BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 74

In the Matter of IDAHO POWER COMPANY 2019 Integrated Resource Plan.	Staff's Final Comments

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Introduction

The following are Oregon PUC Staff's ("Staff") Final Comments concerning Idaho Power Company's ("Idaho Power" or "Company") 2019 *Second Amended* Integrated Resource Plan (IRP).

The 2019 IRP has had an unusual cycle, which affects the extent to which Staff can respond to previous comments filed in this docket; certain components of the *Second Amended* IRP remain the same, but others have changed, rendering previous concerns obsolete.

Below is a brief summary of events to date.

- The Company filed its original 2019 IRP on June 26, 2019.
- Several weeks later, the Company filed a letter asking the Administrative Law Judge to refrain from establishing a procedural schedule to allow the Company to file supplemental analysis related to the Company's Long Term Capacity Expansion (LTCE) modeling approach to confirm the accuracy of the IRP's conclusions and findings.
- On January 31, 2020, the Company filed an *Amended* IRP which included multiple changes to its analysis and some changes to the Company's preferred portfolio.
- On June 1, 2020, Idaho Power amended its IRP again by submitting replacement pages meant to address truncated Bridger coal cost errors it discovered after filing the *Amended* IRP.
- On July 1, 2020, the Company filed a motion to suspend the schedule because it discovered additional errors and felt the need to do a comprehensive review to ensure precision in the IRP.
- On October 2, 2020, the Company filed its fourth iteration of the IRP, the *Second Amended* 2019 IRP, to correct input errors. The Company underwent an extensive verification process in this final version.

As a result, these Final Comments serve as a combination of "Opening Comments" for new components in the IRP and "Final Comments" for residual components. Staff identifies relevant concerns, stakeholder comments, and Company Reply Comments from the *Amended* IRP where they apply. Staff addresses changes it identified and makes recommendations for the Company's Final Comments and the 2021 IRP cycle.

Staff's primary concern about the *Second Amended* IRP is the Company's selection of the preferred portfolio. First, when Staff reviewed the rankings of the portfolios in the IRP, the preferred portfolio did not always perform well. Second, because of the iterative nature of this IRP, and because the Company updated certain assumptions in the latest filing but not in others, it did not take into account certain risks, and it is unclear what impact these risks have on the preferred portfolio.

Despite these concerns, Staff remains appreciative of the substantial work the Company undertook to 1) implement a new modeling process; 2) bring material concerns to the attention of stakeholders; and 3) undertake an arduous process in an attempt to produce a viable IRP. Despite the challenges in the 2019 IRP cycle, Staff believes the Company has made improvements to its planning process and hopes the lessons learned will foster an improved cycle with reliable outputs in 2021.

Load Forecast

Summary of Staff's and Stakeholders' Opening Comments

In Opening Comments, Staff notes its concern with the Company's reliance on ITRON for load forecasting because ITRON's proprietary methods result in black box forecasts with limited access to the inputs that create the forecasts. As a second concern, Staff describes the potential of non-stationarity/unit root in some of the Company's non-time-series based models.

Stop B2H describes a concern in which the Company's forecast does not necessarily match the pattern of historical values and argues that a simpler model would be better. Renewable Energy Coalition (REC) disagrees with the Company's approach to forecasting Qualifying Facility (QF) renewals and describes how QFs can impact a utility's sufficiency period. Sierra Club cites to page 27 of Idaho Power's *Amended* IRP, which states, "the expected-case load forecast for the entire system predicts summer peak-hour load requirements will grow nearly 50 MW per year, and the average-energy requirement is forecast to grow over 20 aMW per year." Sierra Club explains that the more rapid peak growth results in a shift towards capacity resources.

Company's Reply

The Company resolved Staff's first concern of not being able to access ITRON data by supplying Staff with a confidential workpaper of the ITRON model inputs. Staff was able to use this work paper to review the Company's work. The Company also responds to Staff's concern of using non-time-series based models and potential non-stationarity by committing to using ARIMA[1] error testing. The Company argues that more testing is needed to confirm that a time series model would not introduce inaccuracy. The Company replies to Stop B2H by arguing that its model appropriately considers the numerous and complex factors impacting load.

In response to REC, the Company argues that its approach is appropriate and that it will monitor whether wind repowering developments warrant future assumption changes. Finally, in response to Sierra Club, the Company argues that its model results are reliable.

[1] Auto Regressive Integrated Moving Average.

Staff's Final Comments Regarding Load Forecasting

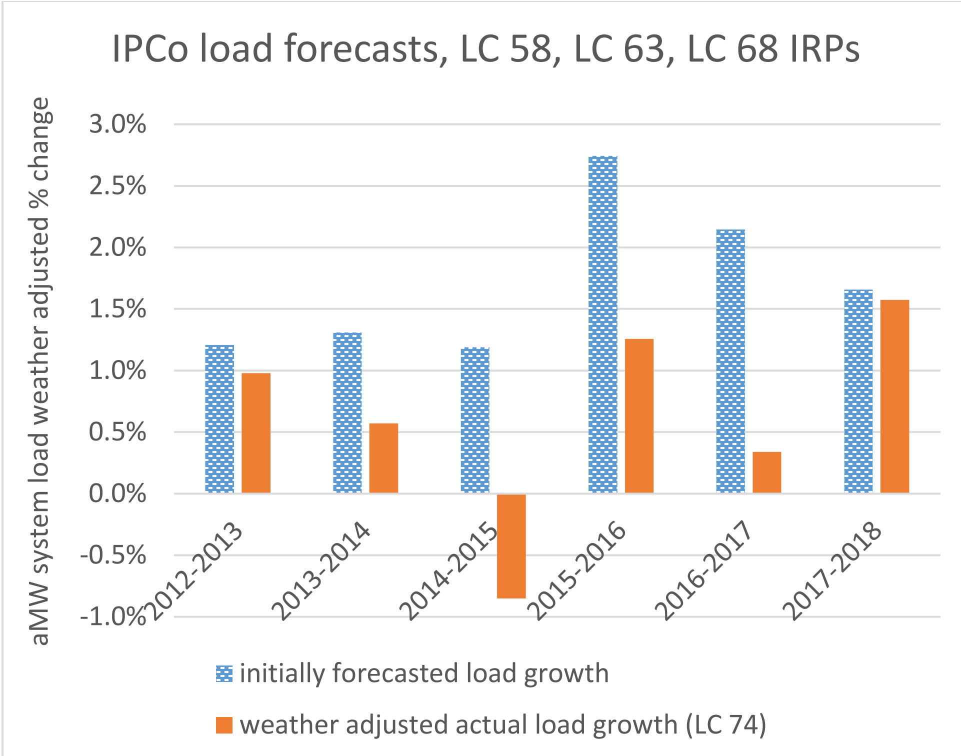
Staff believes that the Company needs to do more work to address potential non-stationarity. Staff maintains that a time series model should be used for time series data in order to prevent problems that can arise from incorrectly assuming that data is not correlated across time. Staff followed up on this issue via information requests. In response to Staff information request (IR) 62, Idaho Power states, "The Company acknowledges the unit root issue associated with the large commercial service model, and is currently in the process of improving the model to correct for this issue."

Staff recommends that in its Final Comments, the Company identify the statistical method it will use to judge whether ARIMA models can reduce forecast error, and that prior to its next IRP filing, the Company hold a workshop to present a statistical method addressing this issue. Staff suggests that Idaho Power compare how each potential model would have performed in LC 68 using only data available as of 2016. Or similarly, the Company can check how well its LC 74 models performed on the actual 2020 data that has come in since the original LC 74 forecasts were made.[2]

Staff investigated STOP B2H's concern that a simpler model should be used for load forecasting. Staff agrees with the Company that econometric models that account for factors impacting load growth are the industry standard and the best method to perform load forecasts. However, Staff also agrees with STOP B2H that the Company should do a better job describing why its models have been inaccurate in the past and how it plans to improve in the future. *Figure 1* on the following page shows forecasted load growth in LC 58, LC 63, and LC 68 versus the actual weather-adjusted load growth provided in LC 74:

[2] This statistical method is sometimes called out-of-sample testing.

Figure 1 - Idaho Power Load Forecasts in Previous IRPs



To address REC's concern of whether Idaho Power is using reasonable assumptions about QF renewals, Staff recommends that in its Final Comments, Idaho Power describe what specific wind repowering developments would cause it to change its wind QF renewal assumptions. The Company states that "…it would be unwise for Idaho Power to simply assume, without a sound basis, that all of that capacity will be available in perpetuity. Idaho Power continues to monitor developments in wind repowering and may choose to adjust future planning processes accordingly."[3] Staff believes the reciprocal is true, and that assuming that none of the wind contracts will renew could pose a risk.

As a comparative example, on PacifiCorp's system a large capacity of wind will be repowered.[4] Idaho Power also argues that "…the cost of repowering wind QFs can be very significant, and therefore the Company cannot as accurately predict whether these generators will choose to repower."[5]

Staff disagrees with Idaho Power that wind repowering decisions cannot at least be somewhat accounted for. Specifically, while the costs of repowering might be high, the potential revenues for QF owners may also be high. A recent news report summary of

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[3] *See* IPCo's May 15, 2020 Reply Comments in LC 74 at 67.

[4] "…initiative will upgrade, or "repower," the company's existing wind fleet" PacifiCorp News Release June 05, 2019 available at: https://www.pacificorp.com/about/newsroom/news-releases/energy-vision-2020-groundbreaking.html.

[5] *Ibid*.

an ICF International study looks at both the capital costs of (partial) repowering and the energy sales revenue, finding that investment returns can be favorable.[6] Thus, Staff disagrees that assuming no wind repowering is the most appropriate assumption.

In LC 70, the Commission directed PacifiCorp to incorporate sensitivities for more QFs in its next IRP.[7] Staff believes this approach is appropriate for Idaho Power. As one approach, the Company should consider a series of sensitivities where half of the wind QFs renew, and all of the wind QFs renew. REC also raised the concern of whether capacity payments for renewing QFs should be treated differently than new QFs. Because this issue does not impact the quantity of QFs that will renew at current prices, it does not affect the load versus resource balance and thus does not seem necessary to address in the IRP. Staff agrees with the Company's Reply Comments that this issue should instead be addressed in UM 2000.

In response to Sierra Club's argument that the post-2007/2008 recession growth is impacting the load forecasts, Staff agrees that the mechanics of the forecasting models are such that historical growth will increase forecasted future growth. Staff also agrees with the Company that omitting recent data would be problematic and supports the use of a long historical time series of input data.

During review of the Company's IRP, Staff considered four additional issues related to Idaho Power's load forecast that are not identified in Opening Comments: the impact of COVID-19 on the Company's load forecast, the adequacy of the Company's weather data, the impact of electric vehicles (EVs) on load, and the use of indicator variables.

Staff reviewed the Company's forecasting workpapers and submitted information requests related to the Company's forecasting models. To Staff's knowledge, the Company's load forecast has not changed since the *Amended* IRP, and therefore the Company has not considered the impact of COVID-19 on load.

Staff did not see a specific description of rising temperatures in the Company's IRP, so Staff investigated the issue via the Company's forecasting workpapers. In its response to Staff IR 63, the Company explains that "…trend variables were added to assist in informing the rising average peak day temperature impact on summertime peak demand." In past proceedings, Staff has been supportive of modeling to reflect climate change.

In response to Staff information requests, the Company describes the third party data used in its EV forecasts. Staff is supportive of the Company's approach of looking at multiple EV data sources to inform the EV forecast and believes it is an appropriate way to track potential upcoming load changes.

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[6] Ford, Neil, "US wind repowering returns stand up against wholesale prices, for now," July 11, 2018, accessed December 29, 2020 at https://www.reutersevents.com/renewables/wind-energy-update/us-wind-repowering-returns-stand-against-wholesale-prices-now.

[7] Order No. 20-186, page 13.

Staff submitted information requests related to the Company's indicator variables in its forecasting models. For example, in the residential use per customer forecasting model, indicator variables alter the relationship between electricity usage and weather variables. The Company explains that one of its indicator variables relates to an extreme weather impact. Because extreme weather impacts will happen again in the future, Staff recommends that the Company explore using a metric like the Akaike Information Criterion (AIC) because it penalizes model complexity and helps select a model that is flexible for future data.

The Company's load forecast feeds into its customer load stochastic risk analysis in IRP Chapter 9. In its customer load stochastic risk analysis, the Company creates 20 adjustments to normally distributed load. Staff is concerned that this approach might not capture the range of potential events. Some recent examples occurred in the 2007/2008 recession during which Astaris[8] terminated a special contract with Idaho Power, and population migrations to Boise had large impacts on load. Staff recommends that the Company address whether the upper and lower bounds on its customer load stochastic risk analysis are wide enough.

Staff Recommendations for Final Comments:

- Identify a statistical method it can use to judge whether ARIMA models can reduce forecast error.

Staff Recommendations for the 2021 IRP:

- Use a metric like the Akaike Information Criterion to confirm that indicator variables are not causing model overfitting.
- Present a plan to use out-of-sample testing or similar to check whether ARIMA models are likely to reduce load forecast error in the next IRP Update.
- Hold a workshop with stakeholders to present the Company's findings of whether ARIMA models are likely to improve the load forecasts.
- Address whether the upper and lower bounds on its customer load stochastic risk analysis are wide enough.
- Describe what specific wind repowering developments would cause it to change its wind QF renewal assumptions and include a range of sensitivities for wind QF renewal in the 2021 IRP.
- Present to Commissioners the impact of COVID-19 on load.

Energy Efficiency

Energy Efficiency Offerings

To Staff's knowledge, changes and assumptions around energy efficiency remained unchanged in the *Second Amended* IRP as compared to the *Amended* IRP.

[8] Astaris was a former special contract customer of Idaho Power.

In Opening Comments, Staff reviews the Company's energy efficiency planning and focuses comments on three areas:

- The reduction in projected energy efficiency load;
- The switch in cost-effectiveness screening; and
- The incorporation of transmission and distribution values for energy efficiency avoided costs.

In Opening Comments, Staff asks the Company to describe what actions it took to respond to Amended 2017 IRP Action Item 9, which indicates that the Company "report on future expanded energy efficiency opportunities."[9] Staff also requests that the Company further explain the drop in forecasted savings despite its response to Action Item 9 from the 2017 IRP.[10]

In its Opening Comments, STOP B2H recommends that the Company reevaluate and improve its energy efficiency programs and increase energy efficiency in its preferred portfolio.[11] STOP B2H observes that Idaho Power has implemented a limited number of pilots and new programs and suggests this indicates insufficient commitment on the Company's part in providing the appropriate level of energy efficiency services.[12]

In Reply Comments, the Company points out that the decreased forecast of energy efficiency potential is due primarily to the Energy Independence Security Act, which was expected to tighten lighting standards on January 1, 2020. Staff appreciates that the Company will be updating its energy efficiency potential based on changes to federal regulations and looks forward to seeing more detailed analysis of the predicted impacts to savings.

Further, the Company states that it achieved the highest level of energy efficiency acquisitions in 2019 and expanded its offerings through no-cost heating system tune-ups, energy efficiency kits, and the "Home Energy Report Pilot." The Company goes on to show that its results are comparable to other utilities and that energy efficiency acquisitions have increased year over year.[13]

While it seems that Idaho Power has, to some extent, expanded energy efficiency offerings, the Company's reporting in response to Action Item 9 was not as direct nor as thorough as Staff had hoped. Staff would have liked to have seen what options were considered but rejected, what analysis was undertaken to explore additional options, and what additional research is planned or underway.

Based on the Company's reply and STOP B2H's observations, Staff recommends that the Company review all piloted measures that the Energy Trust of Oregon has

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[9] Order No. 18-176, page 16.
[10] LC 74, Staff Opening Comments page 11.
[11] LC 74, Stop B2H Opening Comments page 61.
[12] LC 74, Stop B2H Opening Comments page 48.
[13] LC 74, Idaho Power Reply Comments page 48-52.

undertaken in the last three years and report on whether the Company has considered them, what research was conducted to look into these measures, whether there has been a decision on the inclusion of these measures, and what the determination is to date. Staff believes this is a reasonable request as it is neither a time-consuming comparison of measure lists, nor a requirement for alignment. Staff only requests evidence that the Company considered the same new opportunities that are available to other Investor Owned Utility (IOU) ratepayers in Oregon, and that the Company make a determination based on this information. Staff would like this consideration to coincide with the Company's 2021 fall planning process.[14]

Staff's Recommendation for the 2019 IRP Update:

- Review all energy efficiency measures piloted by Energy Trust in 2018-2020 and report on whether the Company has considered them, what research was conducted to look into these measures, whether there has been a decision on the inclusion of these measures, and what the determination is to date. The Company should share the status of its review at an Energy Efficiency Advisory Group meeting in 2021 and as a report in the next IRP Update.

Utility Cost Test and T&D Deferral Values

In Opening Comments, Staff discusses the Idaho Public Utility Commission order to screen measures using the Utility Cost Test (UCT) as the primary test, whereas previously the Company used both the UCT and the Total Resource Cost test (TRC). In Oregon, the Company is still required to screen with both tests. Staff notes that it is unclear how the shift to a UCT-based screening will impact overall energy efficiency potential and requested clarification.[15]

In Reply Comments, the Company states it does not know how the change to using the UCT as the primary screening criteria will impact energy efficiency potential. The Company will compare two approaches through a third-party energy efficiency potential study to see differences at the economically achievable level. The Company will hold an additional workshop prior to the finalization of the energy efficiency potential study, and it will use the rest of 2020 as a transition period to implement the change.

Staff believes this is a reasonable approach. Staff appreciates the additional stakeholder engagement and time for the transition and will stay engaged in the stakeholder review process to ensure the changes still fulfil the cost-effectiveness requirements for Oregon.

In Opening Comments, Staff also asks about the Company's update to transmission and distribution system deferral values for use in energy efficiency avoided costs.[16]

[14] LC 74, Idaho Power Reply Comments page 54.
[15] LC 74, Staff Opening Comments page 12.
[16] LC 74, Staff Opening Comments page 10.

Staff reviewed the Company's responses and found that the deferral values are consistent with filings made by other utilities.

Demand Response

Staff Commends DR Changes in 2019 IRP

In the *Second Amended* IRP, Idaho Power explains that in the course of the Comprehensive 2019 Review Process, it revised its modeling of demand response (DR), and this affected the Preferred Portfolio in the *Second Amended* 2019 IRP. Specifically, the Company reviewed DR dispatch settings and discovered that it only dispatched DR in resource deficit situations.[17] In the *Second Amended* IRP, Idaho Power decided to treat DR as a resource to offset peak load.[18]

Staff is pleased to see that DR has been, and presumably will continue to be, modeled as a resource that might address capacity needs on an economic basis, rather than as a "last resort."[19] The Company notes that, "While the prior approach was not incorrect, the revised approach is more consistent with the way Idaho Power's DR programs work in practice."[20] Staff still has concerns about the modeling of capacity costs of DR, which are discussed further below, but notes the new approach now seems consistent with IRP Guidelines 1a[21] and 7.[22] Staff appreciates the Company's candor in surfacing and documenting this change.

This modification affected the Preferred Portfolio in the following way: demand response and adjusted transmission capacity helped replace wind and solar resources in the outer years of the model time horizon. Specifically, wind adoption drops from 300 MW to 0 MW and solar drops from 1,160 MW to 400 MW.[23] Transmission capacity was adjusted by approximately 50 MW and DR increased by 15 MW (with a total expanded demand response capacity of 45 MW).[24] Again, Staff is pleased to see the results of DR modeled to address capacity on an economic basis.

[17] 2019 IRP Review Report: Process and Findings, page 56.
[18] LC 74 - Second Amended 2019 IRP, page 5.
[19] LC 74 - Second Amended 2019 IRP, page 9.
[20] LC 74 - Second Amended 2019 IRP, page 5.
[21] Guideline 1a. All resources must be evaluated on a consistent and comparable basis. All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power or gas purchases, transportation, and storage and demand side options which focus on conservation and demand response.
[22] Guideline 7. Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities). Second Amended 2019 Integrated Resource Plan—Appendix C, page 84.
[23] Second Amended 2019 IRP, page 16.
[24] Second Amended 2019 IRP, page 16.

Expanded DR in the *Second Amended* IRP

In Opening Comments, Staff reviews Idaho Power's DR planning and focuses its comments on three topics: 1) the cost of expanded DR modeled in the IRP; 2) the extent to which DR can provide similar services as battery storage, and relatedly, the extent to which DR programs may be able to provide more frequent and flexible services in the future; and 3) the levelized cost of capacity of DR programs compared to battery storage.

In Opening Comments, Staff notes the modeled levelized cost of capacity (LCOC) of existing resources is $29 per kW-year and that the modeled LCOC of expanded DR resources is $60 per kW-year, a significant increase (greater than 100 percent). Staff asks the Company to rerun the model varying the LCOC of expanded DR with values less than $60 per kW-year, e.g., a 10 percent increase over the existing resource of $29 per kW-year ($32 per kW-year), a 25 percent increase ($37 per kW-year), and a 50 percent increase ($44 per kW-year).

CUB also notes the modeled cost of $60 per kW-year, as well as the Company's experience running DR programs, and wonders why the actual cost of new DR programs, appropriately adjusted for inflation, couldn't be used as the proxy cost for modeling expanded DR programs.[25] CUB also expresses concern that, per the Preferred Portfolio, no additional DR is added until 2031.[26] STOP B2H notes the modeled cost, opining that with an "insignificant goal" of adding 30 MW to the existing 390 MW of DR capacity "incentives for "additional customer participation" should be minimal." STOP B2H would like the modeled cost to be further justified[27] and requests justification for the delay of additional DR until 2031.[28]

In Reply Comments, Idaho Power first addresses the timing of DR additions:

> The 2019 IRP is not calling for additional DR capacity until 2031 primarily due to Idaho Power currently having 390 MW of demand response—nearly 12 percent of the Company's all-time system peak—as a resource to use for future summer capacity constraints.[29]

The Company goes on to provide background on IPUC Order No. 32923 and OPUC Order No. 13-482, which set numerous operational aspects of the Company's DR programs. In particular, Staff notes the following:

[25] LC 74, CUB Opening Comments, page 6.
[26] LC 74, CUB Opening Comments, page 5.
[27] LC 74, STOP B2H Coalition Opening Comments, page 24.
[28] LC 74, STOP B2H Coalition Opening Comments, page 19.
[29] LC 74, Idaho Power Company's Reply Comments, page 56.

> The agreement stemming from this case restricted Idaho Power's ability to expand its demand programs until the IRP shows a capacity need that could be satisfied by demand response.[30]

Idaho Power later addresses the modeled capacity cost of expanded DR, confirming it is based on approximately one-half the price of a Simple Cycle Combustion Turbine, which has a capacity cost of $136 per kW-year.[31] The Company disagrees that its capacity cost estimate is inappropriate, that reruns are necessary, and notes the 2017 IRP used a similar LCOC value. Idaho Power goes on to say:

> Demand response, as a customer-based program, is difficult to estimate with respect to future costs, particularly more than a decade into the future. Moreover, as the Company explained in its response to Staff's data request, an expanded or new demand response program would entail additional equipment and set-up costs that are not included in recent cost figures. For instance, the $29 per kW-year figure for 2018 does not include equipment or set-up costs, as these were incurred in prior years.[32]

Staff concurs with Idaho Power's rationale that it is unreasonable to assume expanded DR could be added at the same LCOC as existing programs. For example, additional control equipment must be purchased, installed, and configured; software systems may need to be upgraded or licenses expanded; enrolling new participants may require additional marketing and outreach efforts; once signed-up, those new participants may earn enrollment incentives; and once operating, the expanded programs may have to pay out additional incentives. However, given Idaho Power's successful current DR offerings, Staff disagrees that these costs are difficult to estimate.

Staff strongly disagrees with the notion that these costs are more than a decade into the future. To Staff's knowledge, the Company did not alter DR cost assumptions in the *Second Amended* IRP. Staff notes from the 2019 *Second Amended* IRP:

> The company considered achievability and operability to properly model the potential expansion of demand response. Based on this analysis, the company made available 5 MW blocks of incremental new demand response each year for selection in AURORA starting in 2023.[33]

The expanded DR modeled in the IRP is an incremental increase. It is 5 MW added to an existing program of 390 MW, which may begin in 2023 and represents an approximately 1.3 percent increase in program size, starting in as little as 24 months

[30] LC 74, Idaho Power Company's Reply Comments, page 57.
[31] LC 74, Idaho Power Company's Reply Comments, page 59.
[32] LC 74, Idaho Power Company's Reply Comments, page 59.
[33] LC 74 – 2019 Second Amended IRP, page 64.

from now. Staff believes that the modeling of an expanded DR resource with these characteristics, but with a 107 percent increase[34] in the LCOC of the existing resource, is unrealistic. If there is good reason for modeling this resource with this increase in LCOC, Staff welcomes further explanation or clarification from the Company. Absent any such explanation or clarification, Staff suggests the modeling of expanded DR in the future ought to either have a LCOC based on real programmatic approximations for acquiring the said amount of incremental additional DR, or have LCOC estimates representative of incremental increases (e.g., 20 percent increase, 30 percent increase, 50 percent increase).

Staff Recommendation for 2021 IRP:

- The 2021 IRP should model expanded DR with a LCOC based on real programmatic approximations for acquiring the said amount of incremental additional DR; LCOC estimates representative of incremental increases (e.g., 10 percent increase, 20 percent increase, 30 percent increase, 50 percent increase); or some other mutually agreed upon approach to more rationally model this key variable.

DR and Battery Storage

In Opening Comments, Staff asks Idaho Power to address the extent to which DR can provide services similar to battery storage, as well as the extent to which existing DR programs may be able to provide more frequent and flexible services in the future.

In Reply Comments, Idaho Power does not reply to this request directly, but the Company does speak to its approach to DR noting that "Demand response at Idaho Power is intended to be used for short-term capacity deficits in order to minimize or delay the need to build new supply side resources."[35]

The Company points out that while DR is an economical capacity resource, it is a very expensive energy resource with a levelized cost of energy among the most costly of those analyzed in the IRP. In Opening Comments, Staff suggests pairing demand response with solar. Idaho Power indicates such a combination might be feasible if the solar resource was sufficiently large and if the DR resource's load shape matched the solar load shape, though even if feasible, such an approach would be more costly and less flexible than a solar/battery combination. Staff looks forward to discussing these questions further in the future.

In Opening Comments, Staff asks the Company to explain the different LCOCs of DR programs and standalone battery-storage resources included in the table entitled

[34] LC 74, Staff Opening Comments, page 13.
[35] LC 74, Idaho Power Company's Reply Comments, page 55.

Preferred Portfolio Additions and Coal Exits, presents columns of resources: Gas, Wind, Solar, Battery, Demand Response, and Coal Exit.[36] The table demonstrates IRP selection of a battery resource earlier, and in greater amounts, than DR.

In Reply Comments, Idaho Power explains that a combined solar and demand response program would likely result in a higher LCOC than any of the solar/battery combinations analyzed in the IRP.[37] Staff appreciates this explanation, and notes that in the Second Amended 2019 IRP the selection of a battery resource occurs at the same time as DR.

TOU Programs

In Opening Comments, CUB notes that Advanced Metering Infrastructure (AMI) deployment in Oregon is nearing completion and is scheduled to be nearly complete by the end of 2020; with this resource in place CUB recommends Idaho Power initiate pilots such as critical peak pricing, peak time rebates, or time-of -use rates.

In Reply Comments, the Company states that the IRP indicates there is no need for additional DR until 2031 (and no need for winter DR) and thus it's unreasonable to invest in pilots so far in advance of identified need.

Staff notes the Company currently offers an Oregon Residential Time-of-Day Pilot Plan. The pilot launched June 1, 2019, and was most recently updated November 1, 2020.[38] It offers just one percent differential in time-of-day (peak/off-peak) pricing but offers a 64 percent differential in seasonal (summer/winter) pricing. Idaho Power plans to first report pilot results in the 2021 Smart Grid Report.[39] While acknowledging the IRP does not call for DR until 2031, Staff notes the $60 per kW-year LCOC of expanded DR as modeled in the IRP is likely an unrealistic LCOC for behavior-based programs (which lack costs associated with hardware controls) such as those suggested by CUB.

Staff's Recommendations for Final Comments:

- Provide an update on the Oregon Residential Time-of-Day Pilot Plan including number of participants, total cost of the pilot since its 2019 launch, and peak capacity reduction by season, as well as propose an alternative venue for reporting pilot results, given that the 2012 Smart Grid Report will be suspended with the Commission approval of DSP guidelines.

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[36] LC 74, 2019 Amended IRP, Appendix C, p. 25

[37] LC 74, Idaho Power Company's Reply Comments, page 60.

[38] See https://docs.idahopower.com/pdfs/aboutus/ratesregulatory/tariffs/315.pdf, and https://www.idahopower.com/accounts-service/understand-your-bill/pricing/oregon-pricing/oregon-time-day-plan/.

[39] ADV 901, Idaho Power Advice No. 18-12, p. 4

Staff's Recommendations for the 2021 IRP:

- Work with Staff and stakeholders to develop a new modeling approach suitable for behavior-based DR programs that reflects such programs' typical lower costs and less certain results.

Resource Inputs

Capacity Value of Solar

In Opening Comments, Staff seeks an explanation from the Company for how the approach used in the 2019 IRP to estimate the capacity contribution of solar resources is in compliance with Order No. 16-326 issued in Docket No. UM 1719.[40] In Docket No. UM 1719, the Company entered into a stipulation with other parties to the docket that the Commission approved, which states:

> Idaho Power's existing methodology for estimating capacity contribution of wind and solar generators for Integrated Resource Planning is an acceptable [Capacity Factor] CF approximation methodology with the addition of an [Loss of Load Probablility] LOLP analysis that is based on all hours in a year.[41]

Idaho Power's analysis in this IRP is not derived from all 8,760 hours in a year. Instead, Idaho Power uses the highest 100 hours of the Company's load duration curve.

In Reply Comments, the Company attempts to reconcile this analysis with the approved methodology in Order No. 16-326 by making four arguments:

> While Idaho Power recognizes that its approach to calculating solar's capacity value has changed, the Company believes that the National Renewable Energy Laboratory's ("NREL") approach used in this proceeding substantially complies with the parties' stipulation and the Commission's order because (1) the Company clearly communicated to both other parties and the Commission concerning the nature and reason for this change; (2) an alternate approach was plainly necessary to account for the dramatic increase in solar penetration in a few short years, while simultaneously modeling significant additional solar capacity expansions in this IRP; (3) the Company was unable to implement the Effective Load Carrying Capability ("ELCC") method due to lack of data required by that model; and (4) the NREL model is a highly regarded, rigorously supported, third-party method that is closely related to the ELCC and is based on all hours in a year.[42]

The Company goes on to add a fifth and sixth argument: "utilities were free to interpolate or extrapolate from the calculated values as needed, and Idaho Power in

[40] OPUC Staff. *Opening Comments* LC 74, April 1, 2020, page 16.
[41] Order No. 16-326, Appendix A, page 3.
[42] IPC. *Reply Comments* LC 74, May 15, 2020, page 40.

particular could continue to apply its own “approximation” approach to assessing solar’s capacity value, so long as the Company’s Loss of Load Probability (“LOLP”) was similarly based on solar’s contribution during all hours of the year.”[43]

Staff is concerned that Idaho Power is not in compliance with Order No. 16-326. First, the Company’s communication of this change to the Integrated Resource Plan Advisory Committee (IRPAC) on December 13, 2018, and the IRP Update Report on January 28, 2019, does not constitute a Commission order overturning the requirements in Order No. 16-326. The second and third arguments make methodological conclusions that have not been sufficiently predicated. Fourth, the subjective judgement that the NREL method is highly regarded is irrelevant to the question of whether or not the Commission has authorized its use in the IRP. Fifth, interpolation is the estimation of an unknown value that lies within a range of observations. Extrapolation is the estimation of an unknown value outside the range of observations. These two terms do not refer to the size of the range. Order No. 16-326 set the range as all the hours in a year. Interpolate means the Company can estimate the value of data points that might be missing. Extrapolate means the Company can estimate values beyond the data series Idaho Power has. And sixth, when the Commission authorized the Company’s “own” method provided it uses data from all hours of the year, this was referring to the prior approximation method the Company was using, not an alternative method that does not use all hours of the year. To Staff’s knowledge, the Company did not alter this approach for the *Second Amended* IRP.

Staff’s Recommendation for Final Comments:

- Extrapolate from the data the Company has by regressing solar generation on weather data. Map weather data outside the Company’s range of solar generation observations to create a sufficient number of years’ data for the ELCC method; or
- Perform the Company’s approved capacity factor approximation method using all the new data that has become available during the time that has passed due to the delay of the 2019 IRP’s original filing.

Capacity Value of Wind

In Staff’s Opening Comments, Staff observes that the 2019 *Amended* IRP does not go into the same detail about the capacity valuation of wind resources as it does for solar. Staff asks the Company to clarify how the methodology used to derive wind capacity values complies with the stipulation approved by Commission Order No. 16-326.[44]

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[43] IPC. *Reply Comments* LC 74, May 15, 2020, page 41.

[44] OPUC Staff. *Opening Comments* LC 74, April 1, 2020, page 16.

In Reply Comments, the Company states, "In compliance with the stipulation, Idaho Power used a CF approximation method to calculate wind's capacity factor, with the addition of a LOLP analysis based on all hours in a year."[45]

Staff thanks the Idaho Power for this clarification. Staff accepts the Company's answer.

Third-Party Natural Gas Forecast

In the 2019 IRP, the Company refers to a "thorough examination" of its third-party reviewer's methodology, S&P Global Platt's North American Natural Gas Analytics.[46] In Staff's Opening comments, Staff seeks clarification on the criteria used in this examination.[47]

In Reply Comments, the Company explains that it compares Platts' forecast to forecasts by the Energy Information Administration, Moody's Analytics, and the NYMEX natural gas futures settlements, concluding:

> … the EIA "high" and "reference" cases are both elevated, and do not reflect actual market prices. While the Moody's Analytics and Platts forecasts converge around 2029, the near-term Moody's Analytics forecast was far above where the market was trading at the time. Based on this comparative analysis, and given the robust natural gas forecasting methodology employed by Platts, the Company judged that Platts' natural gas forecast was reasonable.[48]

Staff thanks the Company for this added detail and accepts this answer.

Battery Storage

Staff looked into the AURORA modeling assumptions for battery storage in the 2019 IRP and found that the Company places limits on the amount of storage allowed in its portfolios.[49] Based on the data provided to Staff, the amount of standalone storage available for selection in this IRP appears to be limited to 80 MW per year, and the amount of storage that can be paired with solar is limited to 80 MW over the entire planning timeframe. These assumptions do not appear to be based on realistic technology limitations, given that other utilities have constructed battery projects as large as 250 MW in the US.[50] Idaho Power should explain the reasoning behind these limitations in its Final Comments, or else future analysis should remove these limits on battery capacity.

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[45] IPC. *Reply Comments* LC 74, May 15, 2020, page 43.
[46] LC 74, Idaho Power 2019 Amended IRP, p. 89.
[47] OPUC Staff. *Opening Comments* LC 74, April 1, 2020, page 17.
[48] IPC. *Reply Comments* LC 74, May 15, 2020, page 65.
[49] Aurora database provided to Staff for review.
[50] LS Power's Gateway project in California.

Staff Recommendation for Final Comments**:**

- Explain why it limited battery storage to 80 MW.

Staff Recommendations for the 2021 IRP:

- Eliminate or raise the 80 MW cap on battery storage. This includes standalone battery storage as well as storage paired with solar.

Gas Plant Procurement vs. 100 Percent Clean Energy

The 2019 IRP explicitly states the Company has a goal of generating 100 percent clean energy by 2045.[51] However, the Preferred Portfolio includes the acquisition of natural gas plant resources that will have a useful life beyond 2045. Modeling these emitting resources assumes Idaho Power will emit carbon after 2045 and does not account for the cost of buying offsets.[52] To Staff's knowledge, this is an assumption that the Company retains from the *Amended* IRP.

In Opening Comments, Staff seeks clarification on the risk this planning contradiction may pose for ratepayers. Sierra Club's Opening Comments warns such a contradiction may "drive away" environmental, social, and governance investors.[53] In Reply Comments, the Company describes the gas plant as a "surrogate resource" that reflects, "…the attributes and costs that the Company must target to be cost-effective for customers."[54] If the Company has selected the least cost least risk portfolio correctly, such a response implies 100 percent clean energy generation is not cost-effective for customers according to the information available at the time Idaho Power announced its clean energy goal. Staff would like clarification from Idaho Power on what the Company means by targeting costs.

When Idaho Power states, "…the natural gas generation identified in the preferred portfolio is intended as a placeholder for flexible resources that can meet system needs," Staff wonders why the Company's preferred portfolio includes a gas plant rather than the resources the Company would *prefer* to rely on to meet its 100 percent clean energy goal.[55] Staff would like clarification from Idaho Power on whether this means the Company's 2019 IRP does not reflect the Company's actual plans.

REC finds the timing of this resource outside the Action Plan reassuring, recommending the Company keep an "…open mind when assessing potential resources to meet the flexible capacity needs that are currently projected to be met by a 300 MW gas combined cycle combustion turbine plant in 2030."[56] The Company should state clearly in this IRP whether it actually plans to build this gas plant in what is now planned to be

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[51] LC 74 - Idaho Power 2019 Second Amended IRP, page. 13.
[52] Idaho Power Response to Staff DRs 1-2.
[53] Sierra Club. *Opening Comments* LC 74, April 2, 2020, page 5.
[54] IPC. *Reply Comments* LC 74, May 15, 2020, page 44.
[55] IPC. *Reply Comments* LC 74, May 15, 2020, page 78.
[56] Renewable Energy Coalitions. *Opening Comments* LC 74, April 2, 2020, page 6.

2031,[57] or if the Company plans to be a 100 percent clean energy producer by 2045. If Idaho Power plans the latter, then it needs to select a preferred portfolio that accurately reflects the Company's intentions.

In the *Second Amended* IRP, the Company introduces a new range of portfolios created under a High Gas, High Carbon future that did not allow natural gas to be selected, and instead introduces a different blend of carbon free or low carbon resources, including pumped hydro, biomass, and nuclear instead of natural gas.[58] Staff believes this is a step in the right direction and helps stakeholders understand what it would take to achieve a 100 percent energy future. Staff commends the Company for introducing this new step into the IRP. Staff does note, however, that in general, these lower-carbon portfolios reflected higher costs compared to other portfolios.

Staff's Recommendation for Final Comments

- Provide clarification on whether the selection of the preferred portfolio means the Company's 2019 IRP does not reflect the Company's actual plans.
- Address the higher cost of a 100 percent renewable portfolio.

Wind in the Preferred Portfolio

In Opening Comments, Staff finds the $94/MWh of Wyoming wind significantly higher than what is generally found in the resource economics literature.[59] In Reply Comments and in the Company's response to OPUC Staff DR 68, Idaho Power reveals that is not the cost used as an AURORA input.

The Company includes this number in the text of the 2019 IRP for "comparative purposes only."[60] Staff thanks Idaho Power for that clarification. The resource economics literature tends to only publish the levelized cost of energy (LCOE) for each resource individually and does not include the LCOE of the backup generation needed when the wind isn't blowing. Idaho Power's $94/MWh included $25.59/MWh of this extended component of integration cost. Staff sees validity in making this adjustment for comparison to firm resources.

However, the remaining $68.41/MWh still stands above the extant literature. The Company's $133/kW for transmission capital costs does not fully explain this outlier.[61] The investment bank Lazard has found the top range capital cost for a wind resource to be $1,500/kW.[62] Idaho Power assumes $1,755/kW.[63] Lazard finds the top range of fixed

[57] See Technical Appendix C of the Second Amended IRP, page. 58, Portfolio PGPC B2H (1).
[58] LC 74 - Second Amended IRP, page. 110.
[59] OPUC Staff. *Opening Comments* LC 74, April 1, 2020, pages 17, 18.
[60] Idaho Power Response to Staff DR 68, page 1.
[61] Idaho Power Response to Staff DR 68, page 1.
[62] Lazard. *Lazard's Levelized Cost of Energy Analysis Version 13.0* November 2019, page 10.
[63] Idaho Power Response to Staff DR 68, page 1.

operation and maintenance costs to be $11/MWh.[64] Idaho Power assumes $18.16/MWh.[65]

Staff is concerned that the magnitude by which the resource cost of Wyoming wind has been overestimated may have an impact on portfolio modeling in the time period when the 2019 IRP's preferred portfolio has selected a natural gas plant in variance with the Company's goal of generating 100 percent clean energy.

Idaho Power is located next to some of the most productive wind energy sites in the United States.[66] In all iterations of the IRP, including the *Second Amended* IRP, Idaho Power chooses to exclude the PTC from its analysis in the 2019 IRP. When Staff inquired about the PTC, Idaho Power responded that the impending PTC expiration and lack of near-term resource need would prevent any future wind resources from being able to utilize the PTC.[67] Staff agrees that procuring resources according to need is a prudent practice, but Staff is also concerned that excluding the PTC from the IRP analysis may result in lost opportunities to explore the use of wind resources.

The Company undertook a wide number of changes in this IRP, and given potential high costs of transmission associated with wind upgrades, Staff is interested to see how the PTC would affect the preferred portfolio in the 2021 cycle. Staff reiterates its support for a PTC wind analysis and recommends that this further analysis be performed by Idaho Power as part of an overall assessment of the potential for wind as part of the Company's 2021 IRP.

Staff's Recommendation for the 2021 IRP:

- Model the PTC for wind to the extent it is technically achievable by the Company.
- Revise its Wyoming cost inputs to include more reasonable cost assumptions.

Portfolio Development

Because of the vast changes in portfolio development in the *Second Amended IRP*, all of Staff's concerns, and the concerns of stakeholders, with the previous iterations of the IRP may not apply. Because the Company has changed its portfolio selection process and has added new sensitivities, Staff will evaluate the *Second Amended IRP* portfolio selection process as a new process and will leave to stakeholders to express their concerns in Final Comments.

The Company has led stakeholders through many iterations of portfolio analysis. The bones of the Company's analysis have remained the same in the *Second Amended IRP*, but the new sensitivities and scenarios merit review. Staff finds the Review Report

[64] Lazard. *Lazard's Levelized Cost of Energy Analysis Version 13.0* November 2019, page 12.
[65] Idaho Power Response to Staff DR 68, page 2.
[66] Outcalt, Chris. *Wyoming Confronts Its Wind-Powered Destiny* Wired, April, 1, 2020.
[67] IPC response to Staff Information Request 55.

helpful in understanding the changes to the newest iteration of the IRP. However, the portfolio construction process is difficult to follow as a result of the iterative elimination process in this IRP cycle and in the *Second Amended* IRP. Further, repetitive nomenclature made distinguishing between portfolios confusing.

To summarize the Company's portfolio selection process, the Company starts by choosing three gas forecasts (Planning Gas, EIA Reference Gas, and EIA LOG Gas) and four carbon price forecasts (Zero Carbon, Planning Carbon, Generational Carbon, and High Carbon), and inputs these forecasts into AURORA to construct 12 Portfolios without B2H (Labeled Portfolios 1-12) and 12 Portfolios that include B2H (Labeled Portfolios 13-24).[68] Taken together, these initial 24 Portfolios are optimized to the WECC and serve as a starting point the Company then used to "weed out" categories for additional analysis.[69]

Idaho Power categorized these 24 portfolios into six "buckets" based on resource similarity.[70] The buckets are based on the carbon cost, gas forecast baseline, and inclusion of B2H:

Figure 2 - Initial WECC-Optimized Portfolios[71]

Table 8.5 WECC-Optimized Portfolios Selected for Manual Adjustments

Category	B2H Portfolios	Non-B2H Portfolios
Planning Gas, Planning Carbon (PGPC)	P(13), P(14)	P(1), P(2)
Planning Gas, High Carbon (PGHC)	P(15), P(16)	P(3), P(4)
High Gas, High Carbon (HGHC)	P(23), P(24)	P(11), P(12)

As the Company explains, the portfolios in the first two rows (Planning Gas, Planning Carbon (PGPC) and Planning Gas, High Carbon (PGHC)) are the lowest cost WECC-optimized portfolios. The Company determines that because these resources match closely, the PGPC and PGHC categories would be best to use as a backbone for further optimization. The Company also adds an additional category (as compared to the *Amended IRP*)—High Gas, High Carbon (HGHC)—to analyze whether it could obtain a more optimal portfolio with a different blend of flexibility resources. The Company added this High Gas, High Carbon category based on input from stakeholders throughout the docket. This allows the Company to segment its modeling approach into the six different "buckets" for further analysis: Three B2H portfolios created with PGPC, PGHC, and HGHC forecasts, and three non-B2H portfolios also created with PGPC, PGHC, and HGHC forecasts.

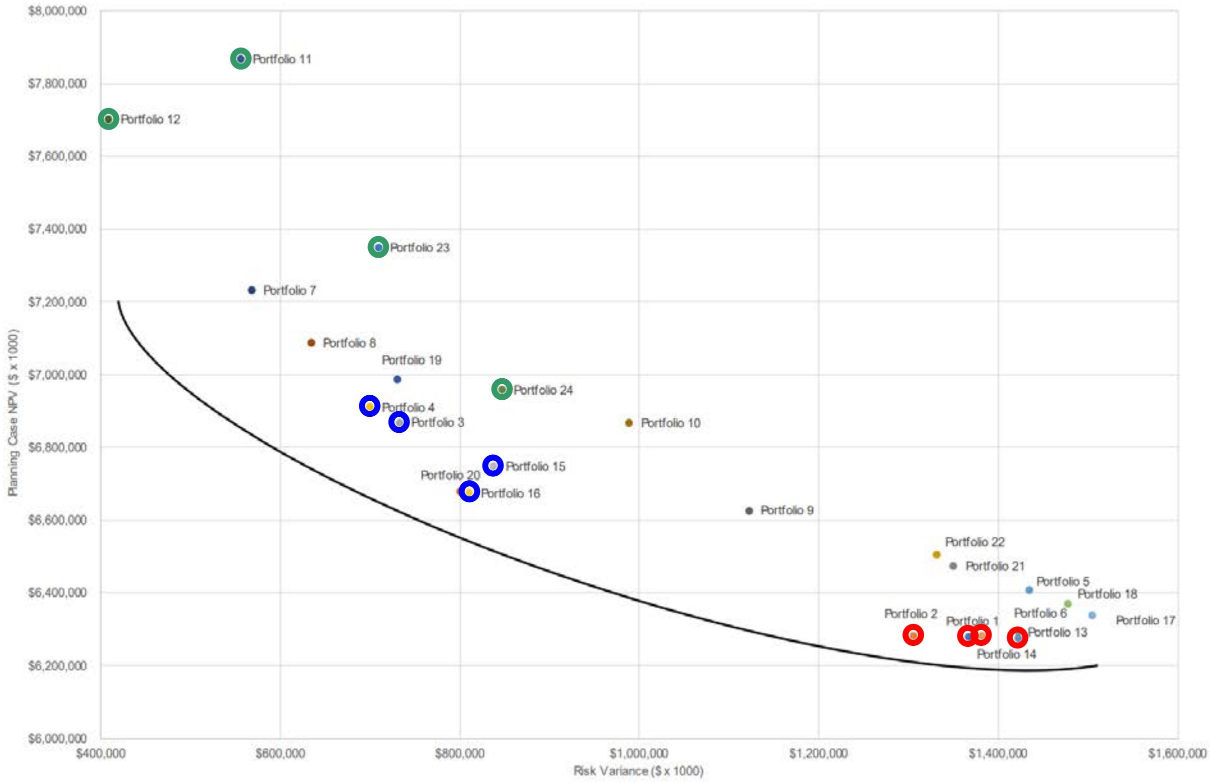
[68] LC 74 – Idaho Power Second Amended IRP, page 106.
[69] LC 74 – Idaho Power Second Amended IRP, page 109.
[70] See pages 108 and 109 of the IRP.
[71] LC 74 – Idaho Power Second Amended IRP, page 110.

This approach was confusing to follow. First, PGPC, PGHC, and HGHC, are highly similar in nomenclature. Second, this nomenclature identically abbreviates the four futures used to compare portfolio risk. Thus, there exists both “PGPC portfolios” and “PGPC futures” in the IRP, which made distinguishing among IRP components a convoluted endeavor.

While Staff can understand wanting to distinguish portfolios by forecast category, the differences among portfolios become even less clear as the IRP progresses. Additionally, the initial WECC Portfolios 1, 3, and 11 do not appear to be determined by planning carbon or high carbon forecasts, but rather zero carbon or generational carbon forecasts. It also appears that the Company chose to re-label these for simplicity. Likewise with Portfolios 13, 15, and 23, these appear to be created with zero carbon or generational carbon forecasts, not the Planning or High Carbon forecasts as suggested in the table. It is thus unclear what carbon forecasts are actually used, and whether the portfolios would really perform the same under a zero carbon or generational carbon forecast when considering different Jim Bridger exit dates. Regardless, the portfolios grouped together do appear similar, and the basic idea here is that the Company uses these gas and carbon forecasts to create an initial range of buckets for further analysis.

On the following page is a graph of the initial 24 WECC-optimized portfolios, with the portfolios from *Figure 3* highlighted for ease of reference.

Figure 3 - Highlighted WECC-Optimized Portfolios



Green represents the High Gas, High Carbon (HGHC) portfolios, blue represents the Planning Gas, High Carbon (PGHC) scenarios, and red represents the Planning Gas, Planning Carbon (PGPC) scenarios.

In the *Amended IRP*, the Company presents a similar graph to illustrate four portfolios it selected for further analysis. These four portfolios were chosen based on their relative low cost and low risk. In the *Second Amended IRP*, it is implied that the Company combines portfolios from Table 8.5 in the following way: P(1) and P(2) to create a PGPC portfolio; P(13) and P(14) to create a PGPC B2H portfolio; P(3) and P(4) to create a PGHC portfolio; P(15) and P(16) to create a PGHC B2H portfolio; P(11) and P(12) to create an HGHC portfolio; and P(23) and P(24) to create an HGHC B2H portfolio.

The Company is not explicit in this identification process for these six “combined” portfolios, which makes reading the IRP difficult to follow.

From these six “combined” portfolios, the Company then creates 24 new, manually-adjusted portfolios that incorporate the planning futures (PGPC, PGHC, HGHC), the addition of B2H or lack thereof, Jim Bridger retirement scenarios, in addition to modifications that supported lower-carbon resources.[72]

[72] The Company refers to these latter modifications as Scenario 4. See page 115 of the Second Amended IRP.

The Company also incorporates an additional coal retirement scenario, such as the Valmy Unit 2 closure in 2022 to further refine the portfolios and includes additional modifications not explicitly delineated in the IRP.

There are multiple sets of 24 portfolios in the IRP, represented by Tables 9.5, 9.6, and 9.7. The Company compares each subset of these 24 portfolios[73] across different gas and carbon pricing futures (Planning Gas Planning Carbon, High Gas Planning Carbon, Planning Gas High Carbon, and High Gas High Carbon) to get a picture of risk, and ultimately identifies the portfolio PGPC B2H (1) as the preferred portfolio, which signifies a manually optimized portfolio created under Planning Gas and Planning Carbon conditions, with B2H, and under a Bridger retirement scenario that retires coal units in 2022, 2026, 2028, and 2030 (the earliest of all retirement scenarios).

Staff appreciates the work the Company undertook in this IRP, and the subsequent changes made. However, Staff reiterates that the changes in the *Second Amended* IRP and the accompanying nomenclature are incredibly difficult to follow. Staff realizes the Company's changes are an effort to address errors and improve the analysis, but the Company should improve upon this methodology in the 2021 IRP. Below are some concerns and improvements that the Company should incorporate.

Qualitative Risk

In Opening Comments, Staff notes that as part of the 2017 IRP, Staff recommended that the Company continue to provide qualitative benefits and risks by portfolio and that Staff is still interested in this information.

In response to IR 45, the Company states, "These risk factors were not quantified, but they were described in detail to provide the reader an understanding of the qualitative risk factors that were not captured quantitatively within the development of each portfolio." In Reply Comments, the Company again points to the description provided in the *Amended* IRP.[74]

Staff understands that the Company incorporates some qualitative criteria in further analysis and that a qualitative analysis tends to yield qualitative results. However, Staff expects that qualitative measures would be consistently applied across portfolios, and that the results of such an analysis could be provided by portfolio, regardless of whether those results are nominal, ordinal, or numeric. For example, when "Technological Obsolescence" is listed as a qualitative risk that each portfolio—and each resource—is scrutinized by, Staff expects a determination by portfolio of which portfolios bear greater or lesser risk of technological obsolescence.[75]

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[73] See Tables 9.5, 9.6, and 9.7 of the *Second Amended* IRP.

[74] LC 74, Idaho Power Reply Comments, page 19.

[75] LC 74 – Idaho Power *Second Amended* 2019 IRP, page 105.

Staff Recommendation for the 2021 IRP:

- Report qualitative benefits and risks by portfolio this in the 2021 IRP and in all IRPs going forward in which a qualitative analysis plays a significant role.

WECC Portfolios

In Opening Comments, Staff acknowledges that the Company applies LTCE modeling as previously requested by Staff. Renewable Northwest also compliments the Company's improvements for selecting portfolios as a marked improvement on the 2017 IRP.[76] Additionally, Staff also recommends that the Company explore modifying its approach to using capacity expansion software in its next IRP for portfolio development by optimizing resource buildouts based on the Company's system only, rather than optimizing for the entire WECC.

In Reply Comments, the Company explains that the modeling software was not set up to support the development of portfolio buildouts using the Company's system specifically, but the Company also appears to be considering Staff's recommendation.[77] It is also Staff's understanding that the LTCE software now supports the ability to optimize for Idaho Power. Staff appreciates that the Company is exploring further improvements to the process and believes this is important. While Staff is not opposed to an initial process of discovery that evaluates WECC-optimized resources, Staff reiterates the need for a process that ensures resource selection is optimized for Idaho Power's customers.

Staff Recommendation for the 2021 IRP:

- Devote resources to improve optimization techniques and address this issue in a 2021 IRP workshop. In particular, the Company should implement techniques in its next IRP to optimize resource buildouts based on the Company's system only.

NPV and Risk

In Opening Comments, Staff raises concerns about using the variance of the net present value (NPV) of four scenarios as a measure of risk. Staff believes that taking the variance of four data points is a poor measure of variance across possible futures. STOP B2H identifies a weakness in the modeling of risk for the purposes of identifying portfolios for further study and says that the Company chose to ignore the risk of carbon in its approach.[78]

In Reply Comments, the Company reviews its analysis methodology, stating:

> While the Company's NPV variance analysis did not weight the relative likelihood of the scenarios, it nonetheless provides valuable insight into the

[76] LC 74, Renewable Northwest Opening Comments page 2.
[77] LC 74, Idaho Power Reply Comments page 21.
[78] LC 74, Stop B2H Opening Comments, pages 9-12.

range of cost risk for each portfolio. By analyzing the performance of each portfolio under this range of future conditions, the Company identified the corresponding range of price risk.[79]

In this new iteration of the IRP, Idaho Power attempts to include a more diverse set of scenarios in the IRP. Staff reviewed the revised data from Table 9.3 (WECC-optimized portfolios) provided in the *Second Amended* IRP that serves as the foundation of portfolio selection.[80] When Staff calculated the correlation of portfolio NPVs among scenarios, Staff found that the correlation between some scenarios was high. The correlation between the Planning Gas, Planning Carbon future and the High Gas, High Carbon future stands at 0.89, and the correlation between Planning Gas, High Carbon and the High Gas, High Carbon scenarios is 0.84 (see *Figure 4*). This suggests that the high gas component had minimal impact on the NPV and differences were driven by the carbon component.

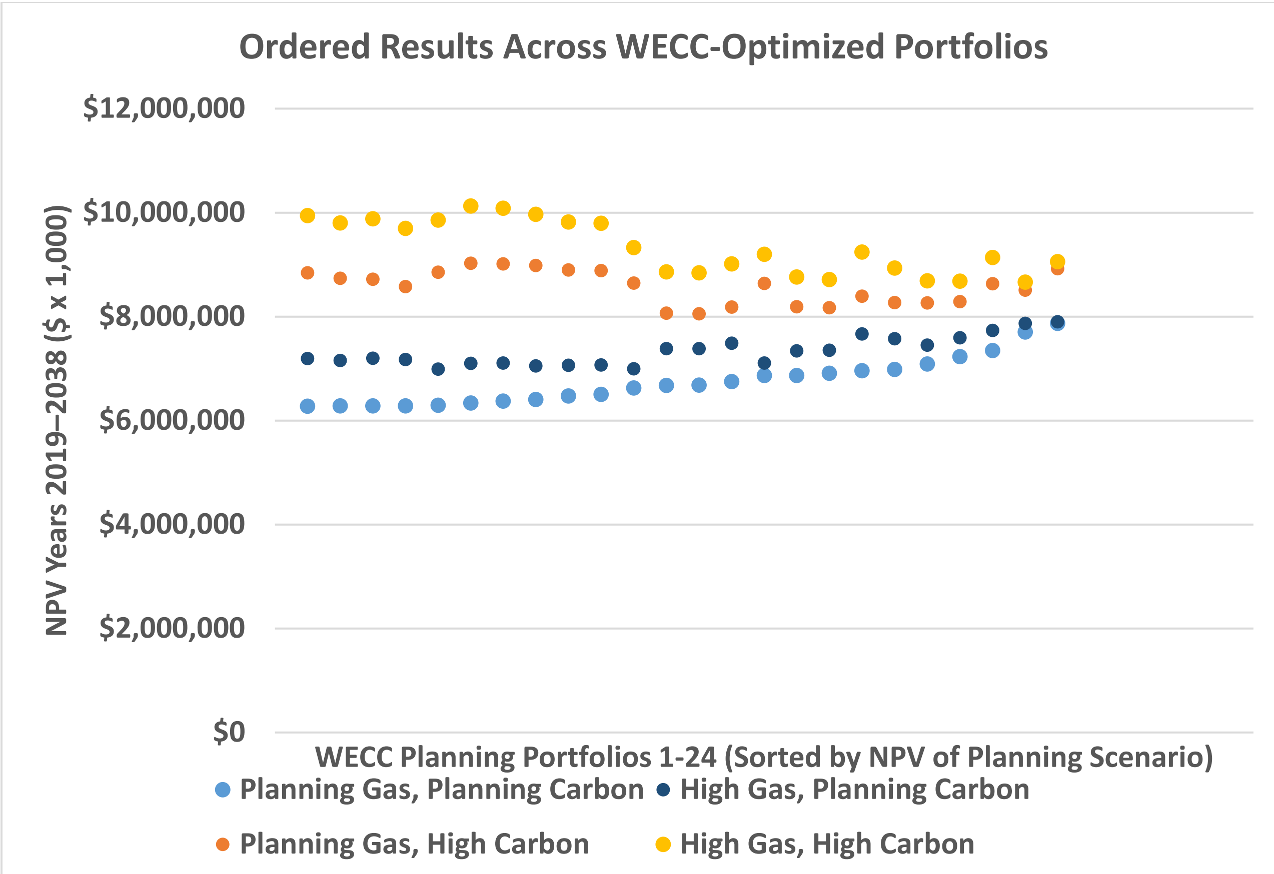
Figure 4 - Correlation Between Gas and Carbon Scenarios for WECC-optimized Portfolios 1-24 (NPV years 2019-2038)

	Planning Gas, Planning Carbon	*High Gas, Planning Carbon*	*Planning Gas, High Carbon*	*High Gas, High Carbon*
Planning Gas, Planning Carbon	1.00			
High Gas, Planning Carbon	0.89	1.00		
Planning Gas, High Carbon	-0.32	-0.44	1.00	
High Gas, High Carbon	-0.75	-0.70	0.84	1.00

The following chart of the initial WECC-optimized portfolios 1-24 illustrates this point. Each dot represents a portfolio, and each color corresponds to a different planning future. The dots are matched so that a vertical set of four colored dots represents a portfolio across the four different planning futures. For ease of reference, the portfolios are ordered left to right by lowest to highest NPV of the Planning Gas, Planning Carbon future. As the graph demonstrates, the scenarios with the strongest correlation move together.

[79] LC 74, Idaho Power Reply Comments, page 25.
[80] Table 9.3 of *Second Amended* IRP, pages 112-113.

Figure 5 - Ordered Results Across WECC Portfolios



A result of the Company's approach, the analysis appears to really only look at the difference between planning carbon and high carbon as an indicator of risk.

The Company makes use of these WECC portfolios as the starting point for further portfolio development. Staff re-asserts that comparing the NPVs across four scenarios is a poor measure of risk, particularly when there is strong correlation between some scenarios.

While Staff does not object to the concept of comparing an expected case portfolio cost to the range of costs across differing scenarios, under such an approach, Staff recommends that more scenarios are used in order to gain a better indication of risk. To reduce confusion, the Company should strongly consider risks or situations that are not used to create the initial portfolios (e.g., PGPC, PGHC, etc.). These scenarios could also draw on qualitative risks.

Staff is not dictating a specific measure for risk but recommends a more robust measure of risk going forward.

Staff Recommendation for the 2021 IRP:

- Implement a more robust measure of risk for evaluating portfolios. The Company should incorporate risks or situations that are not used to create the initial portfolios and should strive to incorporate qualitative risks into the portfolio development process.

Modifications to Manual Adjustments were not Explicitly Delineated in the IRP

Staff recognizes the wide, dynamic changes in the *Second Amended* IRP and the inspection process the Company underwent to verify inputs. However, Staff feels that various details are either left out or not sufficiently clarified in the IRP. The two most notable examples are listed below . While the Company hosted two workshops for stakeholders and the Commission, the Company should provide additional clarity in its Final Comments for some of these changes.

The first is the difference between Tables 9.5 and 9.6 in the IRP. These tables are similarly named, and it is unclear which of these is ultimately characterized in Technical Appendix C.

Table 9.5 is titled "2019 manually built portfolios, NPV years 2019-2038 ($ x 1,000)." Table 9.6 is titled "2019 manually built portfolios, WECC buildout comparison, NPV years 2019-2038 ($ x 1,000)." To further confuse the tables, there is no difference between the portfolio names other than the insertion of the word "Portfolio" in Table 9.6.

The Company explains that for the values in Table 9.6, it "…inserted its manual portfolios into four distinct WECC buildouts…",[81] but the Company did not clarify what manual adjustments it is referring to, and what this additional table represents. Idaho Power goes on to say that it compares these two tables to focus on differences "specific to Idaho Power's portfolio design, rather than differences stemming from future WECC buildout scenarios." Again, it is unclear what the Company is referencing here. As not all of these portfolios are included in the Technical Report, it is unclear what changes the Company is attempting to highlight across its analysis. Staff was able to receive additional clarity on this issue through a phone call with the Company, but the Company's Final Comments needs to provide a clearer and more detailed clarification of adjustments it made.

A similar critique involves the guiding principles used in the manual optimization process. The third bullet on page 115 of the *Second Amended* IRP explains that the Company "reduced where possible" resources identified for WECC optimization, presumably because they were not optimal for Idaho Power's customers. However, the Company again does not specify what these reductions were, the systematic process involved in reducing or deferring these resources, or why it made these decisions. In the

[81] LC 74 – Second Amended 2019 IRP, page 117.

Company's Final Comments, Idaho Power should provide detailed clarification of adjustments made to this process.

Staff Recommendation for Final Comments:

- Provide detailed clarification of manual adjustments made in IRP portfolios based on Staff's comments.

Preferred Portfolio Performs Well in Some Futures but is Outranked in Other Futures

The Preferred Portfolio PGPC B2H (1) performs well in some futures, it performs worse in others.[82] Under a Planning Gas, Planning Carbon future, the highest ranking portfolio is PGHC B2H (4).[83] The Preferred Portfolio PGPC B2H (1) ranks second in cost under this same future. The key differences between these portfolios are that with PGHC B2H (4), some renewable resources and demand response would be installed earlier, but the last unit of Jim Bridger retirement would be deferred until 2034, four years later than the Action Plan.[84] The cost difference between these portfolios ranges between $7.3 million and $144.8 million over the planning period.

Based on Staff's analysis, it is unclear why the Company selected PGPC B2H (1) as the Preferred Portfolio. While there is no single portfolio that outranked others in all futures, PGPC B2H (4) ranked higher in a Planning Gas, Planning Carbon future, and PGHC (1) ranked highest in both the Planning Gas, High Carbon and High Gas, High Carbon futures. However, under a Planning Gas, Planning Carbon future, PGHC (1) is more expensive and ranked fourteenth, for a difference of $151.1 million more in NPV than the preferred portfolio.

In general, the portfolios performed differently depending on the type of future; though not always the least cost, PGPC B2H (4) and PGHC (1) outranked the preferred portfolio across the four different futures. To summarize, the preferred portfolio ranked second in the Planning Gas, Planning Carbon future, seventeenth under a High Gas, Planning Carbon future, twelfth in a Planning Gas, High Carbon future, and nineteenth in a High Gas, High Carbon future. Staff's Attachment B contains an overview of the portfolio rankings, in addition to more detailed analysis explaining cost differences among portfolios.

Staff recognizes that cost is not the sole determining factor in selecting a preferred portfolio, but the Company, in its Final Comments, should provide additional justification for why it chooses PCPG B2H (1) as the Preferred Portfolio. For example, the Company should explain why it did not select PGHC B2H (4) as it ranked number one in the Planning Gas, Planning Carbon future and consistently ranks higher than the Preferred

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[82] The Company filed its Second Amended IRP on October 2, 2020. Comparatively, stakeholders have had a relatively limited time to review the newest iteration of this IRP. While part of the IRP remains the same, due to the various changes, and limited time, Staff will provide high-level comments on the ranking of the portfolios.

[83] This signifies a portfolio that was created under a Planning Gas, High Carbon scenario, with B2H, under various Jim Bridger retirement dates.

[84] See Technical Appendix C, pages 58 and 65.

Portfolio across several futures. The Company should also explain why it did not select PGHC (1), as it performed well in high carbon futures and also outranked the Preferred Portfolio in a High Gas, Planning Carbon scenario. Idaho Power lists a series of qualitative risks in Chapter 9 that it appears to have considered in this process, but the Company does not specify how it applied these risks across portfolio construction.

In this last iteration of the IRP, stakeholders had fewer opportunities and less time to review information at same the level of detail as the workshops, so Staff expects a robust account in the Company's Final Comments about justification for the Preferred Portfolio.

Staff Recommendation for Final Comments:

- Provide a robust account of why the Company selected PGPC B2H (1) as the Preferred Portfolio.

Coal

Valmy Unit 2 Early Retirement

In the *Second Amended* IRP, the Company reveals the possibility of an early Valmy Unit 2 retirement in 2022. The Company also explained this topic in further detail at the Special Public Meeting on October 22, 2020. This is a noteworthy discovery, and Staff supports further analysis on this subject. The Company lists a series of considerations required for this analysis, including the acquisition of firm transmission capacity from Southern markets, reliability assumptions, and operating budgets.[85]

Despite noting additional research is required, Idaho Power requests acknowledgment the Action Item of early retirement of Valmy Unit 2 in 2022. At this point in time, Staff is not comfortable recommending acknowledgment of this early shut down date without the required analysis the Company stated must occur. The Preferred Portfolio selects 2025 as an optimal retirement year, and this was the same year acknowledged in the 2017 IRP. Staff would support an amended Action Item requesting further analysis of this possibility in the 2021 IRP.

Staff Recommendation for Final Comments:

- Change its Action Item to include a Valmy Retirement in 2025 in addition to a study proposal for a 2022 retirement date for the 2021 IRP.

Jim Bridger

The Jim Bridger coal plant contributes substantially to Idaho Power's generating capacity, and the retirement dates of Jim Bridger units are important drivers of resource selections in the IRP. In its Opening Comments, CUB questions Idaho Power's statement that a 2026 retirement of the second Jim Bridger unit is not possible without the addition of B2H to Idaho Power's resource portfolio in the same year. Staff agrees

[85] LC 74 – Second Amended IRP, page 18.

with CUB that this statement does not seem self-apparent, and Staff would request Idaho Power provide a justification for these claims. As some of the preferred portfolios indicate, even without B2H, replacement generation resources could be constructed to facilitate an economic retirement of a second Jim Bridger unit in 2026.

In Opening Comments, Staff planned to look into the cost assumptions for Jim Bridger. Staff has looked into Idaho Power's fuel cost and fixed cost forecasts for Jim Bridger. Staff checked the coal fuel price forecast used by Idaho Power and compared it to that used by PacifiCorp in its 2019 IRP. In PacifiCorp's IRP, Staff and Sierra Club expressed concern with the coal fuel cost forecast for Jim Bridger, which appeared to be unreasonably low. Staff finds that Idaho Power's coal fuel price forecast does not provide the same cause for concern.

Regarding fixed costs, Staff has reviewed the fixed O&M costs of the Bridger units, and has one remaining question for the Company regarding the allocation of fixed costs between Idaho Power and PacifiCorp. Idaho Power is a one-third co-owner of Jim Bridger with PacifiCorp owning the other two-thirds. Staff's review of the AURORA model inputs found that the fixed costs for PacifiCorp's share of the plant are different than for Idaho Power's share of the plant. In a phone conference with Staff, Idaho Power confirmed this finding, and it is Staff's understanding that Idaho Power developed the fixed costs for Idaho Power's share of the plant, whereas a vendor developed the fixed costs for PacifiCorp's share.

Staff requests that Idaho Power review its cost assumptions for both companies' shares of the plant and report in Final Comments regarding the cause and significance of the difference in fixed O&M between these two shares of the plant. Staff would also like the Company to address whether the difference in fixed O&M costs had any significant effect on the selection of the Preferred Portfolio.

Staff Recommendation for Final Comments:

- Assess the fixed O&M cost input to AURORA for its share and PacifiCorp's share of the Jim Bridger plant, and report in Final Comments regarding the cause and significance of the difference in costs. Additionally, Staff would like Idaho Power to weigh in on whether these two values should be the same in future IRPs, or whether there is a reason they should be allowed to differ.
- Update the Oregon Commission on any planned or actual negotiations with PacifiCorp regarding exit dates for Jim Bridger.

Transmission

B2H

STOP B2H and Staff submitted comments on the Boardman to Hemingway transmission line. STOP B2H's comments contained extensive criticisms of the project. Many of these comments are based on portfolios and numbers that no longer exist in the newest version of the IRP, so Staff will not address these older concerns here, particularly if they are based on older portfolios. Where Staff believes concerns still stand, they will be addressed briefly here.

One of STOP B2H's critiques of the B2H line involves real power losses due to the transport of power across long distances. While Staff can agree that line losses are inevitable when transporting power across long distances, Staff does not agree that the addition of B2H would serve as a detriment to the system because of increases in line losses. On a surface level, the addition of a transmission line facilitating connection between two market hubs would provide a bolstered path, and reduce constraints and thermal losses across the system. The Company provides additional analysis in a table in its Reply Comments[86] showing that the addition of B2H reduces line losses overall. Further, it is Staff's understanding that AURORA considers line losses as an input when it is run.

Stop B2H is also concerned that the Company is assuming too high a level of Capacity Benefit Margin (CBM) in the IRP. Stop B2H believes that the Company is reserving too much capacity for emergencies, that the Company could stand to relax the CBM constraint, and that it could devote more capacity for firm transport of other resources. Staff addresses this issue in the Staff Report for the 2017 IRP. Staff is not convinced by the idea that all of CBM should be used as firm capacity. While STOP B2H may be correct that relaxing the assumptions would provide some additional flexibility, Staff does not agree that this capacity should necessarily be treated as firm capacity for a planning document like the IRP. Utilities must plan to meet peak load when the system is stressed or during an emergency condition. STOP B2H states that it reviewed 12 years of data and that the Company never used CBM, but going back one more year reveals that there was a loss of two Bridger units that required the use of emergency CBM capacity. Staff would be open to additional conversations on this topic, but given upcoming coal retirements, increased intermittent resources, and other changes on the grid, Staff still believes that reserving CBM for emergencies is a prudent practice.

STOP B2H also disputes that Idaho Power has met the standards under the Energy Facilities Siting Council (EFSC) System Reliability Rule. STOP B2H argues that Idaho Power's justification for B2H is only based on Idaho Power's share, or 20 percent of the capacity of the B2H line. Because only Idaho Power's share was acknowledged in an IRP, STOP B2H argues that only that subset of the line technically meets EFSC criteria, and not the full capacity of the line. Staff has two responses to this. The first is that decisions made by other agencies are outside the scope of this docket. However, Staff notes that at the time STOP B2H filed its Opening Comments, the Oregon Department of Energy (ODOE) had not yet released its Proposed Order. As of this filing, ODOE has issued is proposed order and recommends that Idaho Power's site certificate be

[86] LC 74, Idaho Power Reply Comments, page 13.

granted.[87] Regarding the 20 percent capacity issue STOP B2H raises in its comments, ODOE seemed to disagree, stating:

> The project participants are not the applicant proposing the facility in the application, and therefore not under consideration by Council. Further, the Council's statutes and rules do not support an evaluation of the project participant information when making its decision on compliance with applicable Council rules and standards, including OAR 345-023-0005.[88]

The Proposed Order also states:

> The nature of regional and individual utility transmission systems is that it is common for utilities to share ownership and maintenance of transmission lines as well as hold ownership of bidirectional transmission capacity for transmission lines to meet seasonal fluctuations to meet the demands of customers. The commenters position is not supported by ORS 469.501(1)(L). To infer that the applicant must provide the information required in OAR 345-021-0010(1)(n)(F) for any service area that may be served by the power transmitted by the proposed facility, would require information not just from BPA and PacifiCorp, but also from Avista Utility, and other utilities that have a connected nexus to the Pacific Northwest and Intermountain regional transmission system.[89]

Again, decisions made by other agencies are outside the scope of this docket, but ODOE's Proposed Order directly rejects the issue raised by STOP B2H.

One final issue STOP B2H brings to attention in its comments is the matter of current participants in the B2H project. STOP B2H states:

> We do not believe Idaho Power is confident that the BPA's business case will be in the affirmative. On November 5, 2019, IDACORP INC published the Securities and Exchange Commission (SEC) announcement that includes an additional $324M for a hypothetical doubling of ownership of the Boardman to Hemingway powerline.[90]

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[87] Oregon Department of Energy, In the Matter of the Application for Site Certificate for the Boardman to Hemingway Transmission Line, Proposed Order on Application for Site Certificate, pg. 2. July 2, 2020. Accessible at: https://www.oregon.gov/energy/facilities-safety/facilities/Facilities%20library/2020-07-02-B2H-PO-ASC.pdf.
[88] Oregon Department of Energy, In the Matter of the Application for Site Certificate for the Boardman to Hemingway Transmission Line, Proposed Order on Application for Site Certificate, pg. 597. July 2, 2020. Accessible at: https://www.oregon.gov/energy/facilities-safety/facilities/Facilities%20library/2020-07-02-B2H-PO-ASC.pdf.
[89] Oregon Department of Energy, In the Matter of the Application for Site Certificate for the Boardman to Hemingway Transmission Line, Proposed Order on Application for Site Certificate, pgs. 599 & 600. July 2, 2020. Accessible at: https://www.oregon.gov/energy/facilities-safety/facilities/Facilities%20library/2020-07-02-B2H-PO-ASC.pdf.
[90] STOP B2H Revised Comments for the 2019 IRP, page 57.

Staff agrees with STOP B2H that the issue of project participants and project cost is a material issue. Staff also raises this concern in its Opening Comments. On July 1, 2020, several months after stakeholders and the Company submitted comments on the *Amended* IRP, Idaho Power submitted a B2H update in this docket. Briefly summarized, Idaho Power explains, “The B2H co-participants are exploring several scenarios of asset and service arrangements” for the project.[91] Importantly, the Company explains that the co-participants are discussing changes in the project’s ownership agreement, and more specifically, that Bonneville Power Administration (BPA) is considering relinquishing its ownership share of the line and transferring this share to Idaho Power.[92]

In the *Second Amended* IRP, Idaho Power continues to assume that Oregon and Idaho native load customers would only fund 21 percent of the line. The Company clarified in its presentation on October 22, 2020, that Idaho Power and BPA are discussing an agreement whereby Idaho Power would provide BPA transmission service across B2H and through its existing network in Southeast Idaho to serve BPA’s Southeast Idaho customer demand. This would hypothetically occur through a Network Integration Transmission Service (NITS) agreement, and Idaho Power would presumably recover the cost of the line through Open Access Transmission Tariff (OATT) rates.

At the October 22 public meeting, the Commission expressed concern about the risk of a material change in ownership. The Company assured the Commission that these discussions were only “hypothetical” and that it was looking for an opportunity to align both entities (BPA and Idaho Power). Further, the Company assured the Commission that this would not have any impact on the 2019 IRP because, hypothetically, cost recovery of the line would occur through the NITS agreement, and the Company would strive to ensure that its retail customers are held harmless. In other words, under such an arrangement, Idaho Power native load customers would still only be paying for 21 percent of the line.

As of these comments, there have been no additional updates on this issue. Like the Commission, Staff is concerned about what a change in ownership could mean for ratepayers. Staff has many questions:

- What is the risk that costs would increase under such an arrangement?
- What sort of capital risk would Idaho Power be taking on by assuming additional ownership?
- How would these risks impact the Preferred Portfolio in an IRP?
- How is the Company going to model this risk in the 2021 IRP cycle?
- What would be the specific accounting authorizations needed for such an arrangement?

[91] LC 74 – Idaho Power’s motion to suspend schedule, page 1, July 1, 2020.
[92] LC 74 – Idaho Power’s motion to suspend schedule, page 2, July 1, 2020.

- What would be the specific types of contracts needed for such an arrangement?
- Would a change in partnership or service arrangement affect the in-service date of B2H?
- Is there still a possibility that another third party would step in for BPA?

Staff was made aware that Puget Sound Energy is considering investing in B2H, and Puget mentioned this in a presentation earlier this year.[93] The Company also clarifies in an IR that it has spoken to PGE, Puget Sound Energy, Avista, LS Power, California ISO, Umatilla Electric Cooperative, Snohomish County PUD, NV Energy, and PowerEx. However, in discussions with those entities, the Company indicated that it did not get into the details of whether parties would be interested in being an asset owner or whether they would prefer to take transmission service.[94]

At the October 22 meeting, the Company explained that nothing is definitive, yet assumptions about the cost of B2H remain the same. It is unfortunate that the Company did not include a risk scenario with increased share of the project being borne by Idaho Power customers as a component of this IRP. While the Company's hypothetical agreement intends for BPA to cover the cost of 24 percent of the project through wheeling rates, there is still an uncomfortable level of uncertainty surrounding the details of project ownership.

At one level, Staff understands that the Company was attempting to keep the IRP as consistent as possible with previous iterations given the numerous errors discovered and updates in this process. This "frozen in time" approach grants the ability to perform more of an apples-to-apples comparison to previous iterations of the 2019 IRP. For example, the Company did not change its energy efficiency assumptions, resource cost assumptions, or the effects of COVID-19 into its load forecast.

This IRP cycle was highly unusual. When the Company requested its first amendment in July 2019, it was uncertain how long it would take, but the Company eventually filed an *Amended* IRP on January 31, 2020. At that time, Staff was aware of co-participant risks, but the Company continued to reassure Staff in the *Amended* IRP and its Reply Comments that all three parties were financially committed.[95] The Company submitted two additional updates—one that was shorter and only involved a few updated pages, and finally the *Second Amended* IRP on October 2, 2020. It was not until July 1, 2020, that the Commission received a concrete update about a change in partnership, about four months before the Company filed its final iteration of the IRP.[96]

[93] June 30, 2020 presentation on PSE's 2021 IRP.
[94] Staff IR 100.
[95] LC 74, Idaho Power Reply Comments, page 5.
[96] LC 74, Idaho Power motion to suspend procedural schedule and update regarding Boardman to Hemingway transmission line project.

Because of the unusual nature of this IRP cycle, introducing significant updates to data and assumptions late into the process, and across four different iterations did not seem practicable, and would have introduced further confusion into an already convoluted IRP cycle. The downside to this approach is that because Idaho Power has held certain assumptions constant, Staff is concerned that the Preferred Portfolio may not provide an accurate reflection of current costs and risks to Idaho Power customers. These are valid concerns, and Staff reiterates its previous recommendation that the Company's Final Comments should defend its preferred portfolio and provide any material updates to concerns Staff has raised in these comments.

Staff has and continues to believe that B2H would be a valuable resource for Idaho Power's customers and the Pacific Northwest region. For example, a recent study completed by BPA, Idaho Power, and PacifiCorp shows that with stressed flow on the California-Oregon Intertie (COI)/Northwest AC Intertie and <u>unstressed</u> flow on the Idaho-to-Northwest transmission path, the addition of B2H may provide for additional central Oregon load service. When the three entities studied Idaho-to-Northwest unstressed cases, B2H, in combination with other identified upgrades, may provide further benefits to central Oregon and/or southern Oregon.[97]

A change in cost risk is nevertheless of concern to Staff.

Staff Recommendations for Final Comments:

- Address capital cost or increased cost risk as a result of new participant arrangements.

Staff Recommendations for the 2021 IRP:

- The Company **must** model cost risk as it relates to a change in ownership arrangement in the 2021 cycle. This could be in the form of a series of sensitivities, where the Company continues to own 21 percent of the line and retail customers are held harmless, and introduce additional costs to customers based on a range of capital risks.

Gateway West

In Opening Comments, Staff asks whether the Company is still invested in this project, and if so, why it does not include it in the Action Plan. The Company briefly responds to Staff regarding this project by saying that it did not include Gateway West in its action plan because it is not a viable replacement for Idaho Power's supply-side resources, and that "…the project will provide other long-term benefits such as relieving transmission constraints, providing greater options for future generation resources, and helping to meet future transmission needs." The Company has also indicated that

[97] Staff IR 109 (redacted).

Gateway West, in addition to B2H, are key components to facilitating its 100 percent clean energy goal.[98]

Staff's concerns remain regarding the lack of consideration of this project in the IRP relative to the efforts devoted to B2H and believes the Company should apply more resources to examining the value of this project in the 2021 IRP.

Conclusion

The circumstances surrounding the 2019 IRP are unprecedented. Staff appreciates the gargantuan effort the Company undertook to ensure that it is basing its resource decisions on sound judgment. Staff appreciates the Company's inclusion of additional lower carbon portfolios, the new approach to modeling DR, and the new analysis on an early Valmy closure. However, Staff has concerns about the reasoning behind the selection of the preferred portfolio PGPC B2H (1) and various other assumptions in the IRP. While Staff believes, and has argued in the past, that the B2H transmission line has merits for customers and the region, Staff remains concerned about co-participant and risk and the implications this would have on cost, and subsequently the preferred portfolio. Staff expects the Company to address these concerns in Final Comments.

For Idaho Power's Final Comments, Staff recommends the following:

- Identify a statistical method it can use to judge whether ARIMA models can reduce forecast error.
- Provide an update on the Oregon Residential Time-of-Day Pilot Plan, including number of participants, total cost of the pilot since its 2019 launch, and peak capacity reduction by season, as well as propose an alternative venue for reporting pilot results, given that the 2012 Smart Grid Report will be suspended with the Commission approval of DSP guidelines.
- Extrapolate from the data the Company has by regressing solar generation on weather data. Map weather data outside the Company's range of solar generation observations to create a sufficient number of years' data for the ELCC method; or
- Perform the Company's approved capacity factor approximation method using all the new data that has become available during the time that has passed due to the delay of the 2019 IRP's original filing.
- Explain why it limited battery storage to 80 MW.
- Provide clarification on whether the selection of the preferred portfolio means the Company's 2019 IRP does not reflect the Company's actual plans.
- Address the higher cost of a 100 percent renewable portfolio.

[98] See https://www.youtube.com/watch?v=cANKx3ah96w.

- Provide detailed clarification of manual adjustments made in IRP portfolios based on Staff's comments.
- Provide a robust account of why the Company selected PGPC B2H (1) as the Preferred Portfolio.
- Change its Action Item to include a Valmy Retirement in 2025 in addition to a study proposal for a 2022 retirement date for the 2021 IRP.
- Assess the fixed O&M cost input to AURORA for its share and PacifiCorp's share of the Jim Bridger plant, and report in Final Comments regarding the cause and significance of the difference in costs. Additionally, Staff would like Idaho Power to weigh in on whether these two values should be the same in future IRPs, or whether there is a reason they should be allowed to differ.
- Update the Oregon Commission on any planned or actual negotiations with PacifiCorp regarding exit dates for Jim Bridger.
- Address capital cost or increased cost risk as a result of new participant arrangements.

For the 2019 IRP Update, Staff recommends the following:

- Review all energy efficiency measures piloted by Energy Trust in 2018-2020 and report on whether the Company has considered them, what research was conducted to look into these measures, whether there has been a decision on the inclusion of these measures, and what the determination is to date. The Company should share the status of its review at an Energy Efficiency Advisory Group meeting in 2021 and as a report in the next IRP Update.

For the 2021 IRP, Staff recommends the following:

- Use a metric like the Akaike Information Criterion to confirm that indicator variables are not causing model overfitting.
- Present a plan to use out-of-sample testing or similar to check whether ARIMA models are likely to reduce load forecast error in the next IRP Update.
- Hold a workshop with stakeholders to present the Company's findings of whether ARIMA models are likely to improve the load forecasts.
- Address whether the upper and lower bounds on its customer load stochastic risk analysis are wide enough.
- Describe what specific wind repowering developments would cause it to change its wind QF renewal assumptions and include a range of sensitivities for wind QF renewal in the 2021 IRP.
- Present to Commissioners the impact of COVID-19 on load.
- The 2021 IRP should model expanded DR with a LCOC based on real programmatic approximations for acquiring the said amount of incremental additional DR; LCOC estimates representative of incremental increases (e.g., 10 percent increase, 20 percent increase, 30 percent increase, 50 percent

increase); or some other mutually agreed upon approach to more rationally model this key variable.

- Work with Staff and stakeholders to develop a new modeling approach suitable for behavior-based DR programs that reflects such programs' typical lower costs and less certain results.
- Eliminate or raise the 80 MW cap on battery storage. This includes standalone battery storage as well as storage paired with solar.
- Model the PTC for wind to the extent it is technically achievable by the Company.
- Revise its Wyoming cost inputs to include more reasonable cost assumptions.
- Report qualitative benefits and risks by portfolio this in the 2021 IRP and in all IRPs going forward in which a qualitative analysis plays a significant role.
- Devote resources to improve optimization techniques and address this issue in a 2021 IRP workshop. In particular, the Company should implement techniques in its next IRP to optimize resource buildouts based on the Company's system only.
- Implement a more robust measure of risk for evaluating portfolios. The Company should incorporate risks or situations that are not used to create the initial portfolios and should strive to incorporate qualitative risks into the portfolio development process.
- The Company **must** model cost risk as it relates to a change in ownership arrangement in the 2021 cycle. This could be in the form of a series of sensitivities, where the Company continues to own 21 percent of the line and retail customers are held harmless, and introduce additional costs to customers based on a range of capital risks.

This concludes Staff's Final Comments.

Dated at Salem, Oregon, this 8th day of January, 2020.

Nadine Hanhan

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Nadine Hanhan
Senior Utility Analyst
Energy Resources and Planning Division

TOPIC/KEYWORD: MODELING ANALYSIS

STAFF'S DATA REQUEST NO. 45:

See page 119. Please provide the results of the qualitative risk analysis by portfolio and qualitative risk component in a spreadsheet.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 45:

Page 117 of the Amended 2019 IRP describes the major qualitative risks that were identified during the 2019 IRP. These risk factors were not quantified, but they were described in detail to provide the reader an understanding of the qualitative risk factors that were not captured quantitatively within the development of each portfolio.

Please see the attachment provided for this response which contains the output of the Loss of Load Evaluation discussed on page 119 of the Amended 2019 IRP.

STAFF'S DATA REQUEST NO. 55:

Did Idaho Power model the PTC (for wind) and the ITC (for solar) in its Aurora capacity expansion runs

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 55:

The investment tax credit for solar was included in the Aurora LTCE simulations. The production tax credit for wind was evaluated during the 2019 IRP setup; however, the Company determined that because of the impending tax credit expiration and lack of near-term resource need, any future wind resource builds would not be able to utilize the production tax credits so Production Tax Credits were not included.

TOPIC/KEYWORD: SALES AND LOAD FORECAST

STAFF'S INFORMATION REQUEST NO. 62:

See IPCo's response to Staff DR 20. Please describe how IPCo avoids unit root problems in its regression forecasts, especially the large commercial service forecast.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S INFORMATION REQUEST NO. 62:

The Company acknowledges the unit root issue associated with the large commercial service model, and is currently in the process of improving the model to correct for this issue.

The rate schedules associated with this model are in many ways the most dynamic set of customers in terms of the percentage of new customers relative to existing. New customers often begin service as Rate 09P/T and evolve over time to Rate 19P, and their growth curves are often erratic and subject to variable ramp rates. Conversely, this segment exhibits a higher incidence of rate of change wherein the segment gains customers due to rate schedule rules that move an existing customer from Rate 19 to Rate 09 P/T (i.e. sustained load below a 1 megawatt threshold). These countervailing influences make the large commercial segment particularly difficult to model.

In more current analyses, the Company has restructured the model to mitigate the issues associated with unit-root impacts on the forecast. Efforts include an aggregation of the service and manufacturing customers into a single series. This modification is testing the significance of the dynamics of new and existing customer influence. Additionally, an effort has been undertaken to develop additional explanatory variables to allow for accommodation for rate-shifting influence. Time series differencing is also being tested with positive results.

TOPIC/KEYWORD: SALES AND LOAD FORECAST

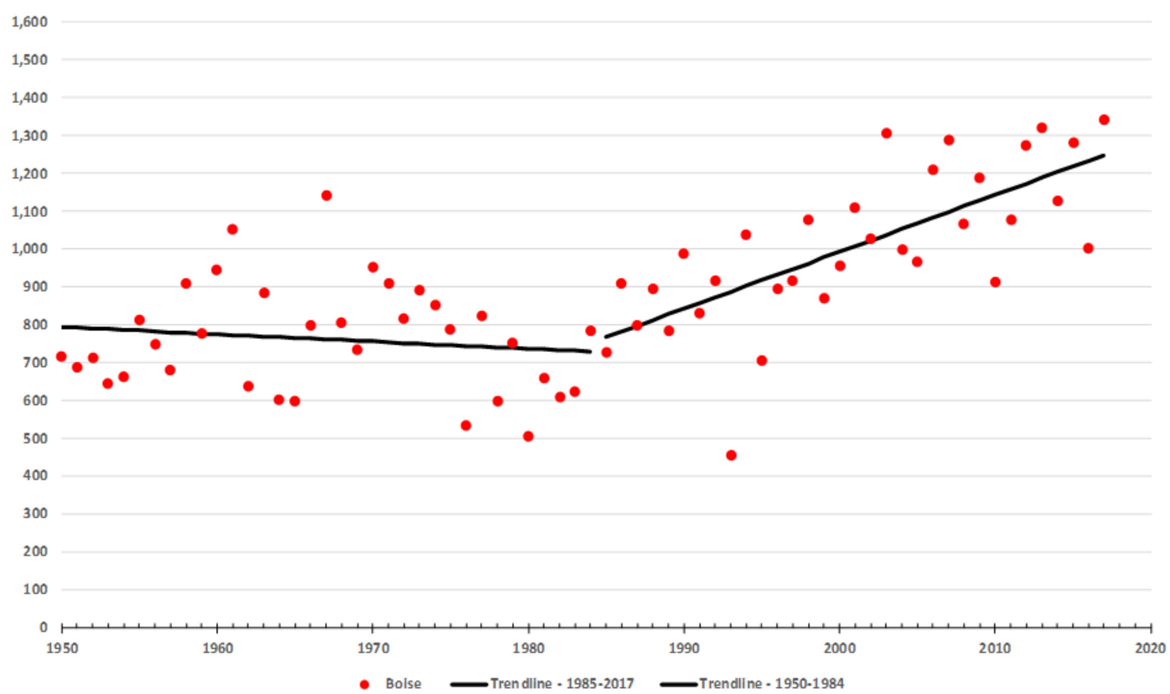
STAFF'S INFORMATION REQUEST NO. 63:

See IPCo's response to Staff DR 20. Please describe the use of the peak temperature trend variable in the LC 74 peak forecasts. Include in your description the relationship between the peak temperature variable and the peak temperature trend variable.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S INFORMATION REQUEST NO. 63:

The forecasted values of the average peak-day temperature explanatory variable in the Company's monthly peak regressions is static--or assumes temperatures will not change. Using trendline analysis through the historical weighted average peak-day temperatures over the period 1950-2017, a clear hinge was present. This is noted in Figure 1 below. A hinge-fit analysis of weather depicts a steady increase in seasonal CDDs as measured at Boise Weather Station since 1985. Subsequently, linear temperature trend variables were added as explanatory variables in the summertime regression models (Jun, July, and August). These trend variables were added to assist in informing the rising average peak day temperature impact on summertime peak demand. Inclusion of a trend variable increases peak day temperatures for planning on average 0.1%-0.2% per year depending on the month.

Figure 1



Topic or Keyword: Boardman to Hemingway (B2H) Transmission Line

STAFF'S INFORMATION REQUEST NO. 100:

Regarding the potential new ownership structure for B2H:

- **a. Has Idaho Power approached Portland General Electric as a potential co-owner?**
- **b. Has Idaho Power approached Puget Sound Energy as a potential co-owner?**
- **c. Has Idaho Power approached Northwestern Energy as a potential co-owner?**
- **d. Has Idaho Power approached Avista Utilities as a potential co-owner?**
- **e. Are there other entities that have expressed interest in becoming a B2H i) asset owner or ii) transmission capacity holder?**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 100:

a. Portland General Electric - Yes
b. Puget Sound Energy - Yes
c. Northwestern Energy - No
d. Avista Utilities – Yes
e. Idaho Power has also discussed B2H-related participation with the following entities:

- LS Power
- California ISO
- Umatilla Electric Cooperative
- Snohomish County PUD
- NV Energy
- PowerEx

In discussions with these entities, the Company did not get into the details of whether parties would be interested in being an asset owner, or whether they would prefer to take transmission service.

Topic or Keyword: Boardman to Hemingway (B2H) Transmission Line

STAFF'S INFORMATION REQUEST NO. 109:

Please provide an executive summary and findings of each study that Idaho Power performs, or has a copy of from PacifiCorp or BPA, showing impacts on the COI/Northwest AC Intertie if B2H is constructed and energized as now planned. These reports should be accompanied with an explanation of cost impact (inclusive of any incremental substation equipment needed) on Idaho Power and on its Oregon customers. This is an ongoing request until B2H is energized.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 109:

Idaho Power provided two studies in its response to Staff Request No. 108 with the requested information.

The B2H Project Review Group Phase II Rating Report (2012)

An executive summary is provided starting on page 4 of the report. To further summarize, the Idaho to Northwest path, following the addition of B2H, and with 2,250 MW of west-to-east transfers and 3,400 MW of east-to-west transfers, does not have a simultaneous interaction with any of the studied paths, including the COI/Northwest AC Intertie.

The Final B2H and the Pacific AC Intertie Initial Study Report Phase 1 (2019)

While a 3-page executive summary is provided at the beginning of the document, a short summary is provided below.

The initial study showed with stressed flow on COI/Northwest AC Intertie and *unstressed* flow on Idaho to Northwest, the addition of B2H may provide for additional central Oregon load service. In the Idaho to Northwest unstressed cases, B2H, in combination with other identified upgrades, may provide further benefits to central Oregon and/or southern Oregon. The study does not consider impacts of existing commercial arrangements associated with the COI/Northwest AC Intertie.

Given there was no Idaho to Northwest stress, this study was an initial feasibility study completed by BPA, PacifiCorp and Idaho Power with the primary purpose to inform discussions and determine if there was justification for further study efforts. The three parties are currently working to increase the robustness of the study to incorporate high west-to-east and east-to-west transfers on the Idaho to Northwest path (and B2H), consider system capacity to accommodate potential future Central Oregon and Southern Oregon resource and load additions, consider modifications/additions to series compensation, and other general planning-level opportunities. These studies will include stressed COI/Northwest AC Intertie flows in both the north-to-south and south-to-north directions. These studies are not considering impacts of existing commercial arrangements associated with the COI/Northwest AC Intertie.

Costs

The costs to Idaho Power and its Oregon customers associated with the 'B2H Project Review Group Phase II Rating Report' remain consistent with assumptions in the Second Amended 2019 IRP. Non-B2H costs associated with upgrades identified in the 'Final B2H and the Pacific AC Intertie Study Report Phase 1' have not been allocated between the parties.

Futures Ranked Highest to Lowest by Planning Gas, Planning Carbon					
Rank	Portfolio	Planning Gas, Planning Carbon	High Gas, Planning Carbon	Planning Gas, High Carbon	High Gas, High Carbon
1	PGHCB2H-4	$6,231,882	$7,378,575	$8,244,490	$9,576,761
2	PGPCB2H -1	$6,239,229	$7,436,314	$8,389,315	$9,634,337
3	PGPCB2H -4	$6,247,768	$7,457,533	$8,453,137	$9,705,863
4	PGPCB2H -3	$6,267,257	$7,327,131	$8,650,207	$9,858,607
5	PGPCB2H -2	$6,267,445	$7,285,695	$8,662,735	$9,863,352
6	PGPC-2	$6,273,071	$7,246,081	$8,490,274	$9,625,390
7	PGPC-1	$6,279,509	$7,426,379	$8,233,137	$9,440,332
8	PGPC-4	$6,279,772	$7,259,024	$8,558,682	$9,716,348
9	PGPC-3	$6,284,277	$7,277,944	$8,431,678	$9,560,285
10	PGHC-4	$6,294,814	$7,359,094	$8,091,963	$9,277,557
11	PGHCB2H-3	$6,325,327	$7,260,956	$8,336,880	$9,508,616
12	PGHCB2H-2	$6,326,907	$7,223,445	$8,356,141	$9,518,984
13	PGHCB2H -1	$6,342,373	$7,377,938	$8,113,174	$9,290,421
14	PGHC-1	$6,390,311	$7,319,067	$8,032,346	$9,067,148
15	PGHC-2	$6,442,048	$7,144,213	$8,264,118	$9,181,798
16	PGHC-3	$6,453,111	$7,181,508	$8,242,129	$9,151,410
17	HGHCB2H-4	$6,505,943	$7,500,370	$8,259,364	$9,394,863
18	HGHCB2H-3	$6,549,962	$7,402,601	$8,507,236	$9,581,960
19	HGHCB2H-2	$6,551,203	$7,370,092	$8,519,476	$9,591,880
20	HGHCB2H-1	$6,627,133	$7,560,819	$8,321,638	$9,377,658
21	HGHC-4	$6,855,447	$7,783,286	$8,595,740	$9,639,967
22	HGHC-2	$6,987,986	$7,521,331	$8,665,974	$9,374,281
23	HGHC-3	$7,043,235	$7,575,393	$8,654,276	$9,326,503
24	HGHC-1	$7,469,519	$7,934,725	$8,635,143	$9,153,185

Futures Ranked Highest to Lowest by High Gas, Planning Carbon					
Rank	Portfolio	Planning Gas, Planning Carbon	High Gas, Planning Carbon	Planning Gas, High Carbon	High Gas, High Carbon
1	PGHC-2	$6,442,048	$7,144,213	$8,264,118	$9,181,798
2	PGHC-3	$6,453,111	$7,181,508	$8,242,129	$9,151,410
3	PGHCB2H-2	$6,326,907	$7,223,445	$8,356,141	$9,518,984
4	PGPC-2	$6,273,071	$7,246,081	$8,490,274	$9,625,390
5	PGPC-4	$6,279,772	$7,259,024	$8,558,682	$9,716,348
6	PGHCB2H-3	$6,325,327	$7,260,956	$8,336,880	$9,508,616
7	PGPC-3	$6,284,277	$7,277,944	$8,431,678	$9,560,285
8	PGPCB2H -2	$6,267,445	$7,285,695	$8,662,735	$9,863,352
9	PGHC-1	$6,390,311	$7,319,067	$8,032,346	$9,067,148
10	PGPCB2H -3	$6,267,257	$7,327,131	$8,650,207	$9,858,607
11	PGHC-4	$6,294,814	$7,359,094	$8,091,963	$9,277,557
12	HGHCB2H-2	$6,551,203	$7,370,092	$8,519,476	$9,591,880
13	PGHCB2H -1	$6,342,373	$7,377,938	$8,113,174	$9,290,421
14	PGHCB2H-4	$6,231,882	$7,378,575	$8,244,490	$9,576,761
15	HGHCB2H-3	$6,549,962	$7,402,601	$8,507,236	$9,581,960
16	PGPC-1	$6,279,509	$7,426,379	$8,233,137	$9,440,332
17	PGPCB2H -1	$6,239,229	$\boxed{\$7,436,314}$	$8,389,315	$9,634,337
18	PGPCB2H -4	$6,247,768	$7,457,533	$8,453,137	$9,705,863
19	HGHCB2H-4	$6,505,943	$7,500,370	$8,259,364	$9,394,863
20	HGHC-2	$6,987,986	$7,521,331	$8,665,974	$9,374,281
21	HGHCB2H-1	$6,627,133	$7,560,819	$8,321,638	$9,377,658
22	HGHC-3	$7,043,235	$7,575,393	$8,654,276	$9,326,503
23	HGHC-4	$6,855,447	$7,783,286	$8,595,740	$9,639,967
24	HGHC-1	$7,469,519	$7,934,725	$8,635,143	$9,153,185

Futures Ranked Highest to Lowest by Planning Gas, High Carbon					
Rank	Portfolio	Planning Gas, Planning Carbon	High Gas, Planning Carbon	Planning Gas, High Carbon	High Gas, High Carbon
1	PGHC-1	$6,390,311	$7,319,067	$8,032,346	$9,067,148
2	PGHC-4	$6,294,814	$7,359,094	$8,091,963	$9,277,557
3	PGHCB2H -1	$6,342,373	$7,377,938	$8,113,174	$9,290,421
4	PGPC-1	$6,279,509	$7,426,379	$8,233,137	$9,440,332
5	PGHC-3	$6,453,111	$7,181,508	$8,242,129	$9,151,410
6	PGHCB2H-4	$6,231,882	$7,378,575	$8,244,490	$9,576,761
7	HGHCB2H-4	$6,505,943	$7,500,370	$8,259,364	$9,394,863
8	PGHC-2	$6,442,048	$7,144,213	$8,264,118	$9,181,798
9	HGHCB2H-1	$6,627,133	$7,560,819	$8,321,638	$9,377,658
10	PGHCB2H-3	$6,325,327	$7,260,956	$8,336,880	$9,508,616
11	PGHCB2H-2	$6,326,907	$7,223,445	$8,356,141	$9,518,984
12	PGPCB2H -1	$6,239,229	$7,436,314	$\boxed{\$8,389,315}$	$9,634,337
13	PGPC-3	$6,284,277	$7,277,944	$8,431,678	$9,560,285
14	PGPCB2H -4	$6,247,768	$7,457,533	$8,453,137	$9,705,863
15	PGPC-2	$6,273,071	$7,246,081	$8,490,274	$9,625,390
16	HGHCB2H-3	$6,549,962	$7,402,601	$8,507,236	$9,581,960
17	HGHCB2H-2	$6,551,203	$7,370,092	$8,519,476	$9,591,880
18	PGPC-4	$6,279,772	$7,259,024	$8,558,682	$9,716,348
19	HGHC-4	$6,855,447	$7,783,286	$8,595,740	$9,639,967
20	HGHC-1	$7,469,519	$7,934,725	$8,635,143	$9,153,185
21	PGPCB2H -3	$6,267,257	$7,327,131	$8,650,207	$9,858,607
22	HGHC-3	$7,043,235	$7,575,393	$8,654,276	$9,326,503
23	PGPCB2H -2	$6,267,445	$7,285,695	$8,662,735	$9,863,352
24	HGHC-2	$6,987,986	$7,521,331	$8,665,974	$9,374,281

Futures Ranked Highest to Lowest by Planning Gas, High Carbon					
Rank	Portfolio	Planning Gas, Planning Carbon	High Gas, Planning Carbon	Planning Gas, High Carbon	High Gas, High Carbon
1	PGHC-1	$6,390,311	$7,319,067	$8,032,346	$9,067,148
2	PGHC-3	$6,453,111	$7,181,508	$8,242,129	$9,151,410
3	HGHC-1	$7,469,519	$7,934,725	$8,635,143	$9,153,185
4	PGHC-2	$6,442,048	$7,144,213	$8,264,118	$9,181,798
5	PGHC-4	$6,294,814	$7,359,094	$8,091,963	$9,277,557
6	PGHCB2H -1	$6,342,373	$7,377,938	$8,113,174	$9,290,421
7	HGHC-3	$7,043,235	$7,575,393	$8,654,276	$9,326,503
8	HGHC-2	$6,987,986	$7,521,331	$8,665,974	$9,374,281
9	HGHCB2H-1	$6,627,133	$7,560,819	$8,321,638	$9,377,658
10	HGHCB2H-4	$6,505,943	$7,500,370	$8,259,364	$9,394,863
11	PGPC-1	$6,279,509	$7,426,379	$8,233,137	$9,440,332
12	PGHCB2H-3	$6,325,327	$7,260,956	$8,336,880	$9,508,616
13	PGHCB2H-2	$6,326,907	$7,223,445	$8,356,141	$9,518,984
14	PGPC-3	$6,284,277	$7,277,944	$8,431,678	$9,560,285
15	PGHCB2H-4	$6,231,882	$7,378,575	$8,244,490	$9,576,761
16	HGHCB2H-3	$6,549,962	$7,402,601	$8,507,236	$9,581,960
17	HGHCB2H-2	$6,551,203	$7,370,092	$8,519,476	$9,591,880
18	PGPC-2	$6,273,071	$7,246,081	$8,490,274	$9,625,390
19	PGPCB2H -1	$6,239,229	$7,436,314	$8,389,315	$9,634,337
20	HGHC-4	$6,855,447	$7,783,286	$8,595,740	$9,639,967
21	PGPCB2H -4	$6,247,768	$7,457,533	$8,453,137	$9,705,863
22	PGPC-4	$6,279,772	$7,259,024	$8,558,682	$9,716,348
23	PGPCB2H -3	$6,267,257	$7,327,131	$8,650,207	$9,858,607
24	PGPCB2H -2	$6,267,445	$7,285,695	$8,662,735	$9,863,352

Under a High Gas, Planning Carbon future, the Preferred Portfolio PGPC B2H (1) ranks seventeenth. The lowest cost B2H portfolio, PGHC B2H (2), ranks third behind PGHC (2) and PGHC (3). These latter two portfolios do not include B2H, but they would require a final Jim Bridger unit retirement in 2034, and the Company would need to add almost double[1] the gas capacity as compared to the Preferred Portfolio. However, the cost differences between these two portfolios and the Preferred Portfolio are large—$292.1 million and $254.8 million, respectively, *under a High Gas, Planning Carbon future*.

Under a Planning Gas, High Carbon future, the Preferred Portfolio ranks twelfth. The lowest cost B2H portfolio, PGHC B2H (1), ranks third behind PGHC (1) and PGHC (4). These latter two portfolios do not include B2H, but both would require almost double the gas capacity, in addition to increased renewable capacity. Both would retire Jim Bridger in 2030, as with the Preferred Portfolio.[2] The cost differences between these latter two portfolios and the Preferred Portfolio PGPC B2H (1) are $357.0 million and $297.4 million, respectively, *under a Planning Gas, High Carbon future.*

Finally, under a High Gas, High Carbon future, the Preferred Portfolio ranks nineteenth. The next-closest B2H portfolio, PGHC B2H (1), ranks sixth under this future, behind PGHC (1) as the top ranking portfolio. PGHC (1), as stated above, would require double the gas capacity, in addition to over 1 GW of renewable buildout as compared to the Preferred Portfolio. The cost difference between the Preferred Portfolio and PGHC (1) is $567.1 million under a High Gas, High Carbon future.

A quick review of rankings according to these futures is consistent with Staff's Final Comments; that is, the price of carbon appears to generally have a greater impact on the portfolio rankings than the price of gas. In all four futures, Planning Gas portfolios rank highest, suggesting that portfolios optimized under high gas futures did not rank much better, or ranked worse, in an actual future with high gas prices.

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[1] 767 MW for both non-B2H portfolios compared to 411 MW in the preferred portfolio. See pages 58, 63, and 64 of Technical Appendix C.

[2] See pages 62 and 65 of Technical Appendix C.