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IDAHO PUBLIC
UTILITIES COMMISSION

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February 29, 2024

VIA ELECTRONIC EMAIL

Commission Secretary
Idaho Public Utilities Commission
11331 W. Chinden Blvd., Bldg 8,
Suite 201-A (83714)
PO Box 83720
Boise, Idaho 83720-0074

Re: Case No. IPC-E-23-23
Idaho Power Company's 2023 Integrated Resource Plan

Dear Commission Secretary:

Attached for electronic filing is Idaho Power Company's Reply Comments in the above-entitled matter. If you have any questions about the attached document, please do not hesitate to contact me.

Very truly yours,

Lisa D. Nordstrom

Lisa D. Nordstrom

LDN:cd
Attachments

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S 2023 INTEGRATED RESOURCE PLAN	)	CASE NO. IPC-E-23-23 IDAHO POWER COMPANY'S REPLY COMMENTS

Table of Contents

I. INTRODUCTION

Idaho Power Company ("Idaho Power" or "Company") respectfully submits these Reply Comments to the Idaho Public Utilities Commission ("Commission") in the matter of Idaho Power's 2023 Integrated Resource Plan ("IRP"). These comments respond to Commission Staff ("Staff"), Micron Technology, Inc. ("Micron"), and several comments from the public.

The 2023 IRP is a comprehensive analysis of the optimal mix of both demand- and supply-side resources needed to meet flexible capacity needs and reliably serve customer demand over the IRP's 20-year planning horizon from 2024 to 2043. As a result of collaborative work with Commission Staff and other stakeholders through the IRP Advisory Council ("IRPAC"), the 2023 IRP constitutes a robust analysis confirmed by comprehensive validation and verification and resulting in a Preferred Portfolio that represents the best combination of least-cost and least-risk.

Idaho Power is operating in a dynamic time for the industry. Some of the Company's operational challenges include substantial load growth, the timely procurement of resources, transmission siting, supply chain issues and materials shortages, and inflationary pressures. In each IRP, Idaho Power endeavors to develop a Preferred Portfolio that captures the best available information at the time and, to the extent possible, reasonably accounts for each of the challenges listed above. As a result, each IRP is a snapshot in time in an otherwise fluid planning environment and should be considered in the context in which it was developed. The resources represented in one IRP may not be the same resources that drive the next IRP, as new circumstances and market dynamics may change what technology or technologies are the most cost-effective to satisfy growing demand.

As explained in these Reply Comments, the Preferred Portfolio of the 2023 IRP successfully positions Idaho Power to continue to provide reliable and economic service to its customers into the future. The 2024-2028 Near-Term Action Plan associated with the Preferred Portfolio includes core resource actions that fall into two major categories: capacity additions and transmission development. While these items are identified in the Action Plan window, the Company recognizes and agrees with Staff's statement that,

> … the Commission's acknowledgment of the IRP should not imply that the results and resources included in the Preferred Portfolio infer prudence. Staff considers the resources included in the Preferred Portfolio as "proxies" that the Company selected based on assumptions made at the time. Staff expects that the Company will select each resource at the time of acquisition by evaluating it against the range of alternatives that are available at that time and at current prices to obtain a determination of prudence.[1]

The Company's IRP and the associated Near-Term Action Plan are intended to broadly reflect the kinds of activities Idaho Power will undertake to provide consistent, reliable, and affordable electricity to its growing customer base. Idaho Power is fully aligned with Staff's perspective that resources identified in the IRP are best considered "proxies" for resources that will be specifically identified in individual regulatory filings to ensure least-cost procurement. Indeed, Idaho Power has demonstrated its commitment to only procuring necessary and least-cost resources through its Certificate of Public Convenience and Necessity ("CPCN") filings and request for proposals ("RFP") issuances.

The Company considers it important to begin these Reply Comments by

[1] Staff's Comments (Feb. 15, 2024) at 3 and 4.

underscoring the differences between the IRP and individual procurement actions because doing so illuminates the value of long-term planning. Quite simply, the IRP gives stakeholders the opportunity to learn, understand, and provide feedback on Idaho Power's future over the next 20 years. The IRP is intended to reflect an increasingly complex energy system and, as such, is an increasingly complex process that is fully documented, supported, and justified through the IRP itself and the accompanying appendices. This documentation, as well as the work performed during the IRPAC process, provides ample evidence that Idaho Power conducted rigorous analysis, using a robust and meaningful tool (AURORA), supported by the best available data at the time of analysis, and informed by various stakeholder opinions and positions, including those of Staff.

Idaho Power appreciates Staff and other parties' review of the Company's 2023 IRP. In general, stakeholders in this case, including members of the public that provided comment, recognize the hard work and sound analysis of the IRP and, therefore, support acknowledgement of the Company's 2023 IRP. Staff, too, recommends acknowledgement of the IRP but recommends the Commission refrain from acknowledging the Action Plan and recommends the Commission require the Company to make a supplemental filing to the 2023 IRP. Staff bases this split recommendation on a simplistic and incomplete analysis from which Staff incorrectly concludes that the Preferred Portfolio is not the least-cost option for the Company.

In these Reply Comments, Idaho Power provides extensive evidence as to why the Preferred Portfolio is indeed the least-cost, least-risk portfolio option and also provides a rebuttal to Staff's analysis.

While Idaho Power appreciates and agrees with Staff's recommendation for acknowledgement of the 2023 IRP overall, the Company recommends that the Commission reject Staff's recommendation regarding acknowledgment of the Action Plan and the filing of a supplement to the 2023 IRP. The Company welcomes opportunities to work with Staff and other interested stakeholders to inform improvements to the process in advance of the 2025 IRP but also respectfully requests the Commission direct these conversations to occur as a compliance item following this case.

The Company's Reply Comments seek to address Staff and other parties' concerns and recommendations in greater detail herein.

II. STAFF'S COMMENTS

Staff recommends acknowledgement of Idaho Power's 2023 IRP and recognizes the significant effort invested by the Company to develop this IRP and the vast amount of information compiled within it.[2] Staff also acknowledges that the IRP analysis has become increasingly complex and increasingly important.[3] However, Staff identified concerns it believes need to be addressed in a subsequent filing or in the 2025 IRP. Specifically, Staff provides comments and recommendations on the Company's Preferred Portfolio, Near-Term Action Plan, load forecast, Demand-Side Management Program, seasons and hours of highest risk, treatment of Public Utility Regulatory Policies Act ("PURPA") projects, and other planning assumptions. Staff also provides feedback on the Company's incorporation of Staff's 2021 IRP recommendations within the 2023 IRP.

While the Company appreciates Staff's review, the Company finds that several of Staff's comments and recommendations are based on erroneous analysis that is contrary

[2] *Id.* at 3.
[3] *Id.* at 3.

to foundational resource planning concepts that the Company applies in its IRP. As such, Idaho Power opposes Staff's recommendation that the Company file a supplement to the 2023 IRP and seeks to address each of Staff's concerns and recommendations herein.

A. The Preferred Portfolio – Analysis and Recommendations

Staff believes that the Company's Preferred Portfolio may not be the least-cost portfolio and that a portfolio with more coal and natural gas resources could be less expensive.[4] Staff supports its claims with a spreadsheet analysis that seemingly attempts to produce something comparable with the Preferred Portfolio, albeit with, as Staff acknowledges, "…an unknown level of risk."[5]

The Company is confident that Staff's efforts with respect to creating its own hypothetical analysis were well intentioned, but Idaho Power finds that the result is an oversimplification of the robust analysis performed in the AURORA Long-Term Capacity Expansion ("LTCE") model. For example, a spreadsheet model cannot balance supply and demand across the region for every hour of every day over the next 20 years, nor can it model very real and important transmission pathways that have specific constraints and allowances.

Idaho Power acknowledges that future IRP analyses may identify incremental cost-effective baseload resources fueled by natural gas or other fuels; however, the inputs and assumptions available for use in the development of the 2023 IRP analysis did not support such a conclusion. Nonetheless, Idaho Power addresses the issues with Staff's analysis in greater detail in the following sections:

[4] *Id.* at 3.
[5] *Id.* at 3.

1. Portfolio Cost Comparison

In its comments, Staff provides a hypothetical, high-level analysis of a portfolio cost where an assumed Preferred Portfolio exclusively builds baseload and peaking dispatchable resources, such as simple cycle combustion turbines ("SCCT") and combined cycle combustion turbines ("CCCT"), instead of any variable energy resources ("VER") and battery energy storage systems ("BESS") identified in the 20-year planning horizon. Staff provides this simplified analysis as a high-level check of the cost-effectiveness of the Company's selected Preferred Portfolio.[6] Table 3 of Staff's comments display Staff's final portfolio cost comparison, where the "Dispatchable' Portfolio Cost is Staff's hypothetical SCCT/CCCT portfolio cost and the 'VER & BESS' Portfolio Cost is Staff's recalculated portfolio cost of the Preferred Portfolio where VERs and BESSs are built out as originally identified in the Preferred Portfolio.

In replicating Staff's calculations, the Company found it to be materially deficient and identified the following problems:[7]

1. No inclusion of the cost of fuel for natural gas fired plants;
2. No accounting for the cost of a natural gas pipeline expansion associated with additional gas generation greater than 600 megawatts ("MW");
3. No reduction in the cost of renewable resources for the sale of renewable energy credits ("REC");
4. No offset to the cost of renewable resources for Production Tax Credits ("PTC");
5. No offset to the cost of battery storage resources for Investment Tax Credits ("ITC");
6. No consideration of the time needed to permit and construct new resources;
7. No accounting for transmission pathways or where energy will come from; and
8. No accounting for the time value of money.

[6] *Id.* at 6.
[7] The Company identified similar items in its Response to Staff's Request for Production No. 84. See Attachment 1 to these Reply Comments.

These issues are foundational to the resource planning process and represent significant omissions to Staff's analysis. One of the largest omissions in the analysis is the lack of fuel costs for the gas turbines. Idaho Power understands from a conversation with Staff that natural gas fuel costs were inadvertently omitted because Staff believe they were captured within the Variable O&M dollars per megawatt-hour ("$/MWh") total as listed in the IRP. However, the Variable O&M $/MWh metric only captures non-fuel related maintenance.

In its analysis, Staff used the SCCT and CCCT Variable O&M costs listed in the IRP Appendix C, which are $6.00 and $3.10 per MWh, respectively.[8] Once again, however, these O&M costs do not include natural gas fuel costs. In 2024, the natural gas forecast estimates an average cost of about $4-$5 per million British Thermal Units ("MMBtu"). At peak efficiency, heat rates for a SCCT and CCCT,[9] this translates to $40-50 per MWh and $25-$32 per MWh for the generation out of a SCCT and CCCT, respectively. These costs are an order of magnitude higher than the O&M costs Staff assumed in its analysis.

Beyond fuel costs, Idaho Power notes the substantial impact of omitting realistic resource timing assumptions, the time value of money, and gas pipeline additions from Staff's analysis. Staff's analysis assumes that portfolios are fully built in year one[10] rather than incrementally over the 20-year planning period. The Company has significant concerns with this simplified approach.

[8] 2023 IRP Appendix C at 21.
[9] *Id.*
[10] Staff's Comments at 7, "By assuming both portfolios are fully built in year one, with 20 years of operating costs, the portfolios can be evenly compared."

First, this assumption disregards realistic resource procurement and development conditions such as supply-chain lag, project financing, and system reliability—all of which can be (and are) accounted for in AURORA. Second, this assumption fails to account for the declining cost of resources over time due to technological advancements. Further, Staff's analysis does not account for the time value of money. Net Present Value ("NPV") is the primary manner in which portfolio costs are compared and, thus, is the foundation on which Idaho Power meets its responsibility and commitment to least-cost and least-risk planning. By omitting this step (that is, NPV cannot be applied to an analysis that lumps resources additions all at once, as Staff constructed), Staff's analysis does not reasonably nor accurately compare costs that naturally occur over time to make a least-cost determination.

Lastly, Staff's analysis does not account for the cost to build the additional natural gas pipeline necessary to serve more than 600 MW of additional natural gas fired generation in Idaho Power's service area. Idaho Power's IRP modeling allows for new natural gas additions but also requires associated pipeline expansion and delivery costs. For instance, an example of a new pipeline could be a 430-mile extension from Opal, Wyoming to the Treasure Valley. At $10.7 million per mile,[11] the cost of this new pipeline could exceed $4.5 billion. Costs of this magnitude are why the 2023 IRP Preferred Portfolio does not include large increments of new natural gas but, instead, includes the least-cost conversion of coal fired units to natural gas.

To address these apparent oversights, the Company recalculated Table 3 from Staff's comments and accounted for the above-mentioned omissions. When adding these costs,

[11] https://www.ogj.com/pipelines-transportation/pipelines/article/14299952/land-pipeline-construction-costs-hit-record-107-million-mile

the Company attempted to use conservative assumptions based on the inputs of the IRP. Table 1 below (Attachment 2 to these Reply Comments) compares Staff's original analysis (as replicated by Idaho Power) to the same analysis but including the costs the Company believes were omitted by Staff.

Table 1: Comparison of Staff's Calculations With and Without Omissions

Replication of Staff's Table

Resource	Nominal Capacity	Total Capital ($/kW)	Capital cost	Fixed O&M ($/kW-Month)	Fixed O&M	Variable O&M ($/MWh)	Variable O&M	Fuel Cost	REC	PTC/ITC	Portfolio Cost
CCCT	1773	1590	$2,818,636,364	1.4	$595,636,364	3.1	$529,542,000	$0	$0	$0	$6,739,155,758
SCCT	1658	991	$1,642,944,994	2.1	$835,564,356	6	$316,831,680	$0	$0	$0	
Solar	3325	1222	$4,063,150,000	1.9	$1,516,200,000	0	$0	$0	$0	$0	$13,894,238,000
Wind (ID)	1800	1782	$3,207,600,000	4.1	$1,771,200,000	0	$0	$0	$0	$0	
BESS	1453	1600	$2,324,800,000	2.9	$1,011,288,000	0	$0	$0	$0	$0	

All Calculations assume 20 Years of Operations

Replication of Staff's Table with Fuel, REC, and Tax Credits

Resource	Nominal Capacity	Total Capital ($/kW)	Capital cost	Fixed O&M ($/kW-Month)	Fixed O&M	Variable O&M ($/MWh)	Variable O&M	Fuel Cost	REC	PTC/ITC	Portfolio Cost
CCCT	1773	1590	$2,818,636,364	1.4	$595,636,364	3.1	$529,542,000	$4,376,985,600	$0	$0	$11,116,141,358
SCCT	1658	991	$1,642,944,994	2.1	$835,564,356	6	$316,831,680	$0	$0	$0	
Solar	3325	1222	$4,063,150,000	1.9	$1,516,200,000	0	$0	$0	($3,989,203,702)	($2,711,284,800)	$2,321,556,508
Wind (ID)	1800	1782	$3,207,600,000	4.1	$1,771,200,000	0	$0	$0	($2,507,886,490)	($1,704,499,200)	
BESS	1453	1637	$2,378,561,000	2.9	$1,011,288,000	0	$0	$0	$0	($713,568,300)	

All Calculations assume 20 Years of Operations
CCCT Fuel cost calculated at $4/MMBtu at peak efficiency of 6400 Btu/kWh
REC calculated using -22.07 $/MWh
PTC calculated at -30.00 $/MWh for 10 years
ITC calculated at 30% of capital cost

Once the omitted costs and cost reductions are included in the analysis, the 'Dispatchable' portfolio cost derived by Staff increases from $6.7 billion to $11.1 billion, largely due to the inclusion of fuel costs in the latter. In contrast, the cost of Staff's 'VER & BESS' Portfolio declines from $13.9 billion to $2.3 billion, largely due to the inclusion of federal tax credits (PTC and ITC) and the sale of RECs that reduce the cost of renewables. The Company also notes that the updated costs in Table 1 are conservative and do not address all of the issues identified in the spreadsheet analysis, such as pipeline expansion costs, which, if included, would only further increase the spread between the Dispatchable and VER & BESS portfolio costs.

To further support Idaho Power's analysis in Table 1, the Company allowed the LTCE model to create a portfolio that relied predominantly on natural gas resources instead of the wind, solar, and storage resources it optimally selected in the 2023 IRP Preferred Portfolio. To remain relatively consistent with the scenarios in the 2023 IRP (and even though Staff's analysis did not factor in transmission), the Company tested two future scenarios related to the timing of Boardman to Hemingway ("B2H"): a July 2026 and November 2026 online date. The buildout of these two portfolios can be seen in Tables 2 and 3 below.

Table 2: Limited VERs, July B2H Portfolio Buildout and Cost Estimate

Jul B2H Valmy 1 and 2 Limited VERs (MW)															
Year	Coal Exits	Gas Exits	New Gas	H2	Wind	Solar	4Hr	8Hr	Pumped Storage	100Hr	Trans.	Geo	DR	EE Forecast	EE Bundles
2024	-357	0	357	0	0	100	96	0	0	0	0	0	0	17	0
2025	0	0	0	0	0	200	227	0	0	0	0	0	0	18	0
2026	-134	0	261	0	0	0	0	0	0	0	Jul B2H	0	0	19	0
2027	0	0	0	0	0	675	0	0	0	0	0	0	0	20	0
2028	0	0	0	0	0	150	0	0	0	0	0	0	0	21	0
2029	0	0	300	0	0	0	0	0	0	0	0	0	0	22	0
2030	-350	0	350	0	0	0	0	0	0	0	0	0	0	21	0
2031	0	0	170	0	0	0	0	0	0	0	0	0	0	21	0
2032	0	0	0	0	0	0	0	0	0	0	0	30	0	20	0
2033	0	0	0	0	400	0	0	0	0	0	0	0	0	20	0
2034	0	0	0	0	0	0	0	0	0	0	0	0	0	19	0
2035	0	0	170	0	0	0	0	0	0	0	0	0	0	18	0
2036	0	0	0	0	0	0	0	0	0	0	0	0	0	17	0
2037	0	0	170	0	0	0	0	0	0	0	Pipeline	0	0	17	0
2038	0	-706	640	0	0	0	0	0	0	0	0	0	0	17	0
2039	0	0	0	0	0	0	0	0	0	0	0	0	0	15	0
2040	0	0	0	0	0	0	0	0	0	0	0	0	0	14	0
2041	0	0	170	0	0	0	0	0	0	0	0	0	0	14	0
2042	0	0	0	0	0	0	0	0	0	0	0	0	0	14	0
2043	0	0	170	0	0	0	0	0	0	0	0	0	0	14	0
Sub Total	-841	-706	2,757	0	400	1,125	323	0	0	0		30	0	360	0
Total	**3,448**	**Portfolio Cost**	**$10,861M**												

Table 3: Limited VERs, November B2H Portfolio Buildout and Cost Estimate

Nov B2H Valmy 1 and 2 Limited VERs (MW)															
Year	Coal Exits	Gas Exits	New Gas	H2	Wind	Solar	4Hr	8Hr	Pumped Storage	100Hr	Trans.	Geo	DR	EE Forecast	EE Bundles
2024	-357	0	357	0	0	100	96	0	0	0	0	0	0	17	0
2025	0	0	0	0	0	200	227	0	0	0	0	0	0	18	0
2026	-134	0	261	0	0	0	50	150	0	0	Nov B2H	0	40	19	7
2027	0	0	0	0	0	475	0	0	0	0	0	0	0	20	0
2028	0	0	0	0	0	150	0	0	0	0	0	0	0	21	0
2029	0	0	170	0	0	0	0	0	0	0	0	0	0	22	0
2030	-350	0	520	0	0	0	0	0	0	0	0	0	0	21	0
2031	0	0	0	0	0	100	0	0	0	0	0	30	0	21	0
2032	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0
2033	0	0	0	0	400	100	0	0	0	0	0	0	0	20	0
2034	0	0	470	0	0	0	0	0	0	0	Pipeline	0	0	19	0
2035	0	0	0	0	0	0	0	0	0	0	0	0	0	18	0
2036	0	0	0	0	0	0	0	0	0	0	0	0	0	17	0
2037	0	0	300	0	0	0	0	0	0	0	0	0	0	17	0
2038	0	-706	300	0	0	0	0	0	0	0	0	0	0	17	0
2039	0	0	0	0	0	0	0	0	0	0	0	0	0	15	0
2040	0	0	0	0	0	0	0	0	0	0	0	0	0	14	0
2041	0	0	170	0	0	0	0	0	0	0	0	0	0	14	0
2042	0	0	0	0	0	0	0	0	0	0	0	0	0	14	0
2043	0	0	0	0	0	0	0	0	0	0	0	0	0	14	0
Sub Total	-841	-706	2,547	0	400	1,125	373	150	0	0		30	40	360	7
Total	**3,485**	**Portfolio Cost**		**$10,970M**											

The buildouts of the two portfolios reflect a future in which capacity and energy needs are predominantly fulfilled by the addition of an LTCE-optimized mix of SCCTs and CCCTs, instead of renewable and battery storage resources. The cost of these portfolios reflects simulated operations of the new gas plants and include all the same model parameters as included in other portfolios in the 2023 IRP. These portfolio costs also account for the time value of money and include the levelized cost of the gas pipeline additions needed for SCCT and CCCT builds. (These pipeline costs amount to approximately $81 million in the July B2H scenario and $92 million in the November B2H scenario on a NPV basis.[12])

[12] The Company made the very conservative assumption that the cost allocated to the Company for the new pipeline would be proportional to the amount required by the new plants, and that Idaho Power's customers would not bear the entire cost of the pipeline by themselves. The NPV costs presented reflect the proportional allocation for the years in which the pipeline is necessary to serve the new gas plants.

As shown below, Table 4 compares the 2023 IRP Preferred Portfolio (Valmy 1 & 2), which assumes a July online date for B2H, and the November B2H portfolio, to a forced limited VERs portfolio (intended to mimic Staff's 'Dispatchable' Portfolio) under the same two B2H dates (July and November). The table shows that under both B2H online dates, the "limited VER" portfolios cost more than $1 billion more than the portfolios Idaho Power produced in the 2023 IRP.

Table 4: Limited VERs Portfolio Cost Comparisons

Portfolio	Cost ($000,000)
Preferred Portfolio-Valmy 1 & 2	$9,746
July B2H Valmy 1 & 2 Limited VERs	$10,861
Cost Increase of Gas Heavy Portfolio	$1,115
November 2026 B2H Valmy 1 & 2	$9,767
Nov B2H Valmy 1 & 2 Limited VERs	$10,970
Cost Increase of Gas Heavy Portfolio	$1,203

Consistent with the Company's findings in Table 1, the LTCE-optimized portfolios with a buildout of VERs are lower cost compared to the Limited VER cases that built predominantly new gas resources. It can be observed clearly that Table 1 shows a spread between these two portfolio costs of about $8.8 billion, while Table 4 shows a spread of only about $1.1 billion. This reduction in portfolio cost spread is largely due to the fact that the LTCE portfolio buildouts and cost estimates are consistent with the analysis of the 2023 IRP, which accounts for the manner in which the resources would serve load on an hour-to-hour basis, the costs involved with the new resources, the need to build reliable portfolios, interactions with the energy markets, and the use of NPV to factor in the time value of money. Stated another way: Table 4 takes Staff's spreadsheet analysis and adapts it to an AURORA-based simulation of the actual energy system in which Idaho

Power operates. This analysis shows that a Limited VER (heavy fossil fuel) environment is more expensive.

In summary, there are material deficiencies in Staff's analysis, which, once accounted for, do not support the conclusion that a fossil-based portfolio is less expensive than the 2023 IRP Preferred Portfolio. Idaho Power is disappointed that Staff believes Idaho Power showed any amount of resource bias in its 2023 IRP.[13] To be clear, the Company develops its IRP without bias toward any single technology or set of technologies. Rather, market costs, best available market and resource information, documented operating characteristics of technologies, and established policies (including ones with financial elements) are the factors that shape the Preferred Portfolio.

While the Company's counter analysis shows that a heavy gas build is not least-cost, least-risk for Idaho Power's long-term planning for the 2023 IRP at this time, such an outcome does not preclude that future circumstances and analyses could lead to selection of gas resources in the preferred portfolio of a future IRP.

As demonstrated by past acknowledged IRPs and continued methodology improvements incorporated by the Company, Idaho Power is confident that the rigor and depth of analysis used in the preparation of its IRPs is sufficient to determine an optimal and least-cost, least-risk portfolio. Therefore, as demonstrated by the analysis presented above, the Company believes Staff's recommendation that the Company provide an IRP supplement is unnecessary and duplicative as it relates to testing additional gas-reliant portfolios.

[13] Staff's Comments at 8-14.

However, the Company recognizes that more conversations about modeling assumptions would be of value to both Staff and the Company. The Company welcomes continued conversations with Staff and other interested stakeholders to inform future modeling assumptions.

2. Possible Sources of Portfolio Bias

Because of the portfolio cost differences suggested by Staff's analysis, Staff examined the LTCE modeling process and identified three areas it believes are potential sources of portfolio bias.

Idaho Power addresses Staff's concerns regarding portfolio bias, in the following sub-sections.

a. External Constraints – Forcing a Coal Exit of a Conversion to Gas at a Predetermined Time

Staff believes one of the potential sources of portfolio bias came from the external constraints included in the model, such as resource conversion and exit dates.[14] The Company appreciates Staff recognizing the transmission line completion date assumptions as appropriate external constraints.[15] However, Staff is concerned that the Company forced the LTCE model to choose between exiting coal and converting to gas in a predetermined year without economic basis. Specifically, Staff highlights that the Company placed a constraint on the model in which it must select between exit or conversion for Valmy Coal Unit 2 in 2025, and Bridger Coal Units 3 and 4 in 2029.[16]

[14] *Id.* at 8.
[15] *Id.* at 8, "Some of these constraints assumed complete dates of transmission lines, which Staff agrees are appropriate."
[16] *Id.* at 8.

While Idaho Power recognizes and agrees that model constraints should not be arbitrary, the Company emphasizes that these particular model constraints reflect the *only* real and possible options available for Idaho Power's participation in these units. In the Company's Response to Staff's Production Request No. 32 (Attachment 3 to these Reply Comments), the Company explained that both the exit and conversion timing for Valmy and Bridger are based on alignment with Idaho Power's co-owners, NV Energy and PacifiCorp, respectively. It is unfeasible and unrealistic for Idaho Power to exit or convert under a different timeline than its co-owner. To maintain the integrity of the IRP as a reflection of the most up-to-date planning information, it is crucial for the Company to align these model assumptions with its co-owners.

Additionally, regarding the Valmy Units 1 and 2 coal-to-gas conversion, Idaho Power's model constraints directly reflect what is provided in the Valmy Stipulation Order:

> The parties agreed Idaho Power will negotiate with co-owner NV Energy – using prudent and commercially reasonable efforts – to accomplish a permanent end to coal-burning operations of Valmy Unit 1 by December 31, 2019, and of Valmy Unit 2 by December 31, 2025.[17]

As such, the Company did not study continued coal operations for Valmy past 2025 in the 2023 IRP. Rather than impose any model constraints contrary to the Stipulation Order, the Company extensively studied several different scenarios in the 2023 IRP that analyzed different combinations of Valmy Units 1 and 2 conversions. Considering the Company's compliance with the Valmy Stipulation Order, alignment with NV Energy, and analysis of extensive portfolio scenarios in the IRP, the Company believes there is ample justification for the Valmy Units 1 and 2 model constraints.

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[17] Case No. IPC-E-16-24, Order No. 33771 at 3.

Regarding the coal-to-gas conversion of Bridger Units 3 and 4, the Company underscores its commitment to collaborating and aligning with its co-owner, PacifiCorp, on the Bridger model constraints. The Company would not be planning with the most realistic and accurate model assumptions if it did not consider PacifiCorp's plans for those units. Further, the Bridger conversion is identified outside of the Action Plan window in the Preferred Portfolio. The Company will continue evaluating the selected conversion and its options in the 2025 IRP.[18] While the 2023 IRP did show the need for continued operations at Bridger Units 3 and 4, the Company does not believe there to be any material impact to the Action Plan as the capacity position would not change depending on fuel source.

b. External Constraints – Forcing an Exit from Gas at a Predetermined Time

Similarly, Staff expressed concern regarding the Company's external model constraints for forced gas exits at a predetermined time. Specifically, Staff is concerned that the end-of-life for Bridger is flexible, as the Company constrained the LTCE model to exit the converted-to-gas Bridger Units in 2037, instead of by 2034 as was modeled in the 2021 IRP.[19]

Once again, Idaho Power's Response to Staff's Production Request No. 32 states that the extended end-of-life for Bridger to 2037 aligns with the assumptions made by the co-owner and operator, PacifiCorp. The Company must include the most up-to-date model assumptions in its IRP, which includes any assumptions that are updated in collaboration with its co-owners. However, the Company will continue to evaluate the economics and operations of Bridger in future IRPs, as there is still a significant amount

[18] 2023 IRP at 10.
[19] Staff's Comments at 9.

of time before the Bridger exit nears the Action Plan window. For these reasons, the Company believes there is ample justification for the 2037 end-of-life assumption for Bridger.

c. Internal Cost Inputs and Operating Assumptions – CFs and LCOC

Staff identifies various internal cost inputs and operating assumptions that it suggests could potentially bias portfolio selections. Specifically, Staff identifies capacity factor ("CF"), the Levelized Cost of Capacity ("LCOC"), and interconnection costs as potential sources of bias.[20] However, the Company notes that CFs and LCOCs are not cost inputs or operating assumptions used in IRP modeling, as explained below.

Regarding CFs and LCOC, Staff notes that it was difficult to find CF information within the IRP report and suggests that some of the CFs are biased toward VERs and BESSs and away from fossil fuel resources. Further, Staff states that Table 8.3 in the IRP is misleading because it lists LCOC values for each resource based on its nominal capacity, rather than adjusted for peak CF.[21]

In comments, Staff uses the terms "energy CF" and "peak CF" when discussing LCOC, however, the Company believes it is important to consider the distinct differences between capacity factor ("CF"), which is a measure of a resource's average or expected output divided by its nameplate capacity over a period of time, and peak coincidence factor, which the Company assesses using capacity contribution (for the 2023 IRP, the Effective Load Carrying Capability ("ELCC") methodology). In responding to Staff's comments, the Company uses CF to mean capacity factor and uses ELCC to represent capacity contribution.

[20] *Id.* at 9 and 10.
[21] *Id.* at 11.

Staff asserts that “The smaller the CF, the smaller the resource’s contribution to peak load and energy provided to the system.”[22] This statement incorrectly implies that CF and ELCC are correlated. In the IRP, a resource’s CF is independent of its ELCC. A high CF resource means that the resource provides more energy to the system relative to a similarly sized resource with a lower CF. It is not necessarily true, however, that a lower CF leads to a resource having a lower contribution to system load during the Company’s high-risk hours. Conceptually, a resource that was used only to reduce system capacity need could have a very low CF while also having a high ELCC (this is, in fact, the precise definition and operational characterization of a peaking plant). The opposite could be true, too, if a resource were to generate all through the year but were offline during high-risk hours, resulting in a high CF but a low ELCC.

Staff also asserts that “the CF data was not easy to find in the report.”[23] However, Idaho Power notes that the capacity factor of different resources is displayed in the IRP on page 116 and in Appendix C on page 24. For flexible resources like natural gas units, a CF is not available, as the dispatch of these resources changes their CFs from year to year. The ELCC methodology is discussed in detail in the IRP Appendix C starting on page 89, along with the new resource ELCCs for variable and energy-limited resources. Nonetheless, as Staff noted, Idaho Power provided the capacity contribution for new variable, energy-limited and flexible resources as part of its Response to Staff’s Production Request No. 38 (Attachment 4 to these Reply Comments). Idaho Power appreciates Staff’s suggestion to display the ELCCs and capacity factors of new

[22] *Id.* at 10.
[23] *Id.* at 10.

resources more clearly in the IRP and will work to improve this in the next IRP and appendices.

Staff further asserts that "some of the peak CFs and energy CFs are biased toward VERs and BESSs and away from fossil fuel resources."[24] As noted above, capacity factor is a broad assessment of a resource's utility over time, expressed as a percentage. Capacity factors are not calculated separately for peak versus energy, leaving the Company to deduce that Staff may be confusing terms and, most likely, is referring to capacity contribution, or ELCC, which is also expressed as a percentage. As shown in Appendix C on page 92, the ELCC is 27.7 percent for solar, between 15.5 and 20.8 percent for wind, and 38.5 percent for 4-hour BESS (4-hour BESS constitutes the primary duration selected in the Preferred Portfolio). Meanwhile, the capacity contributions for both CCCTs and SCCTs are above 90 percent (as also provided in the Company's response to Staff's Request for Production No. 38). This means that for the 2023 IRP, the capacity contributions for fossil fuel resources are more than threefold that of VERs and more than twofold that of 4-hour BESS—disproving an assertion of capacity contribution bias toward VERs and BESSs.

The capacity factors listed in the 2023 IRP are not biased for two reasons. First, the CFs for solar and wind are representative of the CFs that Idaho Power has seen on its system for similar resources and is comparable with bids received in recent RFPs, meaning the CFs are consistent with industry best practices and with measured values. Second, the CFs displayed in the IRP report and appendices for BESS and fossil fuel resources cannot bias portfolio development because they are not used in the modeling.

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[24] *Id.* at 10.

This is a critical point—these values are illustrative, as a CF is needed to calculate the LCOE of a resource. The printed CFs in the IRP are meant to help the reader generally understand the characteristics of the resource and its utilization, but, again, these figures are <u>not</u> used in actual IRP modeling.

VER, BESS, and fossil fuel resources that can be selected in AURORA are allowed to dispatch according to their unique characteristics in the most optimal way to meet system demand, allowing for operational flexibility. This means that, contrary to Staff's assertion, a CCCT could have a CF in the AURORA model of 65 percent, if it was optimal.

Additionally, Idaho Power would like to correct Staff's assertion that "The Company also used the same 55 percent CF for SCCTs."[25] As shown in the IRP Report on page 116, the CF for an SCCT (again for purposes of calculating LCOE and <u>not</u> for use in IRP modeling) is 12 percent. Again, this is different from the capacity contribution of an SCCT. Idaho Power would also like to clarify that the 27.7 percent that Staff refers to as "peak CF"[26] is the assumed ELCC for solar, rather than the CF for solar, which can be found on page 116 of the IRP Report. The Company agrees with Staff's statement that as more solar is added to the system, the ELCC will diminish (but is dependent on the other resource types being added to the system). Idaho Power's Reliability and Capacity Assessment Tool ("RCAT") captures the interaction between resources and their varying capacity contribution values by solving each year in the planning horizon utilizing its hourly output. Because the Company calculates and captures the interaction of these resources with each new resource addition, it is worth noting that resources can—and do—still bring value, even if its ELCC is quite low. AURORA is an optimization model that

[25] *Id.* at 10.
[26] *Id.* at 10, "Another example is the utility-scale solar resource, the Company assumed a peak CF of 27.7 percent."

looks for the lowest cost solution to meet system needs. As such, the model would not select a resource with a low ELCC if it were not the most cost-effective way to meet load.

Lastly, as shared in its Response to Staff's Request for Production No. 83 (Attachment 5 to these Reply Comments), the Company would like to clarify that the 'ELCC adjusted' LCOC value was also intended to be illustrative. It is not a common industry metric, like unadjusted LCOC, and is <u>not</u> used in the IRP analysis. The levelized cost of a resource, along with other inputs including ELCC, output shape, and ramp rates are used in the AURORA LTCE model (as has been historically done in past IRPs). Idaho Power commits to improve its display of LCOC in future IRPs.

d. Internal Cost Inputs and Operating Assumptions – Interconnection Costs

Staff believes that the interconnection cost data is biased toward VERs and away from fossil fuel resources.[27] However, the Company disagrees with Staff's assertion, as the interconnection costs are driven by location and voltage of the interconnection, rather than the fuel type of the resource. The interconnection costs used in the 2023 IRP were based on the costs identified in actual interconnection studies and provided to Staff in Idaho Power's Response to Request for Production No. 80 (Attachment 6 to these Reply Comments).

The Company would also like to note that the Gateway West ("GWW") project costs only affect renewables, because those transmission projects are <u>required</u> to integrate renewable resources and do not impact fossil fuel resources. Stated another way, GWW is a renewable-enabling transmission project. GWW project costs were included for portfolios where they were necessary, increasing portfolio costs. As shown

[27] *Id.* at 12.

in the Company's responses to Staff's comments regarding fossil fuel-heavy portfolios, the Preferred Portfolio, including additional cost adders for GWW (necessitated by the renewable buildout in the portfolios), is lower cost than the fossil fuel-heavy portfolio that Staff proposed (which does not include GWW transmission costs because it was not triggered by a renewable buildout).

The Company welcomes Staff's input and follow-up meetings to discuss GWW costs or review the data-backed interconnection costs, in addition to how interconnection assumptions are displayed in future IRPs.

e. The Resource Selection and Optimization Algorithms

Staff expressed concern that as a potential source of portfolio bias, the LTCE model may not select large resources when the incremental load deficit is small.[28] To support its concern, Staff provides hypothetical examples of large and small deficits occurring at different times throughout the planning period.

The Company does not believe the LTCE model inherently overlooks or deprioritizes large resources when optimizing for small load deficits. For example, the LTCE model selected more than 300 MW of resources in single year for 9 of the 18 years available for resource selection in the model, which provides evidence that resource size was not a single determining factor in the model's selection, as the standard size of a CCCT available in the model is 300 MW. This resource was available to the model in times with 300 MW or greater capacity need, and the model opted to select other resources because they were more cost effective at providing the same amount of

[28] *Id.* at 13.

capacity. Notwithstanding this example of lack of size bias, the Company offers additional response to Staff's hypothetical examples regarding model optimization of load deficits.

In Staff's example of a 100 MW deficit,[29] the LTCE model first considers what type of load needs to be served (i.e., 100 MW peak or 100 MW base load) and the full cost of the resources that can serve that load. The model then minimizes the cost of the resource selection on an NPV basis. In this example, the model will determine which resource is least cost on an NPV basis from the available options: 300 MW CCCT, 170 MW SCCT, 700 MW[30] of Idaho Wind, 400 MW[31] of solar, or any other resource available to the model.

In Staff's hypothetical example where 100 MW deficits[32] occur in years one, four, and seven, the model will consider if it is lower cost to install a large resource up-front or if it is more cost effective to install smaller resources to meet the incremental need over time. The model determines whether a large resource or smaller, better-timed resources (but potentially more expensive on a dollar per kilowatt basis) is lower cost on an NPV basis.

Considering the above explained logic, the Company is confident that the model is not overlooking larger fossil resources for selection in the model.

3. Recommendations

In summary, because of Staff's concerns regarding the Preferred Portfolio, Staff recommends the Company file an IRP supplement in this docket, provide separate

[29] *Id.* at 13.

[30] $\left(\left(\frac{MW\ Deficit}{ID\ Wind\ ELCC}\right) = \left(\frac{100\ MW}{15.5\%}\right) = Round\ Up_{Nearest\ 100\ MW}(645.16\ MW) = 700\ MW\right)$

[31] $\left(\left(\frac{MW\ Deficit}{Solar\ ELCC}\right) = \left(\frac{100\ MW}{27.7\%}\right) = Round\ Up_{Nearest\ 100\ MW}(361.01\ MW) = 400\ MW\right)$

[32] Staff's Comments at 13.

justification for the conversion or exits of Valmy and Bridger, and implement changes to future IRPs.

As further explained above, the Company does not believe Staff's recommendation for a supplemental IRP is warranted and, therefore, respectfully requests that the Commission not adopt this particular recommendation from Staff.

With respect to separate filings for Valmy and Bridger and implementing changes in future IRPs, Idaho Power is not opposed. The Company reiterates its understanding that identification and acknowledgement of items in the Near-Term Action plan do not infer their prudence. As such, the Company will provide separate regulatory filings for the conversions of Valmy and Bridger to assess their prudence. While the Company agrees to provide these filings, doing so should not preclude acknowledgement of these Action Items by the Commission. Additionally, Staff has pointed out areas where Idaho Power can provide additional transparency, more education, and a more robust explanation of resource planning principles. The Company will pay particular attention to its discussion of CFs, LCOC, and interconnection costs in future IRPs and welcomes further discussions with Staff and other interested stakeholders to identify opportunities for continued improvement in its planning process.

B. The Near-Term Action Plan

Staff recommends that the Commission refrain from acknowledging the Company's Near-Term Action Plan and, instead, limit itself to only acknowledging the overall 2023 IRP.[33] Staff makes this recommendation because several of the Action Plan items are derived from the Preferred Portfolio, which Staff believes may not be the least-

[33] *Id.* at 15.

cost portfolio.[34] As addressed in the section above, Idaho Power employed a robust, thorough portfolio analysis that accounted for foundational elements of resource planning and system reliability. Further, the Company conducted comprehensive verification and validation model runs to support the identification of the Preferred Portfolio as least-cost and least-risk. As such, Idaho Power believes the Commission should acknowledge the Action Plan items that are derived from the Preferred Portfolio.

For additional consideration, the Company provides the following responses to Staff's comments on the Company's Action Items:

1. Boardman to Hemingway ("B2H") Online by Summer 2026

Staff notes that while the Company's Preferred Portfolio relies on a July 2026 B2H in-service date, the November 2026 B2H portfolio was created as one of the alternative portfolio scenarios. Because the November 2026 B2H portfolio cost is estimated to be $21 million more than the Preferred Portfolio, Staff is concerned about schedule delays and continued cost growth for the B2H project.[35]

The Company appreciates Staff's concern regarding schedule delays and cost growth and reiterates its commitment to working toward minimizing these impacts and putting B2H in-service with minimal schedule delays. As noted above, the November 2026 B2H portfolio cost is estimated to be in $21 million more in NPV than the Preferred Portfolio. However, the Company also looked at an alternative portfolio scenario without B2H, which resulted in a $836 million higher NPV portfolio cost than the Preferred Portfolio.

[34] *Id.* at 15, "Staff notes that the Near-Term Action Plan consists of eight action items, some of which derive from the Preferred Portfolio. Since Staff believes the Preferred Portfolio may not be least-cost, Action Plan items that are based on the portfolio may not be appropriate."
[35] *Id.* at 15 and 16.

2. Continue Exploring the Company's Participation in Southwest Intertie Project—North ("SWIP-N")

Due to the minimal amount of information regarding the Company's participation in SWIP-N within the 2023 IRP, Staff recommends the next IRP provide more detailed information about the scope and cost of the project.[36]

Idaho Power understands Staff's interest in the Company's participation in SWIP-N and appreciates Staff's recommendation for future IRPs. As expressed in the Company's Response to Staff's Request for Production No. 50, the Company is in active negotiations regarding the SWIP-N project. As information becomes available to share, Idaho Power agrees to incorporate and provide this information in the 2025 IRP.

3. Install Cost Effective Distribution-Connected Storage from 2025 to 2028

Staff noted that the Company did not provide details regarding this Action Item within the 2023 IRP or in discovery. As a result, Staff recommends that the Company provide additional analysis for any distribution-connected battery projects it is planning in future filings, such as a general rate case. Staff also recommends that the Company clarify how it selects between distribution-connected and transmission-connected battery projects in future IRP filings.[37]

With respect to the modeling of distribution-connected storage, the Company provides a description of how distribution-connected storage was modeled in the 2023 IRP on page 58. While the Company is confident in the model's selection of distribution-connected storage, Idaho Power will review the assumptions and modeling of both distribution- and transmission-connected storage and commits to providing these details

[36] *Id.* at 16.
[37] *Id.* at 17.

in future IRPs, as it has in the past, when projects are identified and there is information available to share.

4. Convert Valmy 1 & 2 from Coal to Natural Gas by Summer 2026

Staff recommends the Company submit separate filings for each proposed conversion or closure of Valmy and Bridger.[38] The Company agrees that all items in the Near-Term Action Plan will be supported by individual regulatory filings.

5. Acquire up to 1,425 MW of Combined Wind and Solar in 2026-2028

Because this Action Item is based on the Preferred Portfolio, which Staff believes is insufficiently validated, Staff recommends the Company provide a supplemental IRP filing and analysis.[39]

Idaho Power reiterates its stance that a supplemental filing is not necessary and that the filed 2023 IRP and the associated appendices are sufficient to support the resources selected in the Preferred Portfolio. The analysis performed by the Company and described within these Reply Comments highlights the omissions and oversights in Staff's cost analysis and provides evidence that an IRP supplement is unnecessary to validate the Preferred Portfolio.

6. Explore a 5 MW Long-Duration Storage Pilot Project

Staff agrees with the Company's plan to seek Commission approval with a formal filing if it decides to move forward with this Action Item.[40] The Company appreciates Staff's alignment and reiterates it commitment to submit a formal filing if the Company moves forward with such a project.

[38] *Id.* at 17.
[39] *Id.* at 17.
[40] *Id.* at 17.

7. Include 14 MW of Western Resource Adequacy Program ("WRAP") Capacity

The Company appreciates Staff's review of Idaho Power's compliance with Order No. 35920 and how it modeled the Company's WRAP participation in the 2023 IRP. As the Company learns more through its participation in the non-binding phases of WRAP, it may refine to how it models WRAP in the IRP.

8. Gateway West ("GWW") Phase 1 Online by End of 2028

Due to the risks of schedule delays and cost growth, Staff is concerned that the assumed availability date for GWW Phase 1 may be optimistic, which could affect the availability of renewable energy in the Preferred Portfolio.[41]

Idaho Power recognizes Staff's concerns regarding unanticipated delays to GWW and the potential impacts such a delay could pose. In an effort to minimize these risks, Idaho Power is presently in discussions with its project partner, PacifiCorp, to discuss project execution and timing. From a final permitting and construction standpoint, it is anticipated that GWW will be less complex than B2H, which should mitigate risk of delays due to permitting and construction.

Within the 2023 IRP analysis, the Company looked at alternative scenarios with differing assumed GWW additions. After modeling these scenarios, the "Without GWW" portfolio resulted in a $580 million higher NPV portfolio cost than the Preferred Portfolio. Similar to the B2H project, delays to GWW may increase costs compared to the Preferred Portfolio but remain the best option by a large margin compared to a portfolio without GWW. Given the large gap comparing the Without GWW and the Preferred Portfolio, a

[41] *Id.* at 18.

delayed GWW remains more cost-effective than an alternative portfolio without GWW and the associated incremental renewable resources.

C. The Load Forecast

In preparation of the 2023 IRP, the Company switched from the 50th percentile ("P50") to the 70th percentile ("P70") energy and peak forecast to comply with Staff's recommendation from the 2021 IRP that the 2023 IRP "Incorporate extreme weather events and variability of water availability through its load and resource input assumptions, rather than compensating by changing the LOLE reliability target, which should be set as a matter of public policy."[42] In response, Idaho Power adjusted the load forecast to P70 to ensure reliability within the developed portfolios. However, Staff is now concerned with the change that was initiated by one of its prior recommendations. Staff asserts that: (1) the Company did not properly justify the use of a P70 load forecast, and (2) the higher load forecast percentile may inflate expected energy costs for customer rates and avoided cost rates.[43]

Idaho Power addresses Staff's concerns regarding load forecast justification and cost implications, in the sub-sections below.

1. Justification for the P70 Load Forecast

Staff states that it does not believe the Company provided sufficient evidence that the P70 load forecast was the appropriate choice. Therefore, Staff recommends that the Company meet with Staff during the 2025 IRP cycle to discuss methods to determine and verify the percentile of load that is appropriate to meet its reliability target in the next IRP.[44]

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[42] IPC-E-21-43 Order No. 35603 at 4.
[43] Staff's Comments at 18.
[44] *Id.* at 19.

The Company recognizes Staff's concern with the load forecast percentile and LOLE threshold selections used in the 2023 IRP. However, Idaho Power would like to note that those decisions were made early on in the IRP development process and were publicly introduced in the IRPAC meeting on December 8, 2022. This provided Staff and other stakeholders the opportunity to provide feedback and express concern with these selections well in advance of the portfolio development process. Staff did not raise concerns with the 70th percentile peak load forecast and 0.1 event-days per year LOLE threshold until after the filing of the 2023 IRP.

In the Company's Response to Staff's Production Request No. 21(Attachment 7 to these Reply Comments), Idaho Power explained that the P70 load forecast selection was made in response to Staff's 2021 IRP recommendation that the Company use a 0.1 event-days per year LOLE threshold in the 2023 IRP, instead of a 0.05 event-days LOLE threshold as was used in the 2021 IRP. As the Company changed to a less stringent LOLE reliability threshold in the 2023 IRP, it believed the selection of a P70 load forecast was a valid way to account for extreme weather events and other reliability risks. The Company considers its intent to account for reliability risks in this way as a reasonable and sound justification for selection of the P70 peak load forecast in the 2023 IRP.

Nonetheless, to further support the analysis conducted by the Company in its Response to Staff's Production Request No. 21, Idaho Power has prepared the analysis below, which validates the selection of the P70 peak load forecast for reliability purposes over the P50 peak load forecast. The Company recognizes that a single percentile of load cannot be expected every year but that, in reality, the percentile varies from year to year. To illustrate this concept, Idaho Power calculated the LOLE over a range of peak load forecast percentiles utilizing the capacity positions to meet a 0.1 event-days per year LOLE threshold using both the P50 and P70 (as the two base cases) for all six test years used in the 2023 IRP analysis. These calculations were used to approximate the resulting average LOLE across all load forecast percentiles.

The results of this analysis are provided in Tables 5 and 6 below and show that utilizing the P50 load forecast as a base produces an average LOLE across all percentiles of 0.1650 event-days per year. Meanwhile, utilizing the 70th percentile as a base produces an average LOLE across all percentiles of 0.0965 event-days per year. These results show that the selection of the P70 peak load forecast produces an average LOLE across a wide spread of percentiles closer to the Company's target LOLE threshold of 0.1 event-days per year than the P50, thus validating Idaho Power's selection of the P70 peak load forecast for the 2023 IRP.

Table 5: LOLE with P50 Load Forecast

2024 L&R	Resource Need & LOLE for Load Forecast Comparison using Current RCAT							
		LOLE with 50th Percentile Load Forecast RCAT Perfect Generation						
		Corresponding 50th RCAT Gen	10th Percentile	30th Percentile	50th Percentile	70th Percentile	95th Percentile	
	Test Year 1	-90	0.0285	0.0570	0.0993	0.1762	0.4490	
	Test Year 2	-162	0.0283	0.0571	0.0999	0.1733	0.5095	
	Test Year 3	-88	0.0275	0.0557	0.0992	0.1748	0.5116	
	Test Year 4	-125	0.0305	0.0590	0.0990	0.1663	0.4975	
	Test Year 5	-25	0.0286	0.0580	0.0998	0.1698	0.4447	Average LOLE of All Percentiles
	Test Year 6	83	0.0279	0.0580	0.0996	0.1678	0.3964	
	Average	-68	0.0285	0.0575	0.0995	0.1714	0.4681	0.1650
		68 MW Capacity Length						

Table 6: LOLE with P70 Load Forecast

	Resource Need & LOLE for Load Forecast Comparison using Current RCAT							
		LOLE with 70th Percentile Load Forecast RCAT Perfect Generation						
		Corresponding 70th RCAT Gen	10th Percentile	30th Percentile	50th Percentile	70th Percentile	95th Percentile	
2024 L&R	Test Year 1	-30	0.0154	0.0308	0.0555	0.0991	0.2552	
	Test Year 2	-104	0.0156	0.0320	0.0559	0.0997	0.3032	
	Test Year 3	-28	0.0148	0.0305	0.0552	0.0999	0.2976	
	Test Year 4	-71	0.0175	0.0350	0.0585	0.0991	0.3039	
	Test Year 5	32	0.0162	0.0336	0.0574	0.0998	0.2674	Average LOLE of All Percentiles
	Test Year 6	138	0.0161	0.0337	0.0584	0.0993	0.2401	
	Average	-11	0.0159	0.0326	0.0568	0.0995	0.2779	0.0965
		11 MW Capacity Length						

While the Company believes that the use of P70 was appropriate and justified, Idaho Power is open to making adjustments and considering other options for accounting for extreme weather and other reliability risks in future IRPs. The Company welcomes additional discussions with Staff and other interested parties to find a path forward that does not compromise the Company's ability to reliably plan in the IRP.

2. <u>Cost Implications from using the P70 Load Forecast</u>

While analyzing the 2023 IRP, Staff asked whether the Company's use of P70 load forecast had the potential to impact the variable energy costs used to value Demand-Side Management ("DSM") benefits and customer rates that utilize outputs from the IRP.[45] Based on this concern that avoided costs derived from P70 are elevated relative to avoided costs derived from P50, Staff recommends that, for future IRPs, the Company use the P50 load forecast in its dispatch model to calculate IRP portfolio energy costs and marginal avoided costs, regardless if the Preferred Portfolio uses a different load percentile. Staff also recommends that for tariffs that are affected by avoided cost

[45] *Id.* at 19 and 20.

calculations, separate dockets should be filed, and Staff will analyze the Company's cost bases in those dockets.[46]

While the Company agrees with Staff's assessment that the use of a P70 energy and peak forecast can increase average energy costs compared to a P50 energy and peak forecast, the Company believes that the more important consideration is whether any variation is significant—and in the case of avoided costs from P50 versus P70, the impact is *de minimis*. Subsequent to filing the 2023 IRP and after discussions with Staff in January 2024, the Company ran the analysis recommended by Staff and used the Preferred Portfolio from the 2023 IRP within the dispatch model under a P50 load forecast rather than a P70 load forecast. This analysis showed that over the entire 20-year planning horizon, the change in load forecast from P70 to P50 created an approximate 1.0 percent change in avoided costs. This impact does not, in the Company's estimation, warrant a concern or a need to reevaluate rates based on the 2023 IRP and a P70 load forecast.

Nevertheless, the Company agrees that the appropriate venue to have such conversations is within the specific cases where avoided cost rates are used. As such, the Company will seek explicit Commission approval for any rates that are informed by the IRP prior to implementation.

D. The Demand-Side Management ("DSM") Program

In its comments, Staff makes note of the fundamental interconnectedness of the Company's IRP and its DSM programs. In review of the Company's IRP in conjunction

[46] *Id.* at 20.

with its DSM report, Staff provides comments and recommendations on DSM program planning and avoided costs.

The Company addresses Staff's DSM-related comments and recommendations in the following sub-sections.

1. Program Planning

Staff acknowledges the Company's change to plan and evaluate its DSM programs using avoided cost averages provided by the most recently *filed* IRP, rather than the most recently *acknowledged* IRP, as it was historically. Staff believes this change will allow DSM programs to reflect the Company's system and planning process more closely. Further, by using the most recently filed avoided costs, Staff notes that DSM program planning will more closely reflect the most current data.[47]

The Company appreciates Staff's recognition of this policy change as a positive improvement for the overall accuracy of the DSM program planning process. The Company is encouraged that this policy change will help mitigate lag between each respective IRP planning cycle and DSM program planning.

2. Avoided Costs

As discussed above in these Reply Comments, Staff is concerned that the 2023 IRP avoided costs are based on the Preferred Portfolio, which uses a P70 load forecast. Staff further addresses how avoided costs may be impacted by the Preferred Portfolio resource selections and the load forecast itself.[48]

The Company offers its response to Staff regarding these concerns in the following sections.

[47] *Id.* at 20.
[48] *Id.* at 21.

a. Preferred Portfolio Impact

Staff reiterates its belief that the Company's cost input assumptions may be biased toward VERs and away from fossil fuel resources. As such, Staff suggests that different input assumptions and a different portfolio buildout could affect the avoided cost of capacity and avoided cost of energy. For this reason, Staff recommends that the Company not use the 2023 IRP DSM avoided costs and reassess avoided costs as part of a supplemental IRP filing.[49]

As already addressed extensively in these Reply Comments, the Company has disproved Staff's assertion that a portfolio buildout with more dispatchable resources would be lesser cost than the Preferred Portfolio. Further, these Reply Comments have addressed the reasonableness and accuracy of the Company's model input assumptions. Therefore, the Company does not believe there is a need to create a supplemental filing to the 2023 IRP, as the Preferred Portfolio selected in the 2023 IRP is the least cost, least risk portfolio. By extension, there is no basis to reject the avoided costs generated in the 2023 IRP based on resource selection.

b. P70 Impact

Similar to Staff's comments on the Company's load forecast, Staff reiterates its concern that a P70 load forecast skews DSM avoided costs. In response to this, Staff, once again, recommends that the Company use the P50 load forecast when determining avoided costs in the next IRP.[50]

The Company reiterates its response to Staff's comments regarding the load forecast and understands that the P70 load forecast may have downstream impacts on

[49] *Id.* at 21.
[50] *Id.* at 21.

avoided costs. As stated above in these Reply Comments, the Company's analysis showed that over the entire 20-year planning horizon, the change in load forecast from P70 to P50 created an approximate 1.0 percent change in avoided costs—a difference that the Company considers *de minimis*. Given the close agreement in the avoided costs produced using the P70 or P50 load forecast, and that both were generated from the same modeling methods, the Company believes there is sufficient support of either load forecast percentile for calculating avoided costs. However, the Company is open to incorporating Staff's recommendation to use the P50 load when determining avoided costs in the 2025 IRP or identify another method that may not require the Company to plan at a load forecast percentile other than P50.

E. The Seasons and Hours of Highest Risk

As part of its review of the 2023 IRP, Staff reviewed the methodologies and results for the Company's seasons of highest risk and hours of highest risk. In general, Staff supports the seasons and hours of highest risk as reasonable. However, Staff has concerns with specific assumptions and practices and does not recommend updating the seasons or hours of highest risk in conjunction with this report.[51]

The Company appreciates Staff's review and support for the reasonableness of the Company's methodologies regarding seasons and hours of highest risk. However, the Company seeks to address Staff's remaining concerns in the following sub-sections.

1. Seasons of Highest Risk

After reviewing the Company's methods for determining the seasons of highest risk, Staff suggests that the Company's approach is reasonable. However, Staff is

[51] *Id.* at 22.

concerned with the risk hours being captured in the months of June, September, and February. As such, Staff recommends the Company provide analysis that supports the percentage of total risk hours threshold used to select seasons of highest risk, and that the Company should evaluate why other percentages may or may not be appropriate for determining the season of highest risk.[52]

Idaho Power appreciates Staff's review of the seasons of highest risk analysis described in the 2023 IRP. The Company agrees that it should evaluate and justify the selected percentage of total risk hours threshold utilized to develop the seasons of highest risk in the next IRP. The Company believes this would be a valuable improvement to the methodology for future IRPs.

2. Hours of Highest Risk

After reviewing the Company's method for determining the hours of highest risk, Staff suggests that the Company's method is reasonable. However, Staff believes the analysis should include BESS projects and DR programs. Staff recommends that the Company maintain its current hours of highest risk and provide analysis in the next IRP (and any future case that uses this analysis) to support the percentage of the total risk hours threshold used to select hours of highest risk. Staff further recommends that the selected percentage should balance capturing the critical risk hours while providing a focused perspective on when those hours occur within a given season. Additionally, Staff suggests that the analysis should evaluate why other percentages are or are not appropriate for determining the hours of highest risk.[53]

[52] *Id.* at 22 and 23.
[53] *Id.* at 23 and 24.

While Idaho Power understands Staff's concerns with the exclusion of BESS projects and DR programs from the hours of highest risk analysis, the Company would like to clarify that the information provided in Appendix C regarding the timing of highest risk was prepared independently from the development of the 2023 IRP portfolios. The impact of BESS resources and DR programs on all portfolio resource selections are accounted for in the calculation of ELCC and planning reserve margin values, which are an input to the LTCE model. In addition, the calculation of portfolio annual capacity positions considers the impact of BESS projects and DR programs to the system, while Idaho Power's RCAT also considers round-trip efficiency losses on the charging semi-cycle.

Idaho Power believes that the hours of highest risk presented in the 2023 IRP are accurate and valid for their intended purpose. However, the Company agrees to Staff's recommendation of providing an analysis that supports the percentage of total risk hours threshold used to select the hours of highest risk in the next IRP and respectfully requests the Commission not adopt Staff's recommendation to include BESS and DR resources in the analysis, rather that it direct the Company and Staff to evaluate those assumptions as part of the broader discussions regarding hours of highest risk.

F. PURPA and Other Planning Assumptions

Staff recommends the Company adjust its PURPA assumptions in future IRPs and provides additional comments on other planning assumptions. The Company appreciates Staff's review of its various planning assumptions and addresses Staff's comments and recommendations in the following sub-sections.

1. <u>PURPA</u>

a. New PURPA Resources Should Not Be Excluded from Baseline

Staff believes the Company did not reasonably justify why it did not include any forecasted PURPA projects in its base planning conditions in the 2023 IRP.[54] However, the Company discussed its PURPA assumptions for the 2023 IRP at length with IRPAC[55] and provided ample opportunity for feedback from stakeholders. In those IRPAC discussions, the Company explained its assumptions for the base planning conditions as well as the assumptions for the "New Forecasted PURPA" scenario.

In the base planning condition, the Company assumed that all existing PURPA projects enter into replacement contracts when the existing contracts expire, except for wind. Regarding new PURPA project development, in the base planning condition, the Company did not make any assumptions or forecast of new projects entering into PURPA contracts. Meanwhile, in the "New Forecasted PURPA" scenario, the Company assumed that 100 percent of existing PURPA wind projects enter into replacement contracts when their existing contracts expire (in addition to continuing to make the same assumption for other PURPA resource types) and also assumed that 57 MW of new PURPA projects come online each year starting in 2028.

Based on discussions with the IRPAC and other internal research, Idaho Power recognizes that there are various approaches to developing assumptions that are reasonable for a PURPA forecast. As Idaho Power understands it, Staff's position is that the Company should make an assumption of new PURPA development based on actual historical development in the base planning condition. Idaho Power made such an

[54] *Id.* at 25.
[55] Idaho Power's meetings with IRPAC on October 13, 2022, and December 8, 2022.

assumption in the “New Forecasted PURPA” scenario. Idaho Power feels that assumptions about new PURPA development are so speculative that they should remain in a separate scenario and not be included in base planning conditions, as doing so could distort the Company’s identified capacity need and resource selections in the IRP process. As a result, the Company could end up under-forecasting resources because it assumed PURPA projects would come online that might never materialize at all, let alone in the right quantity, timing, and technology to match the IRP forecast.

Stated another way, if the Company assumes new PURPA resources will be online in the IRP, and they do not actually come to fruition when assumed, then the Company will be left with a larger capacity deficit to fill. Further, Idaho Power will have less time to seek and procure other resources to fill that deficit than if it had been originally identified in the IRP, especially when you consider current supply chain constraints. In other words, the Company’s base planning condition assumptions are rooted in the best information about specific resources that the Company has at the time. Using these assumptions in the IRP allows the Company to identify the amount of capacity needed to serve load earlier in time, giving the Company a greater chance of filling that need with cost-effective resources through the RFP process.

Further, and as stated in the Company’s 2023 IRP,[56] this approach allows sufficient resources to be identified in the IRP and has <u>no impact</u> on the ability of new PURPA projects to enter into contracts with Idaho Power (or, with respect to the wind assumptions, on the ability of existing PURPA projects to enter into replacement agreements if they desire). If new PURPA projects do enter into agreements with Idaho

[56] 2023 IRP at 128.

Power, the Company will update its capacity positions in its planning at that time, and that information will be reflected in any procurement activities, RFPs, or IRP development from that point forward.

b. Use the Most Recent PURPA Data

Staff notes that the Company conducted a 10-year PURPA trend analysis from 2012 through 2021 but does not include data from 2022 and 2023. Staff believes this data should not be excluded in the analysis and recommends the Company include the most recent data in future analyses.[57]

Idaho Power agrees that the most recent data should be included in this trend analysis and clarifies that the Company did in fact include the most recent data *available* for the 2023 IRP. Idaho Power conducted the historical trend analysis for years 2012-2021, as those were the most recent full calendar years for which data was available at the time Idaho Power performed the analysis and shared it with the IRPAC in the fall of 2022. Due to the relative time it takes to prepare and fully process the IRP each cycle, there is notable lag in the most recent and available data at the time the IRP is prepared versus at the time the IRP is under review by Staff and parties. Anecdotally, no new PURPA projects came online in 2022 and one small project (less than 1 MW) came online in 2023. Idaho Power will use the most recent data available for this assumption, as it does for all assumptions, in its next IRP.

c. The New Forecasted PURPA Scenario

In review of the Company's New Forecasted PURPA Scenario, Staff expressed concern that the portfolio scenario applies the estimated PURPA trend after the Action

[57] Staff's Comments at 25.

Plan window in 2029.[58] Staff believes this undermines the purpose of exploring different future scenarios and, instead, recommends that PURPA resources be brought online in the IRP starting the first year of the planning horizon.

As discussed above, Idaho Power's PURPA-related assumptions in the base planning condition and in the "New Forecasted PURPA" scenario were implemented to enable the Company to adequately plan for reliability needs, while also reasonably considering PURPA qualifying facilities ("QF") that may or may not be developed or choose to enter into replacement agreements. The inclusion of new forecasted QFs starting in 2029 was made for the same reason—to ensure that the Company's more near-term deficits are based on the most accurate information known at the time.

If the Company assumes near-term PURPA development in the IRP, any identified near-term capacity deficits would be reduced. However, if that near-term PURPA development does not actually materialize, the Company would be left a larger deficit and likely not enough time fill the deficit with alternate resources. Trying to procure resources with inadequate time for development and construction could lead to, at best, higher resource costs, or at worst, an inability to meet the capacity need within the short timeline.

Given the challenges that exist today with supply-chain, permitting, and development and construction generally, this presents a <u>significant reliability risk</u> that resources would not be online in time to meet the capacity need. The Company does not believe it is reasonable to accept this reliability risk and therefore chose to include the forecasted new PURPA development after the Action Plan window, starting in 2029. A planning horizon outside of the Action Plan window allows the Company adequate time

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[58] *Id.* at 25 and 26.

to evaluate and shift to alternative resources, if the forecasted PURPA projects do not materialize.

2. Planning Assumptions

In addition to the Company's PURPA assumptions, Staff makes a variety of other recommendations regarding planning assumptions.[59] The Company addresses these recommendations in the following sub-sections.

a. BESS Degradation

Staff is concerned that the Company did not include the full cost of a BESS over its lifecycle in comparison with other resource alternatives, due to battery degradation. Therefore, Staff recommends that the Company include degradation incremental costs and be able to reflect them explicitly in its cost analysis in its supplemental filing, future IRPs, and in future prudence reviews.[60]

For Idaho Power's 2023 IRP, the Company included the incremental cost to augment the BESS capacity in the fixed O&M cost assumption, as it also did in the 2021 IRP. The Company is confident its BESS degradation augmentation assumption is the most reasonable planning assumption that does not bias BESS relative to other alternative resources.

b. Electric Vehicle ("EV") Adoption

The Company appreciates Staff's acknowledgment of assumed EV adoption as reasonable.[61] Idaho Power will continue to evaluate and update its assumed EV adoption rate in future IRPs.

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[59] *Id.* at 26.
[60] *Id.* at 26.
[61] *Id.* at 26.

c. Customer Generation Adoption

The Company appreciates Staff's acknowledgement of its customer generation adoption assumptions as reasonable. The Company agrees with Staff's recommendation to monitor the Residential and Irrigation Class adoption rates as a result of changes to the Company's Export Credit Rate starting in 2024 and adjust the IRP forecast as necessary based on actual adoption rates.[62]

d. Transmission Capacity – B2H

The Company appreciates Staff's recognition that the Company's B2H transmission capacity assumptions are "…reasonable as B2H has been permitted, contracted, and construction is soon to begin."[63]

e. Transmission Capacity – GWW Phases

Staff reiterates its concerns regarding GWW construction delays, project cost growth, and availability of capacity for incremental resources.[64]

As previously stated in these Reply Comments, Idaho Power is presently in discussions with its project partner, PacifiCorp, to discuss project execution and timing and believes that, from a final permitting and construction standpoint, the GWW projects will be less complex than the B2H project, which should mitigate risk of delays due to permitting and construction.

Within the 2023 IRP analysis, the Company looked at alternative scenarios with differing assumed GWW additions. After modeling these scenarios, the portfolio costs showed that a delayed GWW would remain more cost-effective than an alternative

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[62] *Id.* at 27.
[63] *Id.* at 27.
[64] *Id.* at 28.

portfolio without GWW and the associated incremental renewable resources. As such, the Company is confident in the cost-effectiveness and reasonableness of its planning assumptions regarding GWW.

f. Transmission Capacity – Capacity Benefit Margin ("CBM")

The Company appreciates Staff's belief that the Company's adjusted CBM planning assumption is reasonable. Specifically, Staff states that it "…believes it is reasonable to lower the CBM capacity from the 330 MW level due to the transmission market limitations in the summer and the wholesale energy market depth in the winter."[65] Idaho Power will continue to evaluate its CBM assumptions for potential update in the 2025 IRP.

G. Review of 2021 Staff Recommendations

Staff reviewed the 2023 IRP for its compliance with Commission Order No. 35837 from Case No. IPC-E-23-17 and for its alignment with Staff's recommendations from the 2021 IRP. The Company offers the following responses to Staff's review of the 2023 IRP in this regard.

1. Compliance with Order 35837

To ensure on-time submittal of the 2025 IRP, Order No. 35837 directed the Company to submit a plan and schedule in the 2023 IRP filing. Staff concurs that the Company complied with the Order, as the 2023 IRP proposes a reasonable timeline for the 2025 IRP, with a final filing date of June 2025. However, Staff notes that the 2025 IRP schedule could be in jeopardy due to its recommended supplemental 2023 IRP filing. As

[65] *Id.* at 28.

such, Staff recommends the Company plan accordingly to ensure that it files the 2025 IRP on time.[66]

Idaho Power appreciates Staff's concurrence with its compliance with Order No. 35837. The Company believes its timeline for the 2025 IRP sufficiently accounts for the necessary steps for IRP development and associated public process. However, the Company reiterates that Staff's recommendation for an IRP supplemental filing is unnecessary and unwarranted and as Staff notes, an IRP supplement would put the Company's 2025 IRP timeline at risk for timely filing. While the Company concurs that the filing of an IRP supplement could impact the timing of the 2025 IRP, Idaho Power reiterates that it disagrees with Staff's recommendation to make a supplemental filing.

2. <u>Review of Staff's 2021 IRP Recommendations</u>

a. Market Access

In the 2021 IRP, Staff recommended that the Company only include market access backed by firm transmission reservations in its load and resource balance for the 2023 IRP. Staff concurs that the 2023 IRP adhered to this recommendation. However, Staff notes that CBM is included in the Load and Resource Balance ("L&RB"), but it does not have any firm third-party reservation. In the next IRP filing, Staff recommends that the Company provide justification for why the CBM should be included in the L&RB.[67]

As noted earlier, the Company continues to evaluate the inclusion of a resource capacity credit toward the annual capacity position for CBM and agrees to further evaluate and justify any amount of CBM in the 2025 IRP.

[66] *Id.* at 28.
[67] *Id.* at 29.

b. Model Validation and Verification

In the 2021 IRP, Staff recommended a comprehensive analysis plan to verify and validate the 2023 IRP analysis. Staff concurs that the Company generally followed this recommendation. However, Staff does not believe that the verification and validation adequately tested the model output, as explained in the Preferred Portfolio section.[68] Idaho Power welcomes further conversations with Staff and other interested stakeholders in advance of the 2025 IRP, to help inform whether modifications to the AURORA-related verification and validation processes are warranted.

c. Development of a Bridger Exit Agreement

In the 2021 IRP, Staff recommended that the Company develop a Bridger exit agreement with PacifiCorp that would determine the potential cost of extending or exiting operations. The exit costs could then be used in the 2023 IRP analysis to accurately assess the costs and benefits of different coal exit dates. Because a Bridger exit agreement was not yet available at the time of the 2023 IRP filing, Staff reiterates its recommendation that the Company provide separate filings for each proposed conversion or closure of Valmy and Bridger.[69]

The Company appreciates Staff's review and reiterates that separate filings will be provided for Valmy and Bridger.

III. MICRON COMMENTS

As Idaho Power's largest customer, Micron is keenly interested in all aspects of Idaho Power's cost of service and service reliability, including Idaho Power's resource

[68] *Id.* at 29.
[69] *Id.* at 30.

planning processes and the types of resources used to serve its electric load.[70] The Company appreciates Micron's participation in the planning process and their support in its transition to clean energy. Micron also notes that the Company supports customers' clean energy needs and, as such, recommends that the Commission ensure Idaho Power plans future resource procurements with an eye toward other large loads that may transition to customer-specific resources to ensure it does not procure excess resources.[71] While the Company cannot always predict if a future resource may be a good candidate for a large load customer's clean energy objective, the Company commits to continue evaluating resource needs holistically to avoid unnecessary or excess procurement.

While Micron supports Idaho Power's clean energy transition, it encourages Idaho Power to continually investigate and implement strategies to mitigate the rate impacts of the transition.[72] Idaho Power is sensitive to the rates and charges paid by its customers. Through the IRP process, the Company seeks to produce a portfolio of resources that represents the least-cost, least-risk path to serving its customers' needs over the planning horizon.

IV. PUBLIC COMMENTS

A. City of Boise Comments

Idaho Power is grateful for the City of Boise's participation in the 2023 IRP planning process and for their support of the Company's plan. Specifically, the City of Boise recommends the Commission acknowledge the 2023 IRP and notes its appreciation of

[70] Micron's Comments at 2 (Feb. 15, 2024).
[71] *Id.* at 2.
[72] *Id.* at 3-4.

the Company's continued refinement of more detailed scenario analysis.[73] The City of Boise also highlights its support for the Company's efforts to mitigate long-term risks, incorporate Inflation Reduction Act incentives, and evaluate the selection of additional demand-side resources.[74] The Company is eager to convene the IRPAC in the forthcoming development of the 2025 IRP and looks forward to continued work and collaboration with the City of Boise.

B. FFP Project 101, LLC ("Goldendale") Comments

Idaho Power appreciates Goldendale's comments, which were focused on pumped hydro storage. The 2023 IRP assumes a 30 percent ITC for all storage resources, including pumped hydropower storage. Due to pumped hydro storage's long duration, Idaho Power assumes an approximately 100 percent ELCC for the resource. Idaho Power agrees Goldendale's comments regarding the need to issue longer lead-time RFPs and plans to do so in the future.

C. KITZWORKS, LLC Comments

Idaho Power values KITZWORKS, LLC's comments, which were focused on the two heat pump scenarios in the 2023 IRP. Idaho Power looks forward to continued collaboration with KITZWORKS, LLC on future IRP electrification scenario assumptions.

D. Zanskar Comments

Idaho Power appreciates Zanskar's comments, which were focused on geothermal resources. Idaho Power's recent experience with geothermal projects (in RFPs and developer discussions) and with geothermal data in public sources (such as the National Renewable Energy Laboratory's Annual Technology Baseline report) suggests that the

[73] City of Boise's Comments at 1 (Feb. 15, 2024).
[74] *Id.* at 1.

Company's current assumptions are reasonable. However, Idaho Power will consider the points listed by Zanskar and looks forward to finding ways to refine geothermal assumptions in the next IRP.

V. CONCLUSION

Based on the detailed and comprehensive analysis set forth in the 2023 IRP, Idaho Power has demonstrated that its Preferred Portfolio, which includes a variety of resources and the conversion of several coal-fired units to natural gas, is the best combination of least-cost, least-risk resources to meet Idaho Power's growing demand over the next 20 years.

The Company is grateful for stakeholders' interest and commitment to the IRP process. In particular, Idaho Power appreciates Staff's collaboration throughout IRPAC and during the processing of this case. While Idaho Power supports most of Staff's recommendations with respect to updates to future IRPs, the Company disagrees with Staff's recommendation that the Company provide an IRP supplement as a compliance filing in this case. As supported by these Reply Comments, Idaho Power does not believe such a supplemental filing is warranted. Based on the analysis presented in the 2023 IRP, Idaho Power is confident in the items in its Near-Term Action Plan window and does not believe Staff provided adequate support to suggest that any of these items or actions are unjustified.

As a result, Idaho Power respectfully requests that the Commission accept and/or acknowledge the Company's 2023 IRP as meeting both the procedural and substantive requirements of Order Nos. 22299, 25260, and 30317. Such acknowledgment is consistent with Staff's high-level recommendation of the 2023 IRP.

Further, the Company also respectfully requests that the Commission reject Staff's specific recommendations regarding an IRP supplement and the Near-Term Action Plan.

DATED at Boise, Idaho, this 29th day of February 2024.

Lisa D. Nordstrom

LISA D. NORDSTROM
Attorney for Idaho Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 29th day of February 2024, I served a true and correct copy of Idaho Power Company's Reply Comments upon the following named parties by the method indicated below, and addressed to the following:

Commission Staff Chris Burdin Deputy Attorney General Idaho Public Utilities Commission 11331 W. Chinden Blvd., Bldg No. 8 Suite 201-A (83714) PO Box 83720 Boise, ID 83720-0074	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX ____FTP Site __X__Email Chris.Burdin@puc.idaho.gov
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Christy Davenport
Legal Administrative Assistant

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-23

IDAHO POWER COMPANY

ATTACHMENT 1

<u>STAFF REQUEST FOR PRODUCTION NO. 84</u>: The 2023 IRP load forecast shows that the average system load will grow by 975 MW, and the peak load by 1,507 MW, by 2043. To satisfy this load increase, the preferred portfolio recommends adding 5,125 MW of wind and solar and 1,453 MW of battery storage. Using the cost inputs on page 21 of Appendix C, Staff estimates the simple cost to build these resources and operate them for 10 years to be approximately $11.7 billion.

Using the Baseload Gas cost input data, Staff calculates that a single 1,073 MW combined-cycle combustion turbine (90.9 percent capacity factor), and a single 585 MW SCCT for peaking capacity, could provide the same 10 years of power for approximately $2.9 billion.

Using the Small Modular Reactor data, Staff calculates that a 994 MW nuclear reactor (98.1 percent capacity factor), and a 585 MW SCCT for peaking capacity, could provide the same power for $10.5 billion, along with a 60-year life expectancy.

These simple alternative scenarios don't account for diversification risks, the timing of need, and the time value of money; however, they do highlight a much higher cost of a solar, wind, and battery portfolio relative to a baseload thermal resource portfolio. Please explain why none of the scenario portfolios include significant baseload thermal resource additions, but invariably add solar, wind, and batteries, instead.

<u>RESPONSE TO STAFF'S REQUEST FOR PRODUCTION NO. 84</u>:

Although the Company was not provided with the derivation of the numbers listed in this request, the Company believes it was able to replicate the Staff's approximated $11.7 billion Preferred Portfolio case, the $2.9 billion baseload gas cost, and the $10.5 billion small modular reactor ("SMR") and Simple Cycle Combustion Turbine ("SCCT") combination costs. Based on the Company's replication of these values, the simplifications used in the values' construction are missing some key considerations:

a. As stated in the request, the values here do not account for the time value of money and the resource selections do not account for diversification risks.

b. The portfolios presented by Staff have not been tested to determine if they provide adequate capacity and energy to create reliable resource portfolios. By comparison, the Preferred Portfolio was tested for reliability and accounts for diversification risk.

c. Based on the Company's replication of the numbers provided in this request, the values presented do not include:

   i. The reduction in costs associated with wind and solar energy production related to the selling of Renewable Energy Credits.

   ii. The reduction in costs associated with Production Tax Credits ("PTC") that have now been extended for renewable resources and battery storage.

   iii. The cost of fuel. For the baseload gas scenario, it's reasonable to expect the substantial addition of gas resources to need fuel to provide the energy and capacity expected. Likewise, in the SMR case, the cost of uranium fuel is also missing from the calculations.

   iv. The environmental regulations that make it difficult to construct natural gas generation quickly.

   v. The cost of Carbon used in the 2023 Integrated Resource Plan ("IRP"). Although more a concern in the baseload gas numbers, even the SMR case includes an SCCT that will need to run during peak periods.

   vi. The cost of a gas pipeline expansion necessitated by the addition of more than 600 megawatts ("MW") of new gas resources[6].

d. Based on the Company's replication of the numbers provided in this request, the values presented do not account for dispatch of resources. Specifically:

   i. The Baseload gas and SMR cases generate all their energy from the baseload resource with the SCCT providing only capacity. This is not a feasible dispatch

[6] 2023 IRP Report at page 112.

solution because, during the peak hour, the SCCT must be both incurring its fixed and variable cost. Indeed, there are many hours when the SCCT would need to operate.

ii. The simplified use of 975 MW in all hours does not account for the reality that there would be many hours below the average 975 MW of load. Likewise, there would be many hours where load was above the average of 975 MW. Without accounting for the load variability and using only the 975 MW, both the Baseload gas and SMR cases underestimate the cost of serving variable load.

iii. The lack of dispatch modeling doesn't capture the ancillary benefits of storage resources (such as arbitrage) in the Preferred Portfolio.

e. The capacity factors used in this calculation are high. According to the Energy Information Administration ("EIA"), a typical modern high efficiency Combined Cycle Combustion Turbine ("CCCT") plant capacity factor is about 65 percent while a nuclear plant operates closer to 92 percent. The CCCT value of 90.9 percent and the SMR value of 98.1 percent likely represent the theoretical maximum in a perfect year of operations and do not reasonably incorporate maintenance time, economic operations, and refueling cycles.

The Company's analysis in the 2023 IRP accounted for the time value of money, resource diversification and the need to build reliable portfolios, a full accounting of costs including Renewable Energy Credits, PTCs, fuel, and environmental, reasonable operations of plants and their capacity factors, actual modeling of resource dispatch to match load, and the necessity of a pipeline expansion after 600 MW of new gas. Once the full accounting of costs and operating characteristics is included in an analysis, as was done in the 2023 IRP, then the addition of solar, wind, and batteries are a lower-cost and lower-risk alternative to baseload thermal resources.

The response to this Request is sponsored by Jared Hansen, Resource Planning Leader, Idaho Power Company.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-23

IDAHO POWER COMPANY

ATTACHMENT 2

Table 1: Comparison of Staff's Calculations With and Without Omissions

Replication of Staff's Table

Resource	Nominal Capacity	Total Capital ($/kW)	Capital cost	Fixed O&M ($/kW-Month)	Fixed O&M	Variable O&M ($/MWh)	Variable O&M	Fuel Cost	REC	PTC/ITC	Portfolio Cost
CCCT	1773	1590	$2,818,636,364	1.4	$595,636,364	3.1	$529,542,000	$0	$0	$0	$6,739,155,758
SCCT	1658	991	$1,642,944,994	2.1	$835,564,356	6	$316,831,680	$0	$0	$0	
Solar	3325	1222	$4,063,150,000	1.9	$1,516,200,000	0	$0	$0	$0	$0	$13,894,238,000
Wind (ID)	1800	1782	$3,207,600,000	4.1	$1,771,200,000	0	$0	$0	$0	$0	
BESS	1453	1600	$2,324,800,000	2.9	$1,011,288,000	0	$0	$0	$0	$0	

All Calculations assume 20 Years of Operations

Replication of Staff's Table with Fuel, REC, and Tax Credits

Resource	Nominal Capacity	Total Capital ($/kW)	Capital cost	Fixed O&M ($/kW-Month)	Fixed O&M	Variable O&M ($/MWh)	Variable O&M	Fuel Cost	REC	PTC/ITC	Portfolio Cost
CCCT	1773	1590	$2,818,636,364	1.4	$595,636,364	3.1	$529,542,000	$4,376,985,600	$0	$0	$11,116,141,358
SCCT	1658	991	$1,642,944,994	2.1	$835,564,356	6	$316,831,680	$0	$0	$0	
Solar	3325	1222	$4,063,150,000	1.9	$1,516,200,000	0	$0	$0	($3,989,203,702)	($2,711,284,800)	$2,321,556,508
Wind (ID)	1800	1782	$3,207,600,000	4.1	$1,771,200,000	0	$0	$0	($2,507,886,490)	($1,704,499,200)	
BESS	1453	1637	$2,378,561,000	2.9	$1,011,288,000	0	$0	$0	$0	($713,568,300)	

All Calculations assume 20 Years of Operations

CCCT Fuel cost calculated at $4/MMBtu at peak efficiency of 6400 Btu/kWh

REC calculated using -22.07 $/MWh

PTC calculated at -30.00 $/MWh for 10 years

ITC calculated at 30% of capital cost

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-23

IDAHO POWER COMPANY

ATTACHMENT 3

<u>STAFF REQUEST FOR PRODUCTION NO. 32</u>: Please explain why the Company built the following constraints into its AURORA Long Term Capacity Expansion ("LTCE") model:

a. Please explain why the Company constrained the LTCE model to select between exiting Valmy Unit 2 at the end of 2025 or converting to natural gas in 2026. IRP at 9;

b. Please explain why the Company required Bridger Units 1 and 2 (already converted to natural gas in 2024) to shut down at the end of 2037. IRP at 10;

c. Please explain why the Company required Bridger Units 3 and 4 to shut down at the end of 2029 or convert to natural gas in 2030;

d. Please explain why the Company required Bridger Units 3 and 4 (if converted to natural gas in 2030) to shut down at the end of 2037; and

e. Please explain why the Company allowed Valmy Units 1 & 2 to operate indefinitely on natural gas, if economically favorable.

<u>RESPONSE TO STAFF'S REQUEST FOR PRODUCTION NO. 32</u>:

a. The Valmy coal to gas conversion or exit date is based on alignment with the plant's co-owner and operator, NV Energy. As such, the modeling constraints discussed on page 9 of the 2023 Integrated Resource Plan ("IRP") for the Valmy Unit Conversions match Idaho Power's options for participation in the plant.

b. The 2037 shutdown for Bridger Units 1 and 2 (provided there was not an early exit) was an update from the assumed end of life for these units of 2034 used in the 2021 IRP. This extension to 2037 aligns with the assumptions made by the co-owner and operator, PacifiCorp.

c. The Company would like to clarify the language on page 10 of the 2023 IRP report about Bridger Units 3 and 4. Rather than an end of year shut down in 2029 or a conversion to gas being the only two options available to those units, the model was also allowed to exit from those units in years 2026-2029 before the conversion occurs. The exit and conversion timing are based on alignment with the co-owner and operator, PacifiCorp.

d. The 2037 shutdown for Bridger Units 3 and 4 was an update from the 2034 assumed end of life for these units used in the 2021 IRP. The extension to 2037 aligns with the assumptions made by the co-owner and operator, PacifiCorp.

e. Based on alignment with the plant's co-owner and operator, NV Energy, the converted Valmy units are assumed to have an end of life that occurs after the planning horizon, in 2045.

The response to this Request is sponsored by Jared Hansen, Resource Planning Leader, Idaho Power Company.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-23

IDAHO POWER COMPANY

ATTACHMENT 4

<u>STAFF REQUEST FOR PRODUCTION NO. 38</u>: Table 8.3 is the Levelized Cost of Capacity ("LCOC") for supply-side resources. The Company states that the values "are presented in terms of dollars per kW of nameplate capacity per month." IRP at 114. However, the Company also says that "expression of these costs in terms of kW of peaking capacity can have a significant effect...." Id. Please provide the following information:

a. Please clarify the definition of peaking capacity;

b. If peaking capacity is different from a resource's Effective Load Carrying Capacity please explain any differences and explain how peaking capacity is determined;

c. Please provide an expanded version of Table 8.3 that includes the following for each resource:

   i. The raw capital cost, without normalizing, and without adjusting for the tax credits;

   ii. The raw capital cost, without normalizing, but adjusted for tax credits;

   iii. The resource's assumed peaking capacity; and

   iv. The resource's Total Cost per kW/mo., adjusted for peaking capacity.

d. Please provide the basis for each resource's assumed peaking capacity; and

e. Please provide the underlying worksheets that inform Table 8.3.

<u>RESPONSE TO STAFF'S REQUEST FOR PRODUCTION NO. 38</u>:

a. Peaking Capacity, or contribution to peak, can be defined as a resource's Effective Load Carrying Capability ("ELCC") value multiplied by its nameplate capacity for Variable Energy Resources ("VER") and Energy Limited Resources ("ELR"). For flexible resources, the peaking capacity is the nameplate multiplied by one, minus their Equivalent Forced Outage Rate during Demand ("EFORd").

b. Please see the response to part (a) of this request.

c. Please see the attached Excel spreadsheet.

d. Please see the response to part (a) of this request.

e. Please see the attached Excel spreadsheet.

The response to this Request is sponsored by Jared Hansen, Resource Planning Leader, Idaho Power Company.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-23

IDAHO POWER COMPANY

ATTACHMENT 5

STAFF REQUEST FOR PRODUCTION NO. 83: In its response to Production Request No. 38, the Company provided Attachment 1. Please answer the following questions about Attachment 1.

a. Please explain how the Company determined the Effective Load Carrying Capability ("ELCC") values for the Variable Energy Resources ("VER") and ELRs. If the Company obtained the values from an external source, please list the source, and provide a copy. If the Company calculated the values internally, please provide the supporting worksheets with formulas enabled;

b. Please explain why the Levelized Cost of Energy ("LCOE") capacity factors differ from the Levelized Cost of Capacity ("LCOC") peaking capacity factors for each VER; and

c. The LCOC for each resource changes significantly after the Company adjusts for that resource's ELCC. Please explain whether the AURORA LTCE model uses adjusted or unadjusted LCOC values when it selects new resources. If it uses adjusted values, please explain why the Company does not list the adjusted values in the Integrated Resource Plan. If it uses unadjusted values, please explain why this is economically accurate.

RESPONSE TO STAFF'S REQUEST FOR PRODUCTION NO. 83:

a. The Effective Load Carrying Capability ("ELCC") values of variable and energy-limited resources utilized in Attachment 1 of the Company's Response to Staff's Request for Production No. 38 were calculated with Idaho Power's Reliability and Capacity Assessment Tool ("RCAT") and were provided on page 92 of the 2023 Integrated Resource Plan ("IRP") Appendix C: Technical Report. For further explanation on how ELCC values are calculated by the internally developed RCAT, please refer to the following sources:

- Loss of Load Expectation section of the 2023 IRP Appendix C: Technical Report[2]
- The December 8th, 2022, Integrated Resource Plan Advisory Council ("IRPAC") meeting, Reliability & Capacity Assessment presentation[3]
- The March 9th, 2023, IRPAC meeting, Loss of Load Analysis & ELCC Update presentation[4]
- The Idaho Power pre-recorded IRP Educational Resource video on Reliability & Capacity Assessment[5]

All MATLAB scripts and input files required to perform the ELCC calculation in the Company's RCAT were provided as attachments to the Company's Response to Request Nos. 1 and 2.

b. Capacity factor is a metric used to determine how frequently a power plant operates for a given amount of time. It is computed by dividing the actual unit electricity output by the maximum output (nameplate) multiplied by the number of hours in that same time, and it is expressed as a percentage. As defined in the Company's Response to Staff's Request for Production No. 38, peaking capacity (factor), or contribution to peak, can be defined as a resource's ELCC; ELCC is not a function of energy or time like the capacity factor. For further information on ELCC please see the 2023 Integrated Resource Plan ("IRP") Report, starting on page 56.

c. The Company would like to clarify that the 'ELCC adjusted' Levelized Cost of Capacity ("LCOC") value was intended to be illustrative and is not a common industry metric, like "unadjusted" LCOC. The "unadjusted" LCOC of a resource, along with its unique characteristics, such as ELCC, output shape, and ramp rates are all input into the

[2] https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2023/2023-appendix-c-final.pdf
[3] https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2023/2023IRP_ReliabilityCapacityAssessment.pdf
[4] https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2023/2023_03_07_PRM_ELCC_WRAP.pdf
[5] https://youtu.be/Ds968-NI3wc?si=i62PQPYN2GpYYb2T

AURORA Long-Term Capacity Expansion ("LTCE") model (as has been historically done in past IRPs). AURORA optimizes to meet peak demand, as well as demand in every hour, while meeting reliability constraints and minimizing cost. As shown through the portfolio analysis, stochastic analysis, and validation/verification process, the AURORA LTCE model produced a Preferred Portfolio that was least-cost and least-risk.

The response to this Request is sponsored by Jared Hansen, Resource Planning Leader, Idaho Power Company.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-23

IDAHO POWER COMPANY

ATTACHMENT 6

STAFF REQUEST FOR PRODUCTION NO. 80: As part of its response to Production Request No. 36, the Company submitted Attachment 1, which provides additional details regarding interconnection cost assumptions. Please answer the following questions concerning this information:

a. Please explain why the Company estimated the interconnection cost for a new 100 MW solar resource in Mountain Home to be $6,500,000, while it estimated the interconnection cost for a 90 MW upgrade to Danskin 1 (also in Mountain Home, with existing interconnection infrastructure) to be $9,370,000, nearly 45 percent higher. Please provide the underlying worksheets for both estimates;

b. The cost estimate to connect 50 and 170 MW thermal resources to the 230-kV Bus at the Langley Gulch location (where interconnection infrastructure already exists) is $8,054,000. The cost estimate to connect a 100 MW wind or solar resource to a 230-kV or 345-kV Bus (where interconnection infrastructure does not exist) is $6,500,000. Please explain why the wind and solar resource interconnections are 20 percent less costly. Please provide the underlying worksheets for the thermal and variable resource estimates;

c. Please explain why the Company assumes additional expenses for a feeder connection are appropriate for Geothermal and Biomass resources, but additional feeder expenses are not appropriate for wind and solar resources;

d. Staff is unable to recreate the Attachment 1 normalized results (per kW) by dividing the Cost Estimate by the Capacity. Please provide Attachment 1 with formulas enabled; and

e. Staff believes the normalized (per kW) cost estimate for a natural gas reciprocating engine is erroneous because it shares the same full interconnection cost estimate as the hydrogen combustion turbine and the simple cycle combustion turbine

("SCCT"), yet it has only 29 percent of the nominal capacity. Please verify and provide the underlying calculations.

RESPONSE TO STAFF'S REQUEST FOR PRODUCTION NO. 80:

a. The interconnection costs provided in the 2023 Integrated Resource Plan ("IRP") were based on actual projects in the Company's Generation Interconnection ("GI") Queue. For example, the interconnection cost for a 90-megawatt ("MW") increase at the Danskin substation was modeled after GI Queue #604 assumptions, and the 100 MW solar resource in Mountain Home was modeled after GI Queue #607 assumptions. In explanation of the cost differences, the existing Danskin substation is already built out and would require further modifications to adjust existing infrastructure to add a breaker position, while a new solar plant in the Mountain Home area is assumed to be a new build site without any costs associated with modifying existing equipment. The redacted system impact studies for the specified GI Queue projects are publicly available on Idaho Power's website.[1]

b. Please see the response to part (a) of this request.

c. Idaho Power did not assume that additional expenses for a feeder connection were appropriate for geothermal and biomass resources. Rather, the Company assumed that the projects were connected to a lower voltage level and utilized the typical interconnection cost for a project at the distribution level.

d. Please see the attached Excel spreadsheet.

e. Please see the attached Excel spreadsheet.

The response to this Request is sponsored by Andrés Valdepeña Delgado, System Consulting Engineer, Idaho Power Company.

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[1] https://www.idahopower.com/about-us/doing-business-with-us/generator-interconnection/generator-interconnection-study-reports/

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-23

IDAHO POWER COMPANY

ATTACHMENT 7

<u>STAFF REQUEST FOR PRODUCTION NO. 21</u>: Please answer the following regarding the 70th percentile energy load forecast and the 70th percentile peak load forecast used in the 2023 IRP.

a. Please list all the study areas and the analysis models in the 2023 IRP where the 70th percentile of energy load forecast and the 70th percentile of peak load forecast are used;

b. Please explain why and how the Company determined that the 70th percentile energy load forecast was the right level to use for its planning case. Please provide evidence and any workpapers to explain the answer; and

c. Please explain why and how the Company determined that the 70th percentile peak load forecast was the right level to use for its planning case. Please provide evidence and any workpapers to explain the answer.

<u>RESPONSE TO STAFF'S REQUEST FOR PRODUCTION NO. 21</u>:

a. The 70th percentile energy and 70th percentile peak forecast were used throughout the 2023 Integrated Resource Plan ("IRP") analysis except where otherwise noted for scenarios such as "Extreme Weather." Please note that for the Company's Reliability and Capacity Assessment Tool ("RCAT"), historical hourly load is adjusted to reflect only the forecasted monthly 70th percentile peak loads.

b. The 70th percentile energy load forecast was utilized in response to the selection of the 70th percentile peak load forecast for reliability purposes. The Company considers it important to maintain consistency in the relationship between the energy and peak load forecast percentiles.

c. The adjustment to the 70th percentile peak load forecast was made in conjunction with moving back to a 0.1 event-days per year Loss of Load Expectation ("LOLE") threshold from a 0.05 LOLE threshold. In response to Staff's Comments on the Company's 2021 IRP in Case No. IPC-E-21-43[3], Idaho Power moved forward with the combination of the 70th percentile peak load forecast and a 0.1 event-days per year LOLE threshold for the 2023 IRP, as it produced similar reliability results when compared to the combination of the 50th percentile peak load forecast and a 0.05 event-days per year LOLE threshold. Please see the attached Excel spreadsheet for supporting workpapers.

The response to this Request is sponsored by Jared Hansen, Resource Planning Leader, Idaho Power Company.

[3] IPC-E-21-43, Staff's Comments, p. 9 ("Instead of using a more stringent target to compensate for the variability of weather, it is more appropriate to incorporate year-to-year variability in both the Company's load forecast and availability of hydro generation in its resource assumptions rather than assuming average weather conditions in the IRP.")