power will engage Staff and stakeholders regarding DR block size during the development of the 2025 IRP.

Summary of Recommendations and Expectations

Recommendations

Draft Recommendation 1: Acknowledge Idaho Power's proposed action to convert Valmy Units 1 and 2 to natural gas in 2026.

Draft Recommendation 2: In the next IRP, the Company should elaborate on its anticipated cadence of RFPs and identify the future IRPs to which expected RFPs will be connected.

Draft Recommendation 3**:** Acknowledge Idaho Power's proposed action to acquire up to 1,425 MW of combined wind and solar in 2026-2028.

Draft Recommendation 4*:* Acknowledge Idaho Power's proposed action to *bring the first phase of GWW online* in 2028.

Draft Recommendation 5: Prior to the public meeting scheduled for the Commission's decision on the 2023 IRP and subject to the Company firm agreements, the Company will update the Commission in a workshop with the latest developments in the SWIP-North project and how the outcomes could alter the selection of the Preferred Portfolio in the 2023 IRP.

Draft Recommendation 6: Acknowledge Idaho Power's proposed action to continue exploring potential participation in the SWIP-North project in 2023-2024.

Draft Recommendation 7: Acknowledge Idaho Power's proposed action to install cost effective distribution-connected storage in 2025-2028.

Draft Recommendation 8: Acknowledge Idaho Power's proposed action to explore a 5 MW long-duration storage pilot project in 2024-2028.

Draft Recommendation 9: Prior to portfolio optimization for the next IRP, the Company must work with Staff and Stakeholders to determine and employ a non-zero renewal rate for all QFs in line with PacifiCorp's estimation methodology, or other similar methodologies, to be adopted in the 2025 IRP.

Draft Recommendation 10: Idaho Power should assume a 75 percent wind QF renewal rate pending a non-zero renewal rate determination via a methodology accepted by the Commission in the next IRP.

Draft Recommendation 11: In the 2025 IRP and future IRPs, IPC should change the avoided cost calculation methodology to rely on the most recently "filed" rather than the most recently "acknowledged" IRP in its energy efficiency program planning. This change will require the Company to provide the necessary data to members of the IRPAC meetings so they are able to effectively review and provide feedback on the new methodology before it is implemented in the filed IRP.

Expectations

Expectation 1: In its next IRP, Idaho Power must evaluate two alternative portfolios to address risks associated with coal to gas conversions**:**

I. Exit all coal plants in 2030 without Valmy and Bridger 3 and 4 conversions.

II. Delay Valmy conversion with a November 2026 online date for B2H.

Expectation 2: In the next IRP, the company should provide workpapers for the projected number of hours for both baseload and peaking operation of the Valmy coal-to-gas converted units, and the corresponding hours for CCCT, SCCT, 4-hour and 8-hour batteries, in the Preferred Portfolio.

Expectation 3**:** In the next IRP, as suggested by RNW, IPC *should* evaluate an alternative portfolio with a 2030 exit date from all coal operations and without the gas conversion of Valmy and Bridger 3 and 4 units for a better understanding of emissions implications of continued use of fossil fuel generation.

Expectation 4: In the lead up to the 2025 IRP, Idaho Power should provide cost estimates of SO2 and NOX emissions related to the converted plant, in its advisory IRPAC meetings.

Expectation 5: In the next IRP, the company should provide workpapers for the projected number of hours for regulation reserves operation of the Valmy coal-to-gas converted units, and the corresponding hours for SCCT, 4-hour and 8-hour batteries, in the Preferred Portfolio.

Expectation 6**:** In future IRPs, the Company should include the constraints related to system resilience in portfolio modeling if the estimated cost of ancillary services to preserve system resilience will be significant enough to warrant such inclusion**.**

Expectation 7: In the next IRP, the Company must share information with Staff about lessons learned regarding the incorporation of best-practices in battery project construction, commissioning, and operations to mitigate operational risks.

Expectation 8: In the next IRP, Idaho Power should document and share the a priori reasons for all econometric model specification.

Expectation 9: In the next IRP, Idaho Power should use the 50th percentile for the expected case load forecast in future IRPs.

Expectation 10: In the next IRP, the Company should consider and demonstrate the steps taken to provide oversight for special contract customers' forecasting of load growth.

Expectation 11: In the next IRP, the Company should preserve and be prepared to provide hourly wholesale electricity price data from the stochastic risk analysis.

Expectation 12: Idaho Power should investigate the possibility that migration of power sellers to balancing markets may cause Aurora to overestimate resources available for purchase by Idaho Power and report its findings in the next IRP.

Expectation 13: In the lead up to the 2025 IRP, the Company should work with and provide workpapers to Staff that explore the costs and benefits of portfolio runs with more 'low-cost' bundles, such as bundles of measures costing below $30/MWh.

Expectation 14: Idaho Power will engage Staff and stakeholders regarding DR block size during the development of the 2025 IRP.

Dated at Salem, Oregon this 25th of April, 2024.

/s/ Abe Abdallah
Senior Utility Analyst
Utility Strategy & Planning Division

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

Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
Telephone: (971) 375-5079

LC 84 SERVICE LIST

IDAHO POWER	
IDAHO POWER COMPANY	PO BOX 70 BOISE ID 83707-0070 dockets@idahopower.com
LISA D NORDSTROM **(C)** IDAHO POWER COMPANY	PO BOX 70 BOISE ID 83707-0070 lnordstrom@idahopower.com; dockets@idahopower.com
LISA F RACKNER **(C)** MCDOWELL RACKNER & GIBSON PC	419 SW 11TH AVE., SUITE 400 PORTLAND OR 97205 dockets@mrg-law.com
OREGON CITIZENS UTILITY BOARD	
JOHN GARRETT **(C)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY STE 400 PORTLAND OR 97205 john@oregoncub.org
MICHAEL GOETZ **(C)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY STE 400 PORTLAND OR 97205 mike@oregoncub.org
Share OREGON CITIZENS' UTILITY BOARD OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY, STE 400 PORTLAND OR 97205 dockets@oregoncub.org
RENEWABLE ENERGY COALITION	
ELLIE HARDWICK SANGER LAW PC	4031 SE HAWTHORNE BLVD PORTLAND OR 97214 ellie@sanger-law.com
JOHN LOWE RENEWABLE ENERGY COALITION	PO BOX 25576 PORTLAND OR 97298 johnl@recoalition.com
IRION A SANGER SANGER LAW PC	4031 SE HAWTHORNE BLVD PORTLAND OR 97214 irion@sanger-law.com
STAFF	
ABE ABDALLAH **(C)** PUBLIC UTILITY COMMISSION OF OREGON	PO BOX 1088 SALEM OR 97308-1088 abe.abdallah@puc.oregon.gov
MARLI KLASS **(C)** OREGON DEPARTMENT OF JUSTICE	1162 COURT STREET NE SALEM OR 97301-4096 marli.klass@doj.state.or.us
STOP B2H	
JIM KREIDER **(C)** No Business Name	60366 MARVIN RD LA GRANDE OR 97850 jkreider@campblackdog.org