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November 18, 2022

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Filing Center
P.O. Box 1088
Salem, OR 97308-1088

Re: Docket LC 78 – In the Matter of Idaho Power Company's 2021 Integrated Resource Plan ("IRP").

Attention Filing Center:

Attached for filing in the above-referenced docket are Idaho Power Company's Comments on the Staff Report for the Special Public Meeting on November 29, 2022.

Please contact this office with any questions.

Sincerely,

Alisha Till

Alisha Till
Paralegal

Attachment

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 78

In the Matter of: IDAHO POWER COMPANY'S 2021 Integrated Resource Plan.	**IDAHO POWER COMPANY'S COMMENTS ON STAFF REPORT FOR SPECIAL PUBLIC MEETING NOVEMBER 29, 2022**

I. INTRODUCTION

Idaho Power Company ("Idaho Power" or "Company") appreciates Staff's thorough review of the Company's *2021 Integrated Resource Plan* ("IRP") and Staff's thoughtful consideration of strategies to improve future IRP processes, as set forth in Staff's recent Report for Special Public Meeting November 29, 2022 ("Staff Report"). The Company supports many of Staff's recommendations—in particular, the recommended acknowledgment for the conversion to natural gas operation at Jim Bridger units 1 and 2 and conducting ongoing Boardman-to-Hemingway ("B2H") permitting and construction activities.[1] With respect to Staff's recommendations for future IRP processes and methods, the Company requests modification on five recommendations, offers clarification on three recommendations, and provides contextual comment on Staff's Load Forecast section. The following table presents the Company's position on each of Staff's recommendations:

Table 1: Company's Position on Staff Recommendations.

	Staff Recommendations[2]	Company Response
Recommendation 1	Acknowledge Action Item 4 - Plan and coordinate with PacifiCorp and regulators for conversion to natural gas operation with a 2034 exit date for Bridger Units 1 and 2. The conversion is targeted before the summer peak of 2024.	Accept

[1] Staff Report for the November 29, 2022 Special Public Meeting (Item No. 1) at 1-2 (Oct. 28, 2022) [hereinafter, "Staff Report"].
[2] Please note that the number of recommendations in the body of the Staff Report totals 25, however, the Summary of Staff Recommendations on pages 39-41 includes 26 recommendations, resulting in misalignment. For purposes of these comments, the Company used the numbering from the body of the Staff Report.

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Recommendation 2	Acknowledge Action Item 6 - Plan and coordinate with PacifiCorp and regulators for the exit/closure of Bridger Unit 3 by year-end 2025 with Bridger Unit 4 following the Action Plan window in 2028.	Accept
Recommendation 3	Acknowledge Action Item 13 - Subject to coordination with PacifiCorp, and B2H in-service prior to summer 2026, exit Bridger Unit 3 by December 31, 2025.	Accept
Recommendation 4	Acknowledge Action Item 2 - Discuss partnership opportunities related to SWIP-North with the project developer for more detailed evaluation in future IRPs with the condition that Idaho Power study the impact of the Greenlink transmission projects in reducing congestion between Idaho Power's service territory and southern wholesale energy markets.	Accept with Comment
Recommendation 5	Acknowledge Action Item 1 - Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreements. Once the agreements are in place, file for a certificate of public convenience and necessity with state Commissions.	Accept with Modification
Recommendation 6	Acknowledge Action Item 8 - Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.	Accept
Recommendation 7	Direct Idaho Power to produce a fresh, rigorous estimate of the total cost of B2H and all associated swaps and investments, breaking the total cost down by component, disclosing all data and assumptions for each estimated component cost, and model cost contingencies based on this updated total cost estimate for the 2023 IRP or sooner if necessary to support procurement actions.	Accept
Recommendation 8	Direct Idaho Power to model extremely high wholesale electricity prices and decreased liquidity in the 2023 IRP with greater input from stakeholders on these topics.	Accept with Modification
Recommendation 9	Direct Idaho Power to document the Company's monitoring and pursuit of grant opportunities in the regular reporting on transmission projects under Docket No. RE 136, including the items bulleted in Staff's Report.	Accept
Recommendation 10	Not acknowledge Action Item 5 - Issue a Request for Proposal ("RFP") to procure resources to meet identified deficits in 2024 and 2025.	Accept
Recommendation 11	Acknowledge Action Item 7 - Redesign existing DR programs then determine the amount of additional DR necessary to meet the identified need.	Accept
Recommendation 12	Acknowledge Action Item 9 - Implement cost-effective energy efficiency measures each year as identified in the energy efficiency potential assessment.	Accept
Recommendation 13	Direct Idaho Power to model new DR for the 2023 IRP based on the results of the IPC-specific DR potential study expected to be complete in the fall of 2022. Results should include exploring whether current programs have additional potential, additional kinds of DR programs including pricing programs, and more accurately estimating costs of future programs.	Accept with Comment
Recommendation 14	Acknowledge Action Item 10 - Work with large-load customers to support their energy needs with solar resources.	Accept
Recommendation 15	Direct Idaho Power to include large-load customer resource acquisition sizing and timing needs in the 2023 IRP Action Plan.	Accept with Modification
Recommendation 16	Acknowledge Action Item 12 - Exit Valmy unit 2 by December 31, 2025.	Accept
Recommendation 17	Not Acknowledge Action Item 3 - Solar is contracted to provide 120 MW starting December 2022. Work with the developer to determine, if necessary, mitigating measures if the project cannot meet the negotiated timeline.	Accept
Recommendation 18	Acknowledge 29 MW of the 40 MW from the Preferred Portfolio referenced in Action Item 11 - Finalize candidate locations for distributed storage projects and implement where possible to defer T&D investments as identified in the Action Plan.	Accept
Recommendation 19	Not Acknowledge the following 11 MWs of investments from the 2023 RFP that have already been secured - 2 MW in Melba, 3 MW in Weiser, 2 MW in Filer, and 4 MW in Elmore.	Accept

Recommendation 20	Direct Idaho Power to continue to explore how participating in the WRAP may alter transmission assumptions.	Accept
Recommendation 21	Direct Idaho Power to include all necessary resources in scored portfolios to meet the Company's reliability standard.	Accept with Comment
Recommendation 22	Direct Idaho Power to revisit the assumed renewal rate of wind QFs.	Accept
Recommendation 23	Direct Idaho Power to apply a reasonable forecast of new QFs beginning in the fifth year of the planning cycle.	Accept with Modification
Recommendation 24	Direct Idaho Power to include, in the executive summary of the Company's 2023 IRP, a graph showing Idaho Power's GHG emissions for 2019-2022 and comparing those historical emissions to the IRP 20-year forecast of IRP emissions calculated in the same manner. The data should include emissions from market purchases and remove emissions from market sales.	Accept with Modification
Recommendation 25	Direct Idaho Power to include the most reasonable proxy of green hydrogen as a potential resource in its next IRP, either available for selection in a portfolio or in a sensitivity.	Accept

II. DISCUSSION

A. Staff's Recommendation 4

Staff recommends the Commission acknowledge Action Item 2:

> Discuss partnership opportunities related to SWIP-North with the project developer for more detailed evaluation in future IRPs" and further added that "Idaho Power should study the impact of the Greenlink transmission projects in reducing congestion between Idaho Power's service territory and southern wholesale energy markets.[3]

Idaho Power appreciates Staff's acknowledgement and agrees with the expanded recommendation. The Company would like to highlight that although the SWIP-North and Greenlink projects may provide access to the southern power markets, the depth of resource availability in those markets during the Company's summer peak times is questionable and without available resources during summer peak, the transmission capacity is of limited value at that time. Conversely, the Company believes the southern power markets are set up well to leverage winter availability.

Additionally, within the discussion for Recommendation 4, Staff suggests that for the next IRP, the Company should "model how transmission projects to its south may create sufficient

[3] Staff Report at 10.

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capacity to only pay Open Access Transmission Tariffs (OATT) when needed rather than assume the hazards of ownership, like becoming an investor in SWIP-North."[4] Although Idaho Power accepts Recommendation 4, the Company would like to respond to Staff's suggestion.

The Company is unclear of the risks[5] of ownership to which Staff refers compared to the risks of taking transmission service. A transmission owner/provider will include any unexpected costs incurred in its transmission rate base and pass those costs onto transmission customers through the transmission provider's OATT rate. The transmission customer pays for any costs regardless of ownership. Acquiring long-term firm transmission service as an OATT customer requires a five-plus year transmission service agreement with roll-over rights, if that capacity is even available. Transmission service payments will be at the OATT rate, as established by the transmission provider with the oversight of the Federal Energy Regulatory Commission. OATT rates are subject to change, often annually for transmission providers with formula rates, and generally increase over time, whereas transmission ownership costs to customers reduce over time.

In sum, Idaho Power agrees with Staff's Recommendation 4 but cautions against identifying preconceived benefits via the southern power markets or from not owning transmission. The Company commits to engage with both the SWIP North developer and NV Energy to further evaluate transmission opportunities.

B. <u>Staff's Recommendation 5</u>

Staff recommends the Commission acknowledge Action Item 1:

> Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreements. Once the agreements are in place, file for a certificate of public convenience and necessity with state Commissions.[6]

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[4] *Id.* at 10.
[5] Please note that the Staff Report used the term "hazard" not "risk." *See id.* at 10.
[6] *Id.* at 19.

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Idaho Power has an update and clarification related to Action Item 1 and as detailed below, asks that the Commission acknowledge a slightly modified version of Action Item 1.

First, as an update, Idaho Power has already filed its certificate of public convenience and necessity ("CPCN") with the Public Utility Commission of Oregon ("Commission") on September 30, 2022,[7] and thus a portion of Action Item 1 has already been substantially completed. When Idaho Power initially included Action Item 1 as part of its IRP filing submitted on December 30, 2021, Idaho Power expected that the construction agreements with B2H partners would be in place prior to filing for a CPCN with the Oregon and Idaho Commissions. However, Idaho Power ultimately determined that it was necessary to file the petition for a CPCN prior to finalizing the partner agreements in order to meet the target 2026 in service date. Idaho Power is still diligently working with its partners toward definitive construction agreements, but they have not been completed at this time.

Second, as a clarification, Idaho Power included Action Item 1 in its IRP, which was filed with both the Oregon and Idaho Commissions. By referencing the filing of a petition for a CPCN with the Idaho Commission in Action Item 1, Idaho Power did not intend for the Oregon Commission to direct Idaho Power to make a filing with the Idaho Commission, or that the timing for such filing would be prescribed by the Oregon Commission—which would be beyond the scope of the Commission's authority.

In light of the foregoing, Idaho Power proposes that the Commission acknowledge a modified version of Action Item 1:

> Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreements. ~~Once the agreements are in place,~~ <u>Conduct ongoing activities related to petitions</u> for a certificate of public convenience and necessity with state commissions. [8]

[7] See *In the Matter of Idaho Power Company's Petition for Certificate of Public Convenience and Necessity*, Docket No. PCN 5, Petition for Certificate of Convenience and Necessity (Sept. 30, 2022).
[8] Staff Report at 5, 19.

C. Staff's Recommendation 8

Staff recommends the Commission direct Idaho Power to model "extremely high wholesale electricity prices and decreased liquidity in the 2023 IRP with greater input from stakeholders on these topics."[9] The Company disagrees with this recommendation and requests that the Commission not direct such a specific modeling scenario.

Recognizing Staff's interest in a "high market price" view, the Company has already commenced collaborative discussions with its IRP Advisory Council for the 2023 IRP to determine valuable scenario exercises, one of which could be a proxy method for high market prices. The Company cautions that market prices are not inputs to the model and, as a result, cannot simply be manipulated to understand a high-market price environment. Such an approach would compromise the validity of model results and is not advised by the developers of AURORA, Energy Exemplar. As a result, the Company requests that the Commission decline to approve a specific scenario. As an alternative, the Company would support a directive to further discuss the impact of high-market prices on resource selection in the 2023 IRP such as:

> Direct Idaho Power to work with stakeholders and discuss the impact of ~~model~~ extremely high wholesale electricity prices and decreased liquidity on resource selection in the 2023 IRP~~with greater input from stakeholders on these topics~~.

Additionally, within the Planning Input Updates section of Staff's analysis, Staff incorrectly states: "With respect to Mid-C prices, Idaho Power's 2021 IRP did not perform the way the Company stated it should perform in IPC's Final Reply Comments."[10] The Company's Final Reply Comments on this subject state the opposite.[11] Notwithstanding this misstatement, the Company commits to working with Staff and stakeholders within the 2023 IRP process to ensure the IRP inputs and modeling are robust.

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[9] *Id*. at 19.
[10] *Id.* at 16
[11] Idaho Power Company's Final Reply Comments and Request for Waiver of the 2022 IRP Update at 13-18 (Sept. 23, 2022) [hereinafter, "Idaho Power's Final Reply Comments"].

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D. Staff's Recommendation 13

While Idaho Power does not have concerns with Staff Recommendation 13 as written, the Company's comments herein respond to elements of Staff's Analysis on demand response ("DR").

1. 2022 DR Program Season

Regarding the 2022 DR program season, Staff states: "As an institution, IPC does not yet know the nameplate capacity of a DR season that [sic] ended last month. This means that even power operations does not know how much DR was dispatched."[12] Idaho Power would like to offer clarification on this statement.

The Company knew and provided to Staff the 2022 season DR amounts for two of its three programs. For the third and largest program—Irrigation Peak Rewards—the data had not yet been collected and analyzed in time for inclusion in Staff's memo, given the late date of the final DR event. Idaho Power provided to Staff final Irrigation Peak Rewards information when the calculations were completed in the Company's supplemental response to Staff Request No. 156, which was provided on November 1.[13]

2. New DR Blocks in AURORA

Staff states it has lingering questions and does not understand why choosing blocks that increased the average size of new DR was more reasonable than other choices that would have assumed significantly lower costs.[14]

In the 2019 IRP, the Company had ten 5 MW blocks of selectable DR (max of 5 MW per year). In the 2021 IRP, the Company had fourteen 20 MW blocks of selectable DR (max of 20 MW per year), however it is important to recognize these numbers are not directly comparable.

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[12] Staff Report.at 22.
[13] *See* Attachment 1 at 5-6 (Idaho Power Company's Supplemental Response to Staff's Information Request No. 156 and Attachment (Nov. 1, 2022)).
[14] Staff Report at 22.

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The 2021 IRP 20 MW blocks had an Effective Load Carrying Capability ("ELCC") of approximately 35 percent, thus reducing a 20 MW block's effective capacity toward meeting peak to about 7 MW, which was comparable to the 5 MW blocks from the 2019 IRP. It is unlikely that reducing the 20 MW block size in the 2023 IRP would alter the results, as the Company completed Validation and Verification testing in the 2021 IRP[15] showing the selection of additional DR was not cost effective.

3. Dispatch of DR in AURORA

Staff observed that AURORA did not dispatch DR in the highest loss of load probability ("LOLP") hours and is concerned about the differences in the dispatch of DR between MATLAB and the AURORA model. Staff concludes that some variation can be reasonable, but excessive difference between the two models might mean that AURORA is not dispatching resources in accordance with the Company's assumptions about resource adequacy.[16]

The LOLP data provided to Staff during discovery[17] was exported from the Company's Loss of Load Expectation ("LOLE") tool, which utilizes several years of historical data. For the 2021 IRP, four years of historical data were used, meaning there were four sets of LOLP values provided. The referenced DR shape that was used in AURORA was not developed using the four years of historical data; instead, the DR shape was created using hourly forecasted data. Direct comparisons should not be made between (1) the LOLP hours of any of the four historical years to (2) the forecasted DR shape created for utilization in AURORA because the two sets of information will not align. Simply, it may be 100 degrees on July 1, 2021, and not 100 degrees on

[15] Idaho Power Company's 2021 Integrated Resource Plan at 123, 131 (Dec. 30, 2021) (Table 10.5) [hereinafter, "2021 IRP"].
[16] Staff Report at 22.
[17] Attachment 1 at 1-2 (Idaho Power Company's Response to Staff Information Request No. 41 (June 8, 2022)); Attachment 1 at 4 (Idaho Power Company's Response to Staff Information Request No. 146 (Sept. 2, 2022)) ("The hourly DR portfolio shape provided to AURORA was a direct output from the Company's LOLE tool, which uses perfect foresight regarding load and resource output and is designed to optimize dispatch.").

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July 1, 2022. The Company developed the DR shape based on AURORA's inputted hourly forecast data to ensure that resources would be dispatched during the high-risk hours, as detailed in the Company's response to Staff's IR 146(d).

Overall, the Company appreciates Staff's analysis and positive conclusions regarding its Energy Efficiency and DR programs. The Company will continue to work with Staff and stakeholders in the 2023 IRP process to ensure demand-side resources are modeled appropriately.

E. <u>Staff's Recommendation 15</u>

Staff recommends the Commission direct Idaho Power to "include large-load customer resource acquisition sizing and timing needs in the 2023 IRP Action Plan."[18] Regarding this recommendation, Idaho Power offers both clarification and a suggestion for modifying the recommendation.

Idaho Power believes this recommendation from Staff stems from some of the solar resources added in the 2021 IRP Action Plan window to support a then-unnamed large customer's renewable energy goals under the Company's Clean Energy Your Way ("CEYW") Construction option in Idaho. When the 2021 IRP was being developed, this customer—later identified as Brisbie, LLC—was not known publicly and its special contract had not yet been submitted to the Idaho Public Utilities Commission ("IPUC").[19] As a result, the Company added solar acquisitions to the Action Plan window but did not identify the customer until later. Idaho Power understands that this may have been confusing.

The Company recognizes that there is interest in both large customer load growth and renewable resources that will be procured to support a given customer's clean energy requirements, but these two interests are not mutually exclusive. To be clear, the Company *does*

[18] Staff Report at 24.
[19] *See* IPUC Docket No. IPC-E-21-42.

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not identify specific resources to serve an individual customer's load growth. The Company has only identified such resources in this case because the customer had voluntarily entered into a CEYW special contract arrangement with the Company. It is also important to note that not all of Idaho Power's special contract customers may seek similar arrangements.

To ensure that Staff's recommendation reflects the dynamics taking place with respect to CEYW and accounts for confidentiality, the Company recommends the following additions to Recommendation 15:

> <u>For all clean energy special contracts with large load customers,</u> ~~D~~direct Idaho Power to include large-load customer resource acquisition sizing and timing needs in the 2023 IRP Action Plan <u>in a manner that does not compromise Idaho Power or customer confidentiality</u>.

F. <u>Staff's Recommendation 21</u>

Staff recommends the Commission direct Idaho Power to include all necessary resources in scored portfolios to meet the Company's reliability standard.[20] Staff states that they are opposed to the use of a gas plant to meet the reliability standard while not including that gas plant in the portfolio. Staff explains that Idaho Power is relying on a gas plant in these portfolios to overcome a reliability issue but not transparently including the resource in portfolios or in the Company's emissions forecast.[21]

The Company accepts this recommendation and understands Staff's concerns on the subject. The high penetration of variable energy resources has created considerable challenges for the power industry, including Idaho Power. The Company recognizes that the use of multiple metrics, including planning margin and LOLE, are now necessary to generate reliable portfolios. During the 2021 IRP, the Company implemented a two-step verification method to ensure selected portfolios were reliable, as measured by both the planning margin and LOLE. Idaho

[20] Staff Report at 35.
[21] *Id*. at 34-35

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Power believes that there is room for improvement regarding the two-step verification process and will continue to work with Staff and members of the IRPAC to improve the reliability evaluation for the 2023 IRP.

G. Staff's Recommendation 23

Staff recommends the Commission direct Idaho Power to apply a reasonable forecast of new qualifying facilities ("QFs") beginning in the fifth year of the planning cycle.[22] Idaho Power is not opposed to some method of forecasting new QFs among other scenarios but requests the Commission not apply Staff's prescriptive approach.

Staff states that an underestimation of new QFs would displace future QF development due to distortion of price signals. [23] Idaho Power does not fully understand Staff's argument. By not including a forecast of new QFs for which the Company has no actual information, the IRP is able to comprehensively identify resource needs and the resource types and attributes to optimally meet the needs. This approach also results in a potentially earlier capacity deficiency date that would trigger capacity pricing for future QFs. In other words, comprehensively identifying future resource needs – by not assuming a forecast of new QFs – sends appropriate price signals to incent resource development, including QF development. Conversely, including a forecast of QF development could reduce the identified resource need and extend the capacity sufficiency period, thereby reducing the price signals otherwise sent by capacity pricing. While Idaho Power is not opposed to considering a scenario that includes future QF development, Idaho Power does not agree that this approach would result in price signals that incent such development.

Further, including a forecast of speculative QF resources has the potential to hide real capacity deficits that would be revealed in the model—an outcome that would undermine one of

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[22] *Id.* at 37.
[23] *Id*. at 36.

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the fundamental objectives of performing long-term planning exercises. The act of including speculative PURPA resources that may not come to fruition is particularly risky in the current supply chain environment where projects needed to meet known deficits are being delayed considerably. Further, including a forecast of future QF development will have the potential to distort model results by forcing in specific types and quantities of resources without allowing the model to select these resources to meet modeling criteria.

Objections notwithstanding, Idaho Power understands that the Company is likely to experience some QF activity—however, it does not have any reliable way to estimate the timing and volume on such activity. As a solution, Idaho Power proposes working with Staff and stakeholders on how to incorporate a future QF forecast in the 2023 IRP, potentially through a scenario exercise or other method, and can accept Staff's recommendation with the following modification:

> Direct Idaho Power to ~~apply a reasonable forecast of new QFs beginning in the fifth year of the planning cycle~~ <u>work with Staff and stakeholders to develop a reasonable forecast of new QFs in the 2023 IRP</u>.

Additionally, Idaho Power would like to clarify Staff's statement that the Company already forecasts QFs in the Company's Annual Power Cost Update ("APCU"). The PURPA forecast in the APCU includes existing PURPA projects, as well as any new projects with signed contracts that are <u>expected</u> to come online during the test year.

In the October Update portion of the APCU, the PURPA forecast is normalized so that any new projects coming online in the test year are modelled as annualized online resources for the entire APCU year.

In the March Forecast portion of the APCU, the PURPA forecast is adjusted according to the settlement stipulation approved in the Company's 2018 APCU.[24] Per the stipulation, for any

[24] See *In the Matter of Idaho Power Company's 2018 Annual Power Cost Update*, Docket No. UE 333, Order No. 18-170 (May 21, 2018).

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new PURPA project expected to come online during the test year, the forecast generation and expense will be included in the forecast beginning in the month in which the project is expected to come online. In addition, the expected online date for any new PURPA project will be adjusted using the three-year average Contract Delay Rate ("CDR") of historical PURPA projects. The CDR is based on the average of differences in scheduled operation date and actual operation date for historical PURPA projects. The three-year historical average CDR is applied to any new PURPA project expected to come online during the forecast test period.

H. Staff's Recommendation 24

Staff recommends the Commission direct Idaho Power to include, in the executive summary of the Company's 2023 IRP, a graph showing Idaho Power's greenhouse gas ("GHG") emissions for 2019-2022 and comparing those historical emissions to the IRP 20-year forecast of IRP emissions calculated in the same manner. Staff directs the Company to include emissions from market purchases and remove emissions from market sales.[25]

The Company stands by its assertion and its concerns first stated in its Reply Comments:

> [T]he Company will review its emissions modeling procedure for the 2023 IRP and attempt to reasonably align historical and forecast emissions. Specifically, the Company is concerned with Staff's request that historical and forecast emissions be calculated *in the same manner*, as this is technically impossible. The data sources and methods used to calculate estimated historical emissions and estimated forecast emissions are different and, therefore, they cannot be calculated in the same manner.[26]

Staff rightfully acknowledged that the process to estimate emissions associated with historical sales will be complicated and offers two methods for the Company to consider; however, Staff did not address methods to estimate emissions associated with purchases.[27] Calculating emissions from purchases will be even more difficult to capture, as the Company would need to

[25] Staff Report at 38.
[26] Idaho Power's Final Reply Comments at 32.
[27] Staff Report at 38.

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know the temporal emissions intensity of each zone from which it purchases power (similar to what Staff has outlined for sales related emissions). This data is unlikely to be available to the Company and, thus, historical and forecast emissions associated with purchases will need to be calculated in different ways.

Because of these concerns about the technical feasibility of this recommendation, Idaho Power proposes that the Commission acknowledge a modified Recommendation 24:

> Direct Idaho Power to include, in the executive summary of the Company's 2023 IRP, a graph showing Idaho Power's GHG emissions for 2019-2022 and comparing those historical emissions to the IRP 20-year forecast of IRP emissions calculated in ~~the same manner~~ a reasonably similar method. The data should include emissions from market purchases and remove emissions from market sales.

I. Load Forecast

Idaho Power appreciates Staff's robust review and conclusions of the load forecast for the 2021 IRP. While Staff did not offer a particular recommendation on the load forecast, the Company nevertheless offers brief comment on some of Staff's conclusions and suggestions.

1. Monthly Load Forecasting Error in First Year

To assess the accuracy of Idaho Power's load forecasting methodology, Staff compared the first year of the 2021 IRP forecast to actual energy sales. The system energy forecast overestimated energy load in 2021 by around 1 percent. The system peak forecast overestimated peak load in 2021 by less than 0.25 percent. Staff finds this to be a "reasonable" amount of forecasting error.[28] While Idaho Power appreciates Staff's conclusion, the Company feels that margins of error of 1 percent and less than 0.25 for energy and peak demand, respectively, are extremely narrow bounds for what should be considered "reasonable." Although no recommendation was made on this subject, the Company considers it important to note that

[28] *Id.* at 31.

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forecasts are, by nature, subject to error or deviations and that the narrow margin of error in the 2021 IRP should not be the basis for future determinations of what is reasonable.

2. *Outstanding Issues*

Staff identified four modeling issues that they were not able to resolve, noting that it is unknown if resolution would materially impact the long-term forecast of load.[29] Given that Staff's concerns center around data that could not be shared given it was either not yet available or too voluminous to share, the Company suggests that these issues can best be resolved in the 2023 IRP process through timely workshops with Staff and providing Staff with the "over the shoulder" ability to view load forecasting data that is contained and/or transformed in proprietary databases. As is always true, the Company strives to make model/method improvements each iteration and commits to providing opportunity to fully evaluate the load forecast for the 2023 IRP.

3. *Special Contracts*

Regarding Special Contracts, Staff states that "it has found methodological issues that could impact the reasonableness of the Company's long-term load forecast, but given the data Idaho Power has provided Staff, Staff does not find alternatives to IPC's regression models that materially impact the forecast of load."[30] While the Company believes it has provided sufficient response on this topic in both sets of comments,[31] the Company reiterates its position.

Special Contract customers provide forecasts to the Company under the terms of their special contract. The Company vets these forecasts through engineering and financial filters and gauges the probability of realization. However, at the end of the day, the forecasts are in fact an exogenous value from a third-party. These forecasts are subject to the same economic and financial influences that are relevant to the business investment plans of these companies. These

[29] *Id.* at 32.
[30] *Id.* at 32.
[31] Idaho Power's Final Reply Comments at 9-11; *see also* Idaho Power Company's Reply Comments at 9-11 (Aug. 4, 2022).

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forecasts are monitored closely by the Company and are a key element of the two-year IRP update dynamic.

III. CONCLUSION

Idaho Power again thanks Staff for its thoughtful report and recommendations on the 2021 IRP. As noted earlier, Idaho Power agrees with most of Staff's recommendations for improving future IRPs, beginning with the 2023 IRP. By and large, the Company considers Staff's recommendations to be reasonable courses of action and thoughtful ways to improve the IRP process and analysis going forward. The Company takes issue with only five items and respectfully requests that the Commission: (1) modify the language in Staff Recommendation 5 regarding Action Item 1; (2) modify the language in Staff Recommendation 8 to allow flexibility in the approach to evaluating the impact of extremely high wholesale electricity prices on resource selection in the 2023 IRP; (3) modify the language of Recommendation 15 to reference non-confidential information that can be provided about clean energy special contract customers; (4) approve a non-prescriptive approach for inclusion of a QF forecast (Recommendation 23); and (5) modify the language of Recommendation 24 to recognize the differences between historical and forecast emission calculations.

Respectfully submitted this 18th day of November 2022.

MCDOWELL RACKNER GIBSON PC

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IDAHO POWER COMPANY

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Attachment 1

to

Idaho Power's Comments on Staff Report

LC 78
Idaho Power Company's Response to
Staff's Information Request No. 40-44

Topic or Keyword: Portfolio Modeling

<u>STAFF'S DATA REQUEST NO. 41:</u>

Referencing the loss of load expectation values presented on page 100 of the 2021 IRP's Appendix C:

a. Please provide all workpapers supporting these results.
b. Please provide a 12X24 matrix for hourly loss of load probability where the twelve columns are the months of the year, and the twenty-four rows are the twenty-four hours in a day. Please exclude weekends and holidays from these averages.

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 41:</u>

a. The Loss of Load Expectation ("LOLE") results presented on page 100 of the 2021 Integrated Resource Plan, ("IRP") Appendix C were obtained by running the Company's internally developed LOLE MATLAB® algorithm. This LOLE tool is comprised of a multitude of interplaying scripts that apply the methods and equations described in the *Reliability Evaluation of Power Systems* (Billinton & Allan, 1984) textbook.
    - Billinton, Roy, and Ronald N. Allan. *Reliability Evaluation of Power Systems*. Pitman Books Limited, 1984.

    Attachment 1 contains the LOLE tool scripts (a total of ten). The scripts can be viewed in any text editor application.

b. Staff's request for a 24X12 matrix of average Loss of Load Probability ("LOLP") is provided in Attachment 2 of this request; however, the Company cautions against using this information for any further calculations because it provides a limited view of time-limited energy resources (e.g.., demand response that can only be operated under certain conditions). Because the LOLE result of each year is driven by just a few days during the summer months, averaging the LOLPs before calculating the LOLE would skew the data and provide erroneous results. Due to this consideration with respect to the requested dataset, Idaho Power has also provided Staff with the 8,760X1 LOLPs that were used to calculate the LOLE results shown on page 100 of Appendix C.

    Attachment 2 is a zip file containing the following datasets in Excel format for the portfolios requested:
    1. The 8,760X1 LOLPs
    2. The 24X12 matrix with average LOLPs excluding weekends and holidays (*these results have been provided only because they were requested; the Company believes they should not be used for capacity contribution calculations*).

    For each of the five portfolios included in the table on page 100 of Appendix C, LOLP results have been provided by test year. The test years include annual data for the entirety of the planning horizon (2021-2040), with each case having requested 24X12 matrix results and the 8,760X1 results.

    To navigate the files, here is an example to find the 8,760X1 hourly LOLP results for the Preferred Portfolio (Base with B2H), test year 1, year 2021:

Attachment 2 > Base_B2H > TY1 > BASE_B2H_TY1_Y1.xlsx

In this example, "Base_B2H" represents the selected portfolio, "TY1" represents the selected test year, "Y" represents the 8,760X1 LOLP results (the Excel files with "M" instead of "Y" represent the 24X12 matrix results), and the "1" represents the selected year of the 2021 IRP planning timeframe (1 corresponds to 2021, whereas 20 corresponds to 2040).

Topic or Keyword: Demand Response

STAFF'S DATA REQUEST NO. 146:

Referencing the Company's response to OPUC IR 115:

a. Please explain why the sum of each column is larger than the totals in row 3.

b. Please explain why modeling more total dispatch of DR than what is expected to be dispatched improves resource planning.

c. Please explain the effect modeling more total dispatch of DR than what is expected to be dispatched has on the selection of new DR.

d. Please explain why modeling a maximum of 150 MWh per hour is the most reasonable assumption.

e. Please explain the effect modeling a higher maximum dispatch per hour would have on the selection of new DR.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 146:

a. The total shown in column B, row 3 of the spreadsheet attached to the Company's response to Staff Request No. 115 represents the Demand Response ("DR") portfolio annual energy output from the Company's Loss of Load Expectation ("LOLE") tool and provided to AURORA for use in the Long-Term Capacity Expansion ("LTCE") modeling. The LOLE tool dispatches DR to its full extent (meaning it utilizes all the events allowed based on the Company's program parameters), and for this run the LOLE tool used the same hourly shaping data utilized in the AURORA model. The total shown in column C, row 3 of that same spreadsheet represents the actual DR portfolio dispatch from the 2021 season. The difference between the two totals is that the LOLE tool dispatches the maximum number of DR portfolio events allowed, while in real-time operations the Company strives to reduce the impact to customers; historically, Idaho Power has never dispatched the DR portfolio to its full capability in terms of number of events allowed per season.

b. AURORA's LTCE model builds portfolios under a multitude of scenarios that all meet a minimum reliability threshold that accounts for uncertainties in load, weather, unplanned resource outages, among other factors over the entirety of the 20-year planning horizon. Modeling the DR portfolio to its full capability improves resource planning by crediting the programs for their maximum potential benefit, whether the Company elects to use them in real-time operations or not.

c. While it is anticipated that modeling more total dispatch of DR than what is expected to be dispatched would have minimal effect on the selection of new DR, this sensitivity was not conducted. Utilizing an hourly DR shape that has been reduced for an expected number of events would call for new Effective Load Carrying Capability ("ELCC") calculations for current and new DR programs, as well as a new shape for the new DR bundles based on the corresponding expected number of events; these changes would make all DR look less desirable in the LTCE model. As the LTCE model iterates through multiple costing runs to solve for the least-cost mix of resources, the amount of DR provided could affect portfolio costs throughout the iteration process and interplay differently with the output shape of another resource in contention for selection.

d. The hourly DR portfolio shape provided to AURORA was a direct output from the Company's LOLE tool, which uses perfect foresight regarding load and resource output and is designed to optimize dispatch. To create this shape, the LOLE tool was provided the *same* hourly shapes that are utilized in the AURORA model. Using this data the LOLE tool creates an hourly DR portfolio shape that minimizes net load. When generating this shape, there was not a single hour that required more than 150 MW to drop the highest net load hour below the second highest net load hour. For clarification, the Company's ELCC calculations were performed by averaging the results of four different test years of hourly shapes. Each of these runs resulted in a different hourly DR portfolio shape where the maximum amount of DR dispatched in a single hour varied.

e. Please reference subpart "c" of this request.

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Idaho Power Company's Supplemental Response to
Staff's Information Request No. 156

Topic or Keyword: Demand Response

STAFF'S DATA REQUEST NO. 156:

Please provide the date, time, maximum reduction in load (MW), and average reduction in load (MWh) for every DR event called in 2022, broken down by program.

IDAHO POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S DATA REQUEST NO. 156:

In the Company's response to Staff Request No. 156, Idaho Power committed to provide the information for the Irrigation Peak Rewards 2022 Demand Response ("DR") season by the first week of November. The information for the AC Cool Credit, Flex Peak, and Irrigation Peak Rewards 2022 demand response ("DR") program season is provided in the attached Excel spreadsheet. Please note, the Irrigation Peak Rewards information was appended to the prior list so that all the information was in a single attachment.

Program	Date	Hours	Max_kW	Avg_kW
Flex Peak	26-Jul-22	5-9 PM	15,870	15,418
Flex Peak	28-Jul-22	5-9 PM	23,300	20,499
Flex Peak	8-Aug-22	5-9 PM	14,367	13,296
Flex Peak	17-Aug-22	5-9 PM	17,680	16,981
Flex Peak	31-Aug-22	6-10 PM	14,985	12,707
Flex Peak	2-Sep-22	5-9 PM	9,727	7,984
Flex Peak	6-Sep-22	5-9 PM	6,322	4,785
AC Cool Credit	7-Jul-22	6-9 PM	11,657	10,762
AC Cool Credit	27-Jul-22	4-8 PM	17,047	15,289
AC Cool Credit	28-Jul-22	4-8 PM	18,437	16,650
AC Cool Credit	29-Jul-22	4-8 PM	20,467	18,470
AC Cool Credit	1-Aug-22	6-9 PM	19,090	17,658
AC Cool Credit	8-Aug-22	5-8 PM	16,765	15,518
AC Cool Credit	9-Aug-22	5-8 PM	17,161	16,462
AC Cool Credit	17-Aug-22	6-10 PM	14,804	11,014
AC Cool Credit	31-Aug-22	6-10 PM	15,168	11,415
AC Cool Credit	1-Sep-22	5-8 PM	16,018	14,505
AC Cool Credit	2-Sep-22	5-9 PM	15,809	12,989
AC Cool Credit	6-Sep-22	5-9 PM	13,190	10,199
AC Cool Credit	7-Sep-22	5-9 PM	17,495	14,721
Irrigation Peak Rewards	7/7/2022	6-10 PM	121,248	118,780
Irrigation Peak Rewards	7/12/2022	3-9 PM	109,097	72,016
Irrigation Peak Rewards	7/26/2022	3-9 PM	113,526	75,049
Irrigation Peak Rewards	7/27/2022	5-10 PM	76,238	60,497
Irrigation Peak Rewards	7/28/2022	3-9 PM	102,584	67,709
Irrigation Peak Rewards	7/29/2022	4-10 PM	76,774	50,735
Irrigation Peak Rewards	8/8/2022	3-9 PM	83,878	55,524
Irrigation Peak Rewards	8/9/2022	4-9 PM	75,092	59,501
Irrigation Peak Rewards	8/17/2022	4-10 PM	86,760	57,380
Irrigation Peak Rewards	9/2/2022	3-10 PM	155,129	87,988
Irrigation Peak Rewards	9/6/2022	6-10 PM	152,130	132,171

*All Results are at the system level