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September 23, 2022

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, Oregon 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-captioned docket are Idaho Power Company's Final Reply Comments and Request for Waiver of 2022 IRP Update. Confidential copies will be provided via encrypted zip file to the Filing Center and parties that have signed General Protective Order No. 22-212.

Please contact this office with any questions.

Sincerely,

Alisha Till

Alisha Till

Attachments

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 FINAL REPLY COMMENTS AND REQUEST FOR WAIVER OF 2022 IRP UPDATE**

September 23, 2022

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I. INTRODUCTION

Idaho Power Company ("Idaho Power" or "Company") respectfully submits these Final Reply Comments to the Public Utility Commission of Oregon ("Commission"). These comments respond to the final comments and recommendations from Commission Staff ("Staff"), the Renewable Energy Coalition ("REC"), the Oregon Citizens' Utility Board ("CUB"), Renewable Northwest, and the STOP B2H Coalition ("STOP B2H").

Idaho Power requests that the Commission acknowledge the Company's 2021 Integrated Resource Plan ("IRP"), as submitted to the Commission on December 30, 2021. The IRP satisfies each of the Commission's procedural and substantive requirements. The Company's Short-Term Action Plan ("Action Plan") and preferred long-term resource portfolio ("Preferred Portfolio") are supported by robust and comprehensive analysis demonstrating the reasonableness of the plan.[1]

The 2021 IRP is a comprehensive analysis of the optimal mix of both demand- and supply-side resources needed to meet flexible capacity needs and reliably serve customer demand over the 20-year planning horizon from 2021 to 2040. As a result of meaningful feedback from Commission Staff and stakeholders, the 2021 IRP reflects significant improvements over past IRPs to scenario modeling and other planning analyses, as well as enhanced process controls.

The 2021 IRP Preferred Portfolio successfully positions Idaho Power to provide reliable, economic, and environmentally sound service to its customers into the future. The 2021-2027 Action Plan associated with the Preferred Portfolio includes the following core resource actions: (1) conversion of Bridger Units 1 and 2 from coal to natural gas by summer 2024 with a 2034 plant exit date; (2) acquisition of significant capacity and energy resources to meet demand growth needs in 2023 through 2027, including 120 megawatts ("MW") of added solar PV capacity by 2023; (3) exit from both Jim Bridger Unit 3 and Valmy Unit 2 by year-end 2025; and

[1] *In re Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002, App. A at 1-3 (Jan. 8, 2007).

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(4) completion of the Boardman-to-Hemingway transmission line ("B2H") by 2026.[2]

The B2H transmission line continues to be a top performing resource supply-side resource, providing Idaho Power access to clean and low-cost energy in the Pacific Northwest wholesale electric market. Originally specified as a 285 MW transmission capacity resource in the Company's 2006 IRP's preferred resource portfolio, the B2H project has served as a critical component of Idaho Power's preferred portfolios since the 2009 IRP and has consistently represented the least-cost, least-risk resource for customers. In the last six IRPs, the Commission has recognized that continued development of the project is reasonable.

These resource actions reflected in the 2021 IRP have been largely supported by the parties to this proceeding, with the exception of STOP B2H's general opposition to the B2H transmission line. Nonetheless, parties present a range of suggestions and feedback on the Company's 2021 IRP and recommendations for the 2023 IRP which include portfolio design and analysis, market price forecasts, treatment of certain supply-side and demand-side resources, and development of long-term forecasts. Parties' comments on each of these categories are set out and addressed in turn below.

II. STANDARD FOR ACKNOWLEDGMENT

Idaho Power's IRP must: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) aim to select a resource portfolio with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.[3] The primary goal of an IRP is to select the least cost/risk portfolio for the utility and customers.[4] To meet this goal, the Commission requires the IRP to analyze a

[2] Idaho Power's 2021 IRP at 166 (Dec. 30, 2021) [hereinafter, "2021 IRP"].
[3] *In re Idaho Power Company, 2013 Integrated Resource Plan*, Docket No. LC 58, Order No. 14-253 at 1 (July 8, 2014).
[4] Order No. 07-002 at 5 (Guideline 1(c): "The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.").

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planning horizon of "at least 20 years."[5] While the fundamental goal of the IRP is the identification of the Preferred Portfolio, the Commission's guidelines also require the IRP to include an action plan that identifies the specific resource activities the utility intends to undertake in the next two to four years.[6] When adopting the IRP guidelines, the Commission noted that, "in an IRP, the Commission looks at the reasonableness of individual actions in the context of the entire plan."[7]

When acknowledging an IRP, the Commission acknowledges only the action plan and does not acknowledge action items planned to occur more than four years in the future.[8] Commission acknowledgment confirms that the action plan satisfies the procedural and substantive requirements of the Commission's IRP guidelines and is "reasonable based on the information available at that time."[9]

Importantly, the Commission has repeatedly "reaffirm[ed] [its] long-standing view that decisions made in IRP proceedings do not constitute ratemaking."[10] Further, "[d]ecisions whether to allow a utility to recover from its customers the costs associated with new resources may only be made in a rate proceeding."[11]

III. STAFF'S COMMENTS

Staff's Final Comments discuss various aspects of the 2021 IRP and make recommendations for both the 2021 and 2023 IRPs. Staff's Final Comments focus on the areas of load forecasting, demand response ("DR"), modeling, transmission, modeling of investment costs, and climate change and greenhouse gas ("GHG") emissions. The Company appreciates Staff's review in this docket and, in these Final Reply Comments, provides responses to Staff's analysis and recommendations.

[5] Order No. 07-002 at 5.
[6] Order No. 07-002 at 12 (Guideline 4(n)).
[7] Order No. 07-002 at 25.
[8] Order No. 14-253 at 12; *In re Idaho Power Company, 2011 Integrated Resource Plan*, Docket No. LC 53, Order No. 12-177 at 6 (May 21, 2012) ("We agree with Staff that the desired focus in the IRP is on actions over the next two to four years. We decline to acknowledge the long-term action items . . . .").
[9] Order No. 14-253 at 1.
[10] Order No. 14-253 at 1.
[11] Order No. 14-253 at 1.

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Before exploring specific issues raised by Staff, Idaho Power would like to review the timing of the IRP process and specific milestones. Unfortunately, some of Staff's suggestions—particularly those related to conducting new analysis in this 2021 IRP— are inconsistent with the multi-month effort involved in the development of long-term resource planning. Additionally, Staff's Final Comments suggest that the Company has been withholding and unhelpful in responding to Staff's requests for information related to the 2021 IRP. The Company was disappointed to learn of Staff's view in this regard, as it is quite the opposite of Idaho Power's intent for the IRP process and its intended working relationship with Staff in general. Idaho Power respectfully disagrees with Staff's characterization of its efforts and does not believe Staff's perception is supported by the facts.

Below, in Figure 1, the Company provides a detailed timetable of the 2021 IRP process, this case specifically (Docket No. LC 78), the engagement opportunities afforded to Staff, and relevant Federal actions that are related to Staff's specific modeling recommendations.

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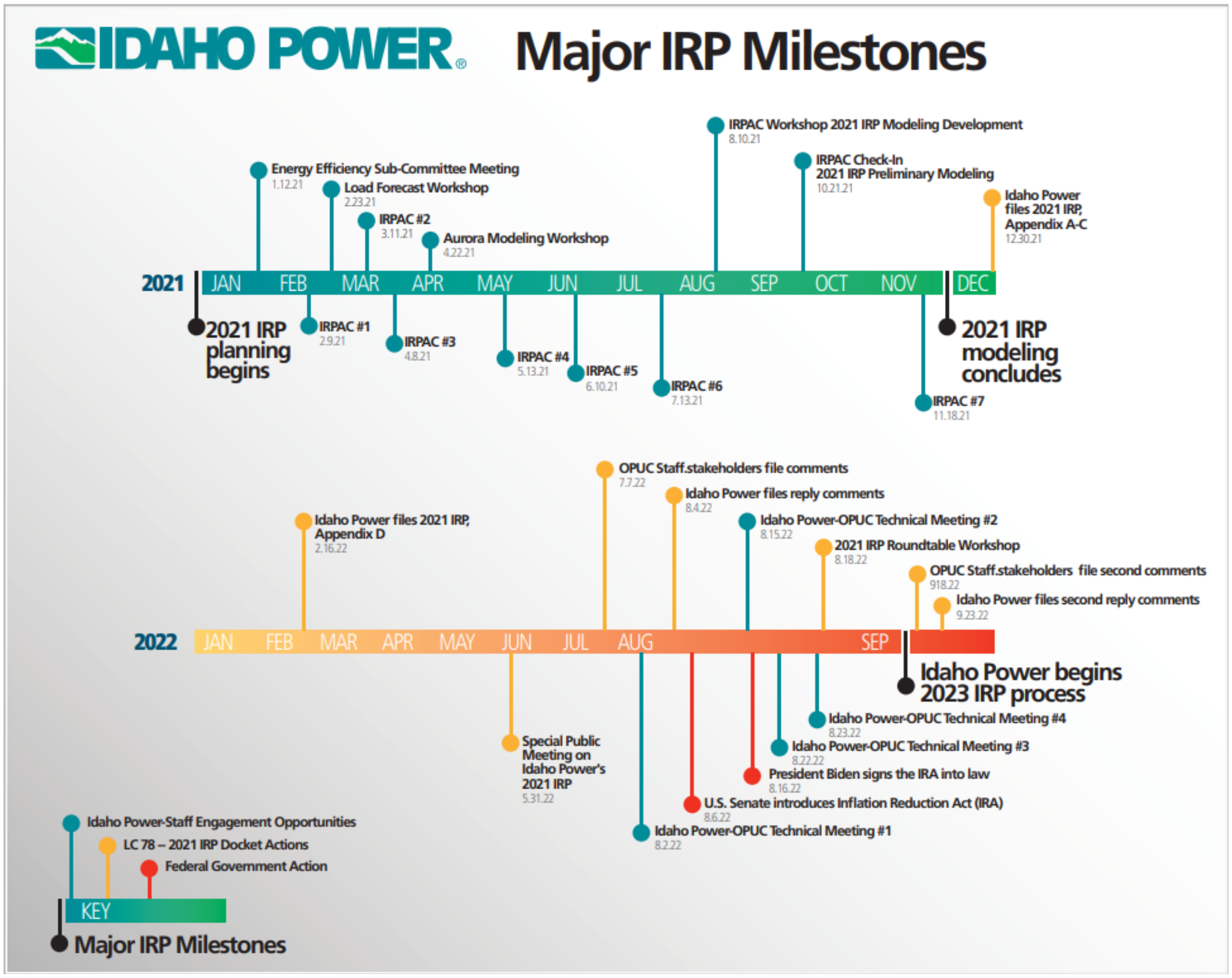
Figure 1: 2021 IRP Timeline and Key Milestones



As shown above, Idaho Power's IRP is composed of two distinct phases: the development/modeling phase and the post-filing phase. In the multi-month development phase—which began in January 2021 and concluded in November 2021—the Company focused on stakeholder input through facilitated meetings with its IRP Advisory Council ("IRPAC"). Monthly meetings of the IRPAC allow for discussion, review, and input on a host of topics, from resources and resource costs to detailed modeling practices and scenario. Staff was present and active in the 2021 IRPAC meetings. Additionally, and in the past, Staff has engaged with Idaho Power during the IRP development phase about any topics it would like to explore in greater detail, including the load forecast, specific resource modeling details, and sensitivity analyses.

The Company acknowledges and understands that a Staff transition occurred early in

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2022, just as the IRP development phase concluded and the processing of this case commenced. Such a Staffing shift could have impacted the continuity between the Staff representative present for the 2021 IRP meetings and the Staff that conducted the post-filing review of the 2021 IRP. It is Idaho Power's understanding that Staff's transition was unexpected and certainly could not have been planned for in advance. However, the Company has worked tirelessly through the late spring and summer to respond to Staff's extensive formal requests. Since May 13, 2022, the Company has responded to 146 Information Requests from Staff, held four individual workshops at Staff's request, and presented to the Commission and stakeholders twice on the 2021 IRP.

In its Final Comments, Staff withholds a recommendation on the Company's 2021 IRP and instead suggests that the Company re-run the analysis to incorporate different modeling assumptions. This suggestion demonstrates a misunderstanding of the time required to conduct IRP modeling, but it also actively ignores a year's worth of effort to develop meaningful IRP inputs and establish valid modeling processes and protocols.

Staff also suggests re-running the 2021 IRP to incorporate elements of the Inflation Reduction Act ("IRA"), legislation that was introduced and signed into law in August 2022, a full seven months after the 2021 IRP was filed. These suggestions by Staff are simply unreasonable. First, re-running an IRP with new information is not a quick nor simple task that can be performed multiple times within an IRP cycle. The IRP modeling process is a long iterative series of steps that involve~~s~~ model testing and setup, development and processing of inputs, configuration of the model and model assumptions, running of the model, model result validation, and output review and analysis. The Company also seeks alignment with the IRPAC on modeling constraints and inputs. Combined, this is a multi-month process involving numerous analysts. Re-running the analysis with different inputs or model settings would require duplication of much of the full IRP modeling process and the time inherent. The model can take days to process a single run, and the Company would need to conduct all of its standard quality assurance testing and review the output before feeling confident in any new analysis.

Moreover, Staff's request that the Company re-run the IRP ignores the cyclical nature of IRPs which are based upon the fundamental understanding that relevant factors in resource planning are subject to constant change, and that new information does not invalidate an IRP, but instead will be captured in either the IRP Update or the next full IRP.

As of these comments, the Company continues to respond to Staff's Information Requests in this case. Idaho Power is eager to work with Staff going forward in a manner that is productive. For the reasons noted above, the Company does not include the requested re-run of the 2021 IRP in these Final Reply Comments. Regarding Staff's individual recommendations, the Company addresses each in turn below.

A. Load Forecast

Staff's Final Comments explain that they were able to draw a conclusion about the reasonableness of the Company's hourly load forecast, but that more information is required before reaching a conclusion on the reasonableness of the monthly load forecast.

1. <u>Idaho Power's Monthly Load Forecast is Reasonable and Opportunity to Review has been Ample.</u>

The Company would like to acknowledge that Staff undertook a detailed review of the load forecast within the 2021 IRP framework. Idaho Power appreciates Staff's conclusion that the hourly load forecast is reasonable. Regarding Staff's concerns and need for more information on the monthly forecast, the Company believes that it has been open with and responsive to Staff and stakeholders on its load forecast methodology. In particular, on February 23, 2021, the Company held a two-hour workshop with the IRPAC dedicated to load forecasting, covering topics such as: peak forecast; comparisons to previous IRPs' data frameworks; philosophy; data segmentation; and out-of-sample performance. In addition, Idaho Power hosted several technical workshops between the Company and Staff during both the development phase and the docketed phase of the 2021 IRP, and provided voluminous responses to Staff's Information Requests

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regarding the load forecast.[12] Following recent technical meetings in August 2022, Staff had expressed appreciation and stated that the meetings were helpful in clarifying Staff's overall understanding.

Idaho Power also disagrees with Staff's characterization of the monthly load forecast as a "hidden black box process" and Staff's insinuation that the Company was not forthcoming with requested information.[13] While some of the load forecast output may be new to this IRP iteration, the forecasting methodologies used in the development of the monthly sales for the 2021 IRP rely upon tested statistical methods and inferences and are consistent with past iterations of acknowledged IRPs. The Company has shown and shared with Staff, through various communication channels as previously described, a detailed discussion on the monthly forecast models and verification. The load forecast source data and transformations take place in an Oracle OLAP environment due to the size of information processing. Staff's inferences that the Company withheld information on the load forecast is not true, as the Company has explained that information maintained in the Oracle OLAP database cannot be shared in Excel. This fact alone does not warrant Staff's description of Idaho Power's load forecasting process as a "black box." The Company has been and remains committed to sharing information on the load forecasting process.

In addition to responding to numerous, detailed Information Requests specific to the load forecast, Idaho Power held two technical meetings for Staff focused on load forecasting—one on August 2, 2022, and the other on August 15, 2022. These meetings offered Staff an opportunity to ask detailed questions about all aspects of the Company's monthly and hourly load forecasts. The Company acknowledges that it has explained to Staff that information maintained in the Oracle OLAP database cannot be shared in Excel. However, to compensate for that limitation, the Company has offered to host an onsite or remote visit with Staff to review the forecasting

[12] To date, the Company responded to 23 multi-part data requests specific to the load forecast.
[13] Staff's Final Comments at 7 (Sept. 8, 2022).

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techniques in detail, an option which has been leveraged by Staff in the past for technical review and education. For these reasons, Staff's suggestion that the Company improperly withheld information on the load forecast is inaccurate and unfair.

Staff references specific responses to data requests from the Company that it believes were incomplete.[14] However, the data responses to which Staff refers reflect the Company's good faith efforts to communicate complicated subject matter. It also should be noted that at the time of developing these Final Reply Comments, the Company is actively working with Staff to provide additional detail to support Staff's review of the monthly load forecast for the 2021 IRP.

2. Additional Firm Load Forecasts were Appropriately Included and Shared with Staff.

Staff states that it is unsure how Idaho Power processes special contract customers' "speculation" of their future load[15] and that the supporting information for the additional firm load was not provided.[16] However, these concerns are unfounded. The special contract—or additional firm load—forecast was shared with Staff on several occasions[17] and the methodology reflecting how the Company includes this information in its load forecast is described in Appendix A of the 2021 IRP: "The anticipated load forecast reflects only those industrial customers that have made a sufficient and significant binding investment and/or interest indicating a commitment of the highest probability of locating in the service area."[18] Further, in its Reply Comments, Idaho Power explained that "[e]ach Special Contract, or additional firm load customer, is required to provide Idaho Power with a forecast of site-specific energy use" and that the "2021 IRP large load forecast was informed by customer-reported near-term growth."[19] Finally, the Company's response to Staff

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[14] Staff's Final Comments at 7.
[15] Staff's Final Comments at 6-7
[16] Staff's Final Comments at 7.
[17] Idaho Power's Reply Comments at 9-11 (Aug. 4, 2022); *see also* Confidential Attachment to Idaho Power's Response to Staff Information Request No. 132 subpart "c" (provided as Attachment 1 to these comments).
[18] 2021 IRP, App. A: Sales & Load Forecast at 4, 31-33.
[19] Idaho Power's Reply Comments at 10.

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Information Request No. 136 subpart "b" described how the Company could adjust the load forecast information provided by a customer, if warranted.

> In terms of the Additional Firm Load customers, information on the specific customers that qualify for this category (typically over 20 MW in size) is collected annually or semiannually through Idaho Power's Special Contract process. The Company can increase or decrease load requirements for the Special Contract customers if more recent information is known at the time the load forecast is developed for the IRP. Typically, the Company relies on the information provided by the customer, as was the case in the 2021 IRP load forecast. Since the development of the 2021 IRP load forecast, each customer's development plan within the Additional Firm Load category has not materially changed.[20]

With these explanations, the Company believes that it has responded to this issue sufficiently for review contrary to Staff's Final Comments. Nevertheless, if there is additional explanation that would be helpful to Staff's analysis, the Company would be happy to provide it upon specific request.

Addressing Staff's statements implying that the Company included speculative special contracts,[21] the Company disagrees. At the outset, the Company acknowledged that the energy needs of some potential large load customers may be subject to considerable uncertainty in which case the Company would not include them in a load forecast.[22] However, the development and execution of any special contract with Idaho Power necessitates reasonable certainty about a customer's load. During the development of the 2021 IRP, the special contract that was new to the group represented a sufficient and significant investment in Idaho Power's service area and indicated a commitment of the highest probability, not solely speculation. At the time of the creation of the 2021 IRP load forecast in the fall of 2021 the Company was not able to divulge specific information due to Non-Disclosure Agreements ("NDA"). Since then, Meta (formerly known as Facebook) has issued numerous press releases on its new data center location in Kuna,

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[20] Idaho Power's Response to Staff Information Request No. 136 subpart "b" (provided as Attachment 2 to these comments).
[21] Staff's Final Comments at 6.
[22] 2021 IRP App. A at 4 ("The large numbers of prospective businesses that have indicated some interest in locating in Idaho Power's service area but have not made sufficient commitments are not included in the anticipated sales and load forecast.").

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Idaho, within Idaho Power's service area. In addition, the Company has opened a docket in Idaho for their special contract under Brisbie, LLC in IPC-E-21-42 and a representative from Meta is now a member of the 2023 IRPAC. Further, the Commission approved a waiver of its competitive bidding rules specific to the acquisition of clean energy resources to serve Brisbie, LLC, in UM 2226. These facts should address Staff's concerns.

Finally, the Company disputes the idea that its special contract customers take a speculative approach to their own load forecasts. These companies know their industries well and have no logical reason to pad their forecasts beyond what they believe is necessary to operate and grow their businesses. Further, these companies have a financial stake in reasonable load forecasts, as some of their rate elements—such as contract demand, for example—stem from their anticipated load. As a result, the Company relies on its special contract customers to offer the best forecast of each individual company's anticipated energy need. As noted earlier, these forecasts are refreshed annually to ensure that shifts in business practice or economic conditions are accounted for.

B. 2021 IRP Recommendations

Staff's Final Comments ask the Company to perform additional modeling of the 2021 IRP analysis in order to establish the reasonableness of some of the assumptions that underlie the 2021 IRP Action Plan. These modified assumptions include the nameplate of existing DR, forecasted wholesale prices, capital costs of a Combined Cycle Combustion Turbine ("CCCT"), and Investment Tax Credits ("ITC") and Production Tax Credits ("PTC").[23]

1. <u>Idaho Power's 2021 IRP Meets the Standards for Acknowledgement and Should Not be Re-run Under New Assumptions.</u>

The Company, for a host of reasons, believes the request to update the 2021 IRP model and present the results is unorthodox and unwarranted. First, the Company is concerned that

[23] Staff's Final Comments at 7-13.

Staff does not fully appreciate the time required to re-run the IRP. As described previously, such a re-run would be a significant undertaking, requiring far longer than the two weeks the Company was afforded to develop these Final Reply Comments. Second, the Company has serious concerns about the validity of updating its IRP with ex-post information.

Across the electric industry, long-range planning is based on the best available information ***at the time***. As a result, the Company cannot support a recommendation to re-run its IRP with information that was not known until months after modeling was complete. Revising an IRP with information after the fact is an attempt to lend credibility and accuracy to the process—but such a revisionist approach would do neither. By Staff's logic, an IRP should be updated each time factual information can replace a forecast. This outcome would lead to an endless cycle of iterations that would lose sight of the ultimate objective of long-term resource planning and decision making.

Notwithstanding the above, the Company recognizes that the energy landscape is changing quickly, accelerated in large part by passage of the IRA. The Company is actively considering ways to incorporate and reflect IRA incentives in the 2023 IRP, the process for which has already commenced. In less than a year, the Company will file its 2023 IRP with the best available information at the time that the analysis is performed, as was done for the 2021 IRP. The Company considers it logical and reasonable, then, to examine all of Staff's requested information in the 2023 IRP.

2. Any Potential Update to Existing DR Nameplate Capacity from the 2022 Season is Appropriate for the 2023 IRP.

Staff's first request was to update the nameplate capacity of existing DR based on the actual observed capacity from the 2022 season.[24] The 2022 DR season just ended on September 15, 2022, during the preparation and subsequent filing of these comments. To determine the

[24] Staff's Final Comments at 8.

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observed capacity from the 2022 DR season requires time to process and analyze the data from the season, then additional time to upload the results to the model and to test and verify. For these reasons, as well as those noted earlier, the Company believes this update should be considered for the 2023 IRP.

3. <u>AURORA Modeled Wholesale Prices are Reasonable and Should not be Overridden.</u>

Staff believes Idaho Power's 2021 IRP underestimates wholesale energy prices during the years of the Action Plan and beyond, resulting in portfolios that are biased in favor of energy storage, market purchases, and, by extension, the construction of transmission resources for expanding capacity market purchases.[25] As a result, Staff has requested the Company update the assumed wholesale prices for the period 2022-2029 for the 2021 IRP with observed historical prices and "observed future prices".[26] Idaho Power believes this request is inappropriate for the following reasons.

First, as a general matter, the manner in which wholesale prices are produced in the AURORA model was discussed in 2021 IRPAC meetings and communicated in the Company's response to Staff's Information Request No. 39. In short, there is no way within the Company's model to update the wholesale prices without updating or overhauling the entire model. To be clear, wholesale prices are not an input to the AURORA model; they are best considered a model output, in that they are derived based on the complicated supply and demand functions taking place within the model. Assuming the Company understands what Staff means by "observed future prices," the model cannot use a particular set of historic wholesale prices and then also integrate a set of forward market prices.

Staff provides several arguments to support its recommendation, and the Company feels it necessary to provide additional responses on the merits of each argument.

[25] Staff's Final Comments at 8.
[26] Staff's Final Comments at 12.

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a) Forcing AURORA's Mid-C Prices Will Cause Bias and Imbalance Within the Model for Transmission.

Staff's Opening Comments took the position that the discrepancy between ex-post (actual) Mid-C market prices and ex-ante (planning conditions) prices has led to biased conclusions on battery storage.[27] However, the Company addressed energy storage in its Reply Comments[28] and Staff has not substantiated that same conclusion in its Final Comments with logic or data.

At a high level, AURORA uses transmission resources to make economic sales or purchases based on the zonal price differential between the zones. When there is a large price differential or imbalance between zones, the model will tend to move power from the lower priced zone into the higher priced zone, subject to normal constraints within the model. That differential is based on planning conditions applied equally to all the zones in the Western Electricity Coordination Council ("WECC"). Thus, no zone will benefit unduly from transmission resources. Setting aside that AURORA does not operate with exogenous market prices, Staff's proposal to force AURORA's Mid-C market prices to match the market forwards would only bias the value of transmission resources. In such a scenario, a structural imbalance would be foisted upon the model because the Mid-C zones will be forced to comport to actual conditions that evolved post-IRP development while the remaining portions of the WECC model will remain based on planning conditions. The imbalance will bias the model toward transmission resources that will attempt to fix the imbalance.

b) The Company's Explanation for Market Price Deviations are Reasonable.

Staff incorrectly summarizes the Company's position on why observed market prices have deviated from modeled prices stating: "The Company pointed to the low hydro conditions last

[27] Staff's Opening Comments at 19 (July 7, 2022).
[28] Idaho Power's Reply Comments at 21.

year, offering a plausible explanation for a one-off event."[29] However, the explanation the Company actually provided was far more nuanced:

> In 2021, energy markets moved due to drought conditions throughout the [WECC], one in 1,000-year type weather events in the Pacific Northwest, post-pandemic related gas supply issues throughout the United States, localized natural gas pipeline disruptions, and wildfire disruptions to transmission infrastructure, amongst many other widely reported events with hard-to-quantify influence on market prices.[30]

Some of these influences have continued, and many additional new ones have occurred in 2022, resulting in further separation of actual conditions from the ex-ante planning conditions. Thus, it is no surprise that actual market prices have deviated from the 2021 IRP's modeled market prices.

c) The AURORA Model Produces Appropriate Market Prices and Idaho Power's Results are in Agreement with Other Plans Developed in the Same Timeframe.

On the subject of model quality, Staff states "a good model would deviate from reality without bias, with real prices falling both higher and lower than the model predicts, producing equal error in both directions."[31] This "good model" requirement is incorrectly applied to ex-ante periods, when, in fact the requirement is correct for regression-based models only in the ex-post period. A statistical requirement of regression models is that the error for time series models in the ex-post period shows both positive and negative deviations that are normally distributed, non-heteroskedastic, and non-autocorrelated among many such requirements. There is no requirement, or generally even the expectation for many variables, that the deviation in the ex-ante period follow the same pattern. This is particularly true for the types of inputs that an IRP depends on. Unforeseeable events can permanently change an explanatory variable's expected value, meaning the entire ex-ante forecast will show autocorrelated deviations. Given the complexity of the IRP modeling process, which requires thousands of explanatory variable inputs that are often determined through public consideration during the IRPAC process many months

[29] Staff's Final Comments at 8.
[30] Idaho Power's Reply Comments at 20-21.
[31] Staff's Final Comments at 10.

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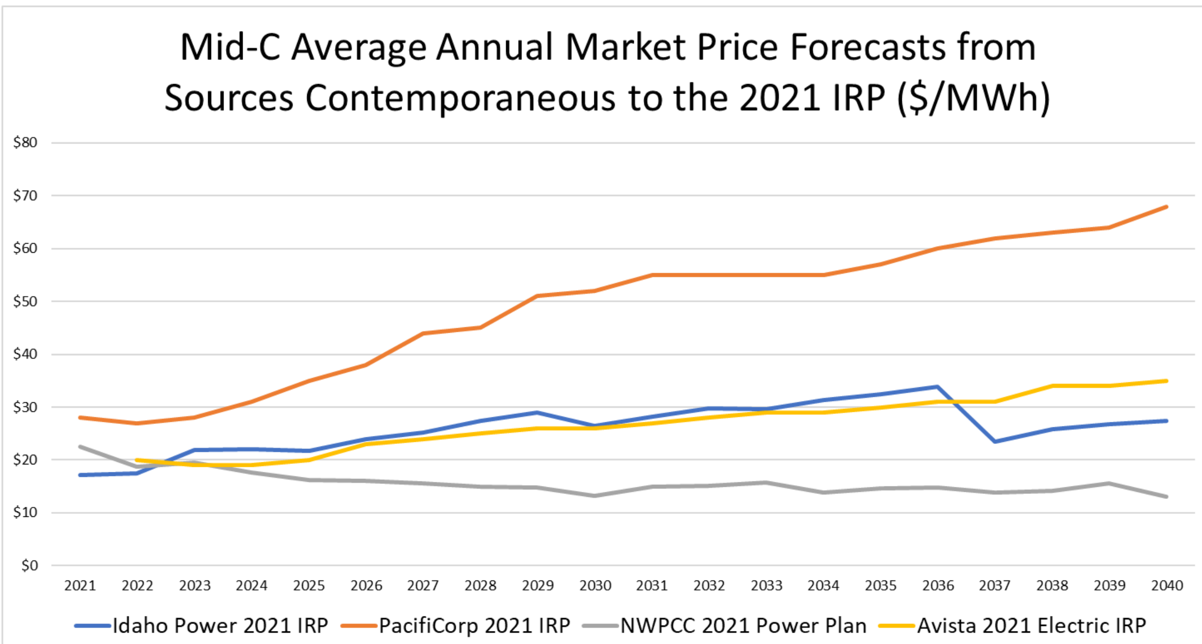
before an IRP filing, pencils must be put down well in advance of the actual filing. It is an impossible, unreasonable expectation and requirement that an IRP anticipate unforeseeable events months after the filing of an IRP.

A far more reasonable assessment of the Company's planning model is to compare it to other estimates made contemporaneously. The figure below shows the modeled Mid-C market price in the Company's 2021 IRP compared to the Mid-C market price estimates from PacifiCorp's 2021 IRP, the Northwest Power and Conservation Council's 2021 Power Plan, and Avista's 2021 Electric IRP.

Figure 2: Mid-C Annual Market Price Forecasts



These plans forecasted 2021 power prices below $30/MWh when actual prices on a weighted average basis were $58.37/MWh.[32] Thus, given the information known and available at the time the 2021 IRP was developed, Idaho Power's IRP was consistent with other regional

[32] Wholesale Electricity and Natural Gas Market Data, U.S. Energy Information Administration, https://www.eia.gov/electricity/wholesale/ (last visited Sept. 13, 2022) (Historical Wholesale Market Data for 2020). The historical wholesale market data for 2020 is available for download here: https://www.eia.gov/electricity/wholesale/xls/archive/ice_electric-2020final.xlsx.

entities making similar forecasts during similar timeframes. Again, given the information known at the time the IRP was developed, Idaho Power's 2021 IRP was aligned with other regional entities.

d) The Company's Inability to Perform an Ex-Post Analysis of Market Prices is Reasonable.

Next, the Company would like to reiterate why it was not possible to conduct an ex-post analysis of market prices, as requested by Staff in Opening Comments.[33] To be clear, the Company provided Staff with its planning conditions modeled Mid-C prices but did not provide a detailed mathematical analysis of why market prices behaved exactly as they did. However, the Company previously explained just why such an analysis would not be possible. As the Company stated in its Reply Comments, "Mid-C prices are influenced by myriad of factors over vast and diverse geographies across the Western Interconnection, for which accurate historical data is not available to the Company."[34] In other words, electric market prices are, indeed, influenced by myriad factors and conditions, some of which may not be known or knowable to the Company, even after they happen. Rather than engage in inherently problematic prediction exercises, the Company and other respected regional entities and planners use planning conditions to approximate the conditions of the region(s) in which they operate. Scenario and sensitivity analyses are then used to ensure those planning conditions are tested against potential alternatives and unexpected events. Even if a postmortem of hourly market prices could be developed to Staff's satisfaction, it would not provide meaningful, actionable information to the IRP process.

e) The Lack of Scarcity Pricing Mechanism in AURORA did Not Cause the Market Price Deviations.

Lastly, the Company offers clarity about what was meant by a "scarcity pricing mechanism," a term introduced by the Company in its Reply Comments[35] and raised by Staff in

[33] Staff's Opening Comments at 19.
[34] Idaho Power's Reply Comments at 20.
[35] Idaho Power's Reply Comments at 24.

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its Final Comments.[36] Scarcity pricing mechanisms are employed in some regional electricity markets and premised on the idea that electricity is a scarce commodity. As such, electricity markets that use a scarcity pricing mechanism do so to escalate prices intentionally when electricity supply is tight. The price escalation is intended to have two effects: (i) encourage demand reduction and (ii) drive supply into the market by prompting power producers to generate power in exchange for escalated prices set by the scarcity pricing mechanism. AURORA, on the other hand, uses a rational economic-based least-cost marginal resource dispatch algorithm to estimate wholesale market prices and does not use a scarcity pricing mechanism because the objective of the model is to identify resource needs, not set prices intended to get power producers to act. AURORA can and does handle periods of low and scarce resource availability but will set the zonal price at the price of the last resource in the resource stack, not beyond it, as is designed to happen with a scarcity pricing mechanism. It is not the lack of a scarcity pricing mechanism that accounts for differences between AURORA's modeled Mid-C prices and actual market prices but rather economic and real-world events that were unknown and unknowable at the time the 2021 modeling was developed.

4. <u>Updates to the Cost of a Combined Cycle Combustion Turbine ("CCCT") is Appropriate for the 2023 IRP Process.</u>

In Staff's estimation, the Company's CCCT costs were too high and Staff asks the Company to re-run its modeling in this IRP either (i) using a CCCT capital cost of $1,300 per KW or (ii) using a capital cost from observed bids from a current all-source Request for Proposal ("RFP").[37] Similar to arguments made above, the Company considers it unreasonable and unwarranted to update CCCT capital costs and rerun the IRP analysis. The Company generated the capital cost estimates in a reasonable way and presented these values to the IRPAC on May 13, 2021. Staff was a party to the IRPAC discussions and participated in developing resource

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[36] Staff's Final Comments at 11.
[37] Staff's Final Comments at 12 ("At $1,656 per kW, Idaho Power's 2021 IRP assumes an unreasonably high capital cost for a CCCT plant.").

costs. The resources costs used in the 2021 IRP reflect the consensus opinion of the IRPAC. The Company will explore modifications to the capital cost of all resources, not just natural gas resources, in the 2023 IRP process.

5. <u>Impacts of the IRA are Appropriate for the 2023 IRP Process.</u>

Idaho Power similarly objects to Staff's request that the Company remodel the 2021 IRP to reflect the IRA's newly announced tax credits for renewable and nuclear energy and storage.[38] Staff is correct that the IRA made significant changes to "federal subsidies of energy projects," and that "the ramifications of this new law may have a variety of impacts that are too complicated to understand at this time."[39] However, the Company cannot reasonably be expected to incorporate policies into the 2021 IRP that were introduced and signed into law in August 2022—a full seven months after the Company filed the 2021 IRP. To do so would significantly delay this docket—a step that is altogether unnecessary given that development of the 2023 IRP is well underway.

The Company agrees fully with Staff about the significance and impact of the IRA; it is the most significant piece of legislation for the electric sector since the American Recovery and Reinvestment Act of 2009. As such, the Company recognizes the IRA must be factored into future IRPs and the Company's resource selections. Doing so will take time and ample consideration, making it a perfect item for inclusion in the 2023 IRP and ongoing and future RFPs.

C. 2023 IRP Recommendation – Demand Response

While Staff states they have remaining questions about how new DR is modeled in the 2021 IRP, Staff does not recommend alternative modeling choices for any of these factors (i.e., new DR costs, declining capacity contribution, and modeling within AURORA).[40] Instead, Staff looks forward to working with Idaho Power and stakeholders as the Company transitions from

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[38] Staff's Final Comments at 12.
[39] Staff's Final Comments at 12.
[40] Staff's Final Comments at 13.

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Northwest Power and Conservation Council ("NWPCC") data to Company-specific data on DR potential.[41]

Idaho Power understands and shares Staff's interest in DR and maximizing its potential to reduce peak load where it is cost-effective to do so. Since 2004, the Company has expanded and modified DR programs many times to respond to system needs. Contemporaneous with development of the 2021 IRP, the Company realized it needed to modify its DR programs and had these modifications approved by the commissions in both Idaho and Oregon prior to the summer of 2022. While customer participation has dropped somewhat as result of program modifications, the Company has been able to retain approximately 320 MW of capacity for the 2022 season. The 2021 IRP Preferred Portfolio assumed 300 MW of existing program capacity—a reasonable amount based on DR capacity prior to the program modifications—as well as an additional 100 MW selected in the IRP analysis over the planning period and utilizing assumptions from the DR potential assessment performed by the NWPCC.[42]

1. <u>The Assumed Cost of New DR was Calculated in a Reasonable Manner for the 2021 IRP.</u>

Staff analyzed the batching of DR into the 100 MW and 180 MW allotments and stated it would welcome explanation or clarification about why 100 MW is a more appropriate allotment when compared to smaller buckets with lower costs.[43] There were multiple ways to split and bucket DR capacity and costs. Idaho Power chose a methodology that allowed DR to compete with other resources in a reasonable way, by creating two cost buckets and allowing the model to pick DR in 20 MW bundles. These buckets were brought before the IRPAC for review and comment and the final modeling represents the consensus reached by that group. Idaho Power in its bucketing of block sizes and costs, as stated, excluded assumed costs from behavioral DR (pricing programs) because it believed the price of those types of programs in the NWPCC

[41] Staff's Final Comments at 13.
[42] 2021 IRP at 63, 68-69.
[43] Staff's Final Comments at 13-16.

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assessment may not represent full costs properly. This approach was reasonable and appropriate, and accepted by the IRPAC.

2. The 2021 IRP DR Block Size is an Increase over the 2019 IRP.

Staff reviewed existing DR program capacity in 2020[44] and, based on this analysis, is not compelled by the Company's argument for larger DR block sizes.[45] Instead, Staff finds a more granular approach to modeling additional DR capacity to be more appropriate.[46] Staff states:

> the prior increment of 5 MW was not a cap on potential DR capacity, rather it was simply a smaller increment of capacity for the model to select. Had there been a 20 MW potential deficit the model could have selected 4 units of 5 MW. Staff welcomes correction if this understanding is incorrect.[47]

In response to Staff's question, the Company would like to clarify that the 5 MW increment was, indeed, an annual cap;[48] therefore, four units of 5 MW could not have been selected. The overall maximum amount of selectable DR was 50 MW in the 2019 IRP.[49] For the 2021 IRP, the block size was increased to 20 MW to reflect an updated estimate of additional DR capacity that could be achieved in a single year and the maximum amount of selectable DR was increased to 280 MW.

In the 2021 IRP, the model selected an additional 100 MW of DR—in five increments of 20 MW—beyond the existing 300 MW,[50] indicating that the 20 MW block size was not a hurdle to the model selecting DR.

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[44] Staff's Final Comments at 18 (AC Cool Credit: 32 MW, Flex Peak: 36 MW, and Irrigation Peak Rewards: 298 MW).
[45] Staff's Final Comments at 18.
[46] Staff's Final Comments at 18.
[47] Staff's Final Comments at 18.
[48] Idaho Power's Second Amended 2019 IRP at 64 (Oct. 2, 2020) ("The company considered achievability and operability to properly model the potential expansion of demand response. Based on this analysis, the company made available 5 MW blocks of incremental new demand response each year for selection in AURORA starting in 2023 at a cost of $60 per kW-year.") [hereinafter, "Second Amended 2019 IRP"].
[49] Second Amended 2019 IRP at 14.
[50] 2021 IRP, App. C: Technical Report at 66.

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Finally, the Company suggests it is logical to place its DR efforts and modeling in the context of the Company's DR performance. Based on the Form EIA-861 data[51] for 2020 (the last actualized year at the time of these comments), Idaho Power accounts for 13 percent of the WECC's non-coincident DR capacity despite only representing 2.7 percent of the WECC's non-coincident peak demand. As a leader in DR, the Company is confident that its DR modeling approach (both size and costs) is warranted based on past performance, regional assessments, and a firm understanding of program potential.

The Company will expand its specific DR knowledge with a forthcoming DR potential study that will, along with the input of the IRPAC, inform the best modeling assumptions for DR in the 2023 IRP. The third-party developed DR potential study is expected to be completed in the fall of 2022.

3. The DR Dispatch Shape was Appropriately Modeled in AURORA and Applied When it was Most Beneficial.

Staff performed an analysis of hourly forced outage rates in comparison to hourly loss of load probability ("LOLP") estimates provided by Idaho Power to assess whether the Company's DR shapes are effectively being applied to the hours of highest risk.[52] Staff's resulting analysis appears to show that the Company is not always applying DR when it would be most beneficial, which may ultimately overstate the need for additional resources.[53]

Staff did not provide documentation of its analysis, meaning that Idaho Power must make assumptions about Staff's methodology. Staff finds, for example, that "for any given year, at least 40 percent of the top 50 hours with the highest LOLP values (during the program window), received a forced outage rate of 100 percent, preventing DR selection."[54] Idaho Power assumes this finding is based on the following data:

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[51] Annual Electric Power Industry Report, Form EIA-861 Detailed Data Files, U.S. Energy Information Administration, https://www.eia.gov/electricity/data/eia861/ (last visited Sept. 14, 2022).
[52] Staff's Final Comments at 19-21.
[53] Staff's Final Comments at 20.
[54] Staff's Final Comments at 19.

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- Portfolio LOLPs provided in the Company's Response to Staff's Information Request No. 41
- Hourly DR forced outage rate shape provided in the Company's Response to Staff's Information Request No. 95

If this is the case, the Company notes that the above two data sets are derived from different sources and cannot be compared. As discussed during Technical Meetings 3 and 4 with Staff on August 22 and 23 of 2022, Effective Load Carrying Capability ("ELCC") calculations are performed in the Loss of Load Expectation ("LOLE") tool and then this individual ELCC value is input into AURORA informing the model logic of the DR programs effectiveness at meeting peak capacity requirements. For the 2021 IRP, ELCC values, the Planning Reserve Margin ("PRM"), and portfolio LOLEs were calculated in the Company's LOLE tool, which used four years of historical data so that the relationship between weather, load, and variable energy resource ("VER") output could be maintained. This means that the portfolio Loss of Load Probability ("LOLP") values provided to Staff are based upon historical data.

Idaho Power recognized that it would be inconsistent to use historical data, rather than forecasted data utilized in AURORA, to create a DR dispatch shape for AURORA. To be optimized, the DR dispatch must occur based on the forecasted need, not based on a historical data source. Importantly, an hourly DR dispatch shape must be provided to AURORA because the software is not currently capable of accurately modeling the parameters of Idaho Power's DR programs. To create the 2021 IRP hourly DR dispatch shape, the historical inputs to the LOLE tool were replaced with the forecasted inputs utilized in AURORA. The DR dispatch shape was created in the previously described manner to ensure alignment with the hours of highest risk identified with the forecasted shapes utilized in AURORA; meaning, DR was applied when it was most beneficial to the model. If the Company's assumption about Staff's analysis is correct, Staff's hour-by-hour evaluation of comparing a historically derived data set against a forecast-derived data set has led to invalid results.

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Notwithstanding the above, the Company will continue to evaluate the modeling of DR in the 2023 IRP and, consistent with Staff's Recommendation 2,[55] the Idaho Power-specific DR potential study is being conducted by a third-party consultant. As stated earlier, the results of this study will inform the modeling of DR expansion in the 2023 IRP.

D. 2023 IRP Recommendation - Transmission

1. <u>The Company will Monitor the Greenlink Transmission Project for the 2023 IRP.</u>

Staff's Final Comments highlight the need to evaluate other planned transmission projects outside of the Company's balancing area. Specifically, Staff's Recommendation 3 is for the Company to study the impact of the Greenlink transmission projects in reducing congestion between Idaho Power's service territory and southern wholesale energy markets in the 2023 IRP.[56] The Company agrees with Staff's recommendation and will continue to monitor NV Energy's Greenlink projects. For the 2023 IRP, the Company will initiate a dialogue with NV Energy regarding the potential of the Greenlink projects to create available transmission capacity across the NV Energy system to the Idaho Power border.

2. <u>The Company will Update the B2H Cost Estimate and Look for Grant Funding Opportunities for B2H.</u>

Based on its review of various costs and revenues estimated for B2H, Staff finds that the Company is not using "rosy assumptions"[57] for new wheeling revenue and that the various cost contingencies fall within the recommendations stemming from the 2019 IRP.[58] However, Staff finds that Idaho Power's original cost estimates for B2H are getting stale.[59] Staff's Recommendation 4 requests the Company produce a fresh, rigorous estimate of the total cost of B2H and all associated swaps and investments, breaking the total cost down by component,

[55] Staff's Final Comments at 21.
[56] Staff's Final Comments at 21-22.
[57] Staff's Final Comments at 26.
[58] Staff's Final Comments at 26.
[59] Staff's Final Comments at 26.

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disclosing all data and assumptions for each estimated component cost, and model cost contingencies based on this updated total cost estimate.[60]

Additionally, because a major objective for the Commission is to reduce the cost of the B2H project on ratepayers, Staff wants to ensure Idaho Power explores all possible avenues of grant funding. Staff's Recommendations 5 asks the Company to document the Company's monitoring and pursuit of grant opportunities in the regular reporting on transmission projects under Docket No. RE 136, including in each report:[61]

a. Identification of what federal funding and guarantees B2H potentially qualifies for under current and emerging law and programs
b. An explanation of what is required for the Company to apply for that funding or guarantee
c. An explanation of whether the Company is preparing an application or grant request at the time of reporting. If the Company is not preparing an application, explain why.

The Company appreciates Staff's recognition that the Company completed various B2H risk sensitivities, including 0, 10, 20, and 30 percent cost contingency sensitivities, and that B2H is expected to fall somewhere within this range. Staff states it "is comfortable that Idaho Power's proposed Action Item related to B2H is adequately supported by Idaho Power's IRP analysis."[62]

The Company does, however, disagree that the B2H estimate utilized in the 2021 IRP is stale. As stated in previous comments, the B2H cost estimate was developed in 2021 throughout the IRP process.[63] The Company is currently working with its constructability consultant to update the B2H cost estimate once again, to be utilized in the 2023 IRP, and for all B2H related activities. Consistent with Staff's Recommendation 4, the Company will seek to increase the transparency

[60] Staff's Final Comments at 27.
[61] Staff's Final Comments at 28.
[62] Staff's Final Comments at 26.
[63] Idaho Power's Reply Comments at 65.

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of this estimate in the 2023 IRP with a cost breakdown by (1) permitting costs, (2) pre-construction costs, (3) transmission line construction costs, (4) substation construction costs, and (5) ancillary project total costs.

With respect to possible avenues for grant funding, the Company will make every effort to acquire any available funds to offset B2H project costs, if possible. It should be noted, however, that the Infrastructure Investment and Jobs Act ("IIJA") that is associated with transmission funding does not include hand-outs to any transmission project. As the Company previously stated in its Reply Comments, to receive grant funding, the U.S. Department of Energy ("DOE") requires that "the project applicant must demonstrate an eligible project is unlikely to be constructed in as timely a manner or with as much transmission capacity in the absence of [Transmission Facilitations Program ("TFP")] facilitation."[64] DOE is still working through approaches to release any funding, and the ability to apply for any funding is not expected to open until Q1 2023. The Company will remain engaged in that effort and is amenable to providing an update as requested by Staff through Docket No. 136.

E. 2023 IRP Recommendation – Forecasting Qualifying Facilities ("QF")

In its Final Comments, Staff summarizes REC's comments and the Company's response, concluding that Idaho Power did not adequately defend its assumption of zero new future qualifying facilities ("QFs").[65] Staff states that the need for speculation cannot be avoided in resource planning, but that unreasonable assumptions can be avoided.[66] Staff's Recommendation 6 is that, in the 2023 IRP, the Company assume zero new QFs only in the first

[64] Idaho Power's Reply Comments at 33; U.S. Department of Energy, Notice of Intent and Request for Information Regarding Establishment of a Transmission Facilitation Program, 87 FR 29142, 29145 (May 12, 2022), https://www.govinfo.gov/content/pkg/FR-2022-05-12/pdf/2022-10137.pdf.
[65] Staff's Final Comments at 28-29.
[66] Staff's Final Comments at 29.

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four years of the planning horizon. Starting in the fifth year, the Company should use a reasonable forecast of new QF resources for the remainder of the planning horizon.[67]

1. <u>The IRP QF Forecast Has No Bearing on Future QF Development.</u>

Idaho Power assumes that all current Public Utility Regulatory Policies Act of 1978 ("PURPA") QFs with existing contracts renew upon expiration of their current contracts, except wind QFs. Based on feedback received in the 2019 IRP, the Company revised its analysis of wind QFs and agreed to conduct QF wind sensitivities in the 2021 IRP. These sensitivities included evaluating 0 percent, 25 percent, and 100 percent renewal rates, and, after discussions with the IRPAC, the Company agreed to use the 25 percent wind renewal case as its base case. Idaho Power plans to continue to discuss these wind renewal scenarios with the IRPAC.

Idaho Power makes no assumptions regarding future QF development in IRP modeling. In other words, the IRP does not include an assumption that Idaho Power will enter into QF contracts of specific sizes beyond the contracts that currently exist. Doing so would require the Company to predict the resource type, size, and location (Idaho or Oregon) of future, as-yet-undeveloped QFs in the IRP modeling process—something that the Company does not have information to be able to do with any level of accuracy. For instance, location alone (Idaho vs. Oregon) makes it hard to predict contract terms, length, and size independent of resource type due to the differences in state regulations and Eligibility Caps. The number of new QF contracts and associated MWs that projects have entered into with Idaho Power over the past five years has varied significantly, from five MW or less total coming online in three of the past five years, to a peak of 21 MW that have come online in one of the past five years. Idaho Power has executed contracts for 75 MW of PURPA generation expected to come online after this year, but it remains to be seen whether these projects will come online on schedule or as planned. Given the variability in development year-to-year and the uncertainties of construction and projects coming

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[67] Staff's Final Comments at 29.

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to fruition, Idaho Power believes the approach that is best suited for resource planning and most supportive of reliability is to not include a forecast of QF development in its IRP modeling. While the Company recognizes that the IRA may have an impact on QF development, the Company disagrees with Staff's recommendation to model QF resources without any supporting evidence that those contracts will materialize.

Importantly, Idaho Power's modeling assumptions related to QFs have no bearing on whether the Company actually enters into new QF contracts, as they are "must purchase" agreements, and thus have no effect on future QF development. QFs may enter the pricing queue for a PURPA contract at any time, regardless of the Company's surplus or deficit position. Idaho Power will continue to enter into such contracts with QFs that meet the relevant requirements, and the capacity from those new contracts will be factored into the development of future RFPs and IRPs.

2. <u>QF Forecasts That Do Not Materialize Negatively Impact Near-Term RFPs Resulting in Less Time to Address the Need.</u>

In addition to the statements above related to the logic of not forecasting future QF development, not including a forecast of such development in the IRP allows the IRP to identify any monthly surpluses or deficits in a more accurate and comprehensive manner. AURORA identifies surplus/deficit amounts and the resource types and sizes to fill those deficits, but it does not dictate the ownership or contract type of new resources. When deficits exist, Idaho Power pursues RFPs to fill those deficits. When Idaho Power develops the RFPs, it considers new information that has materialized since the time of the IRP that may change the deficit volume. If new QFs are developed, Idaho Power updates its load and resource balance analysis to include that capacity and thus the capacity from the new QFs counts toward meeting any identified deficits. The fact that the IRP does not include a forecast of future QF development does not influence actual resource procurement decisions because the deficit information will be updated before those decisions are made.

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Further, including a forecast of QF development in the IRP would add capacity to the load and resource balance, thereby increasing any monthly surpluses and decreasing any monthly deficits. As Idaho Power moves toward RFPs to address any deficits, the actual amount of QFs with signed contracts will inevitably be different than what is forecast. When the QF generation is lower than forecasted, the result will be an increase to deficits, closer in time to the operating month for which the deficit needs to be filled. In other words, if a forecast of QF development was included in the IRP, and those QFs did not materialize, any deficits would increase and because the changes would be occurring post-IRP, Idaho Power would have less time to address them. This creates risks to reliability and costs in terms of having additional needs to fill with less time to fill them.

Finally, the proposal to include a forecast of new QF development in the IRP appears inconsistent with the approach taken in the Company's recent Annual Power Cost Update ("APCU") of reducing expected PURPA generation and expense to account for the expectation that QFs will not complete construction and come online as scheduled. The "contract delay rate" that is used to reduce the forecast of PURPA generation and expense included in the APCU March Forecast essentially assumes that QFs will come online later than expected.[68] This assumption of delay would conflict with including a forecast of future QF development in IRPs, as the latter would not be based on any actual signed contracts or other actual indication of development.

For the above-stated reasons, Idaho Power believes the current IRP assumptions related to QF modeling are appropriate. As always, however, Idaho Power looks forward to discussing these issues further with the IRPAC for the 2023 IRP.

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[68] *In re Idaho Power Company, 2022 Annual Power Cost Update*, Docket No. UE 398, Idaho Power Company's 2022 Annual Power Cost Update, Testimony of Jessica G. Brady, Idaho Power/300, Brady/11 (Mar. 28, 2022).

F. 2023 IRP Recommendation – Modeling Reliability

Staff's review of Idaho Power's use of MATLAB in the 2021 IRP was sufficient to confirm that Idaho Power is following an established method of modeling system reliability. While Staff finds no fault with the Company's calculations of ELCC or LOLE,[69] it does raise concerns about the Company's reliability standard, stating:

> Aside from how Idaho Power calculates reliability, Staff has found an issue in how the Company's reliability standard is applied. The preferred portfolio does not meet the Company's reliability standard for all twenty years in the planning horizon. Or maybe it does by procuring a SCCT plant.[70]

To correct for this perceived concern, in the 2023 IRP, Staff's Recommendation 7 is for all portfolios considered for the Preferred Portfolio to include the necessary resources in the portfolio to meet the Company's reliability standard for a minimum of 20 years.[71]

Idaho Power appreciates Staff review of its ELCC and LOLE calculations. However, the Company disputes Staff's claims about the Preferred Portfolio's reliability. The 2021 IRP Preferred Portfolio ***does*** meet the Company's reliability standard. The Preferred Portfolio, along with four additionally selected AURORA-produced portfolios, were all evaluated under the same reliability criteria.[72] As presented during the November 2021 IRPAC meeting, having a static PRM in AURORA has the potential to lead to deviations between the reliability calculations performed by AURORA and the LOLE tool in the later years of the planning horizon; this is caused by significant amounts of variable energy resources ("VERs") being added to the system and the interactions of those variable resources with each other. The interactions between VERs are significant and challenging to model. An example of these interactions is solar and storage. Adding only solar quickly yields reliability issues around sundown, whereas adding only storage rapidly results in needing larger amounts of storage to dispatch over longer periods to reduce risk. But adding solar

[69] Staff's Final Comments at 29.
[70] Staff's Final Comments at 30.
[71] Staff's Final Comments at 32.
[72] 2021 IRP at 137-139.

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with battery storage is complementary, which results in a more reliable system. Solar addresses daylight hours and storage addresses twilight and early evening hours (assuming summer peak). During the previously referenced November 2021 IRPAC meeting, Idaho Power and the IRPAC members were aligned with the proposed method used to verify that the static PRM produced a reliable portfolio when evaluated with the LOLE tool.

Idaho Power will continue to evaluate and seek input from Staff and other members of the IRPAC throughout the development of the 2023 IRP to determine how the reliability standard can best be addressed in portfolio modeling.

G. 2023 IRP Recommendation – Battery Costs

Staff considers documented bids a good source of cost information, if not better than publicly available research published by sources such as the National Renewable Energy Laboratory ("NREL") or Lazard.[73] The Company disputes that NREL and Lazard data is any less valuable in long-term resource planning. Nevertheless, the Company appreciates Staff's perspective and will incorporate actual bid information from its most recent RFPs into the future supply side resource cost assumptions in the 2023 IRP.

H. 2023 IRP Recommendation – Emissions and Clean Energy Goal

1. <u>Idaho Power Will Review its Emissions Modeling Procedure for the 2023 IRP.</u>

Regarding the Company's emissions forecast and efforts towards its clean energy goal, Staff's Recommendation 8 is for the Company to include in the executive summary of the 2021 IRP a graph showing GHG emissions for 2019-2022 and comparing those historical emissions to the IRP 20-year forecast of IRP emissions calculated in the same manner.[74] Staff requests that the emissions data include emissions from market purchases and remove emissions from market sales.[75]

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[73] Staff's Final Comments at 33.
[74] Staff's Final Comments at 36.
[75] Staff's Final Comments at 36.

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Idaho Power appreciates the desire to have comparable historical and forecast emissions where emissions from Company-owned resources are combined with the emissions from the net of purchased power minus sold power. In this regard, the Company will review its emissions modeling procedure for the 2023 IRP and attempt to reasonably align historical and forecast emissions. However, 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. The Company has already had initial discussions with Staff on the calculation of emissions and will continue to work with Staff to reach an agreeable and technically sound solution for calculating emissions.

2. Idaho Power Included Cost Reduction Curves in the 2021 IRP.

Contrary to Staff's claim,[76] Idaho Power ***did*** include cost reduction curves for technologies where available, and those cost reductions are reflected in resource selections throughout the long-term plan. The Company recognizes that new flexible, cost-effective technologies are being developed and tested to replace carbon-emitting generation. But reliable, commercially developed information for many of these resources was not available at the time the 2021 IRP analysis was performed. For example, the Company did not include green hydrogen in the 2021 IRP analysis due to lack of commercially available data to model such a resource. The decision to exclude this resource and others was made within the IRPAC. Continuing the technology examination that took place for the 2021 IRP, new technologies will be reviewed again for the 2023 IRP and the Company will once again seek feedback from the IRPAC as part of that process.

[76] Staff's Final Comments at 37.

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3. Idaho Power's Preferred Portfolio Demonstrates Progress Toward its Clean Energy Goal.

Staff states that the 2021 IRP Preferred Portfolio will not achieve the Company's clean energy goal.[77] Staff will continue observing Idaho Power's progress toward its 2045 goal and will review advertising expenses related to the Company's clean energy goal in its next rate case.[78]

Regarding Staff's comment that the Company's clean energy goal is misleading to customers given the Preferred Portfolio does not reach this goal, the Company appreciates Staff's perspective. Indeed, the Preferred Portfolio for the 2021 IRP does not fully get the Company to its 2045 goal, but it does take tremendous steps in the right direction. The Preferred Portfolio includes significant amounts of new generation, all of which is clean. The Action Plan identifies more than 1,000 MW of clean resources and more than 200 MW of storage. The Company is taking clear and sizeable steps toward its clean energy goal. Reaching our clean energy goal will take continued planning and iterative adjustments, as well as technological advancements and continued cost declines of clean resources.

IV. REC'S COMMENTS

REC's Final Comments focus on the treatment of QFs in the IRP. REC recommends the Commission adopt Staff's recommendation related to future QF planning assumptions and direct Idaho Power to work with stakeholders in future IRPs to develop a reasonable forecast of future QF development.[79]

Idaho Power appreciates REC's comments and has responded above in in Section III, Part E of these Final Reply Comments. Going forward, Idaho Power commits to work with stakeholders in future IRPs to develop reasonable QF-related assumptions.

[77] Staff's Final Comments at 37.
[78] Staff's Final Comments at 37.
[79] REC's Final Comments at 1 (Sept. 8, 2022).

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V. CUB'S COMMENTS

CUB's comments are generally supportive of the Company's 2021 IRP. CUB offers more specific responses to select portions of the Company's Reply Comments concerning transmission assumptions and the load forecast. CUB also presents its recommendation to the Commission regarding specific new-term items in the Action Plan.

A. 2023 IRP Recommendation – Transmission

CUB offers four recommendations regarding transmission for the 2023 IRP: 1) incorporate risk analyses related to firm transmission capacity for market purchases; 2) explore demand management resources that could potentially offset capacity needs arising from unavailability of firm transmission; 3) keep exploring how participating in the Western Resource Adequacy Program ("WRAP") may alter transmission capacity assumptions; and 4) provide an updated range of cost and time estimates for the construction of specific segments of Gateway West that show up in alternative portfolios.[80]

The Company thanks CUB for the feedback and recommendations regarding transmission. Regarding the incorporation of risk analyses related to firm transmission capacity for market purchases, the Company plans to continue to require a third-party firm reservation between market hubs and Idaho Power, in addition to the internal Idaho Power-controlled transmission set-aside reservation for capacity to be included in the transmission capacity assumptions in the load and resource balance. The risk associated with assuming third-party transmission available for Capacity Benefit Margin ("CBM") set-aside will continue to be evaluated through the 2023 IRP.

The Company expects the WRAP will provide an opportunity to adjust 2023 IRP-related CBM assumptions. Furthermore, demand management resource additions that could contribute to the PRM requirement will continue to be evaluated and available for selection in the 2023 IRP

[80] CUB's Final Comments at 2-3 (Sept. 8, 2022).

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modeling process. The Company also commits to providing more information on Gateway West, including more specific segment requirements for the various portfolios in the 2023 IRP, such as cost and time estimates for construction. For reference, the capital cost assumptions for two phases of the Gateway West Segment 8 (Midpoint to Hemingway #2) were described in Appendix D of the 2021 IRP.[81]

B. 2023 IRP Recommendation – Load Forecast

CUB offers two recommendations regarding the load forecast for the 2023 IRP: 1) Increase load forecasting and associated load shaping model visibility; and 2) provide information on neural network model inputs, output, and how the Company has used the results in its portfolio analysis and comparisons with other model alternatives that show that neural network is the best approach to estimate class contribution to system peak.[82]

The Company appreciates CUB's commitment to building the best process for dissemination of the load forecast and associated shaping within the IRP process. The Company has put forth a strong effort to make this process visible and understandable to stakeholders, including the IRPAC. On numerous occasions in the 2021 IRP process, the Company offered deep dives into load forecasting with the goal of fostering a transparent process of learning and growth. Moving forward, the Company will continue to offer such opportunities and seek additional ways to ensure that stakeholders understand the load forecasting process.

As mentioned in Idaho Power's Reply Comments, information used for shaping the system, which is governed by the monthly sales and peak data, is not used in long-term capacity expansion modeling, which is tied to the portfolios.[83] This was further discussed within many responses to Staff Information Requests on the topic. The Company will provide more detailed information on the hourly model moving forward to be clearer on the topic.

[81] 2021 IRP, App. D: Transmission Supplement at 59.
[82] CUB's Final Comments at 4.
[83] Idaho Power's Reply Comments at 53-54.

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C. 2021 IRP Action Plan Recommendations

CUB offers its recommendation on three near-term action items in the 2021 IRP: 1) not acknowledging Jackpot Solar; 2) adopting the same acknowledgement conditions PacifiCorp received for conversion of Jim Bridger Units 1 and 2;[84] and 3) acknowledging only those large-load related resource additions that specify the size and timing related to the acquisition of additional resources.[85]

Idaho Power appreciates CUB's participation in this proceeding and does not oppose the first two recommendations. However, with respect to the third, Idaho Power would note that clean energy resource decisions related to the large-load customer have not yet been made. For the 2021 IRP, the Company modeled solar resources coming on in waves across the Action Plan window, but these were estimates based on the best available information and assumptions at the time. Rather than assigning uncertain information to Action Plan items, the Company would propose an alternative: adding specificity on resource size and timing in the Company's next Action Plan, as more detailed information will be known for the 2023 IRP.

VI. RENEWABLE NORTHWEST'S COMMENTS

Renewable Northwest's Final Comments offer general support for acknowledgement of Idaho Power's 2021 IRP.[86] Renewable Northwest notes that it is encouraged by the non-emitting resources selected in the Preferred Portfolio and also provides some recommendations for the 2023 IRP to ensure the procurement of least-cost resources to meet future capacity needs.[87]

A. 2023 IRP Recommendation – Capacity Values of Thermal Resources

Renewable Northwest recommends Idaho Power model capacity values of thermal resources using the ELCC methodology with a variability adjustment factor that accounts for

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[84] In re PacifiCorp, dba Pacific Power, 2021 Integrated Resource Plan, Docket No. LC 77, Order No. 22-178 at 7-8 (May 23, 2022).
[85] CUB's Final Comments at 5-6.
[86] Renewable Northwest's Final Comments at 1 (Sept. 8, 2022).
[87] Renewable Northwest's Final Comments at 1.

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thermal derates and correlated outages due to weather-related conditions instead of using fixed forced outage rate assumptions.[88]

Idaho Power appreciates this suggestion on determining capacity values for thermal resources. Currently, the Company models a month-by-month adjustment to thermal resources based on unit nameplate, historic plant performance, temperature factors, and other various considerations. Idaho Power's LOLE tool re-calculates the outage probability table every month to account for the capacity variations of flexible resources.

Idaho Power will continue to evaluate and seek input from members of the IRPAC and other interested parties throughout the development of the 2023 IRP to further improve the modeling of all resources.

B. 2023 IRP Recommendation – Techno-Economic Study for Jim Bridger Gas Conversion

1. <u>The 2021 IRP was an Economic Study for Jim Bridger Gas Conversion.</u>

Renewable Northwest, in its Final Reply Comments, recommends that:

> Idaho Power conduct a holistic techno-economic study (including updated price curves and the economic impacts of IRA) of the proposed coal to gas conversion compared to procuring clean & non-emitting capacity resources as part of the 2023 IRP and present the detailed results to the Commission in a workshop.[89]

Idaho Power respectfully disagrees with this recommendation, as the suggested work was completed in the 2021 IRP.

Indeed, the 2021 IRP is itself a holistic techno-economic study of the proposed coal to gas conversion of Bridger Units 1 and 2, the results of which have been compiled in the IRP report. As part of the validation and verification testing in the 2021 IRP, Idaho Power tested the exit from Bridger Units 1 and 2 at the end of 2023 and allowed the Long-Term Capacity Expansion ("LTCE") model to select the next least-cost portfolio of resources to replace those units. That analysis revealed that 400 MW each of solar and storage resources built in 2024 would be needed to

[88] Renewable Northwest's Final Comments at 3.
[89] Renewable Northwest's Final Comments at 3.

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replace the energy and capacity of the two Bridger units.[90] Other resource changes were necessary in the alternate portfolios, such as the "no conversion" portfolio requiring the Gateway West transmission segment and a reduced wind build in 2024, but these items are small in comparison to the magnitude of the solar and storage necessary to replace the capacity and energy of Bridger Units 1 and 2. When costed and compared to the Preferred Portfolio, the "Bridger Exit Units 1 & 2 at the End of 2023" portfolio was at least $135 million more expensive on a Net Present Value basis.[91] It should be noted that, as a verification scenario, the "Bridger Exit Units 1 & 2 at the End of 2023" portfolio was not tested to determine if a reliability adder would be required. Such an adder would only increase the cost of this portfolio.

2. Gas Conversion of Jim Bridger Units 1 and 2 are part of Wyoming's Regional Haze State Implementation Plan ("SIP").

On August 25, 2022, Wyoming Department of Environmental Quality proposed a 2022 SIP Revision requiring conversion of Jim Bridger Units 1 and 2 from coal to natural gas.[92] Following conversion to natural gas, the proposed 2022 SIP Revision will require that Jim Bridger Units 1 and 2 are operated with a maximum annual boiler heat input of 21,900,000 MMBtu/year which equates to an annual capacity factor of 41.6 percent.[93] Each unit will be limited to a 30-day rolling average nitrogen oxides ("NO_x") emission rate of 0.12 lb/MMBtu and annual NO_x emissions cap of 1,314 tons per year as indicated in a February 14, 2022, consent decree between Wyoming and PacifiCorp.[94]

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[90] 2021 IRP, App. C at 80.
[91] 2021 IRP at 131 (Table 10.5).
[92] Wyoming State Implementation Plan, Regional Haze Revision (Aug. 25, 2022), available at: https://deq.wyoming.gov/aqd/rule-development/proposed-rules-and-regulations/?wpcp_link=JTdCJTIyc291cmNlJTIyJTNBJTIyOTdhOGU5YmNhMzViYTY4YjI4NDM0OTEyNzEyNjI1ZWElMjIlMkMlMjJhY2NvdW50X2lkJTIyJTNBJTIyMTEzMTQyMjM3OTUwMTUyNjI3MzcyJTIyJTJDJTIybGFzdEZvbGRlciUyMiUzQSUyMjFoZTM3MnI1S1JxeDFRN0tVekZoZDZPLTNBLUtyRTJmTCUyMiUyQyUyMmZvbGRlclBhdGglMjIlM0ElMjJXeUl4YUdVek56SnlOVXRTY1hneFVUZExWWHBHYUdRMlR5MHpRUzFMY2tVeVprd2lYUSUzRCUzRCUyMiUyQyUyMmZvY3VzX2lkJTIyJTNBJTIyMTJHTS0td1AwR1JJaGswRjlEMkxhZnJCdk5YbTB6ZlhoJTIyJTdE.
[93] Wyoming State Implementation Plan, Regional Haze Revision at 3.
[94] Wyoming State Implementation Plan, Regional Haze Revision at 3.

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As part of the proposed 2022 SIP Revision, Wyoming also published the four-factor regional haze reasonable progress analysis supporting conversion of Bridger Units 1 and 2 from coal to natural gas. The reasonable progress analysis justifies revising the SIP to require the natural gas conversion as a long-term strategy to meet Wyoming's Reasonable Progress Goals and demonstrates that the natural gas conversion is a better long-term strategy for the state to reduce regional haze than the current federally enforceable SIP requirement to install selective catalytic reduction on Bridger Units 1 and 2.

VII. STOP B2H'S COMMENTS

STOP B2H's Closing Comments focus on concerns related to the various agencies and proceedings in Oregon, changes in metrics between IRPs, B2H cost estimates and transmission revenue, AURORA modeled Mid-C prices, federal funding opportunities and quantifying the impacts to the 2021 IRP PRM.

A. Interrelatedness

Under the banner of "interrelatedness," STOP B2H provides several criticisms of the regulatory processes involving B2H before the Commission and the Energy Facility Siting Council ("EFSC"). These criticisms are only indirectly relevant to the issues under consideration in this case and, in any event, are without merit.

STOP B2H comments that "[i]t is unfortunate that the acknowledgment [the Commission] gave to Idaho Power in 2017 to construct the B2H has not been mapped to the ODOE site certificate standards and their EFSC process."[95] It is not entirely clear what STOP B2H's concern is here. The IRP and EFSC review processes are separate evaluations with distinct purposes. The EFSC process is intended to ensure that the siting of the project is consistent with state and local laws governing land use, environmental protections, and cultural, historical, and archaeological resources, while the IRP is a utility resource planning process. The one point of

[95] STOP B2H's Closing Comments at 4 (Sept. 8, 2022).

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overlap is the fact that EFSC's rules allow a utility under the Commission's jurisdiction to demonstrate compliance with EFSC's Need Standard under the Least-Cost Plan Rule by showing that the proposed facility was acknowledged in the utility's Short-Term Action Plan in its IRP.[96] Therefore, in asserting that the acknowledgment should have been "mapped" to EFSC's standards, STOP B2H seems to be suggesting that the Commission should have tailored its acknowledgment of B2H so that it would somehow be aimed more explicitly at the requirements of EFSC's Least-Cost Plan Rule. However, the Commission expressly rejected a similar argument raised by STOP B2H when it acknowledged B2H in the 2017 IRP, stating: "[O]ur acknowledgment is limited to our interpretation of IRP standards specific to the Public Utility Commission, and does not interpret or apply the standard of any other state or federal agency."[97]

STOP B2H also registers several concerns about the Oregon Department of Energy's ("ODOE") and EFSC's acceptance of the need for B2H, despite the fact that Idaho Power is constructing the project in conjunction with project participants PacifiCorp and the Bonneville Power Administration ("BPA"). These arguments seem to be directed at ODOE's recommendation and the decision of the Hearing Officer, adopted by EFSC, granting Idaho Power's Motion for Summary Determination finding that the Company had satisfied EFSC's Need Standard under the Least-Cost Plan Rule.[98] Specifically, STOP B2H states that "ODOE/EFSC doesn't care if

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[96] OAR 345-023-0005(1) ("The applicant shall demonstrate need…[f]or electric transmission lines under the least-cost plan rule, OAR 345-023-0020(1)…."); OAR 345-023-0020(2) ("The Council shall find that a least-cost plan meets the criteria of an energy resource plan described in section (1) if the Public Utility Commission of Oregon has acknowledged the least cost plan.").

[97] *In re Idaho Power Company, 2017 Integrated Resource Plan*, Docket No. LC 68, Order No. 18-176 at 1 (May 23, 2018).

[98] Proposed Contested Case Order Hearing Day 2, August 30, 2022 (Tr. Day 2), pages 245-46 (Councilmembers voting in agreement with the Hearing Officer's ruling on the motions for summary determination and the Proposed Contested Case Order's findings and conclusions regarding N-1 and N-3, recognizing "the 2019 acknowledgement was brought into the contested case record"); Ruling and Order on Motions for Summary Determination of Contested Case Issues N-1, N-2, and N-3 at 19 (July 29, 2021) ("Because the OPUC has acknowledged the B2H Project as a whole, Idaho Power has demonstrated need for the proposed facility under OAR 345-023-0005(1) and OAR 345-023-0020(2). The bottom line is that the B2H Project satisfies the Need Standard for non-generating facilities under the Least-Cost Plan Rule, regardless of the percentage of megawatt transmission capacity needed for Idaho Power's customers."); Proposed Order at 670 (July 2, 2020) ("In ASC Exhibit N and in this order, the

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there are 'partners' as they have accepted that the OPUC has taken care of that, and that funding is in place."[99] STOP B2H also argues that "EFSC has a requirement that the application show the energy plan or plans (plural) that OPUC has acknowledged in their application" and that "[t]hey don't care that a key partner, PacifiCorp (54%) has not come forward with an acknowledgement for the B2H in their IRP's action plan."[100] STOP B2H concludes that EFSC does not care that the OPUC has approved a 500 kV transmission line with partners, "but there are no partners."[101] These arguments are not properly raised in this proceeding and are substantively flawed as well.

As an initial matter, EFSC's interpretation and application of its Need Standard and the Least-Cost Plan Rule are beyond the scope of this proceeding and outside of the Commission's jurisdiction. The fact of the matter is that the EFSC fully considered the issue and found that the Commission's acknowledgment of B2H in the Action Plan of the 2017 and 2019 IRPs satisfied its standard.[102]

Moreover, to the extent that STOP B2H is suggesting that this Commission acted inappropriately in acknowledging Idaho Power's plan to construct B2H without a showing of need on behalf of PacifiCorp or BPA, that argument was implicitly rejected by the Commission in the context of the 2019 IRP. At the Public Meeting in which the Commission acknowledged the construction of B2H, the Commissioners addressed the arguments made by STOP B2H that its acknowledgement was for only a portion of the capacity of the line and that a smaller line would have sufficed to address Idaho Power's specific capacity need. Commissioner Tawney explained as follows:

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applicant provides documentation that the ongoing permitting as well as the construction of the proposed facility has been acknowledged by the OPUC in its IRP, therefore the Council's Need for a Facility under OAR 345-023-0005 has been met."). Filings available at: https://www.oregon.gov/energy/facilities-safety/facilities/Pages/B2H.aspx?_cldee=am9jZWx5bkBtY2QtbGF3LmNvbQ%3d%3d&recipientid=lead-f40c4e122458ea11a997001dd800a749-b46112cd9d84419db3536ad97458aef3&esid=ed33e9b8-b7bc-ea11-a812-001dd801892c.

[99] STOP B2H's Closing Comments at 4.

[100] STOP B2H's Closing Comments at 4.

[101] STOP B2H's Closing Comments at 4.

[102] *See supra* note 9898.

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> A lot of the comments that get brought to us . . . are around, 'Shouldn't it be a different line? Shouldn't we be evaluating something different?' And I think the challenge we have is what's been brought to us is the 500 kV project, with the transfers at peak times for Idaho Power and the capacity used by others in other times when they need it. ***A different sized project would have really different throughput, it would have really different operational characteristics and it would have a different cost per unit.*** And we see this often in infrastructure in energy: there is an economy of scale with size. That means it's the best price, it's the least cost option—and that means we bring on partners. That's how the coal fleet was built and it is likely how we will build some of the clean energy resources that will come to the table in the coming decade.[103]

Thus, the Commission clarified that it appropriately acknowledged Idaho Power's acquisition of B2H with other participants. Moreover, contrary to STOP B2H's claim, the Commission has acknowledged B2H in PacifiCorp's 2021 IRP.[104]

Finally, STOP B2H refers to docket AR 626, in which the Commission will adopt new rules governing certificates of public convenience and necessity ("CPCN"). STOP B2H claims that Idaho Power has filed for a CPCN for B2H under the "old rules"—suggesting that that filing raises the question as to whether the old or new rules will govern the CPCN process for B2H. STOP B2H's concern is based on a misunderstanding. In fact, the filing made by Idaho Power was not a petition for a CPCN, but rather a letter providing notice to stakeholders and landowners that Idaho Power *intends* to file a petition for a CPCN on or about September 30, 2022, which is after the September 20, 2022, Public Meeting scheduled for the Commission to adopt the final rules.[105] Moreover, the notice explicitly stated that Idaho Power will file its Petition in accordance with the updated CPCN rules that will be adopted in AR 626.[106] The notice was filed simply to give all

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[103] OPUC Special Public Meeting, Docket No. LC 74, Idaho Power IRP Deliberation and Discussion, Recording at 2:27:59 (Apr. 15, 2021), available at: https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=733 (last accessed September 19, 2022).
[104] Order 22-178 at 10-13 (acknowledging "PacifiCorp's transmission action items," which include two new segments of the Gateway line, B2H, and Local Reinforcement Projects as identified).
[105] *See In re Idaho Power Certification of Public Convenience and Necessity*, Docket No. PCN 5, Idaho Power Company's Notice of Intent to File a Petition for Certificate of Public Convenience and Necessity (Sept. 1, 2022) [hereinafter, "Notice of Intent"].
[106] Notice of Intent at 3.

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interested parties a "heads up" so that they would expect the B2H CPCN filing soon after the new rules are adopted. Therefore, STOP B2H's concerns are unfounded.

B. Changes Between IRPs

STOP B2H points out the changing nature of terms and/or measurements used in this IRP and argues that the current IRP, like the 2019 IRP, includes new and confusing methodologies.[107] Referencing OPUC Guideline 1, STOP B2H claims that the Company has not complied with the substantive requirements of evaluating resources on a consistent and comparable basis.[108] Finally, STOP B2H notes that while change is inevitable, the Company's "reconfiguring" of its IRP processing and testing is significant to the extent that "baseline comparisons [are] near impossible."[109]

STOP B2H is correct that integrated resource planning requires utilities to constantly reevaluate and improve their methodologies and other analytic tools. As the energy landscape changes, new tools are needed to ensure resources are adequate, reliable, and cost effective. These tools are being developed by vendors and utilities alike as they grapple with the challenges of a rapidly evolving industry. The challenge is industry-wide and is not exclusive to Idaho Power.

The statement STOP B2H references in Order No. 07-002, Guideline 1—"All resources must be evaluated on a consistent and comparable basis"—is intended to be applied within a single resource plan. Indeed, each resource must be evaluated consistently with other resource options ***within the analysis of a particular resource plan*** to ensure the resources are compared and selected appropriately. This requirement can only be applied at a high level when comparing two separate plans that were formulated with different assumptions and at different points in time.

The Commission, stakeholders, the IRPAC, and Idaho Power's customers and owners expect the Company to continue to evolve its IRP processes and methods. The Company has

[107] STOP B2H's Closing Comments at 5.
[108] STOP B2H's Closing Comments at 5.
[109] STOP B2H's Closing Comments at 5.

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done so—and will continue to do so—with enhanced methods and tools that apply additional rigor to each new IRP. With each iteration of the IRP process, direct comparisons to old IRP methods become more difficult. Such enhancements allow for better review and comparison of resources in each IRP. As such, Idaho Power's 2021 IRP complies with Guideline 1.

C. B2H Budget

1. <u>Idaho Power has Responded to STOP B2H's Requests in the Manner Requested.</u>

STOP B2H continues to stress that the Company has not provided an updated 2021 IRP budget for B2H.[110] STOP B2H claims that the Company did not answer their Information Request No. 18 appropriately, and that the Company should have known that a tabulated B2H budget in the same format the Company provided in 2017 was the requested format. Nowhere in STOP B2H's Information Request No. 18 do they ask for anything specifically related to B2H, nor do they request that the information be provided similar to the 2017 budget format. Rather, STOP B2H asks for information related to three different portfolios in the 2021 IRP. The Company responded to this question with sufficient detail.

2. <u>Idaho Power's B2H Cost Estimate is Reasonable and Does Not Need to Align with the Association for the Advancement of Cost Engineering ("AACE") International Guidelines.</u>

The Company does not understand why STOP B2H is pushing for the Company to align its estimate with the Association for the Advancement of Cost Engineering's ("AACE") International Guidelines.[111] There is no requirement, either regulatory or otherwise, that the Company do so. However, at the Commission's request, the Company did evaluate B2H with various contingency adders (0, 10, 20, and 30 percent), and the Company believes that the cost of B2H will fall in that range. STOP B2H, Staff, and the Commission asked for this B2H robustness

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[110] STOP B2H's Closing Comments at 6-8.
[111] STOP B2H's Closing Comments at 6-8.

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testing at the conclusion of the 2019 IRP, to be included in the 2021 IRP. The Company agreed and delivered this analysis.

With respect to project cost, STOP B2H references third-party information—MISO's April 2022 Transmission Cost Estimation Guide—that fully supports the Company's B2H cost estimate.[112] Based on that MISO guide, which Idaho Power believes is an appropriate source to confirm its cost estimate for B2H, a 500-kV line is estimated at $3.7 million per mile (with a 30 percent cost contingency and 7.5 percent AFUDC included; the assumed comparable state is Montana).[113] Using this line cost estimate, B2H—at 290 miles—would be expected to cost $1,073 million. Generously rounding that amount up to an even $1.2 billion to factor in substation costs (for high-level comparison purposes only), and then applying Idaho Power's 45 percent share to that amount yields $545 million. From Table 10.9 of the 2021 IRP, Idaho Power's 45 percent share of B2H at 0 percent and 30 percent cost contingencies is listed as $485 and $607 million, respectively.[114] STOP B2H's referenced source provides yet another indication that the Company's B2H estimate is reasonable.

D. Mid-C Price Forecast

STOP B2H expresses similar concerns as Staff around the AURORA modeled Mid-C prices compared to forward and actual prices.[115] Idaho Power responds thoroughly to these issues in the Company's response to Staff's Final Comments, above, in Part B(3)(a-e).

E. Transmission Revenues

STOP B2H requests that the Commission ask Idaho Power for an accounting of income credited to B2H by customer class and year. Further, STOP B2H requests that the Commission

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[112] STOP B2H's Closing Comments at 6.
[113] Transmission Cost Estimation Guide for MTE22 at 44 (Apr. 2022), available at: https://cdn.misoenergy.org/20220208%20PSC%20Item%2005c%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP22_Draft622733.pdf.
[114] 2021 IRP at 145 (Table 10.9).
[115] STOP B2H's Closing Comments at 8-10.

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ask the Company "how B2H debt is to be paid down" and "when [B2H will] be paid off."[116]

The Company infers from these questions that STOP B2H perceives that B2H has a payback structure akin to a home mortgage; however, this is not how utility finance works. B2H-related costs allocated to Idaho Power retail customers will reduce over time as the project depreciates over its depreciable life, just like all other Idaho Power-financed projects. Third-party revenues associated with the project will offset customer rates. Similar to most other new resources evaluated in the IRP, B2H has a useful life well beyond the planning horizon. To account for the different useful lives of resources, the Company levelizes the cost of these resources over their useful life.

F. Federal Funding

STOP B2H notes it has been researching federal funding opportunities through both the IIJA and the IRA. Specifically, STOP B2H is interested in federal funding that may be available to the I-84 right of way ("ROW"). Based on this analysis, STOP B2H asserts that burying the B2H as a direct current ("DC") line in the ROW of I-84 with level 3 charging stations at the rest area could get the attention of congressional delegations in Oregon and "would like to collaborate on this potential win-win situation."[117]

The Company shares STOP B2H's interest in expanding electric vehicle ("EV") charging stations across its service area. However, the idea described by STOP B2H to utilize the B2H 500-kV transmission line for charging stations along I-84 is impractical. EV charging stations—even DC fast-charging and supercharging—provide electricity at levels that are orders of magnitude below a 500-kV line. As a result, electricity for EV charging would be better sourced from a distribution line or a low-voltage transmission line.

[116] STOP B2H's Closing Comments at 10-11.
[117] STOP B2H's Closing Comments at 11.

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With respect to undergrounding the B2H line, Idaho Power would only note that such transmission line undergrounding is rare and expensive. The increase in costs would surely be considered problematic to STOP B2H, as they continue to show concern for ratepayer impact.

Independent of STOP B2H's arguments above, Idaho Power will continue to closely monitor funding opportunities in the IIJA and the recently passed IRA that may assist in funding transmission projects, including but not limited to B2H.

G. Planning Reserve Margin

STOP B2H expresses concern with the PRM in the 2021 IRP and suggests that the Commission "urge Idaho Power to study the impacts of these decisions on the ratepayer[.]"[118]

Idaho Power shares STOP B2H's stated concern about the financial impact of new resources on customers. The decision to adjust the planning reliability threshold was made in response to multiple factors including recent extreme temperature events and ensuring reliable service to Idaho Power's customers. Other utilities and planning entities are making similar changes. Importantly, the change was presented to the IRPAC for feedback and alignment;[119] this was not a decision the Company made in a vacuum.

STOP B2H also argues that shift in the reliability standard between the 2019 and 2021 IRPs will occur "all at once" and is not a "best practice."[120] Idaho Power does not understand STOP B2H's concern here but would point out that a change in methodology from one IRP to the next does not have an "all at once" impact. Rather, reliability standard changes will appear in the load and resource balance over the course of multiple years. This staging can be seen in the RFPs the Company has submitted. Both economic and reliability benefits from adding clean, renewable resources and storage to the system will be realized over time, as shown in the economic dispatch analysis and the LOLE analysis provided in the 2021 IRP.

[118] STOP B2H's Closing Comments at 12.
[119] IRPAC Meeting #7 held on November 18, 2021.
[120] STOP B2H's Closing Comments at 12.

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VIII. REQUEST FOR WAIVER OF 2022 IRP UPDATE

Pursuant to OAR-027-0400(1), Idaho Power requests a waiver of the Company's obligation to file an update to the 2021 IRP, as required by OAR 860-027-0400(8). That rule requires that an energy utility submit an annual update on its most recently acknowledged IRP on or before the anniversary of the acknowledgment date. In the case of this 2021 IRP, the schedule contemplates that the Commission will issue its acknowledgement at a Special Public Meeting on December 6, 2022. Meanwhile, the Company's work on its 2023 IRP is well underway, and the Company plans to file that IRP ***before*** December 6, 2023—which would essentially moot the need for an update to the 2021 IRP. Therefore, there is good cause for the Commission to waive the IRP update requirement with respect to the Company's 2021 IRP.

IX. CONCLUSION

Idaho Power again appreciates the opportunity to file comments in this proceeding and continues to value the robust public process and participation in this case. Based on the detailed and comprehensive analysis provided in the Company's 2021 IRP, Idaho Power has fully demonstrated that the preferred portfolio is the least-cost, least-risk means of serving customer need. Idaho Power respectfully requests acknowledgment of the Company's 2021 IRP as meeting both the procedural and substantive requirements of Order Nos. 89-507, 07-Q02, 07-747, and 12-013.

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Respectfully submitted this 23rd day of September 2022.

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ATTACHMENT 1

to

Idaho Power's Final Reply Comments

Redacted

THIS EXHIBIT IS CONFIDENTIAL

PER GENERAL PROTECTIVE ORDER NO. 22-212

IN DOCKET LC 78 AND IS PROVIDED

SEPARATELY

ATTACHMENT 2

to

Idaho Power's Final Reply Comments

LC 78
Idaho Power Company's Response to
Staff's Information Request No. 131-138

Topic or Keyword: Load Forecast

STAFF'S DATA REQUEST NO. 136:

On page 10 of the Company's reply comments, Idaho Power states, in reference to information from state and local community economic development professionals: "The Company uses this information as a check on the reasonableness of customer forecasts."

a. Please describe how this information is used to understand the reasonableness of customer forecasts.

b. Please describe where in the Additional Firm Load forecast for the 2021 IRP a customer's forecast was reduced due to the application of this information.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 136:

a. The Company collects intelligence gathered by economic development professionals in the service area and within the Company. Customer forecasts can be placed in context of what the Company understands to be reasonable estimates of usage and growth for certain sectors.

b. In terms of the Additional Firm Load customers, information on the specific customers that qualify for this category (typically over 20 MW in size) is collected annually or semi-annually through Idaho Power's Special Contract process. The Company can increase or decrease load requirements for the Special Contract customers if more recent information is known at the time the load forecast is developed for the IRP. Typically, the Company relies on the information provided by the customer, as was the case in the 2021 IRP load forecast. Since the development of the 2021 IRP load forecast, each customer's development plan within the Additional Firm Load category has not materially changed.

DOCKET LC 78 - CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the confidential pages of Idaho Power Company's Final Reply Comments and Request for Waiver of 2022 IRP Update, on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below.

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DATED: September 23, 2022

/s/ Alisha Till
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Paralegal