Office of the Secretary
Service Date
June 18, 2024

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S 2023 INTEGRATED RESOURCE PLAN	))))	**CASE NO. IPC-E-23-23** **ORDER NO. 36233**

On September 29, 2023, Idaho Power Company ("Company") filed an application ("Application") with the Idaho Public Utilities Commission ("Commission") requesting that the Commission issue an order acknowledging the Company's 2023 Integrated Resource Plan ("IRP").

The Company stated that the 2023 IRP represented a comprehensive analysis of the optimal mix of both demand- and supply-side resources available to reliably serve customer demand and flexible capacity needs from 2024 to 2043. Application at 1-2.

The Company represented that the primary goals of the 2023 IRP were to: (1) identify sufficient resources to reliably serve the growing demand for energy within the Company's service area throughout the 20-year planning period (2024-2043); (2) ensure the selected Preferred Portfolio balances cost and risk, while including environmental considerations; (3) give equal and balanced treatment to supply-side resources, demand-side measures, and transmission resources; and (4) involve the public in the planning process in a meaningful way. *Id.* at 5.

The Company represented that it used the AURORA model to develop portfolios for the 2023 IRP. *Id.* at 7-8. The Company stated that two notable trends emerged in the 2023 IRP, the vital nature of added transmission and the substantial downward trend in portfolio greenhouse gas emissions. *Id.* at 10.

The Company represented that it identified several key resources or potential projects to evaluate in additional detail, and the Company required the model to build portfolios both with and without each resource or project. *Id.* at 14. The Company stated that those models with and without views include: (1) with and without the B2H project; (2) with and without different phases of the Gateway West projects; and (3) with and without specific Valmy Unit 1 and Unit 2 natural gas conversion assumptions. *Id.*

The Company represented that, based on its analysis, it selected a Preferred Portfolio identified in the 2023 IRP as "Valmy 1 & 2", referring to the portfolio's conversion of both Valmy units from coal to natural gas. *Id.* at 14-15. The Company stated that the Preferred Portfolio was the least-cost, least-risk option that incorporated positive changes toward clean, low-cost resources without compromising system reliability. *Id.*

The Company's Preferred Portfolio adds 3,325 megawatts ("MW") of solar, 1,800 MW of wind, 1,453 MW of storage (four- and eight-hour batteries, as well as long-duration 100-hour storage), 360 MW of additional energy efficiency ("EE"), 340 MW of hydrogen ("H2"), 160 MW of new demand response ("DR"), and 30 MW of geothermal. *Id.* at 3.

Additionally, the Preferred Portfolio includes conversions of multiple coal-fired generation units to natural gas, showing the Company exiting coal entirely in 2030 and adding a net total of 261 MW of natural gas via coal conversions through 2043 (reflecting the addition of 967 MW of gas conversions and 706 MW of gas conversion exits, netting 261 MW of additional gas generation). *Id.*

The Company represented that, in total, the Preferred Portfolio adds 6,888 MW of incremental resource capacity over the next 20 years and includes the B2H transmission line beginning in July 2026 and three Gateway West transmission line segments phased in from 2029 to 2040. *Id.*

The 2023 IRP also contains the Company's Near-Term Action Plan that reflects near-term actionable items of the Preferred Portfolio necessary to successfully position the Company to provide reliable, economic, and environmentally sound service to its customers into the future. *Id.* at 15. The Company represented that the 2023 IRP incorporates prior recommendations it received concerning several issues, and the 2023 IRP provides additional analysis/discussion of those issues. *Id.* at 17.

On October 31, 2023, the Commission issued a Notice of Application and Notice of Intervention Deadline. Order No. 35974. The Commission granted intervention to Micron Technology, Inc. Order No. 36014. On December 1, 2023, a Notice of Parties was issued.

STAFF COMMENTS

Based on its review, Staff recommended the Commission acknowledge the Company's 2023 IRP. Staff Comments at 3. However, Staff believed that the Company's Preferred Portfolio might not be the least-cost portfolio, and Staff recommended that the Company perform additional analyses to validate the least-cost, least-risk portfolio and submit a supplemental report with the results. *Id.*

Staff's comments focused on: (1) The Preferred Portfolio; (2) The Near-Term Action Plan; (3) The Load Forecast; (4) The Demand-Side Management Program; (5) The Seasons and Hours of Highest Risk; (6) PURPA and Other Planning Assumptions; and (7) Review of 2021 Staff Recommendations. *Id.* at 4.

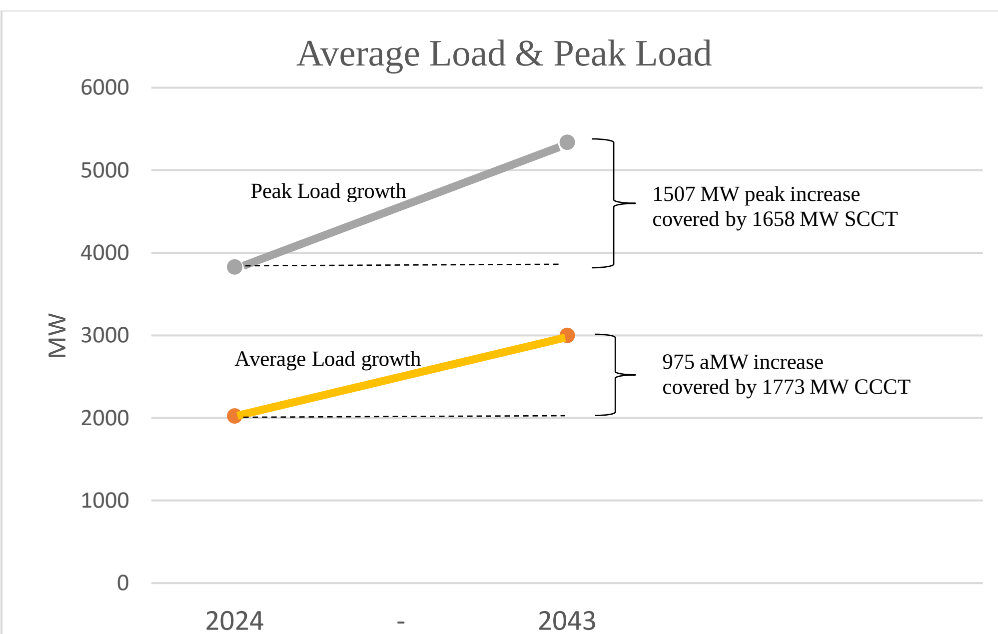
Preferred Portfolio

With respect to the Preferred Portfolio, Staff examined the portfolio development process and found evidence that the Preferred Portfolio may not be the least-cost portfolio. *Id.* Over the IRP's 20-year time window the Company forecasted that system load would grow by 975 average megawatts ("aMW"), and the peak load would increase by 1,507 MW. IRP Appendix C at 16-17.

To satisfy this increased load, the Company proposed a Preferred Portfolio containing a mix of new resources. Staff Comments at 5. To satisfy the 975 aMW increase, the Company proposes to *reduce* its dispatchable resources, build *five times more* variable generation than the average load increase, and add 1,500 MW of BESS resources. *Id.* at 6. The Company's calculated net present value ("NPV") for this 20-year portfolio is $9.7 billion. Application at 11.

Staff created a simplified model of the load requirement, and Staff devised a hypothetical way to satisfy it using a combination of baseload and peaking dispatchable resources. Staff Comments at 6.

Figure No. 1: Model of a Hypothetical Dispatchable Resource Portfolio



Staff also recalculated the Variable Energy Resource and BESS portions of the Preferred Portfolio cost by using the same method as the dispatchable portfolio. *Id.* at 7.

<u>Table No. 3: ‘Dispatchable’ Portfolio Cost versus ‘VER & BESS’ Portfolio Cost</u>

Resource	Reqd MW	Capacity Factor	Nominal MW	Total Capital ($/kW)	Capital Cost	Years of Ops	Fixed O&M ($/kW-month)	Fixed O&M	Variable O&M ($/MWh)	Variable O&M ($)[1]	Total Cost ($)	Portfolio Cost ($)
CCCT	975	55.0%	1773	$ 1,590	$ 2,818,636,364	**20**	$ 1.40	$ 595,636,364	$ 3.10	$ 529,542,000	$ 3,943,814,727	**$ 6,739,155,758**
SCCT	1507	90.9%	1658	$ 991	$ 1,642,944,994	20	$ 2.10	$ 835,564,356	$ 6.00	$ 316,831,680	$ 2,795,341,031	
Solar			3325	$ 1,222	$ 4,063,150,000	20	$ 1.90	$ 1,516,200,000	$ -	$ -	$ 5,579,350,000	**$ 13,894,238,000**
Wind (ID)			1800	$ 1,782	$ 3,207,600,000	20	$ 4.10	$ 1,771,200,000	$ -	$ -	$ 4,978,800,000	
BESS			1453	$ 1,600	$ 2,324,800,000	20	$ 2.90	$ 1,011,288,000	$ -	$ -	$ 3,336,088,000	
Note 1: To estimate the fuel costs, the CCCT is assumed to operate 100% of all hours, and the SCCT to operate 20% of all hours over the 20-year period.												

Staff reasoned that the $7 billion portfolio cost difference calls into question the accuracy of the LTCE model and the Company’s validation process. *Id.*

Staff believed there were several possible sources of potential bias in the Company’s LTCE modeling process including: (1) externally imposed constraints on the LTCE model; (2) internal cost inputs and operating assumptions used by the model; and (3) selection and optimization algorithms within the model. *Id.* at 8.

Based on its review Staff believed that the 2023 IRP’s Preferred Portfolio might not be the least-cost portfolio, and a portfolio with a larger share of dispatchable fossil fuel resources appeared to be substantially less expensive. *Id.* at 14. Because the Company uses IRP assumptions and results as part of its justification for future resource projects, Staff believed that the Company should resolve some of those concerns through additional analysis and through a supplement to the IRP. *Id.*

The Near-Term Action Plan

The Company requested that the Commission acknowledge the Company’s Near-Term Action Plan; however, Staff recommended that the Commission refrain from doing so and only acknowledge the overall 2023 IRP. Staff Comments at 15. Staff noted that the Near-Term Action Plan consists of eight action items, some of which derive from the Preferred Portfolio, and Staff believed the Preferred Portfolio might not be least-cost because Action Plan items that are based on the portfolio might not be appropriate. *Id.*

The Load Forecast

Staff explained that the Company used a P50 load forecast and a more stringent reliability target than the industry standard in its 2021 IRP analyses; however, for the 2023 IRP, the Company adopted the industry standard reliability target, but used a P70 load forecast. *Id.* at 18. Staff identified two issues with the Company's decisions: (1) Staff believed the Company lacked proper justification for using P70 load forecast for reliability purposes; and (2) there were potential inflated expected energy costs for rates and avoided costs when using the higher load forecast. *Id.*

Staff recommended that for future IRPs, if the Company determines its Preferred Portfolio by using something other than the P50 load forecast, the Company should still use the P50 loads in its dispatch model to calculate IRP portfolio energy costs and marginal avoided costs. *Id.* at 20. Further, Staff recommended that for tariffs that are affected by avoided cost calculations (i.e. Lamb Weston, Brisbie, Schedule 20), separate dockets should be filed, and Staff would analyze the Company's cost bases in those dockets. *Id.*

The Demand-Side Management Program

Staff noted that the Demand-Side Management ("DSM") program is fundamentally connected to the IRP. *Id.* Staff was concerned that the 2023 IRP avoided costs were based on the Preferred Portfolio and the P70 load forecast, and therefore the avoided costs might be incorrect. *Id.* at 21.

Staff recommended that the Company not use the 2023 IRP DSM avoided costs included in the 2023 filing and reassess the avoided costs as part of Staff's recommended supplemental filing. *Id.* However, if the Company does not file a supplemental IRP by the time the Company either evaluates its 2024 DSM program or conducts 2025 DSM program planning, Staff believed the Company should use the DSM avoided costs from the Company's 2021 IRP. *Id.* Staff also recommended that the Company use the P50 load when determining avoided costs in the next IRP. *Id.*

The Seasons and Hours of Highest Risk

Staff believed that the methods supporting the seasons and hours of highest risk were generally reasonable; however, Staff did have concerns with certain assumptions and practices, and Staff did not recommend updating the seasons or hours of highest risk in conjunction with this report. *Id.* at 22.

PURPA and Other Planning Assumptions

Staff recommended that the Company adjust its PURPA assumptions in future IRPs. *Id.* at 24. Specifically, Staff recommended that the Company conduct a PURPA trend analysis that includes the most recent data and apply the analysis results in the base planning conditions starting the first year of the planning horizon in the next IRP. *Id.*

Review of 2021 Staff Recommendations

Staff noted that the 2025 IRP schedule could be in jeopardy due to Staff's supplemental 2023 filing recommendation, and Staff recommended that the Company plan accordingly to ensure that it files the 2025 IRP on time. *Id.* at 28. Additionally, Staff recommended that in the next IRP filing, the Company provide justification for why the CBM should be included in the L&RB. *Id.* at 29. Finally, Staff reiterated its recommendation that the Company provide separate filings for each proposed conversion or closure of Valmy and Bridger. *Id.* at 30.

Final Recommendations

Based on its analysis, Staff recommended that the Commission acknowledge the 2023 IRP. *Id.* In addition, Staff recommended:

1. The Commission order the Company to submit a supplemental filing for the 2023 IRP that addressed the Preferred Portfolio concerns, which should include:
    a. Establish a meeting of interested Parties to resolve concerns about model cost inputs and the selection algorithms. Include BESS degradation incremental costs;
    b. Re-run the most prominent existing scenarios with recommended changes to the baseline planning assumptions;
        i. Modify the forced coal exits to allow the model to choose between coal continuation, exit, or conversion to gas, for Valmy and Bridger;
        ii. Eliminate the forced exit from Bridger in 2037. If the Company justifies an end-of-life closure, allow the model to choose between an exit or a service-life extension;
    c. Cost test at least one new portfolio that has a preponderance of dispatchable fossil fuel resources;
    d. Confirm the 2023 DSM avoided cost data; and
    e. Allow for comments from Parties on the Supplement.
2. The Commission order the Company to submit separate filings for approval of each proposed conversion or exit of Valmy and Bridger.
3. The following changes to future IRPs:
    a. Display the assumed peak and energy CFs for each selectable resource;
    b. Display both nominal LCOCs and CF-adjusted LCOCs for each resource;
    c. Display the underlying estimates used to determine interconnection costs;
    d. Provide more detailed information about the scope and cost of the SWIP-N project;

e. Clarify how the Company selects between distribution-connected and transmission-connected battery projects;

f. Meet with Staff to determine the method for selecting the load probability profile;

g. Use the P50 in the dispatch model to calculate IRP portfolio costs and IRP marginal avoided costs;

h. Include BESS and DR resources in analysis of seasons and hours of highest risk;

i. Provide analysis that supports the percentage of total risk hours threshold used to select *seasons* of highest risk;

j. Provide analysis that supports the percentage of total risk hours threshold used to select *hours* of highest risk;

k. Conduct a PURPA trend analysis that includes the most recent data and apply the analysis results in the base planning conditions starting the first year of the planning horizon in the next IRP; and

l. Include BESS degradation incremental costs.

m. Justify why the L&RB should include the CBM.

INTERVENER COMMENTS

Micron Technology, Inc. ("Micron") encouraged the Company to continue working with Micron and other large customers to develop large-scale customer-dedicated generation resources that meet their mutual sustainability goals. Micron Comments at 3. Micron encouraged the Company to continually investigate strategies to mitigate energy transition rate impacts and implement such strategies where appropriate. *Id.* Finally, Micron encouraged the Company to continually investigate and analyze regional markets and coordination efforts and seek opportunities to participate in such programs that result in increased reliability and lower costs to customers. *Id.* at 5.

PUBLIC COMMENTS

1. City of Boise City ("City")

The City supported the 2023 IRP's evaluation and selection of additional demand-side resources. Additionally, the City supported the Company's incorporation of Inflation Reduction Act incentives, and encouraged the Company to identify and evaluate federal funding opportunities that may support the implementation of the Company's Near-Term Action Plan.

2. FFP Project 101, LLC ("Goldendale")

Goldendale sought clarification regarding certain methodologies and values as they relate to the IRP's analysis of pumped storage hydro ("PSH") technology. Goldendale Comments at 1. Goldendale represented that the IRP does not reference the Investment/Production Tax Credits

("ITC/PTC") available to PSH, and it was unclear whether the IRP assigns an Effective Load Carrying Capability ("ELCC") value specific to PSH. *Id.*

Goldendale requested that the Company implement RFPs that have long lead time resource-specific considerations in order to enable these PSH resources to fairly compete with all other resource types. *Id.* at 2. Goldendale represented that to the extent the IRP does not use a PSH-specific ELCC, the Company should also revise the IRP to do so, and the Company should identify and procure PSH projects now given the long lead-time of these resources. *Id.* at 7.

3. KitzWorks LLC ("KitzWorks")

KitzWorks provided comments related to comparisons between Air Source Heat Pumps ("ASHPs") and the other for Ground Source Heat Pumps ("GHPs"). KitzWorks Comments at 1. KitzWorks noted that the difference in results of the two sensitivity studies may suggest that GHPs deserve a higher incentive than ASHPs. *Id.* KitzWorks noted that it could be valuable for the company to conduct a separate study outside of the IRP process to quantify the benefit of large-scale deployment of GHPs. *Id.* at 3. KitzWorks reasoned that assuming that there was a benefit to ratepayers from GHPs, a proportional incentive could be considered to encourage ratepayers to adopt GHPs. *Id.*

4. Zanskar Geothermal & Minerals, Inc. ("Zanskar")

Zanskar recommended that the Company: (1) consider contracted PPA prices, which have been less than $70/MWh versus $78/MWh LCOE in the IRP; (2) increase geothermal power plant capacity factor to 95%, to reflect standard industry practice; (3) adjust monthly capacity factors to reflect that plant overhauls will occur in low-value months; (4) capture all tax benefits for which geothermal power projects are eligible, including a 30% to 50% ITC, MACRS, and Intangible Drilling Cost; and (5) incorporate demonstrated cost reductions that are already occurring in the industry, especially related to drilling. Zanskar Comments at 3. Zanskar also recommended that the Company conduct an avoided cost analysis of 200MW of new geothermal power over the next 10 years to encourage investment in the exploration and drilling required to define a new geothermal resource. *Id.* at 4.

5. Kenneth Winer

Mr. Winer urged the Commission to direct the Company to not invest in more fossil gas infrastructure and instead invest in 100% renewable energy and storage technologies as the Company looks to replace its coal power.

COMPANY REPLY COMMENTS

1. Company's Reply to Staff Comments

a. The Preferred Portfolio

With respect to Staff's analysis of the Preferred Portfolio, the Company identified what it considered material deficiencies including: (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. Company Reply Comments at 6.

The Company recognized that more conversations about modeling assumptions would be of value to both Staff and the Company, and the Company welcomed continued conversations with Staff and other interested stakeholders to inform future modeling assumptions. *Id.* at 14. However, the Company did not believe Staff's recommendation for a supplemental IRP was warranted. *Id.* at 24.

The Company indicated it was not opposed to Staff's recommendations for separate filings for Valmy and Bridger and implementing changes in future IRPs. *Id.* The Company also indicated that it would pay particular attention to its discussion of CFs, LCOC, and interconnection costs in future IRPs, and the Company welcomed further discussions with Staff and other interested stakeholders to identify opportunities for continued improvement in its planning process. *Id.*

b. The Near-Term Action Plan

The Company represented that it employed a robust and thorough portfolio analysis that accounted for foundational elements of resource planning and system reliability. *Id.* at 25. The Company stated that it conducted comprehensive verification and validation model runs to support the identification of the Preferred Portfolio as least-cost and least-risk, and the Company believed that the Commission should acknowledge the Action Plan items that are derived from the Preferred Portfolio. *Id.*

c. The Load Forecast

The Company represented that it recognized Staff's concern with the load forecast percentile and LOLE threshold selections used in the 2023 IRP; however, the Company noted that those decisions were made early on in the IRP development process and were publicly introduced in the IRPAC meeting on December 8, 2022. *Id.* at 30. The Company believed that the use of P70 was appropriate and justified but the Company was open to making adjustments and considering other options for accounting for extreme weather and other reliability risks in future IRPs. *Id.* The Company welcomed additional discussions with Staff and other interested parties to find a path forward. *Id.* at 32.

The Company noted that a change in load forecast from P70 to P50 created an approximate 1.0 percent change in avoided costs that, in the Company's estimation, did not warrant a concern or a need to reevaluate rates based on the 2023 IRP and a P70 load forecast. *Id.* at 33. The Company agreed that the appropriate venue to have such conversations was within the specific cases where avoided cost rates are used, and the Company indicated it would seek explicit Commission approval for any rates that are informed by the IRP prior to implementation. *Id.*

d. The Demand-Side Management Program

The Company reiterated its position that Staff's assertion, that a portfolio buildout with more dispatchable resources would be lesser cost than the Preferred Portfolio, was incorrect. *Id.* at 35. The Company again represented that it did not believe there was a need to create a supplemental filing to the 2023 IRP and there was no basis to reject the avoided costs generated in the 2023 IRP based on resource selection. *Id.*

Further, the Company maintained that its 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 and, 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 believed there was sufficient support of either load forecast percentile for calculating avoided costs. *Id.* at 36. However, the Company stated that it was open to incorporating Staff's recommendation to use the P50 load when determining avoided costs in the 2025 IRP or to identify another method that may not require the Company to plan at a load forecast percentile other than P50. *Id.*

e. The Seasons of Highest Risk

The Company agreed 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, and the Company believed that would be a valuable improvement to the methodology for future IRPs. *Id.* at 37. While the Company believed that the hours of highest risk presented in the 2023 IRP were accurate and valid for their intended purpose, the Company agreed 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. *Id.*

The Company did not agree with Staff's recommendation to include BESS and DR resources in the analysis, rather the Company suggested that it could work with Staff to evaluate those assumptions as part of the broader discussions regarding hours of highest risk. *Id.* at 38.

f. PURPA and other Planning Assumptions

The Company represented that it discussed its PURPA assumptions for the 2023 IRP at length with IRPAC and provided opportunity for feedback from stakeholders. *Id.* at 39. The Company stated 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, so as not to distort the Company's identified capacity need and resource selections in the IRP process. *Id.* at 40.

The Company indicated that it would use the most recent data available for this assumption, as it does for all assumptions, in its next IRP. *Id.* at 41. The Company also represented that a planning horizon outside of the Action Plan window allows the Company adequate time to evaluate and shift to alternative resources, if forecasted PURPA projects do not materialize. *Id.* at 42-43.

2. Company's Reply to Micron

The Company represented that it was sensitive to the rates and charges paid by its customers, and that through the IRP process, the Company sought to produce a portfolio of resources that represents the least-cost, least-risk path to serving its customers' needs over the planning horizon. *Id.* at 48.

3. Company's Reply to Public Comments

a. City of Boise

The Company stated it was eager to convene the IRPAC in the forthcoming development of the 2025 IRP, and the Company looked forward to continued work and collaboration with the City of Boise. *Id.* at 49.

b. FFP Project 101, LLC

The Company appreciated Goldendale's comments and explained that due to pumped hydro storage's long duration, the Company assumes an approximately 100 percent ELCC for the resource. *Id.* the Company agreed with Goldendale's comments regarding the need to issue longer lead time RFPs. *Id.*

c. KitzWorks, LLC

The Company stated that it looked forward to continued collaboration with KitzWorks on future IRP electrification scenario assumptions. *Id.*

d. Zanskar

The Company represented that it would consider the points listed by Zanskar, and the Company looked forward to finding ways to refine geothermal assumptions in the next IRP. *Id.* at 50.

4. Conclusion

The Company requested that the Commission acknowledge the Company's 2023 IRP as meeting both the procedural and substantive requirements of Order Nos. 22299, 25260, and 30317; and reject Staff's specific recommendations regarding an IRP supplement and the Near-Term Action Plan. *Id.* at 51-52.

COMMISSION FINDINGS AND DECISION

The Commission has jurisdiction over the Company's Application and the issues in this case under Title 61 of the Idaho Code including *Idaho Code* §§ 61-301 through 303. The Commission is empowered to investigate rates, charges, rules, regulations, practices, and contracts of all public utilities and to determine whether they are just, reasonable, preferential, discriminatory, or in violation of any provisions of law, and to fix the same by order. *Idaho Code* §§ 61-501 through 503.

The Commission appreciates the active participation and input of Staff and the intervenors, and the Commission is confident that their continued work helps the Company develop a better and more comprehensive IRP.

With respect to Staff's recommendations, the Commission does not believe that a supplemental filing is necessary at this time; however, the Commission notes the importance of ensuring that the IRP process uses the most accurate information and that the IRP itself presents the best representation of the Company's ongoing commitment to serving the needs of its customers. The Commission directs the Company to meet with Staff, as expeditiously as possible, to discuss and resolve those concerns enumerated in Staff's comments including model cost inputs, selection algorithms, and other concerns, prior to the next IRP.

Having reviewed the record, the Commission finds that the Company's 2023 IRP satisfies the requirements in the Commission's prior orders, and the Commission acknowledges the Company's 2023 IRP. In doing so, the Commission reiterates that an IRP is a working document that incorporates many assumptions and projections at a specific point in time. An IRP is a plan, not a blueprint, and by issuing this Order the Commission merely acknowledges the Company's ongoing planning process, not the conclusions or results reached through that process.

The Commission does not approve the Company's 2023 IRP, or any resource acquisitions referenced in it, endorse any particular element in it, opine on the Company's prudence in selecting the 2023 IRP's preferred portfolio, nor allow or approve any form of cost recovery. The appropriate place to determine the prudency of the Company's decisions to follow or not follow the 2023 IRP is in a general rate case or other proceeding where the issue is noticed.

ORDER

IT IS HEREBY ORDERED that the Company's 2023 IRP is acknowledged.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date upon this Order regarding any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *Idaho Code* §§ 61-626 and 62-619.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho, this 18th day of June 2024.

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ERIC ANDERSON, PRESIDENT

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JOHN R. HAMMOND JR., COMMISSIONER

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EDWARD LODGE, COMMISSIONER

ATTEST:

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Monica Barrios-Sanchez
Commission Secretary

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