ORDER NO. 23-004

ENTERED Jan 13, 2023

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 78

In the Matter of IDAHO POWER COMPANY, 2021 Integrated Resource Plan.	ORDER

DISPOSITION: 2021 INTEGRATED RESOURCE PLAN ACKNOWLEDGED

This order memorializes our decision, made and effective at our December 6, 2022 Special Public Meeting, concerning Idaho Power Company's 2021 Integrated Resource Plan (IRP). We acknowledge all action items proposed in Idaho Power's action plan, with the exception of those items that were completed or substantially completed at the time of acknowledgment. We also adopt Staff's additional recommendations as modified at the December 6, 2022 Special Public Meeting.

I. INTRODUCTION

Through this IRP process, we reviewed Idaho Power's long-term plan for a least cost, least risk portfolio of resources to serve customers, as well as a corresponding series of actions that Idaho Power intends to take in the next four years. These action plan items include coordinating an early exit from the Jim Bridger facility coal units and continuing development of the Boardman-to-Hemingway (B2H) project. As described in more detail below, we acknowledge Idaho Power's action plan, including those items related to the Jim Bridger facility and construction of the B2H project. We also accept recommendations from Staff for additional analysis and review for the company's 2023 IRP. Staff's recommendation is attached to this order as Appendix A.

II. IRP PROCESS

A. Purpose

The objective of the IRP process is to ensure an adequate and reliable supply of energy at the least cost and least risk to the utility and its customers in a manner consistent with the public interest.[1] The IRP process provides an opportunity for broad input from a range of stakeholders and public participation. This input and the IRP guideline requirements are meant to ensure a detailed and wide-ranging review of resource options, technology advancements, pricing scenarios, and risk profiles, and to test the utility's conclusions. The IRP process is intended to be iterative. Where weakness in the analysis or issues are identified, stakeholder participation can help identify alternatives and improvements to the action plan or analysis in the next IRP. Utilities should respond proactively to the concerns of stakeholders and consider alternatives.

Ultimately, an acknowledged plan will become a working document for use by the utility, the Commission, and other interested parties in Commission proceedings.[2] We have noted in recent IRP decisions that during a time of considerable electric utility industry transition, IRPs should evaluate opportunities and strategies for course corrections as industry evolution comes into greater focus.[3]

B. Timing and Content

We require regulated energy utilities to prepare and file IRPs within two years of acknowledgment of the utility's last plan.[4] Oregon's IRP guidelines require a minimum 20-year planning period, and include the following core elements: (1) identification of capacity and energy needs to bridge the gap between expected loads and resources; (2) identification and estimated costs of all supply-side and demand-side resource options; (3) construction of a representative set of resource portfolios; (4) evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties; (5) selection of a portfolio that represents the best combination of cost and risk for the utility and its customers; and (6) creation of an action plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.

The primary outcome of the IRP process, after the presentation of the plan and review by Staff and stakeholders, is the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and the customers, culminating in a Commission acknowledgment decision that indicates whether the Commission finds the plan and any specific action items reasonable overall. A Commission acknowledgment decision provides guidance for future prudence review and cost recovery, but the utility maintains the obligation to demonstrate that actions

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[1] *In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon*, Docket No. UM 180, Order No. 89-507 at 2 (Apr. 20, 1989).
[2] *Id*. at 7.
[3] *In the Matter of Portland General Electric Company, 2016 Integrated Resource Plan*, Docket No. LC 66, Order No. 17-386 at 2 (Oct. 9, 2017).
[4] OAR 860-027-0400(3).

remain reasonable and prudent, particularly as conditions change between the IRP development and execution of any resource action.

C. Action Plan

An important product of the IRP process is an action plan. Where the preferred portfolio calls for new supply-side and demand-side resources or resource actions to meet system needs, the action plan will include these resource actions. The action plan identifies the steps the company will take within the next four years to deliver resources identified in the preferred portfolio of resources. Different resources require different actions on different timelines. Transmission, in particular, requires more development lead time than other supply-side resources.

D. Acknowledgment

Our acknowledgment of an IRP means that the Commission finds that the utility's preferred portfolio and action plan is reasonable at the time of acknowledgment.[5] We may decline to acknowledge specific action items if we are not satisfied that the proposed resource decision presents the least cost, least risk option for customers. We may provide the utility an opportunity to revise the IRP before issuing an acknowledgment order.[6]

Acknowledgment is not a guarantee of cost recovery, nor is consistency with an acknowledged plan a requirement for recovery of resource costs in rates. Acknowledgment provides guidance for later ratemaking proceedings, which are the forum for the Commission to make its ultimate decision to approve or disapprove a resource procurement as prudent and subject to recovery in customer rates. Consistency with an acknowledged plan may be used as evidence in support of favorable ratemaking treatment, but the utility still must demonstrate that its actions remained reasonable, particularly in light of any material changes in the facts, circumstances, and assumptions that supported IRP acknowledgment.

III. POSITION OF THE PARTIES

In its 2021 IRP, Idaho Power requests the acknowledgment of 13 action plan items. Staff provides 26 recommendations regarding the action plan items and future IRPs. Staff recommends that the Commission acknowledge Idaho Power's 2021 IRP action plan items, with the exception of those items that were already completed or substantially completed. As part of its recommendations, Staff also proposes some modifications to Idaho Power's action plan items and additional recommendations for Idaho Power's next

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[5] *In the Matter of Public Utility Commission of Oregon, Investigation into Integrated Resource Planning Requirements*, Docket No. UM 1056, Order No. 07-002 at 16 (Jan. 8, 2007).
[6] OAR 860-027-0400(6).

IRP. Staff's recommendations for the next IRP address qualified facilities (QFs), large-load customer resource acquisition, and greenhouse gas emission data for the 2023 IRP. Idaho Power proposes modifications to Staff Recommendations 5, 8, 15, 23, and 24. The Renewable Energy Coalition (REC) supports Staff Recommendations 22 and 23. STOP B2H identifies concerns with the B2H project and Staff Recommendations 4, 6, and 8.

Related to Idaho Power's modeling of the B2H project, Staff identifies four areas of concern: (1) the construction cost estimates; (2) the Mid-C prices modeled in the IRP; (3) the estimates for costs of alternative resources; and (4) emerging federal funding. Regarding the construction cost estimates, Staff agrees with STOP B2H that Idaho Power did not sufficiently update its costs since 2016, noting that other cost assumptions had more transparency. In its recommendation, Staff states that Idaho Power committed to updating the construction cost estimate in its 2023 IRP. Staff recommends that the Commission memorialize this commitment as an action item, which is Staff Recommendation 7.[7] Idaho Power does not object to this recommendation.

Regarding the Mid-C prices, Staff argues in its final comments that the Mid-C prices in Idaho Power's 2021 IRP are substantially lower than observed Mid-C prices. Staff maintains that the company's Aurora modeling accuracy can be improved in the next IRP and that it will work with Idaho Power on the issue prior to the 2023 IRP. Staff also contends that the references in the IRP Guidelines to the "reasonable at the time" standard are not intended to support using outdated data inputs when there are alternatives available. Staff recommends that the Commission acknowledge the B2H action plan items with the condition that Idaho Power needs to model the risk of extremely high Mid-C prices in its 2023 IRP. Specifically, Staff argues that the 2023 stochastic analysis should explore liquidity at Mid-C.[8] This recommendation is Staff Recommendation 8. Idaho Power disagrees with Staff Recommendation 8 and urges the Commission not to direct such a specific modeling scenario. Idaho Power maintains that market prices are not inputs in the model and cannot be manipulated to understand a high-market price environment. Idaho Power proposes an alternative to Staff's recommendation language that would change it from a modeling requirement to a directive to work with stakeholders on the issue.[9] In response to Idaho Power's revisions, Staff proposes an additional modification to Recommendation 8 that would require Idaho Power to demonstrate the impact of high wholesale prices and decreased liquidity.

Similar to the Mid-C price issue, Staff argues that the IRP may overestimate the cost of alternative resources because there are a number of differences in circumstances from the time Idaho Power performed the modeling and the circumstances at the time the

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[7] Staff Report for November 29, 2022 Special Public Meeting at 15 (Oct. 28, 2022).
[8] *Id*. at 17.
[9] Idaho Power Company Comments on Staff Report at 6 (Nov. 18, 2022).

Commission considers acknowledgment. Staff notes that it requested that Idaho Power perform an analysis that included, among other inputs, using observed Mid-C prices, an assumed capital cost for combined cycle combustion turbine (CCCT) plants, and a select list of new Inflation Reduction Act (IRA) related federal subsidies. Staff reports that the company was unable to provide this analysis as proposed, because the company believes that CCCT permitting could not be accomplished within four years and the cost impacts of the IRA are too uncertain.[10]

Regarding federal funding, Staff identifies questions around how Idaho Power is seeking to obtain federal infrastructure funding. Staff maintains that the company should pursue all available federal funding for B2H and recommends that Idaho Power provide a report on the status of any federal funding in RE 136.[11] This recommendation is Staff Recommendation 9, which Idaho Power does not oppose.

Staff ultimately finds that Idaho Power adequately responded to its concerns about the inputs and modeling approach for the B2H project, and recommends acknowledgment accompanied by complete and transparent updates in the next IRP.

STOP B2H urges the Commission not to acknowledge Idaho Power's action plan item for preliminary construction activities to construct the B2H project. STOP B2H argues that starting construction for the B2H project is risky based on the questions raised about the quality of the data provided by Idaho Power and the process in the last several IRPs.[12] Specifically, STOP B2H argues that Idaho Power's IRP analysis is flawed and its construction estimates are inaccurate. STOP B2H maintains that Mid-C prices are rising and that the company's modeling did not factor in Mid-C resource inadequacy. STOP B2H also argues that the conversion data for the Jim Bridger facility is incomplete because Idaho Power used speculative inputs and preliminary expenses and the actual costs are likely to be more than projected.[13]

Staff also offers recommendations regarding Idaho Power's QFs forecasts, arguing that by making no assumptions about new QFs, the company was underestimating QFs. Staff maintains that this can displace future QF development and lead to an overestimation of future resource need. Staff Recommendation 22 would direct Idaho Power to revisit the assumed renewal rate of wind QFs, and Staff Recommendation 23 would direct the company to apply a reasonable forecast of new QFs starting in the fifth year of the planning cycle.[14] REC states that it supports Staff Recommendations 22 and 23

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[10] Staff Report at 13-14.
[11] *Id.* at 14, 18-19.
[12] STOP B2H Comments on Staff Report and Recommendations at 9 (Nov. 18, 2022).
[13] *Id.* at 6.
[14] Staff Report at 36-37.

regarding qualified facility planning assumptions and recommends that the Commission adopt these recommendations.[15] Idaho Power accepts Staff Recommendation 22 but proposes modifications to Staff Recommendation 23. Idaho Power argues that it is comprehensively identifying future resource needs and that by not assuming a forecast of new QFs it is sending appropriate price signals to incent resource development. Idaho Power maintains that including a QF development forecast could reduce the identified resource need and extend the capacity period, which reduces the price signals that would otherwise be sent by capacity pricing. Idaho Power contends that including a forecast of speculative QF resources has the potential to hide real capacity deficits that would otherwise be revealed in the model. Idaho Power proposes to modify the recommendation to direct the company to work with Staff and stakeholders to develop a reasonable forecast of new QFs.

Regarding large-load customer resource acquisition, Staff Recommendation 15 proposes to direct Idaho Power to include large-load customer resource acquisition sizing and timing needs in the company's action plan for its 2023 IRP. Staff's recommendation is based on comments submitted by the Oregon Citizens' Utility Board arguing that Idaho Power had disclosed large load customer's energy needs, but that it had not included any specifications on when the resource acquisition to meet these needs will occur.[16] Idaho Power maintains that it does not specify resources to serve an individual customer's load growth and that it only identifies such resources in this case where a customer had voluntarily entered into a special contract arrangement. Idaho Power proposes to modify Staff's recommendation to clarify that it would include the sizing and timing in its 2023 IRP action plan for clean energy special contracts with large load customers and in a manner that does not compromise the company or the customer's confidentiality.[17]

Staff also recommends that Idaho Power provide a graph in the executive summary of its 2023 IRP that compares its greenhouse gas emissions for 2019-2022 to the IRP 20-year forecast of the IRP emissions calculated in the same manner as the 2019-2022 emissions, which is presented as Staff Recommendation 24. The data for this graph would include emissions from market purchases and remove emissions from market sales. Staff argues that Idaho Power is not subject to the emissions reduction requirements of House Bill 2021 and it should be allowed to remove market sales from its emissions forecasts. Staff contends that it may be difficult to calculate a precise system emissions factor for each hour from 2019-2022 and apply it to actual market sales. Staff asserts that Idaho Power has not provided any support for its claim of technical impossibility. Staff offers two methods for Idaho Power to consider for complying with the recommendation. Idaho

[15] Renewable Energy Coalition Comments on Staff's Report and Recommendations at 1-2 (Nov. 18, 2022).
[16] Staff Report at 23-24.
[17] Idaho Power Company Comments on Staff Report at 9-10.

Power argues that while Staff provided two methods for it to consider, it did not address methods to estimate emissions associated with market purchases. Idaho Power maintains that it is even more difficult to capture emissions from purchases, because the company would need to know the temporal emissions intensity of each zone from which the company purchases power. Idaho Power contends that this information is unlikely to be available. Idaho Power proposes to modify Staff Recommendation 24 to direct the company to calculate the emissions for the IRP 20-year forecast in "a reasonably similar method" to that used for the 2019-2022 emissions.

IV. DISCUSSION

A. IRP Acknowledgment

In its 2021 IRP, Idaho Power requests that we acknowledge 13 action plan items, including those related to its B2H project. We have previously acknowledged action plan items related to the B2H project as part of prior Idaho Power IRPs, including the most recent 2017 and 2019 IRPs and back to our acknowledgment of the 2009 IRP.[18] At that time, in docket LC 50, we noted that there was uncertainty around the key assumptions of the B2H project, but concerns around this uncertainty were tempered by the risk analyses showing that the B2H portfolio was the best portfolio over a range of scenarios.[19] We have continued to follow that approach in subsequent IRPs. We have also acknowledged B2H project action plan as part of PacifiCorp's 2021 IRP, where B2H was part of the preferred portfolio for PacifiCorp's customers.[20, 21]

Portfolios containing the B2H project have remained robust over the range of market and industry contexts and modeling approaches across what now is seven IRPs. This consistent presence in least cost, least risk portfolios speaks to the optionality of transmission as a resource, and leads to a reasonable expectation of continued value for utility customers into the long-term future. However, the risk in this long history of evaluation is complacency, arising as a willingness to assume without fresh scrutiny that past conclusions hold. This risk could be exacerbated by the weight of the corporate and

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[18] *In the Matter of Idaho Power Company, 2019 Integrated Resource Plan*, Docket No. LC 74, Order No. 21-184 at 11, 14-17 (Jun. 4, 2021); *In the Matter of Idaho Power Company, 2017 Integrated Resource Plan*, Docket No LC 68, Order No. 18-176 at 9-11 (May 23, 2018).

[19] *In the Matter of Idaho Power Company, 2009 Integrated Resource Plan*, Docket No. LC 50, Order No. 10-392 at 9 (Oct. 10, 2010).

[20] *In the Matter of PacifiCorp, dba Pacific Power, 2021 Integrated Resource Plan*, Docket No. LC 77, Order No. 22-178 at 5, 11 (May 23, 2022).

[21] On December 14, 2022, STOP B2H filed a request for clarification regarding a statement that Commissioner Letha Tawney made during deliberations at the December 6, 2022 Special Public Meeting regarding the B2H action items in PacifiCorp's last IRP. For IRP proceedings, the Commissioners deliberate in open public meetings and the decision is reflected in a written order issued at a later date. The written order will broadly reflect the decision made at the public meeting, and as such, specific statements made during deliberations may not appear in the written order.

public resource investment in the lengthy permitting history of this project and the ensuing pressure to see the project through.

We are satisfied that the rigorous scrutiny we have applied in prior IRPs was continued here through Staff's and other parties' review, as well as through our public meeting process. Staff and STOP B2H brought appropriately renewed skepticism to modeling inputs, methods, and results. After reviewing these concerns carefully ourselves, we conclude that none of the continuing or new uncertainties are significant enough to erode fundamentally our confidence that the preferred portfolio and action plan containing the B2H project represent the "best combination of cost and risk for the utility and its customers * * * consistent with the long-run public interest as expressed in Oregon and federal energy policies."[22] For the reasons that follow, and for the time period relevant to this IRP, we conclude that the B2H inputs, Mid-C prices, and the cost of alternative resources and portfolios were reasonably modeled.

Regarding its project cost estimates, Idaho Power confirmed that it performed a comprehensive update of all material cost inputs for B2H in late 2020, and ownership changes in 2021. In particular, steel prices were included in the update; though they had increased in late 2020, the increase had a relatively small impact on the total project cost. We explored this point in more detail at the public meeting, and Idaho Power represented that steel costs are a relatively small proportion of the overall project costs due to the method by which the transmission towers are engineered and optimized. While circumstances may continue to change throughout the course of the IRP, inputs need to be locked at some point in order to perform full IRP modeling. The time frame Idaho Power used was reasonable for the 2021 IRP. In addition, we inquired at a high level as to how cost numbers had changed at the time of our review, with the cost inputs filed more recently in docket PCN 5 providing a counterpoint. After clarifying the use of contingencies across these two simultaneously pending dockets, as well as between portfolios containing B2H and the best performing non-B2H portfolios, which also contain significant high-voltage transmission segments such as Gateway West, we are comfortable that the 2021 IRP modeling results remain reasonable. Specifically, the cost delta between the B2H and non-B2H portfolios remains significant, even as the cost of B2H is both, firmer and higher in the later-filed PCN 5 proceeding.

Through this inquiry, Idaho Power clarified that the IRP's elimination of a transmission cost contingency for B2H in the portfolio comparison analyses was designed for comparability to the alternative portfolios that contain a similar scale of new high voltage transmission. These alternative transmission projects also did not contain cost contingency adders, and generation resources are modeled without cost contingencies

[22] Order No. 21-184 at 2.

despite being subject to the risk of cost increases. Although this approach may have caused confusion, we are satisfied that it yielded a reasonable comparison of the various portfolios. Additionally, the 10, 20, and 30 percent contingency sensitivities provided with respect to the B2H project demonstrate transparency on how the overall costs of that project may change.[23] This helps supplement the understanding of the variability of that project, even though the modeling results for comparison purposes did not incorporate that variability. Idaho Power clarified at the December 6, 2022 Special Public Meeting that the analysis was handled in this way because costs in the non-B2H portfolios would increase in a correlated manner with the B2H contingency since those portfolios also relied on transmission, preserving the delta observed in the portfolio comparison.

We also inquired further into Staff's analysis of Mid-C prices, and we appreciate the additional effort Staff and Idaho Power made to stress-test the B2H portfolios against higher observed market prices than were modeled in the IRP. We understand the complexity of varying prices at a market hub within a modeling environment that endogenously produces market prices, and we appreciate the work Staff and the company did in this docket to develop a method to verify that model results were not fundamentally changed when tested against higher Mid-C prices observed in 2021 and forecast into the future. We discuss below both our consideration of the endogenous approach to setting Mid-C prices and the importance of ensuring that the next IRP develops a way to demonstrate how greater volatility impacts planning and procurement.

Finally, we examined the way Idaho Power modeled the costs and risks of alternative portfolios, and we concluded that the company's approach was reasonable. Non-B2H portfolios selected significant high-voltage transmission lines that carry similar price risks and modeling a high cost for CCCTs reasonably reflected a climate policy risk incremental to that modeled in the base carbon prices. As for the impacts of the IRA legislation on renewable energy resources, these were not reasonably predictable in 2021. Even as these impacts become clearer, they are likely to have the most significant impact on Idaho Power's relative reliance on market purchases versus physical renewables for energy—not the relative cost and risk of batteries versus transmission for capacity.

Although Staff ultimately recommended acknowledgment of the B2H action plan items, and we agree based on our review of the areas described above, we appreciate Staff identifying questions and concerns with these action plan items. Staff's questions recognize the need for ongoing scrutiny and the reality that the reasonableness of inputs and modeling approaches continues to change along with the industry and market context.

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[23] *See* Idaho Power Company 2021 Integrated Resource Plan at 145, Figure 10.9 (Dec. 30, 2021).

Having detailed the reasons for our decision to acknowledge the 2021 IRP, we conclude by detailing two important caveats to our acknowledgement decision. The first is the limits of acknowledgment and the remaining responsibility the company carries in its own future analysis of the project and our rate making process. The second is our recognition that IRP acknowledgment does not control our certification of public convenience and necessity (CPCN) decision—a decision that must be made on a different record and under different standards.

As to the first, as explained above, acknowledgment is not a guarantee of future cost recovery but is the Commission's finding that the utility's preferred portfolio and action plan is reasonable at the time of acknowledgment.[24] We have discussed the meaning and role of acknowledgment in many different orders and proceedings and, given the context, select a quotation from the Commission's order in docket LC 50 to express our continuing expectations for the company:

> "We always expect utilities to update their assessments of previously acknowledged projects that are still in the planning or development stages at the time of an IRP acknowledgement. * * *. [W]e reiterate that at the time of ratemaking any utility is required to show that its investment was a prudent decision. Given the inherent risk associated with a transmission facility and the possibility of escalating costs and delays in permitting, the Company will need to address any significant changes in construction cost, equity partnership, or expected third-party subscription and how these factors influenced the Company's subscription and how these factors influenced the Company's decision to continue with the project."[25]

This statement holds today and is particularly important, because although IRPs are updated frequently, they must always contend with lagging information between the IRP's development and our decision. Our decision to acknowledge also may precede a utility's final decision to move forward with procurement or construction, and circumstances may also have changed during that time period. The IRP process also includes more limited discovery rights for parties than the ratemaking process provides. This information asymmetry between the data utilized for modeling and current data, between current data and data available at the moment of utility-decision making, and between those who review IRPs and the company are practical reasons why acknowledgment cannot be preapproval for ratemaking. Utility decision making regarding investments is disciplined by the company's obligation to ensure, at the time that they make a decision to proceed or not, that the decision is reasonable and prudent in light of the best and most up-to-date information then available.

[24] Order No. 07-002 at 16.
[25] Order No. 10-392 at 9-10.

Staff's questions and concerns in this docket should inform ongoing analysis of the project by Idaho Power, Staff, and stakeholders as commencement of construction nears. In particular, analysis occurring in the 2023 IRP and internal to the company should also include scrutiny of project cost assumptions, the Mid-C market price assumptions, and the costs of alternative resources. Of course, many elements relevant to prudence review may not emerge in the IRP analysis, such as procurement specifics, deal structure, and project execution. We will be particularly interested in these, and in the relative risk balance reflected in agreements with PacifiCorp and the Bonneville Power Administration when we assess prudence and cost recovery.

We emphasize once again, as we did in Idaho Power's last IRP and in previous orders, that the company should continue to intensively monitor and evaluate the expected costs, risks, and benefits of the B2H project. We note that some of the sensitivities reviewed in this process indicate a significant reduction of the expected benefits of B2H under certain circumstances and that significant cost increases or cost overruns related to the project could have changed the outcome of Idaho Power's primary least-cost analysis, if those cost drivers were absent for other generation sources. Given the significant investment associated with this project and the nature of the project, which spans hundreds of miles and could be expected to encounter unforeseen circumstances and challenges, it is critical that the company take a realistic and hard look at all costs and contingencies before determining that the project is justified. We encourage Idaho Power to closely review the issues raised by Staff and other stakeholders over the course of these proceedings, as these same issues are likely to be raised and explored in a future prudence review. We also expect that the company will document and make its ongoing analyses of the costs and risks of the project available for review by the Commission and others for future proceedings.

As to the second caveat, we note that, just as the IRP and prudence review are related proceedings but not the same, so too are the IRP and CPCN review. Certainly, acknowledgment decisions and other information from IRPs will be relevant to the proceedings in docket PCN 5; our rules require us to give "due consideration" to other regulatory processes. However, these two proceedings are based on different standards, call for different considerations, and may involve different parties and evidence.[26] We must take a broader view of both benefits and impacts in docket PCN 5 than we take here, where we conclude only that the preferred portfolio and action plan containing the B2H project represent the "best combination of cost and risk for the utility and its

[26] We note, for instance, that we do not view as a substantive issue *for the IRP*, Idaho Power's action plan statement that it would petition for a CPCN after project agreements are finalized, nor do we take issue with Idaho Power's modification to reflect its filing in docket PCN 5 before finalizing the agreements. Our view of the IRP action item has no bearing, however, on how we might approach arguments made in docket PCN 5 about the completeness and sufficiency of Idaho Power's CPCN filing.

customers * * * consistent with the long-run public interest as expressed in Oregon and federal energy policies."[27]

B. Staff Recommendations

As discussed in further detail above, Staff made 26 recommendations regarding Idaho Power's IRP, and Idaho Power accepted most of these, some with modification. STOP B2H objected to a few of Staff's recommendations, though its objections were primarily related to the B2H issues already discussed in this order. We accept Idaho Power's edits to Staff Recommendations 5, 15, 23, and 24 consistent with our deliberations at the December 6, 2022 Special Public Meeting.

For Staff Recommendation 8, we adopt Staff's language presented at the November 29, 2022 Special Public Meeting and as modified during deliberations at the December 6, 2022 Special Public Meeting. As discussed during deliberations, we seek additional insight into the seasons and hours when Idaho Power expects to buy versus when it expects to sell energy to further weigh the reasonableness and risk profile of modeling results and the preferred portfolio. Generally high or low market prices are less material than understanding how the apparent opportunity to sell excess energy at a premium or a downplayed risk of exposure to buying energy at a premium might skew a preferred portfolio. In particular, we have noted that Idaho Power's endogenous market prices are low, in accordance with expectations for a Western Energy Coordinating Council wide buildout of zero marginal cost renewables. We have noted the limitations of the exogenous market price forecast that PacifiCorp uses in its IRP in capturing this dynamic.[28] However, the general trend for lower prices does not mean energy in all hours will be low cost. High-stress time periods might have substantially higher prices than seen in the past. Whether Idaho Power is facing the need to buy during those regionally stressed hours—or is position to sell—fundamentally alters the risks embedded in a preferred portfolio. Thus, market price forecasts that explore the bookends of the pricing risks during this significant transition in the generation fleet is important. These concerns do not impact our acknowledgment of the 2021 IRP, because the current portfolio performs well or can be adapted to a wide range of market price futures. We expect Idaho Power to provide additional clarity on the liquidity at Mid-C for their high need hours, as well as some analysis of their high need hours over time and how that matches expected liquidity at the market. We also expect that Idaho Power will provide an analysis regarding how much the company can reasonably expect to sell. Accordingly, Staff Recommendation 8 is modified as follows: "Direct Idaho Power to work with stakeholders and demonstrate the impact of extremely high wholesale

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[27] Order No. 21-184 at 2.

[28] *See In the Matter of PacifiCorp, dba Pacific Power, 2019 Integrated Resource Plan*, Docket No. LC 70, Order No. 20-186 at 18-19 (Jun. 8, 2020) (discussing market price curves).

electricity prices and decreased liquidity on resource selection in the 2023 IRP. In addition, Idaho Power shall provide insight into volatility and need."

For Staff Recommendation 20, we adopt Staff's recommendation and add additional language to include the implications for capacity contracts as discussed at the December 6, 2022 Special Public Meeting. As discussed during deliberations, we seek additional information from the company regarding how the Western Resource Adequacy Program (WRAP) may alter transmission assumptions as it relates to capacity contracts. WRAP will require participating utilities to have firm transmission, which is likely to create a transmission shortage.[29] It is important that we understand how this requirement for firm transmission affects transmission assumptions and sensitivities, particularly for forward-looking capacity contracts. Accordingly, Staff Recommendation 20 is modified as follows: "Direct Idaho Power to continue to explore how participating in the WRAP may alter transmission assumptions and implications for capacity contracts."

V. ORDER

IT IS ORDERED that the Integrated Resource Plan filed by Idaho Power Company is acknowledged as described with the terms of this order and the attached Appendix A.

Made, entered, and effective Jan 13 2023.

Megan W. Decker Chair	**Letha Tawney** Commissioner
	Mark R. Thompson Commissioner

[29] *See Northwest Power Pool*, *Western Power Pool Western Adequacy Program Tariff*, Docket No. ER22-2762, Western Resource Adequacy Program Tariff of Northwest Power Pool, dba Western Power Pool, Section 16.3.1 (Aug. 31, 2022).

ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
SPECIAL PUBLIC MEETING DATE: November 29, 2022

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** __N/A__

DATE: October 28, 2022

TO: Public Utility Commission

FROM: Eric Shierman

THROUGH: Bryan Conway, JP Batmale, and Kim Herb

SUBJECT: IDAHO POWER COMPANY:
(Docket No. LC 78)
Acknowledgement of the 2021 Integrated Resource Plan.

STAFF RECOMMENDATION:

Acknowledge Idaho Power Company's 2021 Integrated Resource Plan, except for Action Plan Items that have already been substantially completed, and approve Staff's recommendations for the 2023 IRP.

SUMMARY OF STAFF RECOMMENDATIONS REGARDING THE ACTION PLAN:

Below are the Company's Action Plan items and Staff's associated recommendations regarding acknowledgement. Dates in parentheses are taken from the Action Plan target year. All recommendations are for the 2021 IRP unless stated otherwise.

2021 IRP Action Plan Action Items:

1. Conduct ongoing Boardman to Hemmingway (B2H) permitting activities. Negotiate and execute B2H partner construction agreements. Once the agreements are in place, file for a certificate of public convenience and necessity with state Commissions. (2022)
   Recommendation: Acknowledge

2. Discuss partnership opportunities related to SWIP-North with the project developer for more detailed evaluation in future IRPs. (2022)
   Recommendation: Acknowledge with conditions

3. Jackpot Solar is contracted to provide 120 MW starting December 2022. Work with the developer to determine, if necessary, mitigating measures if the project cannot meet the negotiated timeline. (2022-2023)
   Recommendation: Not acknowledge due to substantial completion

4. Plan and coordinate with PacifiCorp and regulators for conversion to natural gas operation with a 2034 exit date for Bridger units 1 and 2. The conversion is targeted before the summer peak of 2024. (2022-2024)
   Recommendation: Acknowledge

5. Issue a Request for Proposal (RFP) to procure resources to meet identified deficits in 2024 and 2025. (2022-2025)
   Recommendation: Not acknowledge due to substantial completion[1]

6. Plan and coordinate with PacifiCorp and regulators for the exit/closure of Bridger Unit 3 by year-end 2025 with Bridger Unit 4 following the Action Plan window in 2028. (2022-2025)
   Recommendation: Acknowledge

7. Redesign existing Demand Response (DR) programs then determine the amount of additional DR necessary to meet the identified need. (2022-2025)
   Recommendation: Acknowledge

8. Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project. (2022-2026)
   Recommendation: Acknowledge

9. Implement cost-effective energy efficiency measures each year as identified in the energy efficiency potential assessment. (2022-2027)
   Recommendation: Acknowledge

10. Work with large-load customers to support their energy needs with solar resources.
    Recommendation: Acknowledge

11. Finalize candidate locations for distributed storage projects and implement where possible to defer T&D investments as identified in the Action Plan. (2022-2027)

[1] Per Order No. 14-252, acknowledgment requests should occur before the required project is substantially completed. Staff's recommendation not to acknowledge an Action Item that is already complete or will be substantially complete by the time the Commission issues its acknowledgment order does not necessarily indicate lack of support for the Action Items.

Recommendation: Acknowledge 29 MW of the 40 MW in the Preferred Portfolio Not acknowledge 11 MW that have already been secured.

12. Exit Valmy Unit 2 by December 31, 2025. (2025)
Recommendation: Acknowledge

13. Subject to coordination with PacifiCorp, and B2H in-service prior to summer 2026, exit Bridger Unit 3 by December 31, 2025. (2025-2026)
Recommendation: Acknowledge

DISCUSSION:

Issue

Whether the Oregon Public Utility Commission (Commission) should acknowledge Idaho Power Company's (Idaho Power, IPC, or the Company) 2021 Integrated Resource Plan (IRP, 2021 IRP), acknowledge specific portions of the IRP with or without certain conditions, or decline to acknowledge the IRP.

Applicable Rule

The Commission adopted least-cost planning as the preferred approach to utility resource planning in 1989.[2] In 2007, the Commission updated its existing least-cost planning principles and established a comprehensive set of "IRP Guidelines" to govern the IRP process. The IRP Guidelines found in Order Nos. 07-002 (corrected by 07-047), 08-339, and 12-013 clarify the procedural steps and substantive analysis required of Oregon's regulated utilities for the Commission to consider acknowledgement of a utility's resource plan.[3] Also applicable to the review of Idaho Power's 2021 IRP is whether it complies with all of the Commission requirements in its previously acknowledged IRPs: LC 68 and LC 74.

The IRP Guidelines and Commission rules require a utility to file an IRP with a planning horizon of at least 20 years within two years of its previous IRP acknowledgment order, or as otherwise directed by the Commission.[4] Further, the IRP must also include an "Action Plan" with resource activities that the utility intends to take over the next two to

[2] See Docket No. UM 180, OPUC, Order No. 89-507, April 20, 1989.
[3] See Docket No. UM 1056, OPUC, Order No. 07-002, January 8, 2007;
See Docket No. UM 1056, OPUC, Order No. 07-047, February 9, 2007;
Additional refinements to the process have been adopted: *See* Order No. 08-339 (Refining IRP Guideline 8 to specify how utilities should treat carbon dioxide (CO_2) risk in their IRP analysis); Order No. 12-013 (Adding guideline directing utilities to evaluate their need and supply of flexible capacity in IRP filings).
[4] Order No. 07-002 (Guidelines 1(c) and 3(a)) and OAR 860-027-0400.

four years.[5] The ultimate goal of the IRP is to select the "portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[6] This is often referred to as the "least cost/least risk portfolio."

The Commission reviews the utility's plan for adherence to the procedural and substantive IRP Guidelines and generally acknowledges the overall plan if it is reasonable based on the information available at the time the Commission decides whether to acknowledge, as the Commission states in Order No. 07-002: "[a]cknowledgment of the company's plan means only that we consider it reasonable at the time of our decision."[7] The Commission also explains "[w]e may also decline to acknowledge specific action items if we question whether the utility's proposed resource decision presents the least cost and risk option for its customers."[8] The Commission may also decline to acknowledge specific Action Items if they are complete or substantially complete by the time the Commission issues its acknowledgment order.[9]

Analysis

Procedural History
Prior to filing the 2021 IRP on December 30, 2021, Idaho Power held twelve IRP Advisory Council (IRPAC) meetings. IRPAC members represent various public agencies, public and private enterprises, and advocacy groups. The IRPAC covers aspects of the IRP development, particularly on the resource stack, resource portfolio considerations, and risk analyses. Staff appreciates the stakeholder process, stakeholder involvement, and Idaho Power's time and energy in fulfilling the public input component of the Company's IRP process.

The Company's Plan includes four appendices.[10] Appendix A covers the sales and load forecast. Appendix B is an annual report on demand-side management. Appendix C provides additional technical details behind the IRP. And Appendix D is a transmission supplement that was filed on February 16, 2022.

Normally Staff and other parties must file their comments and recommendations within six months of the IRP filing.[11] On February 17, 2022, Staff filed for an extension of the review time for this IRP. On April 6, 2022, Administrative Law Judge Sarah Spruce

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[5] See Docket No. LC 56, OPUC, Order No. 14-415, December 2, 2014, p 3.
[6] See Docket No. UM 1056, OPUC, Order No. 07-002, January 8, 2007, pp 1-2.
[7] Ibid. p 16.
[8] Ibid. p 1.
[9] See Docket No. LC 56, OPUC, Order No. 14-415, December 2, 2014, p 7.
[10] The appendices are the "Sales and Load Forecast," the "Demand-Side Management 2018 Annual Report," the "Technical Appendix," and the "Boardman to Hemingway Update."
[11] See OAR 860-027-0400(5)

approved a procedural schedule that has the Commission consider acknowledgement of the 2021 IRP almost a year after Idaho Power filed.

The procedural schedule for this docket has included two rounds of comments and a workshop attended by the Commissioners and Administrative Law Judge on August 18, 2022. Staff, the Citizens' Utility Board (CUB), the Renewable Energy Coalition (REC), Renewable Northwest, (RNW), and the STOP B2H Coalition (STOP) filed Opening Comments on July 7, 2022. Idaho Power filed Reply Comments on August 4, 2022. The same parties filed Final Comments on September 8, 2022, and the Company engaged those comments with Reply Comments on September 23, 2022.

Staff organizes this report by first discussing the Action Items in the Action Plan, followed by additional issues raised by parties and recommendations for the 2023 IRP.

Action Item Discussion

Below is a summary of Idaho Power's Action Plan Items in the 2021 IRP.

Summary of Idaho Power 2021 Action Plan Items by Category	
Category	**Action Plan Item with Associated Action Item Number**
Jim Bridger Early Exits	Action Item 4: Plan and coordinate with PacifiCorp and regulators for conversion to natural gas operation by the summer peak of 2024, with a 2034 exit date for Bridger units 1 and 2.
	Action Item 6: Plan and coordinate with PacifiCorp and regulators for the exit/closure of Bridger Unit 3 by year-end 2025 with Bridger Unit 4 following the Action Plan window in 2028.
	Action Item 13: Subject to coordination with PacifiCorp, and B2H in-service prior to summer 2026, exit Bridger Unit 3 by December 31, 2025.
Southwest Intertie Project (SWIP)-North	Action Item 2: Discuss partnership opportunities related to SWIP-North with the project developer for more detailed evaluation in future IRPs.
B2H	Action Item 1: Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreements. Once the agreements are in place, file for a certificate of public convenience and necessity with state Commissions. Action Item 8: Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.
2024/2025 RFP	Action Item 5: Issue a Request for Proposal (RFP) to procure resources to meet identified deficits in 2024 and 2025.

Demand-Side Resources	Action Item 7: Redesign existing DR programs then determine the amount of additional DR necessary to meet the identified need. Action Item 9: Implement cost-effective energy efficiency measures each year as identified in the energy efficiency potential assessment.
Large-Load Solar	Action Item 10: Work with large-load customers to support their energy needs with solar resources.
Distributed Storage	Action Item 11: Finalize candidate locations for distributed storage projects and implement where possible to defer T&D investments as identified in the Action Plan.
Valmy Unit 2 Exit	Action Item 12: Exit Valmy Unit 2 by December 31, 2025.
Jackpot Solar	Action Item 3: Solar is contracted to provide 120 MW starting December 2022. Work with the developer to determine, if necessary, mitigating measures if the project cannot meet the negotiated timeline.

Jim Bridger Early Exits

Action Items 4, 6, and 13 regard early exits from Jim Bridger coal units. Target dates for early exits involve converting units 1 and 2 to gas before the summer peak of 2024. Coordinating with PacifiCorp and regulators, Idaho Power will plan for the exit/closure of Bridger unit 3 by year-end 2025 and will plan for Bridger unit 4 exit/closure to occur in 2028.

Idaho Power's Analysis

The Jim Bridger coal plant contributes substantially to Idaho Power's generating capacity, and the retirement dates of the Jim Bridger units are important drivers of resource selections in the 2021 IRP. The results of the Company's long-term capacity expansion (LTCE) modeling indicate that the conversion of units 1 and 2 to natural gas in 2023 and exits for units 3 and 4 year-end 2025 and 2028, respectively are economical. Idaho Power also performed validation and verification studies around the Bridger conversions and coal exit dates to explore the robustness of these modeling outcomes.

Stakeholder Positions

CUB

On the Bridger coal to gas conversion, CUB recommends the acknowledgement of the Jim Bridger 1 and 2 conversion and exit Action Item with conditions consistent with PacifiCorp 2021 IRP Order. Those include a long-term fueling plan for Jim Bridger in the 2023 IRP and the exploration of a green hydrogen fueling option. CUB also notes that "[s]hould fueling options change for PacifiCorp, Idaho Power might need to remodel conversions and exits of JB 1 and 2 in its IRP portfolio analysis."[12]

RNW
RNW recommends that Idaho Power reconsider the gas conversion of the Bridger units 1 and 2 in favor of hybrid and standalone storage resources. The recommendation stems from RNW's belief that the capacity contribution of gas resources is overstated due to not applying the effective load carrying capability (ELCC) methodology to thermal assets, as well as the increased gas prices. Reliability concerns associated with the converted gas units' capacity contribution are based on the projected use of the units during peak demand hours that coincide with hours when the probability of correlated, weather-related outages is high. Furthermore, the increased gas prices pose the risk of cost overruns. RNW recommends Idaho Power study the cost-effectiveness of the conversion as part of the 2023 IRP, considering those two factors. RNW further recommends that stakeholders be involved in this "holistic techno-economic study" and that there be transparency around portfolio costs with and without coal to gas conversion. This study should include modeling runs that use capacity values of thermal resources that are lower than what was assumed in the 2021 IRP.

<u>Idaho Power's Position</u>
The Company disagrees with RNW's recommendation to conduct a techno-economic study for Jim Bridger Gas Conversion. Idaho Power believes the 2021 IRP was an economic study for Jim Bridger gas conversion. In the 2021 IRP, the Company evaluated the exit from Bridger Units 1 and 2 by the end of 2023 and reported those results in the 2021 IRP. The findings of that evaluation showed that 400 MW of solar and storage resources would be necessary to replace the two units. Furthermore, the Company notes that additional studies were conducted on the Jim Bridger gas conversion by the Wyoming Department of Environmental Quality after proposing a 2022 State Implementation Plan (SIP) Revision that requires the Jim Bridger gas conversion. This was a four-factor regional haze reasonable progress analysis that evaluated the impacts and reasonableness of the gas conversion. Considering these studies have already been conducted, the Company does not believe additional analysis is necessary.

The Company acknowledges RNW's recommendation to model thermal resources' capacity values using the ELCC methodology and contends that the 2021 IRP did apply an ELCC methodology to thermal resources. The Company plans on continuing to work with stakeholders to improve the methodology of modeling resources for the 2023 IRP.

[12] See Docket No. LC 78, CUB, Final Comments, September 8, 2022, p 6.

Staff's Analysis and Recommendations

Staff reviewed Idaho Power's customized tool for modeling resource ELCC. Staff can confirm the Company did not simply plug in a firm capacity contribution for the converted gas units.[13] With respect to analysis for the 2023 IRP, Staff plans to work with stakeholders to further review this new use of an old method. We encourage RNW and other stakeholders to participate in the upcoming IRPAC process and Commission review of this methodology in the next IRP.

Staff Recommendations:

Recommendation 1: Acknowledge Action Item 4: Plan and coordinate with PacifiCorp and regulators for conversion to natural gas operation with a 2034 exit date for Bridger Units 1 and 2. The conversion is targeted before the summer peak of 2024.

Recommendation 2: Acknowledge Action Item 6: Plan and coordinate with PacifiCorp and regulators for the exit/closure of Bridger Unit 3 by year-end 2025 with Bridger Unit 4 following the Action Plan window in 2028.

Recommendation 3: Acknowledge Action Item 13: Subject to coordination with PacifiCorp, and B2H in-service prior to summer 2026, exit Bridger Unit 3 by December 31, 2025.

SWIP-North

Action Item 2 regards discussing partnership opportunities related to the northern route of the Southwest Intertie Project (SWIP-North) with the project developer for more detailed evaluation in future IRPs.

Idaho Power's Analysis

A major difference in the assumptions of the 2019 IRP and the 2021 IRP is Idaho Power's incorporation of transmission capacity constraints that are a ripple effect of an August 2020 heat wave in California that caused Western Interconnection balancing authorities to declare energy emergencies. Since that time, third-party marketing firms operating just outside Idaho Power's service area have reserved large amounts of firm

[13] IPC modeled the capacity contribution of these gas units as an effective forced outage rate, using empirically derived inputs in accordance with the method described in Roy Billinton and Ronald Allan's 1984 *Reliability Evaluation of Power Systems*.

transmission capacity. This operational change has impacted Idaho Power's ability to use third-party transmission lines to import energy. This effect, which is mostly concentrated in Idaho Power's southern territory, reduced the transmission availability from about 900 MW to approximately 710 MW. The construction of SWIP-North may restore Idaho Power's firm access to southern wholesale markets.

Idaho Power tested a portfolio that included an investment in SWIP-North to procure firm capacity on this new transmission line as an equity partner. This SWIP-North portfolio is the only portfolio that met the Company's loss of load expectation (LOLE) minimum reliability standard without relying on a simple cycle combustion turbine outside the portfolio to meet unserved demand. Idaho Power did not select this SWIP-North portfolio as the Preferred Portfolio, because the Company had no information on whether an opportunity to invest in this project is available.

Staff's Opening and Final Comments

In Opening Comments, Staff expressed concern about the lack of comprehensive analysis of how transmission congestion may change due to other new transmission projects planned outside the Company's balancing area that could provide opportunities for firm transmission. Staff has emphasized the impact of a specific line, the NVE Greenlink Project, which is building 525 kV lines west and south of Reno, Nevada. These lines could relieve the congestion south of Valmy that has blocked Idaho Power's firm access to southern wholesale markets.

Understanding how the Greenlink lines and SWIP-North may interact will be an important analytical compliment to the Company's proposed Action Item. The combination of the two projects may provide enough average transmission capacity (ATC) south of Valmy for Idaho Power to increase the Company's assumed import capacity without the need to make capital expenditures in SWIP-North. In Final Comments, Staff recommended Idaho Power study the impact of the Greenlink transmission projects in reducing congestion between Idaho Power's service territory and southern wholesale energy markets.

Idaho Power's Position

In Opening Reply Comments, Idaho Power recognized potential opportunities to access southern market hubs via the SWIP-North and NVE Greenlink transmission projects. The Company stated it would continue to monitor transmission opportunities in Nevada and perform more detailed evaluation of the SWIP-North project.

In response to Staff's recommendation in Final Comments, IPC stated the Company agrees with Staff's recommendation and will continue to monitor the Greenlink projects. For the 2023 IRP, Idaho Power further stated the Company will initiate a dialogue with

NV Energy exploring the potential of the Greenlink projects to create ATC across the NV Energy system to the Idaho Power border.

Staff's Analysis and Recommendations

Gathering information on investment opportunities is naturally a reasonable proposition, but Idaho Power should consider more than just ownership in SWIP-North. Idaho Power should establish a planning threshold of ATC that can be reasonably assumed to provide firm import capacity. In the next IRP, Staff suggests the Company model how transmission projects to its south may create sufficient capacity to only pay open access transmission tariffs (OATT) when needed rather than assume the hazards of ownership, like becoming an investor in SWIP-North.

Staff recommends the Commission acknowledge Action Item 2, and the Company agrees with Staff's recommendation to study the impact of the Greenlink project. These two recommendations will complement each other as the Company plans for the restoration of firm market purchases from southern wholesale markets.

Staff Recommendation:

Recommendation 4: Acknowledge Action Item 2: Discuss partnership opportunities related to SWIP-North with the project developer for more detailed evaluation in future IRPs with the condition that Idaho Power study the impact of the Greenlink transmission projects in reducing congestion between Idaho Power's service territory and southern wholesale energy markets.

Boardman to Hemingway (B2H)

Action Items 1 and 8 concern ongoing B2H permitting activities, negotiations with B2H partners, preliminary construction activities, acquiring long-lead materials, and constructing B2H.

Idaho Power's Analysis

The B2H project is a planned 500-kilovolt (kV) transmission project that would run between the Hemingway 500-kV substation near Marsing, Idaho, and the Longhorn substation near Boardman, Oregon.[14] The project has consistently been selected as part of the Company's Preferred Portfolio for over a decade. The Company maintains

[14] See Docket No. LC 74, Idaho Power, 2019 *Second Amended* IRP, October 2, 2020, Appendix D, p 1.

that B2H provides the least-cost option for its resource future, in addition to incremental ancillary benefits and additional operational flexibility.[15]

The 2019 *Second Amended* IRP portfolio selection process included a new methodology that created portfolios with and without B2H so that Idaho Power could compare the costs of a resource future with and without the transmission line. The 2021 IRP continues this approach, and the Company again has determined that B2H should be part of a least-cost/least-risk portfolio.

A significant change in the 2021 IRP is the Non-Binding Term Sheet that addresses B2H ownership, transmission service considerations, and asset exchanges executed by three B2H permit funding parties, Idaho Power, PacifiCorp, and Bonneville Power Administration (BPA). As part of the Term Sheet, Idaho Power will increase its B2H ownership to 45.45 percent by acquiring BPA's planned share of B2H capacity. In addition, Idaho Power will utilize a portion of its increased B2H capacity to provide transmission service to BPA's customers in southern Idaho. Idaho Power's analysis shows the revenue from BPA's OATT payments will cover the incremental cost to Idaho Power of a higher ownership share.

For Idaho Power, the transmission capacity the Company plans to reserve for itself is expected to behave like a bargain-price power plant. The Company believes B2H will deliver firm capacity with low fuel prices. The analogous fuel cost for this "power plant" is the wholesale power purchased from Mid-Columbia (Mid-C).

<u>Stakeholder Positions</u>

STOP B2H (STOP)
In its Opening Comments, STOP pointed out that there was no project budget documentation in 2021, as was found in the base budget developed in October 2016 for the 2017 IRP. STOP requested a complete and transparent budget with line items, so that the progression of costs from 2019 IRP to the 2021 IRP could be followed. STOP also questioned the accuracy of the budget, citing little escalation of cost estimates between the 2016 and the 2021 IRPs.

STOP did not receive the cost details it asked for in STOP Information Request (IR) 18 and repeated its request in Closing Comments. STOP asked for detailed cost estimates based on the financial headings presented in Idaho Power's 2021 IRP filing application. STOP stated in Closing Comments that, despite the Company's claim that Aurora does not have a scarcity pricing mechanism and hence cannot capture price spikes, some other method is needed to generate more accurate forward looking market prices.

[15] Ibid.

Given the significant price differences between the forecasted and actual Mid-C market prices, STOP questioned the reliability of the analysis that concluded the preferred portfolio with B2H is least-cost.

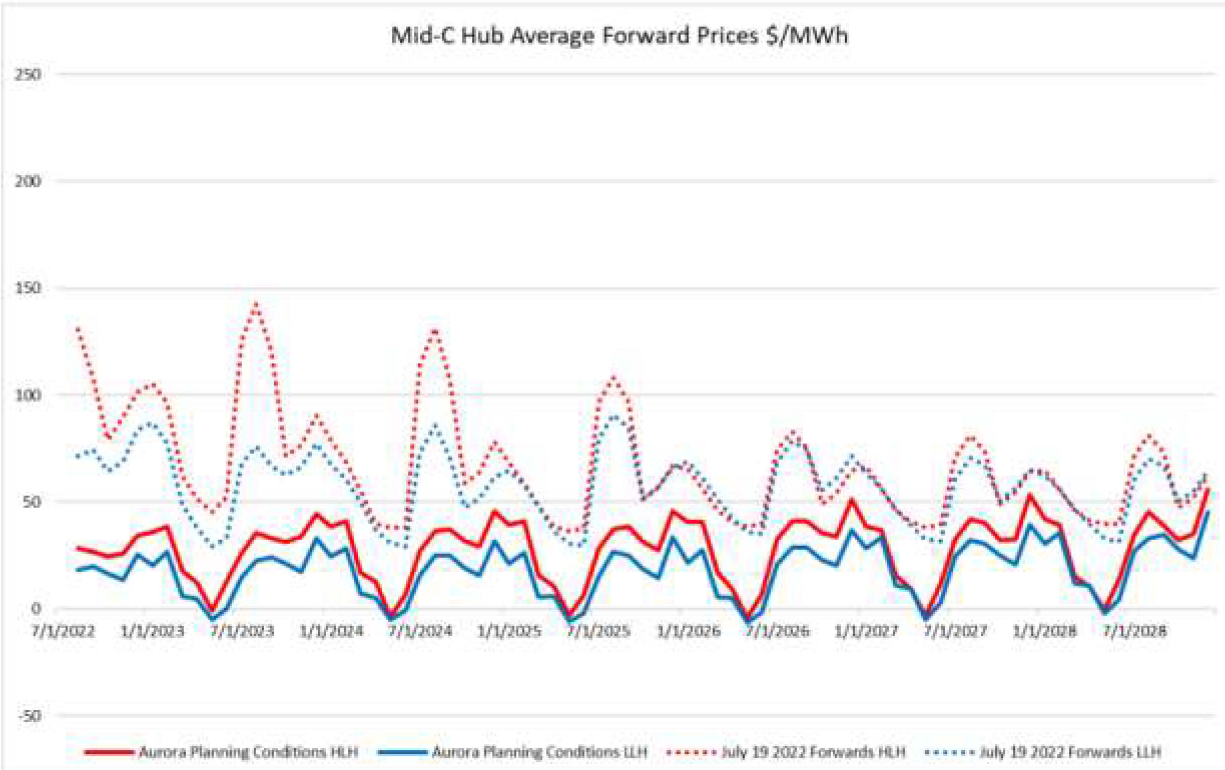
CUB
In Final Comments, CUB expressed concerns about inadequate firm transmission leading to reduced market purchases. Quoting Idaho Power's heavy reliance on regional power markets for capacity and energy needs, CUB recommended the Company incorporate risk analyses related to unavailability of market purchases and explore demand management measures that could potentially offset capacity needs.

<u>Staff's Opening and Final Comments</u>
Staff could continue to find B2H to be a reasonable investment. However, questions have arisen throughout the analysis of this IRP around three key elements supporting the B2H investment: Idaho Power's expected construction costs, forecasted Mid-C prices, and the accuracy of expected B2H costs relative to other resource alternatives' expected costs.

Construction Costs
Staff finds STOP has raised valid points about the construction cost of B2H being too preliminary and not being sufficiently updated since 2016. Other resources have more transparency for cost assumptions, and no other resource costs are priced in 2016 dollars. Idaho Power's modeling of a 30 percent cost contingency mitigates the risk of underestimation, but the cost contingency should be modeled off an updated price. The purpose of the 30 percent cost contingency is to account for the risk of cost overruns during construction, not to adjust for inflation. In Final Comments Staff recommended an updated assessment of B2H construction costs be presented in the 2023 IRP with greater granularity in cost components and greater transparency in underlying assumptions.

Mid-C Prices
The Mid-C prices Idaho Power modeled in the 2021 IRP are substantially lower than observed Mid-C prices. When the Company filed its 2021 IRP on December 30, 2021, the preceding months saw Mid-C prices significantly exceeding the highest estimates Idaho Power included in its stochastic risk analysis, let alone the Company's planning assumption. The current prices of Mid-C futures contracts, referred to in Figure 1 below as the forward price curve, suggests those high prices are indicative of a trend, rather than an anomaly associated with a single low hydro year. Figure 1 shows this trend persists past the window of the 2021 IRP's Action Plan. Persistent high prices in 2022 during a relatively normal hydro year, and the forward price curve show observed market prices that are significantly higher than the 2021 IRP's forecast.

Figure 1: Mid-C Forward Prices vs 2021 IRP Forecast[16]



Alternative Resource Costs

The 2021 IRP may overestimate the cost of alternative resources. Idaho Power's modeling of a combined cycle combustion turbine (CCCT) assumed capital costs of $1,656 per kW, a cost associated with plants running alternative fuels, such as hydrogen, rather than modeling a standard gas plant. Staff welcomes the consideration of alternative fuels for gas plants, but the standard technology should be considered as well. For non-emitting resources, the 2021 IRP assumes federal energy subsidies as they existed in 2021.

Given the numerous differences in circumstances existing at the time Idaho Power performed its modeling for the 2021 IRP and the circumstances known at the time the Commission will decide whether to acknowledge the 2021 IRP's Action Items, Staff recommended the Company rerun its modeling with updated inputs to confirm the robustness of the 2021 IRP's Preferred Portfolio. To accomplish this, Staff requested the Company use observed Mid-C prices, an assumed capital cost for CCCT plants of

[16] See Docket No. LC 78, Idaho Power, Opening Reply Comments, August 4, 2022, p 23.

$1,300 per kW, the updated nameplate capacity of existing DR programs from the 2022 peak season, and a select list of new IRA-related federal subsidies that require only a change in eligibility or expiration. Each of these inputs was selected because they are reasonably expected to have a material impact on resource selection. The Company was unable to perform the analysis as requested by Staff.

However, the Company was able to conduct some new analysis to inform the cost-effectiveness of B2H. After meeting with Staff, Idaho Power performed a stress test in Aurora to assess the cost-effectiveness of B2H under higher Mid-C prices than were previously considered. This new analysis shows B2H to be cost-effective in 18 of 20 model runs. However, the Company was not able to run Aurora with updated costs of alternative resources because the Company believes that the permitting of a CCCT cannot be accomplished within four years and the cost impacts of the IRA are too uncertain.

Finally, through both rounds of comments, Staff engaged Idaho Power on how the Company is seeking to obtain federal infrastructure funding. This resulted in Staff recommending Idaho Power document the Company's efforts to seek this funding through Docket No. RE 136.

<u>Idaho Power's Position</u>
In Final Reply Comments, the Company asserted that the B2H estimated cost was updated throughout 2021 as the Term Sheet was negotiated. IPC also stated that the cost naturally would not have included the inflation, labor, and supply chain increases experienced in 2022. The Company added that the impact on inflation in 2022 would not be isolated to the B2H project, but the cost of alternative resources would also experience the effect of inflationary conditions.

Idaho Power stated that the Company is working with its constructability consultant to update the B2H cost estimate in preparation for the 2023 IRP. Upon recommendation by Staff, the Company agreed to increase the transparency of the estimate in the 2023 IRP and, as such, report the 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.

In response to Staff's recommendation that the Company rerun the Aurora modeling with observed wholesale prices, Idaho Power claimed there is no way within the Company's model to fully update the wholesale prices without updating or overhauling the entire model. The Company stated that to update only the wholesale prices would bias the value of transmission resources while the remaining portions of the WECC model would remain based on planning conditions.

Regarding the high market prices, Idaho Power finds no surprise that actual market prices deviated from the 2021 IRP's modeled 2021 market prices because there were many more factors behind the deviations and not just low hydro conditions. The Company stated that it is "an impossible, unreasonable expectation ... that an IRP model anticipate unforeseeable events months after the filing of an IRP."[17]

It is more reasonable, the Company says, to compare the planning model with other estimates made contemporaneously. A comparison of prices in 2021 shows that Idaho Power's IRP forecast was consistent with other regional entities making similar forecasts during similar timeframes. The Company states the myriad of factors influencing electricity market prices may not be known or knowable even after they happen. As such, the Company and other entities use planning conditions to approximate the regional conditions and perform scenario and sensitivity analysis to emulate alternatives and unexpected events.

Regarding federal funding, the Company pointed out that the solicitation window for applicants to submit projects for grant money under the Infrastructure Investment and Jobs Act had not opened and that it would be monitoring that space. Idaho Power states the B2H project would unlikely qualify for those funds due to the high percentage of prescribed capacity in the negotiated term sheet of the project.

In response to Staff's request to consider federal funding for B2H, the Company stated that the U.S. Department of Energy was still working through approaches to release any funding, and the ability to apply for any funding was not expected to open until Q1 2023. The Company added that it would make every effort to acquire any available funds to offset B2H project costs, and that it was amenable to providing an update as requested by Staff through Docket No. RE 136.

Staff's Analysis and Recommendations

Staff's analysis of B2H covers a variety of topics. This has been broken down into subsections: construction costs, Mid-C prices, Aurora input updates, planning input updates, alternative resources, and federal funding.

Constructions Costs

While STOP and Idaho Power disagree on the reasonableness of the 2021 IRP's assumed construction costs for B2H, the Company has agreed to update this salient assumption in the 2023 IRP. Staff recommends the Commission memorialize Idaho Power's commitment as an Action Item, using the recommendation Staff made in Final Comments on the development of a fresh estimate of costs with detailed granularity.

[17] See Docket No. LC 78, Idaho Power, Final Reply Comments, September 23, 2022, p 16.

Mid-C Prices
Aurora is a tool for predictive modeling. The ultimate benchmark of the Company's reasonableness in the use of this tool is how well the Company predicts market conditions. Staff believes Idaho Power's Aurora modeling accuracy can be improved in the next IRP. Updating with the latest modeling inputs, where and when possible, is in the interest of the customers and the Company. Further, while Staff appreciates the amount of time it takes to develop an IRP, and the importance of engaging stakeholders on IRP modeling inputs and assumptions to materially inform planning, efforts should be made to reflect those updates within reason. The way Idaho Power uses Aurora may require modifications to predict Mid-C prices more accurately. For example, Aurora can exogenously model wholesale energy prices, which may provide a path for more accurate modeling. Staff will work with the Company on this for the 2023 IRP.

Planning Input Updates
Staff believes it is important to note that references to the "reasonable at the time" standard in the IRP Guidelines applies to the decisions made by the Commission and are not intended to support the use of outdated data inputs, where alternatives are available. In the context of the IRP "reasonable at the time" refers to the circumstances known at the time of the Commission action. Order No. 07-002 is clear on this point: "Acknowledgment of the company's plan means only that we consider it reasonable at the time of our decision." Alternatively, the "reasonable at the time" standard applies to the Company at the time of procurement, which occurs after the Commission decides whether to acknowledge an IRP Action Item.

Idaho Power believes the difference between its modeled Mid-C prices and actual prices should be no surprise. While Staff agrees that actual prices should be expected to diverge from a forecast, Staff believes the extent of the discrepancy between the Company's modeling and actual events in 2021 and the current forward price curve should heighten awareness to the modeling of Mid-C and other markets in the next IRP.

With respect to Mid-C prices, Idaho Power's 2021 IRP did not perform the way the Company stated it should perform in IPC's Final Reply Comments.[18] Instead, the 2021 IRP's planning condition resembles a sensitivity for low prices. Specifically, observed prices in 2021 and beyond are significantly higher than the stochastic risk analysis scenarios for Mid-C price risk.[19]

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[18] See Docket No. LC 78, Idaho Power, Final Reply Comments, September 23, 2022, p 17. Specifically, the Company said, "...the Company and other respected regional entities and planners use planning conditions to approximate the conditions of the region(s) in which they operate."
[19] See Docket No. LC 78, OPUC Staff, Final Comments, September 8, 2022, p 11. Highest forecasted December price for stochastic risk was $37/MWh compared to $52/MWh actual. Average peak summer prices were even farther off. For June, July, and August the numbers the IRP forecasted $15, $11, and $26 per MWh respectively compared to actual average peak prices of $59, $98, and $63 per MWh.

Staff has worked with Idaho Power to find some additional analysis to test the robustness of B2H selection in the Preferred Portfolio in the face of high Mid-C prices. On October 14, 2022, the Company sent Staff the results.

One method was to adjust the assumed gas price up and the assumed hydro conditions down. Below is how Idaho Power described the results:

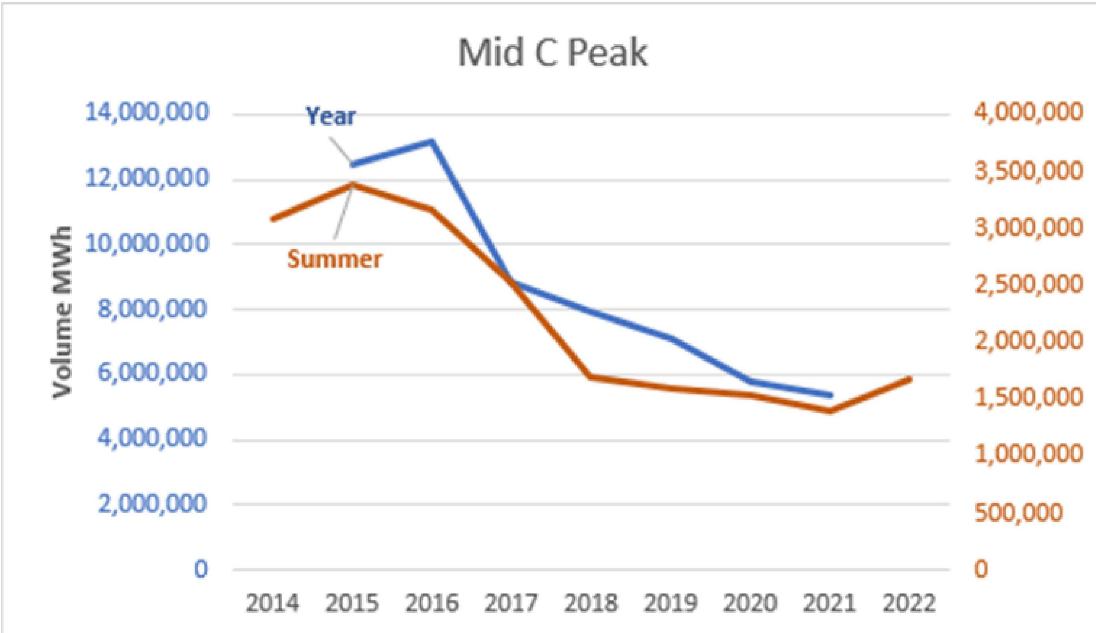
> Those updates did drive higher market prices but also increased the spread, with average monthly Mid-C prices ranging from -$3.31 to $89.39 per MWh for 2023. Even with these updates, the Preferred Portfolio remains the least-cost option for 18 of the 20 iterations. The average price difference between the two portfolios over the 20 iterations is ~$125 million (with the Preferred Portfolio, on average, costing $125 million less than the least cost non-B2H portfolio).

The Company also pointed to the existing High Gas High Carbon sensitivity. Idaho Power stated that this gets the market purchase price up to $68.26 per MWh in 2029. Staff finds this to be a better approximation for the region, and in that scenario, B2H was cost-effective.

Staff finds this sufficient to recommend the Commission acknowledge the B2H Action Items with the condition that the 2023 IRP Idaho Power needs to model the risk of extremely high Mid-C prices better. Failure to explore the potential continuation of these observed prices could lead to unacceptable ratepayer risk with regard to the investment in B2H.

In addition, Staff believes the 2023 stochastic analysis should explore the issue of liquidity at Mid-C. In recent analysis, Staff has noted that the market liquidity at Mid-C has been significantly declining. According to EIA data, the number of counterparties, the number of trades, and the total volume of MWhs traded have trended downward since 2015. Figure 2 depicts the decline in trading volume. The red line depicts the season Idaho Power plans to rely on Mid-C for 500 MW of capacity.

Figure 2: EIA Trading Volume Data



In addition to the myriad of factors that can drive Mid-C prices up, declining liquidity can amplify that price risk. Staff has no certainty that the high Mid-C prices observed today will either persist or get worse. However, Staff expects, in future modeling of wholesale price forecasts, Idaho Power to consider the risk of high Mid-C prices more carefully than was modeled in the 2021 IRP.

Alternative Resource Costs
The relative cost of resource alternatives to B2H also needs an update as well for the next IRP. More robust data on CCCT capital costs and inclusion of new federal subsidies for clean energy could present a lower cost, less risky portfolio.

Federal Funding.
Idaho Power should pursue all available federal funding for B2H. Staff recommends the Company provide a report on the status of federal funding in RE 136. The report should include:

- Identification of what federal funding and guarantees B2H potentially qualifies for under current and emerging law and programs;
- An explanation of what is required for the Company to apply for that funding or guarantee;
- An explanation of whether the Company is preparing an application or grant; and

- If the Company is not preparing an application, an explanation about why.

Staff Recommendations:

Recommendation 5: Acknowledge Action Item 1: Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreements. Once the agreements are in place, file for a certificate of public convenience and necessity with state Commissions.

Recommendation 6: Acknowledge Action Item 8: Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.

Recommendation 7: Direct Idaho Power to produce a fresh, rigorous estimate of the total cost of B2H and all associated swaps and investments, breaking the total cost down by component, disclosing all data and assumptions for each estimated component cost, and model cost contingencies based on this updated total cost estimate for the 2023 IRP or sooner if necessary to support procurement actions.

Recommendation 8: Direct Idaho Power to model extremely high wholesale electricity prices and decreased liquidity in the 2023 IRP with greater input from stakeholders on these topics.

Recommendation 9: Direct Idaho Power to document the Company's monitoring and pursuit of grant opportunities in the regular reporting on transmission projects under Docket No. RE 136, including the items bulleted in Staff's Report.

2024/2025 RFP

Action Item 5 regards Idaho Power's 2024/2025 RFP in Docket No. UM 2210, which was issued three weeks prior to the filing of this IRP on December 30, 2022. Due to several factors, the Commission opted not to grant Idaho Power a waiver to the PUC's competitive bidding rules for this RFP. Instead, the Commission granted an exemption.[20]

Idaho Power's Analysis

The nameplate capacity of resources identified in the Preferred Portfolio were selected to meet the modeled capacity deficit of 85 MW in 2024 and 125 MW in 2025. The

[20] See Docket No. UM 2210, OPUC, Order No 22-081, March 18, 2022.

Preferred Portfolio includes 700 MW of wind and 5 MW of distributed storage in 2024. In 2025 it includes 300 MW of solar, 100 MW of utility scale storage, and 5 MW of distributed storage. Though the Preferred Portfolio selects specific resources, the RFP is all-source. The capacity deficit that prompted the release of this RFP before acknowledgement of the 2021 IRP comes from an increase in forecasted load, derating of the nameplate capacity of existing DR, reduction in firm transmission capacity for market imports, and a recalculation of the planning reserve margin and resource ELCCs.

Staff's Analysis and Recommendations

These resources were not included in the 2019 IRP Action Plan. The immediate need is driven mostly by improvements in how Idaho Power models resource adequacy. Staff finds the Company's new methods to be an improvement over the those used in the 2019 IRP. However, Staff does not recommend acknowledging this Action Item because it is substantially completed.

Staff Recommendation:

Recommendation 10: Not acknowledge Action Item 5: Issue a Request for Proposal (RFP) to procure resources to meet identified deficits in 2024 and 2025.

Demand-Side Resources

Action Items 7 and 9 refer to the redesign of existing DR programs, acquisition of additional DR necessary to meet capacity need, and the implementation of cost-effective energy efficiency measures each year as identified in the energy efficiency potential assessment.

Idaho Power's Analysis

In 2021, before this IRP was filed, Idaho Power redesigned the Company's DR programs to improve their capacity contribution. This made their expected nameplate capacity uncertain, because it was not known how program participants would respond to the changed program requirements and increased incentives. Idaho Power used survey research to estimate the nameplate capacity. This reduced the nameplate capacity of existing DR down from 390 MW to 300 MW. As of June, this year, at the beginning of the 2022 peak season, Idaho Power has estimated this nameplate capacity to be around 320 MW.

Idaho Power's assessment of new DR potential is also undergoing change. The Company is moving away from using regional data from the Northwest Power and Conservation Council (NWPCC). Starting this fall, the Company will instead assess DR potential from IPC-specific studies. For this IRP, new DR was packaged into 20 MW increments whose cost was based on 100 MW tranches from NWPCC cost data.

Idaho Power's Preferred Portfolio also models energy efficiency (EE) as a resource. The Preferred Portfolio acquires an average of around 20 MW a year.

Stakeholder Positions

CUB
In Opening Comments, CUB requested the Company share the observed dispatch of existing DR in the 2022 peak season.

Staff Opening and Final Comments
Like CUB, Staff requested an update on the nameplate capacity of existing DR in the 2022 season. We requested this in Opening Comments and as an update of the model in Final Comments.

Beyond existing DR programs, Staff has had several questions about how Idaho Power modeled new DR in this IRP. In our engagement with the Company, some of the answers we have received from Idaho Power raised new questions. Normally utility modeling selects all potential, cost-effective DR. Idaho Power's Preferred Portfolio does not select all potential DR. Staff has sought to understand why. Is that because additional DR is not cost-effective as the Company's modeling suggests or does the modeling not fully reflect the cost-saving of additional new DR? Staff will further this engagement with Idaho Power in the next IRP when the Company transitions from using NWPCC data to an IPC-specific assessment.

Idaho Power
Throughout the Company's reply Comments, Idaho Power has maintained that the performance of existing DR in the 2022 peak season is not yet known and should wait until the 2023 IRP. In response to OPUC IR 156, the Company shared the observed 2022 dispatch of DR from the Flex Peak and AC Cool Credit programs, Idaho Power's smaller of three programs. The Company's larger program, Irrigation, can be shared by the first week of November.

Idaho Power is confident that new DR has been modeled reasonably. The Company believes that the limited selection of new DR in the Preferred Portfolio is due to the limited number of events for which new DR can be dispatched. IPC explains that DR, like other resources, has a diminishing marginal ELCC such that expansion of DR capacity may not mean adding the new DR reduces revenue requirement.

Staff's Analysis and Recommendations

Staff takes Idaho Power at the Company's word. As an institution, IPC does not yet know the nameplate capacity of a DR season than ended last month. This means that even power operations does not know how much DR was dispatched.

Regarding new DR, Staff has lingering questions from Idaho Power's Final Reply Comments. In response to Staff's observation that NWPCC's data can produce significantly lower cost blocks than Idaho Power modeled, the Company stated: "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."[21] Staff does not understand why choosing blocks that increased the average size of new DR was more reasonable than other choices that would have assumed significantly lower costs. In response to Staff's observation that the dispatch of DR in Aurora does not appear to call events in the highest possible loss of load probability (LOLP) hours, the Company explained that the data for LOLP the Company provided Staff came from Idaho Power's modeling of reliability in MATLAB, and Aurora dispatches DR to a different reliability assessment that does not assign the same LOLP to the same hours. This raises the question of how far off the two models are from each other. Some variation can be reasonable, but excessive difference between the two models might mean that Aurora is not dispatching resources in accordance with the Company's assumptions about resource adequacy.

As Staff composed Final Comments, it did not have specific recommendations on how to improve the modeling of new DR. That remains the case as we compose this Public Meeting Memo. Instead, Staff looks forward to Idaho Power's transition from NWPCC data to an IPC-specific potential study. In Final Comments, Staff recommended a requirement for the 2023 IRP to clarify the scope of that transition to utility-specific data, the inclusion of pricing programs and model contingencies specific to Idaho Power's system. In this Staff Report we recommend the Commission approve that as an Action Item.

Finally, Staff notes that it has not raised issues about EE. That is because Staff has found no issues with the way Idaho Power forecasts and models new EE acquisition. Idaho Power deserves credit for running effective EE programs and modeling them accurately.

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[21] See Docket No. LC 78, Idaho Power, Final Reply Comments, September 23, 2022, p 20.

<u>Staff Recommendations</u>:

Recommendation 11: *Acknowledge Action Item 7: Redesign existing DR programs then determine the amount of additional DR necessary to meet the identified need.*

Recommendation 12: *Acknowledge Action Item 9: Implement cost-effective energy efficiency measures each year as identified in the energy efficiency potential assessment.*

Recommendation 13: *Direct Idaho Power to model new DR for the 2023 IRP based on the results of the IPC-specific DR potential study expected to be complete in the fall of 2022. Results should include exploring whether current programs have additional potential, additional kinds of DR programs including pricing programs, and more accurately estimating costs of future programs.*

<u>Large-Load Solar</u>
Action Item 10 is to work with large-load customers to support their energy needs with solar resources.

<u>Idaho Power's Analysis</u>
Idaho Power does not elaborate much on this action item in the text of the 2021 IRP. However, CUB's engagement on this issue has brought out more information.

<u>Stakeholder Positions</u>

CUB
In Final Comments, CUB noted that while Idaho Power has disclosed that large load customers' energy needs sum up to 785 MW, the Action Plan does not include any specifications on when the resource acquisition to meet these needs will occur. CUB recommends that the Company specify the size and timing of the acquisition of additional solar resources and the Commission acknowledge these specifications.

<u>Idaho Power Position</u>
The Company does not agree with CUB's recommendation to specify size and timing of the acquisition of additional resources to meet large-load needs before they are acknowledged. This is because many of the decisions pertaining to solar resource acquisitions have not been made yet and were instead modeled as estimates based on

current assumptions. Consequently, the Company argues that any sizing or timing specifications made would not be accurate reflections of future decisions. The Company proposes that instead of not acknowledging these resource acquisitions, sizing and timing information will be included in the next Action Plan.

Staff's Analysis and Recommendations

Staff supports CUB's recommendation as an action item in the 2023 IRP. Staff welcomes the Company's commitment to offer more granular detail on these customer-specific resources.

Recommendation 14: Acknowledge Action Item 10: Work with large-load customers to support their energy needs with solar resources.

Recommendation 15: Direct Idaho Power to include large-load customer resource acquisition sizing and timing needs in the 2023 IRP Action Plan.

Valmy Unit 2 Exit

Action Items 12 is to exit Valmy unit 2 by December 31, 2025.

Idaho Power's Analysis

In the process of revising its 2019 *Amended* IRP, the Company undertook additional analysis and ran sensitivities that included a 2022 retirement date for Valmy unit 2. In the 2019 *Second Amended* IRP, Idaho Power subsequently discovered that it is possible to economically retire Valmy unit 2 in 2022 instead of 2025 as originally planned. The Commission acknowledged that 2022 retirement date with the condition that Idaho Power perform an economic and reliability study on early Valmy unit 2 retirement.[22]

The Company filed this study to Docket No. LC 74 on August 4, 2021, finding that a 2022 retirement of Valmy unit 2 was not a least-cost least-risk decision. This analysis was carried forward to the 2021 IRP and the exit date reverted to 2025.

[22] See Docket No. LC 74, OPUC, Order No. 21-184, June 4, 2022, p 9.

Staff's Analysis and Recommendations

No parties have raised an issue with the return to the 2025 retirement date. In the last IRP, Staff recommended the plan to exit Valmy unit 2 remain 2025. Staff continues to recommend the Commission acknowledge this Action Item.

Staff Recommendations:

Recommendation 16: Acknowledge Action Item 12: Exit Valmy unit 2 by December 31, 2025.

Jackpot Solar

Action Item 3 is to bring online 120 MW of solar starting December 2022. Work with the developer to determine, if necessary, mitigating measures if the project cannot meet the negotiated timeline.

Idaho Power's Analysis

For the 2021 IRP, the Company is requesting acknowledgment for a 120 MW solar power purchase agreement (PPA) called Jackpot Solar. On April 4, 2019, Idaho Power notified the Oregon Commission about its intent to acquire this resource because it was a "time limited opportunity."[23] Oregon utilities must comply with the competitive bidding requirements for acquisition of certain generation resources or contracts unless they file a waiver for good cause.[24] The Company believed Jackpot Solar met the criteria under these requirements, so the Company filed a Notice of Exception under the competitive bidding guidelines. Idaho Power indicated that it was approached by Jackpot Solar in September 2018 and that "Jackpot Solar offered to sell to Idaho Power 120 MW of renewable solar generation with very low pricing, significantly below both market prices and Public Utility Regulatory Policies Act of 1978 ("PURPA") avoided cost rates." The PPA is for the purchase of 120 MW of solar with an option to purchase an additional 100 MW at the Contract Price. Idaho Power includes this resource as part of its Preferred Portfolio and Action Plan.

[23] See Docket No. LC 68, Idaho Power, POWER PURCHASE AGREEMENT BETWEEN IDAHO POWER COMPANY AND JACKPOT HOLDINGS, LLC, April 4, 2019, p 1.
[24] OAR 860-089-100(1).

Stakeholder Positions

CUB
CUB recommends the Commission not acknowledge the 120 MW Jackpot Solar project. CUB argues that the Commission cannot assess the prudence of a nearly completed project in an IRP. This process should be reserved for a rate case proceeding.

STOP
STOP notes that in Idaho Public Utilities Commission's Staff report on Jackpot Solar, CASE NO. IPC-E-I9-144, it was determined that the PPA for Jackpot Solar was less expensive than market purchases at the Mid-C.

Idaho Power's Position
In Opening Comments to the 2019 IRP, Idaho Power clarified that Aurora was able to select the Jackpot Solar PPA as a cost-effective resource rather than a resource based on capacity or energy need. In the 2019 *Amended* IRP, Aurora selected the Jackpot Solar PPA in the majority of the 24 WECC-optimized portfolios. However, because the decision to acquire Jackpot Solar was time bound, the Company agreed that the Jackpot Solar Action Item should be removed. Staff notes that IPC did not remove this Action Item in the 2019 IRP or the 2021 IRP. Further, in Final Reply Comments, Idaho Power did not oppose CUB's recommendation against acknowledging Jackpot solar in this IRP because the action item has already been executed.[25]

Staff's Analysis and Recommendations

Staff agrees with CUB that a Commission acknowledgment would be inappropriate based on the timing of this resource's acquisition. The Company may still pursue cost recovery on this project in a rate case. The issue of not acknowledging Jackpot Solar has not been controversial in this IRP.

Staff Recommendation:

Recommendation 17: ***Not Acknowledge Action Item 3: Solar is contracted to provide 120 MW starting December 2022. Work with the developer to determine, if necessary, mitigating measures if the project cannot meet the negotiated timeline.***

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[25] See LC 78, Idaho Power, Final Reply Comments, September 23, 2022, page 36.

Distributed Storage
Action Item 11 is to finalize candidate locations for distributed storage projects and implement where possible to defer T&D investments as identified in the Action Plan.

Idaho Power's Analysis
Beyond procuring energy storage as a capacity resource, Idaho Power is also looking to storage to defer transmission and distribution investments. These will come in 5 MW increments, with 15 MW added in 2023, and 5 MW added in 2024, 2025, and 2027 for a total of 30 MW in the four identified years (2023, 2024, 2025, and 2027).

Idaho Power analyzed historical T&D data to identify potentially deferrable infrastructure investments spanning a 20-year period from 2002 through 2021. The infrastructure investments served as a test bed to identify the attributes of investments required to serve Idaho Power's growing customer base. The limiting capacity was identified for each asset, along with the recommended in-service date, projected cost, peak loading, peak time of day, and projected growth rate.

Staff's Analysis and Recommendations

The preference for Company-owned battery storage resources was raised as a concern in UM 2210, but the need for procurement of these distributed battery storage resources has been uncontroversial in this IRP.[26] Idaho Power has already procured 11 MW of 4-hr battery storage at four sites in Idaho from the Company's 2023 RFP that was released in June 2021. The Company has secured 2 MW in Melba, 3 MW in Weiser, 2 MW in Filer, and 4 MW in Elmore. Like Staff's recommendation on Jackpot Solar, Staff recommends the Commission not acknowledge these resources that have already been acquired, from an Action Plan to procure 40 MW that leaves 29 MW to acknowledge.

Staff Recommendations:

Recommendation 18: *Acknowledge 29 MW of the 40 MW from the Preferred Portfolio referenced in Action Item 11: Finalize candidate locations for distributed storage projects and implement where possible to defer T&D investments as identified in the Action Plan.*

Recommendation 19: *Not Acknowledge the following 11 MWs of investments from the 2023 RFP that have already been secured: 2 MW in Melba, 3 MW in Weiser, 2 MW in Filer, and 4 MW in Elmore.*

[26] See Docket No. UM 2210, Northwest & Intermountain Power Producers Coalition, Comments, March 7, 2022, p 1.

Issues Outside of the Action Plan

Capacity Benefit Margin

Stakeholder Positions

CUB
CUB recommends that the Company continue to explore how participating in the Western Resource Adequacy Program (WRAP) may alter transmission assumptions.

Idaho Power Position
IPC notes that it will continue to examine the impacts of WRAP and will apply those impacts to the 2023 IRP capacity benefit margins accordingly.

Staff's Analysis and Recommendations

Staff supports CUB's recommendation. The Company agrees with CUB, therefore Staff recommends the Commission approve this as an Action Item for the 2021 IRP.

Staff Recommendation

Recommendation 20: Direct Idaho Power to continue to explore how participating in the WRAP may alter transmission assumptions.

Gateway West

Stakeholder Positions

CUB
CUB states that while the Gateway West project is not part of the preferred portfolio, segment 1 is included in the optimal portfolio under several scenarios, especially the ones that explore higher renewable energy futures (under higher renewable targets, higher carbon or gas prices, or the climate sensitivity). As the policy environment is shifting rapidly and those scenarios become more likely, CUB re-iterates its interest in updates on the Gateway West project in future IRPs.

Idaho Power's Position

IPC 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.

Staff's Analysis and Recommendation

Staff appreciates Idaho Power's commitment to provide more information about Gateway West in the 2023 IRP

Load Forecast

Idaho Power's load forecast shows substantial growth and represents a significant increase from the past IRP. The load growth was cited by the Company as one of the drivers of the sudden change in resource need from the 2019 IRP to the 2021 IRP. Given the impact of this forecast load growth, Staff and stakeholders were highly engaged with the Company on this topic. Staff alone issued at least 22 IRs and attended multiple meetings and technical workshops with the Company to develop an understanding of the Company's load forecasting approach, and to ensure modeling accuracy.

Stakeholder Positions

CUB

In Opening and Final Comments, CUB expressed concern about the lack of clarity regarding the benefits provided by the neural network over a regression model and asked the Company to provide clarifying information.[27] CUB further notes that the lack of transparency around the model prevents stakeholders from fully engaging with the Company's approach and providing valuable input.

To increase load forecasting and associated load shaping model visibility, CUB recommends that the Company add a section on the neural network model in the Technical Appendix. CUB recommends the Company also provide information on model inputs, outputs, and how this was applied to the portfolio analysis. A comparison to model alternatives should be included to show that the neural network is the best approach to estimate class contribution to system peak.

[27] See Docket No. LC 74, CUB, Opening Comments, July 7, 2022, p 4.

Staff Opening and Final Comments

In Opening Comments, Staff sought documentation supporting the Company's expected increase of 237 aMW from special contract customers and noted several concerns it had with the Company's modeling of the rest of the system using econometrics, namely:

- Autocorrelation in the residential modelling, wherein past observations have an impact on current ones that can bias the model;
- The use of varying lengths of historical data for different regression models; and
- Avoiding the extrapolation of recent growth out into a future that might contain slower economic growth

In Final Comments, in addition to the outstanding issues from Opening Comments, Staff articulated its concerns about the hourly forecast had been resolved but noted the incomplete responses to IRs related to the monthly load forecast prevent Staff from completing a review.

Idaho Power's Position
In Final Reply Comments, IPC responded to CUB by explaining that the neural network model helps the Company understand what each class contributes to the system peak.[28] The Company contends that it has offered information and shared data to ensure that the load forecasting process was as transparent as possible. Furthermore, the Company notes that it has offered detailed instruction on the load forecasting process and responded to multiple information requests regarding the load forecast. IPC notes that on numerous occasions the Company has 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.

In response to Staff's Opening Comments, Idaho Power stated that the residential model does not have autocorrelation according to the Durbin-Watson Statistic. The Company explained shorter data sets are chosen when the model fits better. IPC believes the risk of unreasonably extrapolating recent economic growth out too far is mitigated from having the planning case load forecast represent the highest probability outcome for load growth during the planning period, or the fiftieth percentile given historic growth rates. Regarding special contract customers the Company stated: "Through frequent communication, which includes ongoing updates and project load and timing, the Company can assess the probability of each potential project."[29]

[28] See Docket No. LC 78, Idaho Power, Final Reply Comments, September 23, 2022, p 35.
[29] See Docket No. LC 78, Idaho Power, Opening Reply Comments, August 4, 2022, p 10.

In response to Staff's Final Reply Comments, Idaho Power stated that Staff has had ample time to review the load forecast. In response to Staff's concerns about incomplete responses to IRs, Idaho Power states the responses "reflect the Company's good faith efforts to communicate complicated subject matter."[30]

Staff's Analysis and Recommendations

Staff appreciates the time and resources the Company has dedicated to engage with Staff regarding the information it has requested. Staff agrees with the Company that there has been ample time to review the information provided by IPC's regarding its load forecast. Having received the last of the information the Company could provide on October 13, 2022, Staff has had enough time to complete a basic review of Idaho Power's load forecast. This included validating the Company's hourly load forecast methodology and evaluating the monthly load forecast for accuracy and potential improvements.

Hourly Load Forecast
The Company's use of neural networks to inform hourly forecast is limited to distributing the monthly forecast into hourly inputs for Aurora. Staff was able to confirm the Company's new approach is valid. Beyond the transparency concerns raised by CUB, Staff does not have concerns with the Company's new approach of using a neural network to inform hourly load forecasting. Staff will take a closer look at the new method's forecasting error in the next IRP.

Monthly Load Forecasting Error in the First Year
Staff compared the first year's actuals to what the 2021 IRP forecast to assess accuracy. The system energy forecast overestimated energy load in 2021 by around one percent. The system peak forecast overestimated peak load in 2021 by less than a quarter of one percent. Staff finds this to be a reasonable amount of forecasting error.

Model Specifications with 2021 Data
In checking for better model specification, Staff found a few opportunities for improvement, but running the impact of the improvements with the Company's forecasted values of the independent variables revealed no material changes to the estimation of load. Two examples of model changes that increase adjusted R squared while reducing the Akaike Information Criterion (AIC) are:

[30] See Docket No. LC 78, Idaho Power, Opening Reply Comments, August 4, 2022, p 9.

- Controlling for seasonality in the residential model rather than using indicator variables to control for random outlier residuals that have no *a priori* hypothesis to test, and
- Controlling for the parabolic shape of the price variables in nonresidential models.

Outstanding Issues
Staff identified models with problems embedded in the data that Staff was unable to correct. So, Staff does not know if a resolution of this problem would materially impact the long-term forecast of load. These include:

- Autocorrelation in the residential load forecast;
- The presence of a unit-root in the industrial services model, which can cause non-stationarity and produce problems with the model, such as drift, which can reduce the model's accuracy;[31]
- The measurement error of Itron's three residential Statistically Adjusted End Use Model (SAE) variables, which estimate the average per household energy consumption for heating, cooling, and other household uses of electricity;[32] and
- The Company's method of assessing the probability range of its load forecast.

Staff plans to work with the Company in the development of the 2023 IRP to address these issues and identify solutions where problems persist.

Special Contracts
Staff finds CUB's recommendation on large customer load, which Staff included in this Report as a condition in Recommendation 15, can overcome concerns Staff had about ambiguity in special contract load.

In our review of Idaho Power's load forecast, Staff has found methodological issues that could impact the reasonableness of the Company's long-term load forecast, but given the data Idaho Power has provided Staff, Staff does not find alternatives to IPC's regression models that materially impact the forecast of load. Staff also finds the observed forecast error in 2021 to be reasonable in magnitude. Therefore, Staff does not believe its lingering concerns on the monthly load forecast methods used will likely materially impact the Company's 2021 IRP Action Plan. Staff will continue to work with

[31] Staff raised this issue in LC 74, recommending ARIMA as a solution. See LC 74, OPUC Staff, Staff Report, March 5, 2021, p 37.
[32] The SAE formulas were not provided by the Company in LC 78, but Staff understands that the Company was able to provide the SAE formulas to Staff in 2020 when responding to OPUC DR 57 in UE 366. For the purpose of this Public Meeting Memo, Staff assumes the formulas have not changed.

the Company to resolve outstanding questions regarding monthly load forecasting in the 2023 IRP to avoid any potential risk of forecasting error in future IRPs.

Resource Adequacy Standards

Stakeholder positions

STOP
In Final Comments, STOP finds concerns with the rapid acquisition of resources (rather than an incremental acquisition waiting for economic conditions to improve). STOP cited back to an IR response from the Company that explained that this is a necessity due to the transmission constraints, demand response assumption changes, and changes to the planning margin and methodology modernization. STOP notes that the two later factors (demand response and planning margin assumptions) are driven by the Company's control. Consequently, before the Company goes through with these acquisitions, STOP urges the Commission to study the economic impacts of acquiring these new resources and study a phased-in approach.

Staff Final Comments
In Final Comments, Staff gave support for Idaho Power's modeling of reliability. The concern it raised was about how the Company applied the LOLE standard of 0.05 in portfolio analysis. All but one of Idaho Power's scored portfolios were unable to meet that reliability standard with the resources included in the portfolio, including the Preferred Portfolio. Idaho Power used a proxy resource outside of the portfolios' resources to meet the reliability standard. That proxy resource has the capital cost and dispatch characteristics of a simple cycle combustion turbine. Staff argued the best interpretation is that these portfolios met the Company's reliability standard and did so with a gas plant. Staff recommended that, in the 2023 IRP, the Company screen portfolios for consideration as the preferred portfolio by whether they include all the necessary resources to meet the Company's reliability standard for a minimum of twenty years.

Idaho Power's Position
In Final Reply Comments, the Company explains that while evaluating the economic impact is certainly important, the reliability standard needed to be adjusted to ensure that reliable service to its customers, and that other utilities and planning entities are making similar changes. The Company also addresses STOP's concerns that the Company is changing the reliability standard "all at once." The Company explains that a change in the reliability standard from one IRP to the next does not have an immediate and concentrated impact as STOP suggests. The impacts of the change in the reliability

standard on load and resource balance will have a gradual impact over the course of several years.

In response to Staff's concerns about how reliability was modeled in portfolio analysis, Idaho Power reiterated that the Preferred Portfolio does meet the Company's reliability standard. IPC explained that having a static planning reserve margin in Aurora has the potential to lead to deviations between the reliability calculations performed by Aurora and the separate calculation of LOLE in MATLAB in the later years of the planning horizon. This problem is caused by significant amounts of variable energy resources (VER) being added to the system and the interactions of those VERs with other resources.

Staff's Analysis and Recommendations

Staff reviewed Idaho Power's changed reliability standard and planning reserve margin. Staff finds the changed standard to likely have had little effect on a change from the 2019 IRP, because the LOLE-scored portfolios of the 2019 IRP meet a higher standard than the LOLE-scored portfolios of the 2021 IRP. Raising the standard is therefore less likely to have led to greater resource need compared to other changes in reliability modeling, such as reassessed capacity contributions.

Staff notes that Idaho PUC Staff share STOP's concern on the higher LOLE standard.[33] The Company should identify a means to establish an optimal standard and rigorously justify why choosing a higher standard than Staff recommends in UM 2011 as being necessary.[34] The Company's resource adequacy decision would benefit from more transparency and discussion among parties in both states, and Staff will work with Idaho Power in the next IRP to identify an objective basis for choosing an LOLE standard.

Regarding Staff's recommendation that reliability analysis of portfolios in the 2023 IRP rely on the resources in the portfolios, Staff is not opposing the modeling means by which Idaho Power found its Preferred Portfolio to meet the LOLE standard of 0.05 in all twenty years of the planning horizon for this IRP. If Idaho Power has computational barriers to optimization that require the selection of a gas plant in the final years, using Aurora's unserved energy feature, that is a reasonable modeling solution.

What Staff is opposed to is the use of a gas plant to meet the reliability standard while not including that gas plant in the portfolio. The computational challenges from high percentages of VERs may be mimicking the reliability challenges that come with high percentages of VERs. The problem is that Idaho Power is relying on a gas plant in

[33] See Case No. IPC-E-21-43, IPUC Staff, Comments, June 2, 2022, p 4.
[34] See Docket No. UM 2011, OPUC Staff, Staff Announcement, September 23, 2033, p 3.

these portfolios to overcome a reliability issue but not transparently including that fact in the list of resources of these portfolios, including that fact in the Company's emissions forecast, and not fully scoring the net present value of the plant's revenue requirement.

Staff recommends the Commission require that the Company's 2023 IRP rely on the resources within a portfolio to meet the Company's reliability standard. If how Idaho Power relied on the cost and dispatch characteristics of a SCCT remain the best the Company can computationally handle, this requirement can be met by including the SCCT in the portfolio, the emissions from the plant in the emissions forecast, and the full costs of a SCCT in the revenue requirement of the portfolio.

Staff Recommendation:

Recommendation 21: Direct Idaho Power to include all necessary resources in scored portfolios to meet the Company's reliability standard.

Forecasting Qualified Facilities (QF)

Through both rounds of comments, Staff has engaged with Idaho Power on improving the accuracy of its forecast of QF resources. In Final Comments, Staff recommended Idaho Power assume zero growth in QFs only for the first four years of the planning period.

Stakeholder positions

REC
REC recommends that the Commission approve Staff's planning assumptions around QFs that include no growth in the first four years and a forecast of future QF development informed by past QF activity and expanded transmission beginning in the fifth year of planning. Additionally, REC recommends that the Commission approve Idaho Power's assumptions regarding QF renewals and direct Idaho Power to revisit its planning assumptions for wind QF renewals during the next IRP.

Idaho Power's Position
In Final Reply Comments, Idaho Power stated the Company makes no assumptions regarding future QF development in IRP modeling. The IRP does not include an assumption that Idaho Power will enter QF contracts of specific sizes beyond the

contracts that currently exist. The Company argues this has no bearing on eventual QF development. QFs are “must purchase” agreements that may enter the pricing queue for a PURPA contract at any time, regardless of the Company’s surplus or deficit position.

The Company sees only risk from assuming a QF growth rate greater than zero, a cost risk and a reliability risk from having additional needs to fill with less time to procure resources. If QF generation becomes lower than forecasted, the result will be an increase to load/resource deficit, closer in time to the operating month for which the deficit needs to be filled. If the Company were to overestimate QF resources in an IRP, the changes would be occurring post-IRP, and Idaho Power would have less time to address the need.

Idaho Power sees Staff’s proposal of new QF development 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. 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.

Staff’s Analysis and Recommendations

Staff supports REC’s recommendation. Idaho Power should derive the planning assumption renewal rate of wind QFs from an empirical basis in the 2023 IRP.

Idaho Power should also base the planning assumption of new QFs on a reasonable forecast. By making no assumptions about new QFs, Idaho Power is assuming no QFs. That is a forecast, a forecast that is well understood to be an underestimation.

This underestimation can displace future QF development. An underestimation of QF development leads to an overestimation of future resource need. An overestimation of resource need impacts the period of resource sufficiency, which impacts PURPA contract prices. So, an underestimation of future QFs can distort the price signals that affect the supply of future QFs.

The reliability and cost risk from an undersized RFP can be mitigated by only enhancing the QF forecast from the fifth through twentieth years of the planning period. Continuing to assume zero growth in QFs in the first four years will allow an RFP following the IRP to avoid under-procurement of resources from any variance in a QF forecast.

Idaho Power already forecasts QFs in the Company's APCU. If IPC prefers consistency with the estimation of power costs, then Staff notes that adding a QF forecast to the IRP will make the two dockets more consistent, not less.

Staff Recommendations

Recommendation 22: Direct Idaho Power to revisit the assumed renewal rate of wind QFs.

Recommendation 23: Direct Idaho Power to apply a reasonable forecast of new QFs beginning in the fifth year of the planning cycle.

Emissions and Clean Energy Goal

In Final Comments, Staff recommended Idaho Power include in the executive summary of the next IRP a graph showing Idaho Power's GHG emissions for 2019-2022 and comparing those historical emissions to the IRP's 20-year forecast of IRP emissions calculated in the same manner. Staff clarified the data should include emissions from market purchases and remove emissions from market sales. Staff finds that Idaho Power should be allowed to remove market sales from its emissions forecast, even though that practice may not be consistent with how other utilities report emissions to Oregon DEQ. This is because Idaho Power is not subject to the emissions reductions requirements of HB 2021. Should the Company become subject to these requirements, Staff's position on market sales reporting in IRPs could change at that time.

Staff called attention to the difference between Idaho Power's planned emissions and the Company's goal of being 100 percent clean by 2045. Staff believes IPC's marketing should reflect its planning.

Idaho Power's Position
Idaho Power's Final Reply Comments state that it would be technically impossible to calculate historical and forecast emissions in the same manner while including emissions from purchases and removing emissions from sales, because the Company explains 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.

Idaho Power explains that the difference between the 2021 IRP's planned emissions and the Company's clean energy goal is explained by a belief that future technology, such as green hydrogen, will one day become commercially available and cost-effective. IPC states that the Company did not include green hydrogen in the 2021 IRP analysis due to a lack of commercially available data to model it and other similarly forthcoming dispatchable sources of non-emitting capacity.

Staff's Analysis and Recommendations

Staff does not agree that the emissions forecasting it has recommended is technically impossible. Although it may be difficult to calculate a precise system emissions factor for each hour of the years 2019-2022 and apply it to the actual market sales during that time, there is no reason that it should be considered impossible, and Idaho Power has provided no reason to support its claim of technical impossibility. Idaho Power should either: a) undergo a rigorous analysis to estimate historical emissions from market sales using historical hourly data on unit-by-unit generation and market sales, or b) estimate the historical emissions attributable to market sales by calculating the average IPC system emissions factor during the hours when market sales tend to be the highest and apply this factor to the historical market sales quantities in each year. While neither analysis would be simple, neither should be technically impossible if the company has retained historical data on hourly market sales and hourly generation.

Regarding hydrogen, the Company states that it did not consider green hydrogen as a resource in the IRP because it did not have access to commercial data on green hydrogen. However, Idaho Power did mark up the capital cost of a CCCT plant twenty percent to account for the economics of running hydrogen. Also, Staff has seen other utilities, including PacifiCorp, model green hydrogen as a resource available after 2028. Given that green hydrogen may become an essential long-duration storage resource for decarbonizing the grid while maintaining reliability, Idaho Power should include green hydrogen as a potential resource available for selection in its next IRP's portfolios or in a sensitivity.

Staff Recommendations:

Recommendation 24: Direct Idaho Power to include, in the executive summary of the Company's 2023 IRP, a graph showing Idaho Power's GHG emissions for 2019-2022 and comparing those historical emissions to the IRP 20-year forecast of IRP emissions calculated in the same manner. The data should include emissions from market purchases and remove emissions from market sales.

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

Conclusion

After reviewing Idaho Power's 2021 IRP, Staff concludes with 26 recommendations.

Summary of Staff Recommendations

Recommendation 1: Acknowledge Action Item 4: Plan and coordinate with PacifiCorp and regulators for conversion to natural gas operation with a 2034 exit date for Bridger Units 1 and 2. The conversion is targeted before the summer peak of 2024.

Recommendation 2: Acknowledge Action Item 6: Plan and coordinate with PacifiCorp and regulators for the exit/closure of Bridger Unit 3 by year-end 2025 with Bridger Unit 4 following the Action Plan window in 2028.

Recommendation 3: Acknowledge Action Item 13: Subject to coordination with PacifiCorp, and B2H in-service prior to summer 2026, exit Bridger Unit 3 by December 31, 2025.

Recommendation 4: Acknowledge Action Item 2: Discuss partnership opportunities related to SWIP-North with the project developer for more detailed evaluation in future IRPs with the condition that Idaho Power study the impact of the Greenlink transmission projects in reducing congestion between Idaho Power's service territory and southern wholesale energy markets.

Recommendation 5: Acknowledge Action Item 1: Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreements. Once the agreements are in place, file for a certificate of public convenience and necessity with state Commissions.

Recommendation 6: Acknowledge Action Item 8: Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.

Recommendation 7: Direct Idaho Power to produce a fresh, rigorous estimate of the total cost of B2H and all associated swaps and investments, breaking the total cost down by component, disclosing all data and assumptions for each estimated component cost, and model cost contingencies based on this updated total cost estimate for the 2023 IRP or sooner if necessary to support procurement actions.

Recommendation 8: Direct Idaho Power to model extremely high wholesale electricity prices and decreased liquidity in the 2023 IRP with greater input from stakeholders on these topics.

Recommendation 9: Direct Idaho Power to document the Company's monitoring and pursuit of grant opportunities in the regular reporting on transmission projects under Docket No. RE 136, including the items bulleted in Staff's Report.

Recommendation 10: Not acknowledge Action Item 5: Issue a Request for Proposal (RFP) to procure resources to meet identified deficits in 2024 and 2025.

Recommendation 11: Acknowledge Action Item 7: Redesign existing DR programs then determine the amount of additional DR necessary to meet the identified need.

Recommendation 12: Acknowledge Action Item 9: Implement cost-effective energy efficiency measures each year as identified in the energy efficiency potential assessment.

Recommendation 13: Direct Idaho Power to model new DR for the 2023 IRP based on the results of the IPC-specific DR potential study expected to be complete in the fall of 2022. Results should include exploring whether current programs have additional potential, additional kinds of DR programs including pricing programs, and more accurately estimating costs of future programs.

Recommendation 14: Acknowledge Action Item 10: Work with large-load customers to support their energy needs with solar resources.

Recommendation 15: Direct Idaho Power to include large-load customer resource acquisition sizing and timing needs in the 2023 IRP Action Plan.

Recommendation 16: Acknowledge Action Item 12: Exit Valmy unit 2 by December 31, 2025.

Recommendation 17: Not Acknowledge Action Item 3: Solar is contracted to provide 120 MW starting December 2022. Work with the developer to determine, if necessary, mitigating measures if the project cannot meet the negotiated timeline.

Recommendation 18: Acknowledge 29 MW of the 40 MW from the Preferred Portfolio referenced in Action Item 11: Finalize candidate locations for distributed storage projects and implement where possible to defer T&D investments as identified in the Action Plan.

Recommendation 19: Not Acknowledge the following 11 MWs of investments from the 2023 RFP that have already been secured: 2 MW in Melba, 3 MW in Weiser, 2 MW in Filer, and 4 MW in Elmore.

Recommendation 20: Direct Idaho Power to continue to explore how participating in the WRAP may alter transmission assumptions.

Recommendation 22: Direct Idaho Power to include all necessary resources in scored portfolios to meet the Company's reliability standard.

Recommendation 23: Direct Idaho Power to revisit the assumed renewal rate of wind QFs.

Recommendation 24: Direct Idaho Power to apply a reasonable forecast of new QFs beginning in the fifth year of the planning cycle.

Recommendation 25: Direct Idaho Power to include, in the executive summary of the Company's 2023 IRP, a graph showing Idaho Power's GHG emissions for 2019-2022 and comparing those historical emissions to the IRP 20-year forecast of IRP emissions calculated in the same manner. The data should include emissions from market purchases and remove emissions from market sales.

Recommendation 26: Direct Idaho Power to include the most reasonable proxy of green hydrogen as a potential resource in its next IRP, either available for selection in a portfolio or in a sensitivity.

PROPOSED COMMISSION MOTION

Acknowledge Idaho Power Company's 2021 Integrated Resource Plan, except for Action Plan Items that have already been substantially completed, and approve Staff's recommendations for the 2023 IRP.

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