

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

LC 87

In the Matter of
IDAHO POWER COMPANY,
2025 Integrated Resource Plan.

OPENING COMMENTS OF
RENEWABLE NORTHWEST
AND NW ENERGY COALITION

I. INTRODUCTION

Renewable Northwest (“RNW”) and NW Energy Coalition (“NWE”) thank the Oregon Public Utility Commission (the “OPUC” or the “Commission”) and OPUC Staff (“Staff”) for this opportunity to comment on Idaho Power Company’s (“Idaho Power” or “the Company”) 2025 Integrated Resource Plan (“IRP”). In the comments that follow, RNW and NWE reflect on the Company’s significant change in direction from their 2023 IRP, highlights some weaknesses in the 2025 IRP’s input assumptions, and offers suggestions to ensure the selection of the least-cost, least-risk plan for the Company’s customers. We note that these opening comments are, to some extent, preliminary, and we look forward to reviewing Idaho Power’s responses as well as the discovery in this docket before preparing our next round of comments. Overall, we are surprised to see Idaho Power turn away from the work presented in the 2023 IRP that put the Company on track to reach its internal goal of 100% clean energy by 2045. We look forward to further engaging in this docket.

II. COMMENTS

A. Idaho Power has not demonstrated its preferred portfolio is a least-cost and least-risk plan to serve future needs.

- 1. Candidate resource cost assumptions stray from industry benchmarks and are fraught with significant variability, creating unacceptable levels of uncertainty and risk in the 2025 IRP results.*

Resource cost assumptions are one of the most critical inputs in long-term capacity expansion (“LTCE”) modeling. Optimized LTCE modeling tools, such as Aurora, seek to minimize portfolio costs while serving system load, meeting the planning reserve margin (“PRM”), and satisfying model constraints. The LTCE model evaluates the relative costs and capabilities of resources when selecting the best candidates to build in each year of the study. Because resource

assumptions are so fundamental to optimized resource planning, they garner significant attention. We are in a very dynamic environment with respect to resource cost assumptions. Regulatory, supply-chain, and market forces are challenging the reliability of these forecasts.

The same dynamics driving significant load growth in Idaho Power's service territory are present across the country. There is significant competition among utilities for combustion turbines, drawing lead times out to more than 5 years¹ and increasing capital costs to more than \$1,500/kW for simple cycle and more than \$2,000/kW for combined cycle combustion turbine ("CCCT") resources^{2 3}. Idaho Power assumes lower capital costs for new combustion turbine resources of \$1,400/kW and \$1,850/kW, simple cycle and combined cycle ("SCCT") respectively. The Company's resource cost assumptions are a product of publicly available datasets and its own procurement efforts. In our analysis, we found cost assumptions for thermal resources to vary widely from source to source (including public datasets and utility IRPs). The dynamic nature of the industry today places significant uncertainty on both the cost of new thermal generation and the lead time for procurement. This creates significant risk for Idaho Power's ratepayers and calls into question whether the Company's heavy reliance on thermal generation assets aligns with a least-cost, least-risk outcome as required by Oregon's IRP Guidelines.

We also found cost estimates for new wind generation to vary considerably, with the Company using the highest costs among sources reviewed. We calculated a median levelized cost of approximately \$185/kW-Yr for new wind resources. For the 2025 Idaho IRP, we calculated a levelized cost of more than \$240/kW-Yr, representing a 30% premium over the median of all sources surveyed. While the Company anticipates the highest costs for wind generation, its forecast is not totally alone. One other publicly available source projects costs above \$225/kW-yr. All other sources forecast levelized costs between \$150 and \$180/kW-Yr. This analysis helps us shed light on the uncertainty present in the industry regarding new resource costs. The Company's reliance on such a high cost assumption introduces a significant bias into its resource planning, ultimately undermining the goal of achieving a least-cost outcome for ratepayers. Specifically, for wind, Idaho Power's cost forecast is an outlier that strongly depresses the LTCE model's selection of new wind capacity despite strong wind resources in the upper mountain west.

Levelized cost forecasts for new 4-hour battery storage candidates provide a clearer picture among the data sources we reviewed. All of the sources we reviewed expect new 4-hour battery storage candidates to range from \$160 to \$180/kW-Yr. The Company's 2025 IRP does forecast costs in the upper end of the distribution, just shy of the 75th percentile. Among the forecasts for near-term costs, there is significant agreement. Where the Company forecasts diverge from

¹ Mark Shenk, Rush for US gas plants drives up costs, lead times. Reuters (July 21, 2025), <https://www.reuters.com/business/energy/rush-us-gas-plants-drives-up-costs-lead-times-2025-07-21/>

² 2024 Joint Integrated Resource Plan of LG&E and KU, Case No. 2024-00326, Volume III

³ Indiana IRP Stakeholder Meeting #2, I&M Power, September 24, 2024

others is in technology maturity curves. Across all clean energy resources, the Company's assumptions predict flat or limited cost reductions in the near-term, followed by steady, linear reductions. Delays in cost reductions will have a significant impact on least-cost resource selection in the critical years of the early 2030s. Barring a generational pandemic and subsequent disruption of supply chains and manufacturing, lithium-ion battery costs have fallen year-over-year⁴. The National Renewable Energy Laboratory's ("NREL") latest 2025 battery storage cost update for storage resources anticipates a reduction in overnight capital costs of 27% by 2035⁵ while the escalation factors for the 2025 IRP forecast a reduction of approximately 7%. For new 4-hour battery storage resources built in 2030, the 2025 Idaho Power IRP assumptions exceed the Company's own 2023 forecast by 15%, the 2023 Portland General Electric ("PGE") IRP forecast by 38%, the 2024 NREL Annual Technology Baseline ("ATB") by 21%, and NREL's 2025 Battery Storage Update forecast by 45%.

Forecasting resource costs is challenging, and no single forecast will likely be 100% correct. Still, the Company's forecasts for resource cost declines reflect a very conservative view that diverges from other publicly available data sources, including industry reports and utility IRPs. Significant cost declines in lithium-ion battery storage technologies, specifically, have been reported in recent years as the industry recovers after COVID. The Company should avoid relying on 'delayed cost reduction' scenarios in its base capacity expansion analysis. These delays have a material impact on the resulting portfolio. Anchoring base assumptions to consensus trajectories will provide a more credible foundation for LTCE modeling and better ensure the pursuit of least-cost, least-risk outcomes. We recommend the Company model a future that more closely follows consensus technology maturity curves and removes delayed cost reductions. Absent this analysis, it is unclear whether the preferred portfolio aligns with Oregon's IRP Guidelines and is in the best interests of its Oregon customers. We recommend that the Company undertake this additional analysis in its next round of comments.

2. *The Company outlines the effective load carrying capacity ("ELCC") of variable energy resources ("VERs") and energy limited resources ("ELRs"), but omits reliability considerations for thermal resources.*

Evaluating ELCC is critical to capture the reliability contributions of VERs and ELRs in LTCE studies. As more of these resources are brought onto the system, their capacity accreditation becomes more dynamic and fundamental to system reliability. For example, ELCCs are known to decline for stand-alone solar installations as their contribution to the afternoon peak load saturates. Alternatively, the combined effects of renewable and storage resources elevate their

⁴ Lithium-Ion Battery Pack Prices See Largest Drop Since 2017, Falling to \$115 per Kilowatt-Hour: BloombergNEF, BNEF (Dec. 10, 2024),

<https://about.bnef.com/insights/commodities/lithium-ion-battery-pack-prices-see-largest-drop-since-2017-falling-to-115-per-kilowatt-hour-bloombergnef/>

⁵ Wesley Cole et al., Cost Projections for Utility-Scale Battery Storage: 2025 Update, NREL (June 2025), <https://docs.nrel.gov/docs/fy25osti/93281.pdf>

combined ELCC⁶. ELCCs, though more computationally intensive to calculate, are necessary metrics because they define the reliable capacity for a portfolio of new, clean resources that are poorly suited for classical reliability metrics developed for thermal resources (UCAP, eFORd).

For thermal resources, assumptions around forced outage rates, derates, loss of fuel, and other outage types can be adopted to calculate ELCCs and reflect the reality that their reliable capacity will be less than nameplate. The 2025 IRP lacks information on the thermal candidate resources' reliability. This omission repeats a finding by RNW in the 2023 IRP. RNW and NWEA would appreciate the opportunity to review this data and would welcome more clarity around how the Company calculated the capacity contribution of thermal resources, particularly for baseload and peaking gas units. It is important to note that the existing coal assets are almost 50 years old. Even if converted to gas, as these aging units approach the end of their design life, their risk of forced outages increases, making them less reliable⁷. A least-cost, least-risk portfolio will require balanced treatment of thermal resources, VERs, and ELRs. We look forward to learning more about the Company's approach to modeling thermal resources through discovery to fill in any questions remaining from the IRP. We request that the Company address this issue in its next round of comments.

3. The 2025 IRP excludes the high-quality Wind-Wyoming candidate resource previously considered in the 2023 IRP.

In the 2023 IRP, the Company included a candidate wind resource in Wyoming. This candidate was a lower-cost, higher-capacity-factor resource than the local Idaho wind resource candidate. The Preferred portfolio in the 2023 IRP built 1,800 MW of economic wind projects from 2027 to 2032 contingent upon the completion of Gateway West. Given the relative quality and cost of the Wind-Wyoming candidate resource, we can assume that the Wyoming resource comprised much of the Company's 2023 IRP wind capacity. The 2025 IRP does not address the removal of this resource candidate, but does continue to pursue Gateway West and other transmission projects that are key enablers of clean energy imports to the system. The removal of the Wyoming wind candidate serves to depress wind expansion realized by the 2025 IRP's LTCE portfolios. Without explanation in the IRP, one can only presume that Idaho Power removed this low-cost, high-capacity-factor resource to more easily realize an optimal portfolio that aligns with its preferred future. This omission is an example of the Company's change in direction from a renewables-forward portfolio in 2023 to a 2025 portfolio that leans more heavily on new thermal generation.

⁶ Kevin Carden et al., Effective Load Carrying Capability Study: Prepared for ERCOT, Astrape Consulting (Dec 7, 2022), <https://www.ercot.com/files/docs/2022/12/09/2022-ERCOT-ELCC-Study-Final-Report-12-9-2022.pdf>

⁷ 2024 State of Reliability, NERC (June 2024), https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2024_Technical_Assessment.pdf

4. *The Company's increased reliance on new thermal capacity exposes the system to fuel price volatility and supply risk.*

The preferred portfolio for the 2025 IRP builds 450 MW more new thermal resources than the 2023 IRP preferred portfolio between 2029 and 2032. The composition of the 2025 builds suggests the LTCE built a 150 MW SCCT in 2029 and a 300 MW CCCT in 2030. Over the same time period, the 2025 IRP reduced wind capacity by 900 MW, solar by 300 MW, and storage by 215 MW. The 2025 preferred portfolio will lean more heavily on thermal generation for both capacity and energy. The system's reliance on natural gas fuel will increase accordingly. The volatility of natural gas prices will introduce additional risk to the preferred portfolio's ability to realize a lowest-cost, lowest-risk future. For example, the Company's "Low Gas Price" and "High Gas & Carbon Prices" portfolios result in the lowest (\$10.16B) and the highest (\$14.16B) total costs, respectively. The costs of these gas price sensitivities, relative to the preferred portfolio (\$10.96B), suggest the Company's capacity to reduce costs under a low gas future (-\$0.80B) is significantly smaller than the increased cost risk (+\$3.20B) that a high gas cost future presents the system. Based on these portfolio results, a reduction in thermal generation is likely to reduce system cost risks.

The Company will have to expand natural gas fuel capacity at the Northwest Pipeline to support additional gas generation resources. The 2025 IRP models this increased expense as an additional \$0.50 to \$1.20/MMBtu on the gas fuel price. Gas prices for the 2025 IRP are based on the 2023 U.S. Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") "Low Oil and Gas Supply." If we adopt the average price over 2030-2039, \$6.23/MMBtu (\$2024), the Northwest Pipeline expansion cost adder is expected to increase fuel price by 8% to 19%. Over the study horizon, the years in which new resources can be selected by the LTCE study (2029-2045), the natural gas price is forecasted to increase by 24% in addition to this Northwest expansion cost adder.

Beyond fuel price risk associated with Northwest Pipeline expansion and market volatility, the fuel supply strategy is a work in progress. The feasibility and timeline for the expansion of the Northwest Pipeline are not addressed in the 2025 IRP. The Company states... the "[fuel supply] expansion options are fluid and this is an area that the company is actively monitoring."⁸ On any given day, the Company expects to procure additional transportation capacity via the short-term capacity release market, further jeopardizing the certainty of the supply and delivered price. Taken together, a portfolio that relies more heavily on thermal resources is likely to suffer higher and more volatile fuel costs, greater supply and transportation uncertainty, and elevated reliability and ratepayer risk. The interdependency between the electric and gas systems increases reliability and ratepayer risk, demonstrating that the preferred portfolio is likely far riskier and more volatile than the company acknowledges.

⁸ Idaho Power 2025 IRP, Ch. 8, page 94

5. *RNW and NWEAC support Idaho Power's use of the RCAT tool to validate the LTCE portfolio reliability.*

Utility resource planning too often relies on an “open loop” process for the development of input assumptions, resource selection, reliability validation, and performance evaluation. Input assumptions are often developed in collaboration with external consultants and passed along to the resource planning process. Given all input assumptions, a utility will conduct LTCE studies across various scenarios to arrive at an “optimal” portfolio. In this “open loop” process, information moves in a single direction from inputs to outputs without feedback from proximate steps. The long time-horizon and complex nature of integrated system planning studies make them organizationally and computationally expensive to conduct. LTCE studies have to rely on sampled chronologies, such as one week per month, to optimally and efficiently select new resources over a long time horizon. This “open loop” process and sampled chronology can misrepresent the reliability of an LTCE portfolio.

Idaho Power has recognized the limitations of using Aurora LTCE studies to ensure a reliable system and introduced its RCAT tool: “[T]he Aurora LTCE model used in the 2025 IRP cannot currently calculate the dynamic diversity benefit caused by a changing resource mix⁹.” We applaud the Company’s introduction of the RCAT tool into a feedback loop with the Aurora LTCE studies to ensure that the resulting portfolio’s capability to meet the LTCE’s planning reserve margin aligns with RCAT’s LOLE-derived capacity requirement. This iterative approach also helps ensure that the ELCC assumptions provided to the LTCE model are tuned to the portfolio composition. The RCAT to LTCE back-and-forth sharpens the portfolio’s reliability evaluation.

B. RNW and NWEAC recommend that the Company develop new large-load tariffs to encourage flexibility when it is needed most.

1. *Idaho Power's preferred capacity expansion portfolio risks overprocurement of capacity for load growth that is unprecedented.*

The Company forecasts total system peak load to increase by 1.1 GW from 2026 to 2032¹⁰. Over the same period, the Company expects to add 800 MW of additional firm load from its largest customers¹¹, representing ~72% of the total forecasted system peak load. Over this period, the preferred portfolio builds 1.2 GW of dispatchable capacity (natural gas plus storage). In the Company’s 300 MW large load sensitivity, the capacity expansion model adds a 300 MW CCCT in 2032 on top of the preferred portfolio. In the Company’s 500 MW large load sensitivity, the capacity expansion model adds a 150 MW SCCT in 2032 and a 300 MW CCCT and a 155 MW battery in 2033, 605 MW in total, on top of the preferred portfolio. These sensitivities suggest

⁹ Idaho Power 2025 IRP, Appendix D, page 8

¹⁰ Idaho Power 2025 IRP, Table 8.2, page 89

¹¹ Idaho Power 2025 IRP, Appendix A, page 44

that large-load growth will require significant firm capacity, nearly one-to-one, in the coming years.

Significant growth of large-loads introduces risks and opportunities for the Company and its rate payers. Thoughtful planning, interconnection processes, and novel rate design will be required to balance the economic potential of large-loads against the reliability and cost-shifting risks they exacerbate. The Company's modeling of additional large-load scenarios offers useful benchmarks for stakeholders and regulators to evaluate the capacity needs and corresponding costs for a system with even more load than is currently forecasted. There is a reliability risk present if the Company underplans for load growth. This reliability risk is most efficiently mitigated when it is balanced against the risk of overprocurement and stranded assets. In its current form, the IRP does not address this second risk.

These potential large-load customers, such as data centers, are expected to be a key part of the Company's future plans. The Company has up-corrected its forecast for 2032 additional firm sales by 200 - 300 MW in every IRP filed since 2019¹². This rapid change in large-load forecasting reflects the volatility inherent in the still-nascent industry of building, interconnecting, and operating very large data centers^{13 14}. Large-load developers and utility business development teams hold a shared incentive to locate a new project in the utility's footprint. Speculative interconnection requests from new large-load developers inflate load forecasts and weaken the reliability of planning assumptions. Beyond the uncertainty surrounding the materialization of large-load projects, there exists load ramp uncertainty. An interconnection request for 100 MW by 2030, with a 20 MW ramp over the first 5 years after energization, may be delayed throughout construction. The prominence of the large-load forecast in the Company's total system peak and the large size of individual interconnection requests, greater than 20 MW, exacerbates the risks posed by the forecast uncertainty. If these large-loads fail to materialize or ramp on schedule, Idaho Power and its ratepayers risk overprocurement, stranded assets, and increased costs.

We credit the Company for recognizing the "inherently uncertain" nature of new industrial and energy service agreement ("ESA") customers. The 2025 IRP suggests that the Company is working to address large-load materialization and ramp uncertainty by only including customers that have made a "significant binding investment" or "interest indicating a commitment of the highest probability." We look forward to further exploring the Company's approach to large-load forecasting risk through discovery. An accurate quantification of anticipated large loads and the resource demand they drive is essential to creating a least-cost, least-risk resource portfolio.

¹² Idaho Power 2019 IRP, Idaho Power 2021 IRP, Idaho Power 2023 IRP, Idaho Power 2025 IRP

¹³ Ian Hitchcock and Merritt Cahoon, Hyperscaler Data Center Buildout: A Sustainability Bane, Boon, or Both? Nicholas Institute for Energy, Environment & Sustainability, Duke University, (Aug. 2025),

<https://nicholasinstitute.duke.edu/publications/hyperscaler-data-center-buildout-sustainability-bane-boon-or-both>

¹⁴ Ryan Quint et al. Practice Guidance and Considerations for Large Load Interconnections, Elevate Energy Consulting and GridLab, (May 2025),

<https://gridlab.org/portfolio-item/practical-guidance-and-considerations-for-large-load-interconnections/>

2. *Limited, demand-side flexibility from large loads offers a significant opportunity to de-risk the Company's load forecast and capacity expansion plans.*

Recent studies demonstrate how limited, demand-side flexibility from large-loads during the periods of highest stress can help to mitigate reliability and planning risks¹⁵. Across the country, 98 GW of new load could be integrated on the power grid without additional generation capacity, if that load is curtailed for just 0.50% of its annual energy demand¹⁶. Among Western Electricity Coordinating Council (“WECC”) balancing authorities evaluated in this study, the average curtailment-enabled headroom, at a 0.50% rate, was greater than 1 GW. We’ll note, 1 GW is approximately the forecast for additional firm sales in the 2025 IRP. In May of 2025, the Public Utilities Commission of Nevada approved NV Energy’s new Clean Transition Tariff (“CTT”), which would allow large-load customers to contract for clean energy service through their utility. Under such a contract, the large-load makes a long-term commitment to paying a premium for clean energy¹⁷. In August of 2025, Google announced agreements with Indiana Michigan Power (“I&M”) and Tennessee Valley Authority (“TVA”) to enable demand response capabilities in its datacenters¹⁸.

The CTT and recent commitments to enable large-load demand side management demonstrate how utilities, regulators, and large loads can collaboratively and creatively develop new solutions to serve, and in fact utilize, these large-load interconnection requests. Flexible loads place a smaller burden on system demand. They are less likely to trigger the need for transmission and generation upgrades, which can allow for accelerated interconnection processes and reduced pressure on electricity rates. The development of innovative large-load tariffs will be a key tool for utilities to benefit economically from the data center boom while efficiently managing cost and reliability risks.

C. RNW and NWEAC support the Company's continued commitment to regional and inter-regional transmission development.

1. *Transmission expansion pursued by Idaho Power supports a least-cost, least-risk system.*

Idaho Power recognizes the critical role transmission expansion plays in building a reliable, low-cost, and adaptable power system. Transmission expansion provides the Company with

¹⁵ Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption, EPRI (May 28, 2024), <https://www.epri.com/research/products/3002028905>

¹⁶ Tyler Norris et al, Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems, Nicholas Institute for Energy, Environment & Sustainability, Duke University (2025), <https://nicholasinstitute.duke.edu/sites/default/files/publications/rethinking-load-growth.pdf>

¹⁷ Lisa Martine Jenkins, The ‘clean transition tariff’ won approval in Nevada. What’s next for Fervo?, Latitude Media (May 15 2025), <https://www.latitudemedia.com/news/the-clean-transition-tariff-won-approval-in-nevada-whats-next-for-fervo/>

¹⁸ Michael Terrell, How we’re making data centers more flexible to benefit power grids, Google (Aug. 4 2025), <https://blog.google/inside-google/infrastructure/how-were-making-data-centers-more-flexible-to-benefit-power-grid/>

avoided-capacity benefits (regional load diversity), increased revenue from off-system sales, improved integration of renewable resources, efficient market operations, and facilitates new industry growth.

In the 2023 IRP, the Company highlighted Boardman to Hemingway's ("B2H") importance to its 100% clean energy by 2045 goals. Specifically, B2H plus the acquisition of capacity at Four Corners will provide the company access to high-quality solar generation and wind potential in the Desert Southwest¹⁹. B2H will allow clean hydroelectric generation in the Pacific Northwest to be shared with the Mountain West, while the Upper Mountain West's wind generation can more easily serve load in the Pacific Northwest²⁰. Gateway West, another transmission project pursued in the 2025 IRP, will help to relieve on-system transmission constraints and integrate additional wind and solar generation from the eastern portion of the state and neighboring Wyoming. In this way, transmission expansion supports Idaho Power's 100% Clean by 2045 goals and improves system reliability. RNW and NWECA urge Idaho Power to continue to robustly analyze transmission development to unlock a broad pool of geographically and technologically diverse resources across a broad footprint to meet customer needs in a least-cost, least-risk manner.

D. RNW and NWECA recommend the Company update its IRP modeling approach to capture the full costs and benefits of system portfolios.

- 1. The Company's IRP modeling approach lacks full, hourly production cost modeling studies to accurately report portfolio performance.*

The 2025 IRP does not mention the use of dispatch or production cost modeling ("PCM") studies to evaluate the portfolio's hour-to-hour performance. The Company's approach fails to capture the hourly performance of the IRP portfolios. Hourly performance (dispatch, emissions, market imports, etc) should be reported from a PCM run, such as the Aurora standard zonal study type. Energy Exemplar, the software vendor for the Aurora modeling software, advises against the use of LTCE studies to evaluate portfolio performance due to their reliance on sampled chronology, such as 1 week per month. Without an explicit description of standard zonal (dispatch) studies used in the IRP, we must presume that the Company has relied on LTCE results²¹. If all hours of a portfolio's operation are not sampled, a study will lack the information needed to accurately capture performance and will instead rely on inter-sample interpolation and inference to fill the gaps and report metrics. Without PCM studies of the LTCE portfolios, the IRP portfolio metrics are less accurate. RNW and NWECA look forward to working with Idaho Power to clarify our understanding of the Company's approach to developing its portfolio performance metrics.

¹⁹ Idaho Power 2023 IRP, Ch. 7, page 86

²⁰ Idaho Power, Boardman to Hemingway - Purpose and Need, <https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/current-projects/boardman-to-hemingway/purpose-and-need/>

²¹ RNW is awaiting information request responses to confirm the details of the Company's modeling.

2. *The Company's evaluation of capacity expansion portfolios relies principally on portfolio costs and overlooks other key portfolio attributes.*

Idaho Power's approach to resource planning adopts many best practices²². The Company engages stakeholders to craft IRP modeling scenarios and solicits feedback. The Company does a laudable job linking resource adequacy assessments with resource planning. The Company relies on recent data for the development of inputs, plans for large loads, and models multiple storage candidate resources (among other prudent measures). The Company conducts scenario-based modeling with additional sensitivities to better evaluate risk and uncertainty. Still, there are areas in this IRP where Idaho Power's approach should be improved.

The 2025 IRP's evaluation of portfolios is overly reliant upon portfolio net present value ("NPV") to identify the least-cost, least-risk plan among the scenarios considered. Total system NPV among the 2025 IRP Main cases differs only slightly. Among cases with the base load forecast, the most expensive main case, "With 111(d) Bridger 3&4 CCS" costs 5% more than the preferred portfolio. In the "Portfolio Emission Results" section, the Company suggests that a 7% difference in CO2 emissions among cases can be considered "comparable."²³ By extension, we can assume that the Company considers the 5% range for total system NPV among the main cases to be comparable. The question then remains how best to rank the main cases.

Beyond the portfolio costs, the Company presents Stochastic and Qualitative Risk analyses as a part of its portfolio evaluation²⁴. The Qualitative Risk Analysis lacks clear values and thresholds to define what constitutes low, medium, or high risk. Clearly presenting these values and the rationale behind them would greatly enhance the clarity and usefulness of the analysis. Further, this analysis is limited to the preferred portfolio with constituent Bridger 3&4 conversion sensitivities and no gas scenarios. An extension of the Qualitative analysis to other future portfolio sensitivities would provide insight into the Company's view of these alternatives' risks. The Stochastic Risk Analysis evaluates the sensitivity of each portfolio's system NPV to select key inputs. The "Preferred - Bridger 3&4 NG" portfolio is among the scenarios with the highest likelihood to result in the lowest portfolio cost despite stochastic inputs. The others are the "Low Gas Price" and "Forced SCCT in 2030" with very similar system NPV distributions. It would be prudent to balance evaluation of the likeliest results, the peak of the distribution, against the range of possible results. The Company should provide the 5th and 95th percentile, or some other measure of variance, of the costs in the stochastic analysis to better quantify the sensitivity, and therefore uncertainty, of each portfolio to these key inputs.

Ultimately, we recommend that the Company develop a portfolio scorecard to holistically compare each of the IRP's resource plans. Stakeholders' and regulators' evaluation of portfolios would benefit from a scorecard that summarizes portfolio performance across key quantitative

²² Bruce Biewald et al, Best Practices in Integrated Resource Planning, Synapse and LBNL (Dec 6, 2024), https://www.synapse-energy.com/sites/default/files/IRP_Best_Practices_2024_Synapse_LBNL_24-061_1.pdf

²³ Idaho Power 2025 IRP, Ch. 10, page 114

²⁴ Idaho Power 2025 IRP, Ch. 10, pages 118-120

(cost, emissions, dispatch), qualitative (regulatory risk, emerging technology), and composite metrics (resource diversity, market reliance). These metrics should be developed in collaboration with the IRP Advisory Council (“IRPAC”) to identify the suite of metrics that are the most important to the Company, stakeholders, and regulators. Certainly, cost is a core metric to evaluate an IRP portfolio, but when total system NPV varies only slightly, it is important to weigh costs against other important portfolio metrics. A scorecard can synthesize a large amount of information into a format that is easy for stakeholders and regulators to review and consider.

The Company presents the results of its modeling studies across various tables in Chapter 10 of the IRP. A reader seeking to understand the differences among portfolios across multiple dimensions must flip back and forth or produce their own side-by-side comparison to understand how the 5% cost savings realized by the preferred plan are reflected across other important dimensions. Aspects of this multi-dimensional analysis are present in the IRP, but they are disjointed. We applaud the Company for attempting to address qualitative risk, the probability distribution of system NPV, and cumulative portfolio emissions, but there are better ways to summarize these results. Interstate Power and Light (Alliant Energy) presented a strong example for a portfolio scorecard in their 2024 Resource Evaluation Study (“RES”)²⁵. Their portfolio dashboards, or scorecards, summarize each portfolio along customer affordability, customer rate stability, flexibility and resource diversity, sustainability, and reliability dimensions. We recommend that the Company develop a portfolio performance scorecard that captures the multidimensional nature of integrated resource planning. The scorecard should summarize portfolio results side-by-side to support transparent decision-making and highlight the relative strengths and weaknesses of alternatives.

III. CONCLUSION

RNW and NWECA offer appreciation to both the Commission and the Company for their consideration of these comments. While we applaud Idaho Power’s continued work in developing regional and inter-regional transmission capacity, we are concerned by the Company’s turn away from the renewable energy resources identified in the 2023 IRP as part of its low-cost, low-risk future. We offer preliminary suggestions for improvement of the IRP. We look forward to continued participation in this docket and in the Company’s resource planning process.

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²⁵ Interstate Power & Light Company, Resource Evaluation Study (Feb 13, 2025). Docket No. RPU-2021-0003

Respectfully submitted this 8th day of September, 2025.

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