Office of the Secretary
Service Date
December 16, 2021

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF AVISTA CORPORATION DBA AVISTA UTILITIES' 2021 ELECTRIC INTEGRATED RESOURCE PLAN	)))))	**CASE NO. AVU-E-21-04** **ORDER NO. 35257**

On March 31, 2021, Avista Corporation dba Avista Utilities ("Company") filed its 2021 Electric Integrated Resource Plan ("Electric IRP" or "IRP"). The IRP outlines and analyzes the Company's strategy for meeting its customers' projected energy needs over the next 24 years. The Company files an IRP every two years and uses it to guide resource acquisitions.[1]

On April 23, 2021, the Commission issued a Notice of Filing and Notice of Intervention Deadline. Order No. 35022. Idaho Conservation League ("ICL") intervened on May 10, 2021. Order 35041.

On June 4, 2021, the Commission issued a Notice of Modified Procedure establishing deadlines for public comments and the Company's reply. Order No. 35062. Commission Staff and ICL filed comments to which the Company replied.

Having reviewed the record in this case, the Commission now issues this Order acknowledging the Company's IRP.

BACKGROUND

An IRP is a status report on the utility's ongoing, changing plans to serve its customers adequately and reliably at the lowest system cost and least risk over the next 20 years. The report informs the Commission and the public about the utility's plans and is like an accounting balance sheet; that is, it is a "freeze frame" look at the utility's fluid resource planning process. *See* Order No. 22299. The IRP is meant to demonstrate to the public that the Company has reasonably planned for different scenarios. The Commission thus expects a utility to vigorously test the IRP's assumptions to ensure the IRP accurately reflects potential changes to markets and customer demand.

[1] The Company was granted a six-month extension to file its 2019 IRP. Order No. 34312. The Commission changed the caption for the Company's filing to the "2020 Electric Integrated Resource Plan" when it issued the Notice of Filing. Order No 34609. The Company's 2020 Electric IRP was acknowledged on October 15, 2020. Order No. 34814.

The Company must update its IRP every two years and allow the public to participate in developing the IRP. *See id.*; Order No. 25260. The final IRP must include the subjects required by the Commission's prior Orders, including Order Nos. 22299 and 25260. In sum, the final IRP should explain the Company's present load/resource position, expected responses to possible future events, and the role of conservation in those responses. It also should discuss:

> any flexibilities and analyses considered during comprehensive resource planning, such as: (1) examination of load forecast uncertainties; (2) effects of known or potential changes to existing resources; (3) consideration of demand and supply side resource options; and (4) contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead time, reliability, risk, etc.) as future events unfold.

Order No. 22299. The IRP should separately address the Company's: (1) existing resource stack; (2) load forecast over a 20 year load growth scenario; and (3) additional resources which "should consist of the utility's plan for meeting all potential jurisdictional load over the 20-year planning period" ideally by describing "the most probable 20-year scenario followed by comparative descriptions of scenarios showing potential variations in expected load and supply conditions, and the utility's expected responses thereto." *Id.*

By acknowledging the IRP, the Commission acknowledges the Company's ongoing planning process, not the conclusions or results reached through that process.

STAFF COMMENTS

Staff recommended the Commission acknowledge the Company's 2021 Electric IRP. Staff's recommendation was based on its active participation in the IRP Technical Advisory Committee ("TAC"), its review of the Company's IRP filing, the Company's responses to audit and production requests, and its review of the customer and stakeholder feedback received through the public input process. Staff acknowledged the Company's IRP team's work to solicit input and feedback from parties throughout the IRP process.

Staff identified several topic areas it believed require additional review in the next Electric IRP cycle. These include: (1) Reliability Analysis; (2) Market Reliance; (3) Colstrip Economic Analysis; (4) Portfolio Optimization by State and System; and (5) Energy Efficiency and Demand Side Management Programs.

(a.) Reliability Analysis

Staff was still concerned with the Company's reliability analysis. Staff expressed concern with the Company assigning a single Planning Reserve Margin to all portfolio scenarios and not verifying reliability across multiple years and portfolios in its 2020 IRP. *See* Staff Comments. While it believed the Company made progress in addressing these concerns in the current IRP, Staff expected the reliability analysis to receive increased focus in the next IRP cycle. Specifically, Staff would have liked to see a reliability analysis which measured the resulting Loss of Load Probability ("LOLP") or Loss of Load Expectation ("LOLE") of all its portfolios under evaluation across the full planning time horizon.

The 2020 IRP reliability analysis only evaluated the resulting LOLP for the Preferred Resource Strategy ("PRS") portfolio for one-year. In the 2021 IRP, the Company increased the number of portfolios it evaluated for the resulting LOLP, but still only for a single year. To understand the reliability performance of the Company's Clean Resource Plan portfolio, however, the Company evaluated its reliability across an additional year. Staff looked forward to continuing improvements in the future.

Coverage of reliability analysis in the IRP process is often limited and presented at the end of the IRP cycle. In the 2021 IRP, the results of the reliability analysis were presented after the draft IRP was sent out for review. Performing a reliability analysis at the very end of the process can result in a portfolio that appears promising from a cost standpoint, only to end up unreliable, according to Staff. Staff believed evaluating scenarios that are not known to meet reliability standards has limited value in an IRP. Staff understood the 2021 IRP cycle was shortened due to the extension of the 2019 IRP; however, Staff believed the reliability analysis should be a larger priority due to the increasing number of factors potentially affecting system reliability.

At a July 21, 2021, meeting, the Company stated its plan to start testing a new modeling software, PLEXOS, with the intention to replace its current reliability modeling software. Staff was encouraged by the Company's efforts to improve reliability analysis and looked forward to reviewing the results. Staff recommended the Company sufficiently test the new software to verify the results are accurate before full implementation.

(b.) Market Reliance

Due to load changes and reduced resource capacity contributions based on new analyses and data, the Company changed its market reliance assumption from 250 MW, as in previous IRPs, to 330 MW in this IRP. *See* Production Response No. 5(c). It was determined 330 MW was necessary during regionally stressed hours to maintain a 5% LOLP with a 16% planning margin. *See* Production Response No. 5(b). Staff was still concerned, however, with the Company's reliability modeling and the Company's failure to determine if it can rely on this additional level of market availability long-term.

To determine a reasonable level of market reliance, Staff recommended that the Company evaluate import capability considering market availability of both firm generation and transmission capacity. The Commission shared this view in previous orders. Order No. 33425 indicated that a utility's import capability—its ability to make short-term purchases using its transmission capacity—should be included in the load and resource balance. Recent, unexpected changes in the market for firm transmission have caused availability to tighten across the Western Interconnection and have affected many utilities' ability to rely on the market in the future.

The Company expected to set future market reliance based on the information gained from its participation in the Northwest Power Pool's Resource Adequacy Program ("RA Program"). *See* Production Response No. 5. Staff indicated that the RA Program, in addition to providing a process for participating utilities to reserve capacity and ensure that it will be available, also provides visibility to capacity available across the region for making future reservations.

(c.) Colstrip Economic Analysis

Staff continued to express concern with the Company's Colstrip analysis as it has in the last three IRP cycles. The Company changed how it modeled Colstrip in the current IRP to address Staff's concerns. Staff appreciated the change and believed it is an improvement. Staff was concerned, however, with how Colstrip's removal in 2021 in the PRS affects reliability. In addition, Staff preferred a Colstrip analysis that accurately quantifies the impact of different exit dates on reliability, cost, and risk to Idaho customers.

In previous IRPs, the Company chose a limited number of years to evaluate Colstrip's retirement. Staff has recommended evaluating more years for retirement or allowing the model to evaluate every year possible. In the current IRP, the Company allowed Colstrip to remain in the Idaho portfolio in any year it remained economic. Staff believed this move was an improvement because it provided a resource portfolio and Colstrip exit scenario to compare against environmental policy driven scenarios.

Staff's concern with Colstrip's removal in 2021 in the PRS was partially based on the Company's failure to provide evidence that retiring Colstrip in 2021 is possible. Staff did not believe the PRS should include resource retirements that are infeasible. Staff was also concerned that by making unrealistic exit date assumptions, portfolios would likely reflect incremental replacement resources that are not optimal for the system. Staff believed it appropriate to evaluate retiring Colstrip in 2021 as a scenario for comparison purposes, but that, ultimately, the Company should not include unrealistic retirement dates for Colstrip in its PRS portfolios.

An additional concern related to removing Colstrip in 2021 was reliability. The Company's reliability analysis focused primarily on a single year—2030—which Staff believed was a flaw in the current reliability analysis. Staff believed that, if Colstrip's retirement is nigh, the Company should conduct a deeper analysis to ensure an early retirement would not affect reliability.

Staff understood the Company's status as a minority partner in Colstrip and that its existing contractual obligations create a difficult situation for modeling Colstrip in the IRP. Commission Order No. 34814 requires the Company to file an annual update on its Colstrip ownership interest by October 1. *See* Case No AVU-E-19-01. Staff looked forward to reviewing the updated Colstrip economic analysis in the annual update later this year and would like to see more on the reliability, cost, and risk to Idaho customers across diverse Colstrip exit dates.

(d.) Portfolio Optimization by State and for the System

The Company changed the IRP portfolio optimization model in the 2021 IRP to allow new resources to be added to the system or assigned to a specific state to better understand the drivers and cost responsibility of state specific resource decisions. Staff Comments at 6. Staff agreed with the Company's statement that "the reason for the modeling change was, 'to better understand the impacts of Washington State policies' effect on Idaho'" and believed that such changes would improve the IRP. *Id.* That said, Staff was concerned with the method the Company used to divide load and resources in the IRP and recommended using methods that maintain the benefits of the system but allow for state-by-state needs and constraints.

Loads and resources are divided using the Production-Transmission ("PT") ratio in the 2021 IRP. *Id.* The PT ratio is the current state allocation method used for generation and cost allocation and is based on the breakdown of load between states. *See* Production Response No. 2(a). Staff believed using the PT ratio to divide existing resources was reasonable in this IRP so long as this method was reevaluated in the future.

Staff believed the Company's progress in developing a multi-jurisdictional workshop to discuss and consider alternative methods to allocate costs and benefits of resources between Idaho and Washington was important to developing resource planning methods, identifying state specific resource needs, and aiding in the update of the current state allocation methods as state policies continue to change.

(e.) Energy Efficiency and Demand Response Programs

Staff outlined its concern in its 2019 IRP comments that the Company's method for energy efficiency savings overstated the peak load reduction obtained from its energy efficiency programs. Staff stated the Company has provided better, more accurate and reliable estimates of energy efficiency savings in the 2021 IRP. Staff appreciated the Company's efforts to improve the accuracy of its estimated energy efficiency savings from these programs and believed the results from the most recent prudency filing—Case No. AVU-E-20-13—will assist the Company in accurately quantifying energy efficiency's contribution to reducing peak load.

In the Company's PRS, energy efficiency will reduce the Company's future load growth by 68% by 2045, with 23% of the new energy efficiency savings coming from Idaho customers. In total, the Company's commercial customers are set to achieve 47% of energy efficiency savings, and its residential customers, 37%. Additionally, the demand response programs in the PRS are estimated to reduce 16 MW of peak load by 2024 for the Company's Idaho service territory; an 8 MW peak load reduction is anticipated to come from third party contracts and another 8 MW from Variable Peak Pricing and Time of Use Rates.

IDAHO CONSERVATION LEAGUE COMMENTS

ICL's comments focused on two process issues in the IRP. First, ICL commented that the IRP risk analysis section only considered a single risk metric for the IRP's PRS that deals with hydropower contracts for Washington customers and fossil fuel powered plants for Idaho customers. ICL recommended the Commission direct the Company to assess the different risk implications that arise from pursuing different resources for Idaho customers, who are subject to volatile gas prices and fossil fuel pollution limitations, compared to Washington customers who enjoy fixed-price hydropower.

Second, ICL commented that the Company's immediate exit from Colstrip is the least cost option for Idaho customers. ICL indicated, however, that the IRP showed that the Company planned to remain in Colstrip notwithstanding the potential of excess costs to Idaho customers. ICL recommended that the Commission direct the Company to improve the IRP process by incorporating methods to protect Idaho customers from decisions prioritizing corporate relationships ahead of economics.

COMPANY REPLY COMMENTS

The Company replied to Staff and ICL. The Company acknowledged that it developed the IRP over a 11-month period with the help of over 100 representatives, six TAC meetings, two workshops, and a virtual public meeting to inform the public and take input. Company Reply Comments at 2.

(a.) Response to Staff's comments

i. Reliability Analysis

The Company agreed with Staff's concerns regarding reliability of the Company's system when the potential resource portfolios are changing. *Id.* at 3. The Company stated that there were two options to address reliability planning.

The first option was to continue improving existing methods. The Company stated it "is evaluating new software ("PLEXOS") to increase the breadth of reliability planning studies across additional scenarios and time horizons as compared to its internal ARAM model." *Id.* The Company acknowledged its "evaluation of [PLEXOS], or an alternative software, may not be available for a complete analysis of all portfolios in time for the 2023 IRP even if the Company finds the new technology to be satisfactory." *Id.*

The second option the Company offered was to forgo detailed utility reliability modeling and use regional planning requirements set by the RA Program. *Id.* at 4. The Company stated that it planned to "select resources in its next IRP to meet the requirements of the RA Program so long as the region continues to pursue the objectives of regional coordination." *Id.* The Company stated, "it will plan to continue conducting reliability studies to understand its market exposure using PLEXOS, ARAM, or other software." *Id.* The Company noted that it "may use this analysis to recommend higher planning margins to either increase reliability above the 1 in 10 criteria or to reduce market exposure." *Id.* The Company planned to discuss the different concepts available with the TAC before deciding which option to pursue.

ii. Market Reliance

The Company stated "[t]here are two main tradeoffs to examine for [LOLP] reliability studies for interconnected systems." *Id.* at 5. The Company explained that "[b]y interchanging the amount [sic] of excess resources under utility control" (Planning Reserve Margin ("PRM")), as compared to the amount of power available from the region during peak hours (expected peak load and market reliance), "the utility can achieve the same reliability metric." *Id.* "If market reliance increases," the Company explained, "then PRM lowers since the utility will rely on the market for resources at time of peak rather than its own resources; increasing PRM will effectively create less reliance on the market because the utility will have additional resources to access." *Id.* The Company noted that, "[i]n the 2021 IRP, [the Company] retains the same level of reliability metric of 5[%] LOLP by retaining its PRM of 16[%]in the winter and 7[%] in the summer . . . ." *Id*. The Company submitted that "[t]his decision increased market reliance based on the study results to maintain 5[%] LOLP." *Id.*

The Company stated that the first limitation in estimating the amount of regional market availability is access to the market through transmission. *Id.* A second limitation, the Company stated, "is whether there are excess resources from neighboring systems to meet demand." *Id.* The Company stated that its primary concern when it comes to accessing energy is availability of surplus resources. *Id.* The Company stated it "has significant transmission interconnections to other utilities including BPA and market purchases from the Mid-Columbia trading hub to the [Company's] system is in a direction that creates counter flow to congested east to west flow." *Id.* at 5. The Company considered the major issue when conducting a reliability analysis on a stand-alone utility to be how the resource need of the Company differs from other utilities or, on other occasions, occurs at the same time. To deal with this issue, the Company began developing the RA Program and "ensuring utilities do not depend on the same market surplus to meet their customers' peak load." *Id.* at 6.

The Company stated that, "it will use the RA Program's planning criteria for resource planning since these requirements are based upon a regional analysis ensuring regional reliability." *Id.* The Company also intended to "study the level of risk it will be relying on in the market and determine if it should acquire additional resources beyond the minimum capacity levels to lessen this market risk." *Id.*

iii. Colstrip Economic Analysis

The Company stated that it improved its "Colstrip modeling based on previous Staff and TAC member recommendations." *Id.* at 6. In particular, the Company examined the economic feasibility of exiting Colstrip immediately, in 2021. The Company acknowledged that, while uneconomic, Montana state legislation, a pre-existing operating agreement, and litigation and arbitration between the owners of the plant, prevent it from having a "good understanding when it can legally exit Colstrip." *Id.*

The Company did, however, "consider reliability effects of exiting Colstrip in other years than 2030." *Id.* at 7. Specifically, the Company examined "the reliability effects in 2025 where the Company will still be within the 5[%] LOLP without Colstrip but will need to replace this lost capacity when its capacity position reverses to a deficit due to the Lancaster contract expiring in 2026." *Id.* Because the resource portfolio is not materially different between 2021 and 2025, the Company did not model any earlier years.

iv. Portfolio Optimization by State or for the System

The Company stated that to begin the process of implementing Staff's guidance on how to optimize its energy portfolio it planned to hold its first workshop in late fall of 2021.

v. Energy Efficiency and Demand Response

The Company indicated it anticipated increased participation in demand response programs. The Company acknowledged that it sought to be more transparent in how it examined energy efficiency programs. The Company stated it intended to implement demand response programs to help meet system peaks by 2026.

vi. Public Participation

The Company stated its plan was "to continue to engage all interested customers to provide an overview of the Company's resource planning efforts, answer questions and to listen to customers concerns about resource planning." *Id.* at 8.

(b.) Response to ICL

To ICL's comment that the IRP risk analysis section was inadequate, the Company responded that "it fully modeled the risk of natural gas resources by studying the cost of the resource, natural gas prices and carbon pricing risk." *Id.* The Company further explained that it "conducted a risk analysis showing the portfolio cost impacts of a national carbon tax, priced at the social cost of carbon." *Id.* As such, the Company concluded "that it provided significant risk analysis of natural gas resources." *Id.* at 9.

The Company responded to ICL's second comment—that exiting Colstrip immediately was the most economical outcome for Idaho customers—by reiterating that, due to the legal obligations, it could not immediately exit Colstrip.

COMMISSION DISCUSSION AND FINDINGS

The Company is an electrical corporation and public utility as defined in *Idaho Code* §§ 61-119 and -129, and the Commission has jurisdiction over it and the issues in this case under Title 61 of the Idaho Code. Having reviewed the record, we find that the Company's 2021 Electric IRP satisfies the requirements in the Commission's prior orders. We thus acknowledge that the Company has filed its 2021 Electric IRP.

We also recognize the limited scope of the IRP. The IRP is intended to serve as a planning document, and resource decisions are not made in the IRP. We appreciate the active participation of Staff and ICL and members of the TAC in the process and are confident that their input helps the Company develop a better and more comprehensive IRP. We particularly note Staff and ICL's comments discussing the economics of the Company's involvement in Colstrip. We look forward to continuing to work with Staff and the Company on the issues surrounding its involvement in Colstrip.

ORDER

IT IS HEREBY ORDERED that the filing of the Company's 2021 Electric 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 of this Order with regard to 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. *See Idaho Code* § 61-626.

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DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 16th day of December 2021.

PAUL KJELLANDER, PRESIDENT

KRISTINE RAPER, COMMISSIONER

ERIC ANDERSON, COMMISSIONER

ATTEST:

Jan Noriyuki
Commission Secretary

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