BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 81

In the Matter of Avista, 2023 Natural Gas Integrated Resource Plan.	Staff Opening Comments

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Section 1: Executive Summary

Nick Sayen, Senior Utility Analyst

Section 1.1 – Context

Integrated Resource Plans (IRPs) of utilities regulated by the Oregon Public Utility Commission (PUC or Commission) are filed pursuant to the IRP Guidelines in Order Nos. 07-047 and 08-339. These guidelines were written over ten years ago, and in that time, utility planning has increased in uncertainty, complexity, and sophistication.

In December 2021, the Oregon Department of Environmental Quality's (DEQ) Climate Protection Program (CPP) went into effect.[1] The CPP requires covered entities, including natural gas utilities, to reduce emissions 50 percent by 2035 and 90 percent by 2050.[2] This major policy development creates a new dynamic in gas resource planning. The CPP requires utilities, stakeholders, and Staff to incorporate new considerations for least-cost, least-risk investments.

The Commission's recently issued Order No. 23-281 in Docket No. LC 79, NW Natural's 2022 IRP, provides direction on the complex issues regarding CPP compliance and gas utility planning. These Opening Comments, and future memos, reflect direction from Order No. 23-281 and Staff's evolving thinking and approach to gas resource planning in the era of decarbonization in Oregon.

Avista's 2023 IRP includes numerous innovative approaches to utility planning. These include: a new approach to climate modeling, the Company's first natural gas demand response potential study, and modeling of building electrification. In addition, this IRP includes the Company's first use of PLEXOS software, and contemplation of impacts from a variety of new policies at the state and federal levels. Staff applauds Avista's efforts to include this many improvements in one IRP cycle.

Section 1.2 – Staff's Review

Staff review covered the usual requirements of an IRP review while also integrating the new perspective of CPP compliance, direction from Order No. 23-281, the findings from the Natural Gas Fact Finding Investigation (NGFF),[3] and the many Company IRP process improvements. This Executive Summary provides a summary of Staff's major arguments and requests, with references to more detailed analysis in later sections.

[1] Oregon Climate Protection Plan, OAR chapter 340, division 271 (adopted December 15, 2021).
[2] OAR 340-271-900(4); *see also* Oregon Exec. Order No. 20-04, Directing State Agencies to Take Actions to Reduce and Regulate Greenhouse Gas Emissions (March 10, 2020).
[3] Docket No. UM 2178, *Staff's Final Report*, Natural Gas Fact Finding per Executive Order 20-04, (Jan. 31, 2023).

Action Plan

Avista's 2023 IRP includes eight Action Items applicable to its Oregon service territory. These are reproduced below and discussed in later Sections. While Staff finds the Action Items reasonable at this time, Staff notes that the timeframe for the Action Plan varies across items and requests that Avista present a revised Action Plan with Action Items proposed over a consistent timeframe in Reply Comments.

1. Purchase Community Climate Investments for compliance to the Climate Protection Plan [sic] for years 2022, 2023, 2024, 2025 and 2026 to comply with Executive Order 20-04.
2. ETO identified 546,000 therms in the 2023 IRP verses 427,000 therms of planned savings in the 2023 ETO Budget and Action Plan. Avista will work with ETO to meet IRP gross savings target of 568,000 therms in 2024.
3. New program offered by ETO for interruptible customers in 2023 to save 15,000 therms.
4. Engage Oregon stakeholders to explore additional new offerings for interruptible, transport, and low-income customers to work towards identified savings of 375,000 therms in 2024.
5. In Oregon, acquire 8.64 million therms of RNG in 2023 and 21.80 million therms of RNG in 2024.
9. Explore using end use modeling techniques for forecasting customer demand.
10. Consider contracting with an outside entity to help value supply side resource options such as synthetic methane, renewable natural gas, carbon capture, and green hydrogen.
11. Regarding high pressure distribution or city gate station capital work, Avista does not expect any supply side or distribution resource additions to be needed in our Oregon territory for the next four years, based on current projections.

Request for Reply Comments 1: Avista should present a revised Action Plan with Action Items proposed over a consistent timeframe.

Past Orders and IRP Guidelines

The acknowledgement order from Avista's 2021 IRP included 15 recommendations from Oregon, Washington, and Idaho.[4] Staff finds that the 15 recommendations were adequately met. Avista's 2021 IRP included six Action Items. Staff finds that Avista implemented each of these Action Items.

Staff finds that Avista's 2023 IRP follows the PUC's IRP guidelines with several notable exceptions, mentioned briefly below. As discussed in Section 8.3, the IRP presents the cost comparison of alternative scenarios (i.e., portfolios) in terms of annual levelized costs instead of as NPVRR metrics.[5] NPVRR analysis of the Preferred Portfolio and alternative portfolios /

[4] *See generally, In the Matter of Avista Corporation, 2021 Integrated Resource Plan,* Docket No. LC 75, Order No. 21-331 (Oct. 15, 2021).

[5] Staff notes the Guidelines reference PVRR, but in practice NPVRR has been customary as it captures more of the balance around a portfolio; Staff uses NPVRR throughout these Comments.

scenarios is required by the guidelines for transparency purposes and Staff requests that Avista provides this analysis in Reply Comments.

As discussed in Sections 8.3 and 9, the IRP presents 13 alternative scenarios as resource portfolios. However, Staff finds these scenarios function akin to sensitivities rather than alternative portfolios. This contributes to significant concern about acknowledging the long-term plan.

As discussed in Section 8.3, Staff finds that the Company did not use stochastic analysis adequately to stress test, or conduct risk analysis of, the Preferred Resource Portfolio. This further contributes to acknowledgment concerns for the long-term plan.

Additional Concerns and Long-Term Planning

Staff notes several concerns with the IRP that extend beyond Guideline compliance. To begin, while Avista has done ground-breaking work to model electrification, Staff finds that the Building Electrification Resource, as conceived in the IRP, is not a proactive resource strategy. This is discussed in Section 4.5. Staff also notes an error in climate modeling and load forecast impacting long-term investments and decisions. This is discussed in Section 3.2. Finally, the IRP makes assumptions that decarbonized fuels will play a significant near term, and rapidly increasing, role in the Oregon Preferred Resource Strategy (PRS). These assumptions appear unrealistic and fall short of assessing the risks around costs and availability. This is discussed in Section 6.

In summary, Staff finds the following four issues to be critical flaws in the company's long-term plan:

1) The lack of alternative portfolios (as noted above in Past Orders and IRP Guidelines),
2) The lack of adequately employed stochastic analysis (also noted above in Past Orders and IRP Guidelines),
3) The error in climate modeling, and
4) Unrealistic assumptions about costly decarbonized fuels.

When considering the impact of these flaws in aggregate, Staff cannot recommend acknowledging the long-term plan. While we welcome the Company correcting any fundamental misunderstanding or mistakes on the part of Staff, the focus of the balance of Opening Comments is on the Action Plan and near-term planning.

Section 2: Energy Burden

Claire Valentine-Fossum, Senior Energy Policy Analyst

Avista's IRP advances an understanding of how energy transition costs to low-income customers might be considered in energy planning. Avista introduces the topic when considering the costs impacts of electrification to gas customers. The questions of how and where such impacts are considered in an IRP warrant further conversation.

Section 2.1 – Energy Burden Within the IRP

In the Company's 2021 Oregon Low Income Energy Efficiency (AOLIEE) Program report, Avista described partnering with a third-party contractor, Empower Dataworks, to complete an Energy Burden Assessment in 2022. The Energy Burden Assessment informed the Company of gaps in the AOLIEE Program and provided data to better target Avista's energy burdened customers needing weatherization services. The Assessment showed that Avista customers have an average and median gas energy burden of 1.2 percent and 0.7 percent, respectively. In Klamath County, 30 percent of Avista's customers are low-income and 14 percent experience a high energy burden, meaning that their annual natural gas bills exceeded three percent of their income.[6]

In the 2023 IRP, Avista introduces a discussion of equity impacts to low-income customers in the context of electrification.[7] The Company notes increasing financial disparities for low-income ratepayers as gas customers switch from natural gas end-uses to electric end-uses. In response to Staff DR 44, the Company provided analysis showing that the cost of converting from gas to electric can be substantial compared to income. The Company further explained that, if enough customers leave the current gas system, Avista's historical investments would be divided among fewer customers. In this case, Avista explains that rates for remaining customers would need to increase to cover these investments. Staff finds the Company's inclusion of energy burden informative from a planning perspective and notes that understanding how planning might mitigate some of these types of impacts was an issue explored in the NGFF.

Staff appreciates the Company's inclusion of an energy burden discussion. In the NGFF, Staff addressed how resource planning might mitigate these equity impacts Avista raises in the IRP. In the NGFF, Staff found that, absent some kind of intervention, the greatest burden from any CPP compliance-related increase to ratepayer bills would likely fall to those with limited ability to react to higher gas costs. Staff further recognized that:

[6] Empower Dataworks, *Energy Burden Assessment* at 16; *see also* Testimony, *In the Matter of Avista Corporation, Request for a General Rate Revision,* Docket No. UG 461, July 7, 2023, at Staff Exhibit No. 302 (testimony of Scala).
[7] *See* Avista 2023 Integrated Resource Plan at 3-15.

> The rate pressure risk grows beyond just the increasing cost of compliance for the existing system. Customer migration to the electric system, due to any number factors, spreads the cost of gas infrastructure over a smaller customer base. The potential for a feedback loop emerges, where a shrinking customer count potentially accelerates cost pressures, which further motivates those customers that can leave to do so. This problem also calls into question annual expansion of the gas system, as each new customer not only brings increased CPP compliance obligations, but also more gas infrastructure for future ratepayers to cover.[8]

Staff is interested in further exploring how energy system planning can be informed by programs and regulatory tools that address these types of impacts. Staff would like to understand whether there is an opportunity for broader energy system planning to be informed by the type of data Avista has reviewed related to energy burden as well as Avista's own conclusions derived from the Company's LIRAP and AOLIEE programs. Staff does not have explicit requests for the Company at this time but will engage directly with the Company to learn more about its current energy burden study efforts and consider whether such learnings could inform future energy system planning efforts or possible future updates to the IRP Guidelines.

[8] Docket No. UM 2178, *Staff's Final Report*, Natural Gas Fact Finding per Executive Order 20-04, at 19 (Jan. 31, 2023).

Section 3: Load Forecast

Ryan Bain, Senior Utility and Energy Analyst

While Staff is generally comfortable with the Company's load forecast, an area of serious concern is the projection of future increased heating degree days that drive anticipated customer demand. This flaw in forecasting stands in the way of Staff recommending acknowledgement of the long-term plan.

Section 3.1 – Load Forecast

Staff is generally comfortable with the Company's load forecast approach, which is composed of a customer count forecast that is multiplied by an estimate of usage per customer to obtain overall demand for each customer category. The Company's econometric model is well vetted, but as the Action Plan notes, the Company will begin exploring the use of a statistically adjusted end-use (SAE) model in future IRPs to potentially better capture long-term trend drivers. Moving to an SAE model may provide a greater ability to understand the uncertain regulatory landscape through scenario analysis by improving the modelling of appliance efficiency and saturation trends, building thermal shells, and other demand drivers from the bottom up, as opposed to a top-down, macro-economic based model.

Customer Count Forecast

Avista's customer count forecast relies on macroeconomic variables and methodology which again Staff is generally comfortable with. But as the Company notes on page 'i' of their Executive Summary, regulatory uncertainty makes forecasting an accurate customer count an increasingly difficult exercise in the State of Washington, and likely also for Oregon. In future IRPs, the Company's scenario analyses should reflect the potential for future Oregon policies that might reduce customer count, such as the adoption of building codes mandating electrified space and water heating and reductions to line extension allowances.

Use Per Customer Forecast

Usage per customer (UPC) tends to be driven primarily by the weather, with heating degree days (HDD) driving increased usage above a baseline usage level. Staff is generally comfortable with the Company's approach to forecasting usage per customer. With respect to estimating the baseline and weather driven, HDD, usage per customer, Staff in Docket No. LC 75 recommended use of 5-years of Company data.[9] When comparing the UPC estimate using three years of data, Avista states that the recommendation to use five years of data in the UPC estimation could result in an under-forecast of over four million therms annually from 2023 to

[9] *See generally, In the Matter of Avista Corporation, 2021 Integrated Resource Plan,* Docket No. LC 75, Order No. 21-331 (Oct. 15, 2021).

2027.[10] For perspective, the four million therms in reduced usage, associated with the five years of company data, amounts to approximately 4 percent of historical annual retail sales and so is not an inconsequential amount.[11] As Staff supports a fully informed model, recent trends such as the onset of the COVID-19 pandemic represent a source of multicollinearity in modelling that may skew results incorporating both pre- and post-pandemic historical usage.[12] While at present, the estimation of demand coefficients using the limited three years of historical usage data may better capture current trends, this remains a topic of exploration by Staff. At this time Staff remains committed to using five years of data.

Section 3.2 – Climate Modeling

Along with estimating future customer counts and fitting weather-driven usage per customer, there is the issue of how to appropriately model future expected weather. Staff appreciates Avista's approach of incorporating climate models into the load forecast for this IRP. The Company's methodology, as currently implemented, uses a rolling average of the most recent 20 years of HDD data and uses the median daily average temperature from the Representative Concentration Pathway (RCP) 4.5 model to compare to the 20-year rolling average.[13]

While the RCP 4.5 model is reasonable for informing warming expectations, inadequate downscaling of regional weather from the RCP 4.5 model into local topography led to what Staff believes may be forecasting inaccuracy, especially when local topography is varied or complex. Staff finds that weather was not adequately downscaled and, given the complex topography of the Company's service territory, this introduced a "cold bias" that inappropriately forecasts cooler temperatures and increased HDDs for some service areas. For example, at the June 29, 2023, Special Public Meeting the Company presented HDD *increases* by 2045 of approximately 20 percent for the Medford service territory and approximately 28 percent for the Roseburg service territory.[14] These forecasts stand in stark contrast to general expectation of overall warming, observed trends in Oregon weather, and the weather forecast of the electric utility serving the same region of Oregon.

Staff notes this issue results in modest, near-term impacts (100-200 HDDs) over the next two to three years, the scale of which are likely to have negligible impact on the Company's Action Plan decisions. Over the near-term 2023-2025 horizon, the Company's methodology results in

[10] *See* Avista 2023 Integrated Resource Plan at 2-5.
[11] *See* Oregon Public Utility Commission 2021 Oregon Utility Statistics at 43 (updated Aug. 2023) (average of retail sales for 2017-2021) https://www.oregon.gov/puc/forms/Forms%20and%20Reports/2021-Oregon-Utility-Statistics-Book.pdf.
[12] *See* Avista Reply to Staff DR 18.
[13] This is similar to the process implemented by NW Natural to generate expected weather in LC 79, and Cascade Natural Gas' approach currently filed in LC 83.
[14] *See* Docket No. LC 81, *2023 Natural Gas Integrated Resource Plan (IRP) presentation* at 4 (June 29, 2023) (Medford is forecast an increase of approximately 850 HDD from a base of approximately 4,200 HDD. Roseburg is forecast an increase of approximately 1,100 HDD from a base of approximately 4,000 HDD.) available at, https://edocs.puc.state.or.us/efdocs/HAH/lc81hah105011.pdf.

an expected over-forecast ranging from 150,000 to 250,000 dekatherms, a roughly 1 percent error.[15] Staff is similarly concerned about potential impacts this weather modelling error may incorporate into the Peak Day forecast, but this issue remains to be fully evaluated.

Weather is a central component to the overall load forecast, and the load forecast is foundational to the load-resource balance and Action Plan. As discussed above, without correcting for this modeling error, Staff is concerned that by 2045 Avista's models project HDDs well in excess of a reasonable error of what a corrected model would project. Staff has serious concerns about the impact of this error in the out years of this IRP, as well as associated long-term investments and decisions based on the forecast as presented in this IRP.

Staff discussed its concerns with the Company and anticipates corrected modeling in the next IRP. Flawed climate modeling is the first of four major issues standing in the way of Staff recommending acknowledgement of the long-term plan.

Section 3.3 – Requests for Avista

Request for Next IRP 1: Avista's scenario analyses should reflect the potential for Oregon policies mandating electrified space and water heating, reductions in line extension allowances, and other such policies that might reduce customer count expectations.

Request for Reply Comments 2: Avista should detail what steps the Company will take in working with the Technical Advisory Committee (TAC) to correct the Company's approach to climate modeling so future IRPs use a credible forecast for modeling, long-term investments, and decisions.

[15] *See* Avista Reply to Staff DR 83.

Section 4: Demand-Side Resources

Nick Sayen, Senior Utility Analyst, and Claire Valentine-Fossum, Senior Energy Policy Analyst

Avista's Action Plan includes notable new program offerings for interruptible, transport, and low-income customers. Staff is generally comfortable with the energy efficiency potential modeled in the IRP, but is concerned about the decline in savings between this IRP and the 2021 IRP. The Company conducted its first natural gas demand response potential study, though demand response was not selected as a resource.

Avista developed a Building Electrification Proxy Cost and uses a methodology to model it in PLEXOS based on three pillars:

- *End use efficiency: the efficiency of the end use at providing for the customer's need;*
- *Conversion cost: the total cost estimate to convert from gas to electric; and*
- *Energy cost: the increase the ratepayer would pay toward their electric energy bill to power the new end use given the ratepayer's expected use.*

Avista made great strides in including electrification in its modeling, which Staff believes is a tremendous step toward understanding electrification as a potential compliance tool for meeting CPP. Staff finds, however, that Avista's application of a Building Electrification Resource, as conceived in the model, falls short of functioning as a proactive resource strategy, which is the direction the Commission would like to move towards. Further, Staff believes Avista may have erroneously applied electrification conversion values that represent appliance conversions costs from a gas home to a more efficient gas home, not to a home with efficient electric appliances.

Section 4.1 – Summary

In the 2023 IRP, Avista restates its commitment to offering energy efficiency programs and pursuing all cost-effective efficiency for the benefit of customers and the system.[16] As has previously been the case, the process for determining cost-effective efficiency is known as the Conservation Potential Assessment (CPA). Energy Trust of Oregon (Energy Trust) handles the CPA analysis and program delivery for Oregon. Once Energy Trust has developed the Oregon CPA, estimated results are decremented from Avista's load forecast. As the model changes with updated assumptions and costs, avoided costs are revised. Avista and Energy Trust use the Total Resource Cost test to determine measure eligibility in Oregon.

Staff's demand-side topics focus on the following: Oregon efficiency potential; additional program offerings; demand response programs; and building electrification. Avoided costs are discussed further in Section 7. Targeted energy efficiency offerings as part of non-pipe alternatives are discussed further in Section 5.

[16] *See* Avista 2023 Integrated Resource Plan at 3-1.

Section 4.2 – Oregon Efficiency Potential

Table 3.10 on page 3-10 of the IRP shows the 20-Year cumulative savings potential for Oregon, broken down by customer. The table further breaks down the savings by *type* of potential, moving from technical potential (the greatest amount), to achievable potential, to cost-effective achievable potential, to Energy Trust Deployed Savings Projection (the smallest amount). The total cost-effective achievable potential is 21.6 million therms, while the Energy Trust Deployed Savings Projection is 15.3 million therms. When presented at the June 29, 2023, Special Public Meeting, the Commission discussed the drop from cost-effective achievable potential to the Energy Trust Deployed Savings Projection.[17]

Following the June Special Public Meeting, Staff engaged Energy Trust to better understand this drop in potential. Staff learned that adjusting potential from cost-effective achievable down to a deployed savings projection is a result of Energy Trust's analytical processes and has been historically present in IRP analysis and forecasting. However, 2023 IRP planning included unique drivers, which may have contributed to a slightly larger adjustment than in the past. One example of these unique drivers is emerging technology, specifically gas heat pump water heaters. Energy Trust's analysis identified this technology as cost-effective. However, Energy Trust did not include most of the savings from this technology in the deployed savings projection, because it has not been proven to be effective and the market mechanisms to disseminate the technology are not yet in place.

Staff notes the topic of Energy Trust's energy efficiency potential of gas heat pump space and water heater technologies was raised by the Oregon Citizens' Utility Board (CUB) in its Opening Comments in LC 79. CUB raised concerns about discrepancies between forecasted total cumulative savings for these technologies, as provided by Energy Trust, and more optimistic forecasts of technology adoption NW Natural used in its modeling. Upon review, it appears that Avista's modeling makes no modifications to the values provided by Energy Trust. Staff appreciates engagement and follow up from Energy Trust on this topic.

Staff is concerned about the overall decline in savings between IRPs. Avista and Energy Trust should clarify in Reply Comments why the cumulative, 20-year savings potential drops from 18 million therms in the 2021 IRP (LC 75) to 15.3 million therms in this IRP. A more robust explanation would make Staff feel more confident in the amount of Oregon efficiency potential included in Avista's 2023 IRP.

Section 4.3 – Additional Program Offerings

Interruptible Customers and Transportation Customers

Avista has not previously offered carbon reduction programs, via energy efficiency for interruptible or transport customers. However, in preparing the 2023 IRP the Company

[17] *See* Docket No. LC 81, *2023 Natural Gas Integrated Resource Plan (IRP) presentation* at 9 (June 29, 2023) available at, https://edocs.puc.state.or.us/efdocs/HAH/lc81hah105011.pdf.

engaged Energy Trust on this topic, and in March 2023 Energy Trust began offering an efficiency program to Avista's interruptible commercial and industrial customers.

Avista continued to work with interested parties to determine appropriate efficiency programs for transport customers, and in July Avista was granted a waiver to allow the transfer of transportation customer information to the Energy Trust. The customer information will enable Energy Trust to design and run conservation programs for its transportation customers.[18]

Interruptible and transport customers' energy savings potential is presented in the IRP and is included in the overall Oregon potential.

Low-Income Customers

Avista works with Community Action Agencies to implement the Company's AOLIEE Program. As noted in Section 2.1, Avista engaged these and other stakeholders, Energy Trust, and a consultant, Empower Dataworks, to complete an Energy Burden Assessment. This Assessment led to modifications to the AOLIEE Program for 2023 intended to expand the reach of the existing program and to prioritize energy burdened customers within these communities.[19]

Low-income customers' energy savings potential is presented in the IRP and included in the overall Oregon potential.

Staff appreciates the development and launch of new programs, as well as revisions to existing programs, to achieve more efficiency savings and to serve additional customers. In Reply Comments Avista should provide an update on the development of all new program offerings, including timelines for implementation, and if the Company has thoughts on achieving the saving projected for 2023, and the building of programmatic infrastructure to ramp up to the greater savings forecasted for 2024.

Section 4.4 – Demand Response and Interruptible Programs

For the 2023 IRP, Avista performed the Company's first natural gas demand response potential study for Avista's Oregon, Washington, and Idaho service territories. The study considered five offerings for residential, commercial, and industrial customers: smart thermostats for direct-load control, contracting directly with customers for firm curtailment, a behavioral program, and two pricing programs, time of use rate and variable peak pricing.

The study made assumptions about critical program parameters (such as average load reduction, event duration, etc.) and resulted in potential demand savings and total cost estimates for each program. Staff notes that both the behavioral and pricing offerings required Advanced Metering Infrastructure (AMI) as an enabling technology. Currently only Washington

[18] *See In the Matter of Avista Corporation Request for Waiver of OAR 860-0086-0040(2)(j), Gas Utility Customer Information and Transfer of Data,* Docket No. UM 1631, Order No. 23-253 (July 13, 2023).
[19] *See* Docket No. ADV 1452, *Advice No. 22-11-G – Avista Utilities' Revisions to Schedules 469 and 485* (Nov. 15, 2022).

customers have AMI. Logically, this requirement either eliminates Oregon and Idaho customers as eligible participants or includes substantial capital costs for AMI deployment, making such offerings highly unlikely to be cost-effective.

While demand response was not selected by the model for the Oregon PRS, Staff is interested in the potential for smart thermostat direct load control and contracting with customers for firm curtailment as strategies for mitigating distribution system investments. This interest is underscored by the Commission's Order No. 23-281 in NW Natural's 2022 IRP. This Order included direction on several issues pertaining to demand response, including but not limited to:

- Acknowledging NW Natural's plans to scope a residential and small commercial demand response program by 2024, conditional to coordination with any future targeted demand response efforts; and
- In future IRPs, when NW Natural is monitoring areas in the distribution system where system reinforcements may be needed in the future, whenever possible, ample time (suggesting at least five years) should be allowed for evaluation and analysis of targeted demand response.

Targeted demand response programs are discussed more in Section 5.

Finally, Staff is interested in learning about how Avista engages its *current* interruptible customers. Staff submitted data requests to better understand how the Company conceives of this resource, as well as current program characteristics.[20]

Section 4.5 – Building Electrification Methodology and Impacts

Summary

Unique to this IRP filing, Avista includes electrification of major end-uses as a new resource option in the PLEXOS model. Staff is grateful for the Company's willingness to engage on this challenging modeling element and sees Avista's efforts as advancing the understanding around electrification considerations in gas and electric IRPs. Staff finds, however, that the resource option as configured by Avista is not a proactive resource strategy for the utility to undertake in portfolio optimization as the electrification resource option is representative only of customer reactions to prices. Further, Staff believes the Company erroneously use home conversion values of converting a gas home to a more efficient gas home, rather than to an electric one.

Avista incorporates electrification as a *resource option* for residential and commercial customers, rather than including electrification as a fuel-switching component of the demand forecast. Avista's methodology, as described below, attempts to estimate the cost to electrify major building end-uses, *e.g.*, space heat, water heat, and other uses, like cooking and clothes drying, as a resource input comparable to other supply-side resources. Avista included three

[20] See Staff DR 86.

electrification resource options in the PLEXOS model, separated by customer type, class, and major-end use. Avista includes each resource option as a unique supply-side resource in the model, rather than a combination of the end-uses or customer classes. The goal was to create proxy costs for use in PLEXOS' stochastic analysis (herein referred to as Building Electrification Proxy Cost). Like energy efficiency, when the model selects Building Electrification, it selects that option for the entirety of the planning horizon and reduces natural gas demand for the corresponding time period.

In general, resource cost was the primary consideration when evaluating resource options in Avista's IRP. Unlike gas resource options, which only account for the price of daily fuel supply, the Building Electrification Proxy Cost is the build cost of electrification. Avista notes that estimating a Building Electrification proxy cost is a complex analysis as costs vary by structure size, efficiency, shell efficiency, and geographical location with respect to weather. Discussions on development of this proxy cost revealed that the copious assumptions and uncertainties underlying the Building Electrification Proxy Cost was not lost on Avista. Company personnel noted that a lack of information made estimating the pillars of the proxy cost difficult. Avista further recognized that a changing policy and technology landscape will add new uncertainties in the planning horizon.

Staff understands Avista's Building Electrification Proxy Cost computation to include the following steps:

1. Calculate gas use per customer (gas demand BBtu/gas customer).[21]
2. Convert daily efficiency of gas end-use (therm) to electric end-use (kWh).
3. Estimate the costs of an electrification retrofit including interest payments of a 5-year loan to pay for the retrofit.
4. Calculate rate impact by service area and customer class. This includes additional supply resources and T&D costs for electric service.
5. Amortize total electrification costs per year over the planning horizon.

In this respect, the methodology of Avista's Building Electrification Proxy Cost, as used by the PLEXOS, model rests on three pillars:

- End use efficiency: the efficiency of the end use at providing for the customer's need (i.e., for space heat, the efficiency of the appliance at heating the home);
- Conversion cost: the total cost estimate to convert from gas to electric; and
- Energy cost: the increase the ratepayer would pay toward their electric energy bill to power the new end use given the ratepayer's expected use.

Avista combined the assumptions of each pillar, discussed in more detail below, to provide a proxy cost for each customer's electric end-use model input.

[21] Unit of demand in Avista worksheet is BBtu.

End Use Efficiency

The first pillar of the Building Electrification Proxy Cost is the energy efficiency of the end-use, i.e., the electric appliance. The assumption here is that, as electric appliances are more efficient than gas appliances, the customer will use less energy to meet their needs. Avista calculates the value for end use efficiency using Energy Trust's CPA study, demand variability, and temperature. Avista estimates monthly customer use of the gas appliance in therms and technology efficiencies based on weather, customer class, and end-use. Avista then uses the conversion coefficient to estimate the daily efficiency gained from the gas to electric switch. The efficiency value in kWh for each end use/customer class is included as a monthly average in the Building Electrification Proxy Cost.

Conversion Costs

The second pillar of the Building Electrification Proxy Cost is the conversion cost from gas to electric for each major end-use. Avista's estimated conversion costs are comprised of three assumptions – Home conversion costs, IRA incentive discount, and loan terms:

- First, Avista assumes an estimated cost to transition gas equipment and appliances to electric. This retrofit assumption included costs for demolition, installation labor, and materials. The estimated costs come from values from the Home Innovation Research Labs 2021 report "Cost and Other Implications of Electrification Policies on Residential Construction."[22] These costs taken from the Home Innovation Research Labs report, however, are not the costs to convert a gas home to an electric home, but the costs to upgrade a gas home from old gas appliances to new more efficient gas appliances, as depicted in Figure 1 below.[23] Staff confirmed that the values from of this gas-to-gas table are the same gas upgrade costs used as inputs to form the capital investment assumption for the electrification conversion costs calculations provided in the IRP supporting files.[24] The Home Innovation Research Labs report includes figures to convert from a gas home to an electric home in Appendix B of the report. These electrification figures show the retrofit costs twice as much as the total cost to switch out gas appliances for more efficient gas appliances. Staff has not yet had an opportunity to discuss this finding with the Company to see if there were other reasons for relying on these values.
- Staff notes that using these gas-to-gas costs, rather than electrification costs, as the basis for the electrification conversion costs underscores the uncertainty of the data the

[22] HOME INNOVATION RESEARCH LABS, Cost and Other Implications of Electrification Policies on Residential Construction (Feb. 2021).

[23] This table shows the conversion of a baseline gas house to a high-efficiency gas house. It showed the conversion to a 96 percent efficient gas furnace (96 AFUE GF); a 16 Seasonal Energy Efficiency Ratio air conditioning (16 SEER AC); and 93 percent efficient tankless condensing water heater (0.93 UEF WH). The table does not include a heat pump conversion.

[24] *See* Avista 2023 Integrated Resource Plan, Final IRP Supporting Files, *Home Electrification Conversion (macro) 1.07* workbook at Assumptions worksheet.

Company used and the risk that the final Building Electrification Proxy Cost does not accurately represent electrification prices comparable to those of competing resources.

- Avista notes a wide variability of conversion costs by study, location, building size, and structure. To account for variability, the Company used 50 percent of the cost for the low-cost conversion, and 150 percent for the high-cost conversion for the high-cost conversion. Avista notes that, unlike other reports, the Home Innovation Research Labs 2021 report has the benefit that it was produced for the industry building homes rather than utilities or government agencies. In response to Staff DR 50, Avista notes that the Home Innovation Research Labs 2021 report may underestimate costs as "other studies point to higher conversion and equipment costs as compared to the one used in this IRP. Supply chain issues to acquire these materials, available skilled labor to perform this work, and permitting are additional costs at risk."

Figure 1: Estimated Conversion Costs from Home Innovation Research Labs, Cost and Other Implications of Electrification Policies on Residential Construction Figure 3.6 in Avista's IRP

Retrofit Cost of Gas Equipment and Appliances for an Existing Gas Baseline House: 96 AFUE GF; 16 SEER AC; Tankless Condensing 0.93 UEF WH

Component	Unit	Material	Labor	Total	w/O&P	Quantity	Cost
Demo and Install GF, labor	EA				377.00	1	377
Demo and Install AC system, labor	EA				943.00	1	943
Demo and Install WH, labor	EA				499.00	1	499
Reclaim old refrigerant	LB		8.40	8.40	13.75	5	69
Install new Refrigerant piping	EA	204.00	21.50	225.50	261.00	1	261
GF materials, est.	EA	200.00		200.00	220.00	1	220
AC materials, est.	EA	200.00		200.00	220.00	1	220
WH materials, est.	EA	100.00		100.00	110.00	1	110
96 AFUE GF	EA	1,295.00		1,295.00	1,424.50	1	1,425
GF Vent piping, PVC, 2" dia.	LF	3.45	2.97	6.42	8.65	40	346
GF 2" concentric vent kit	EA	59.95		59.95	65.95	1	66
16 SEER AC	EA	1,346.00		1,346.00	1,480.60	1	1,481
Coil	EA	439.00		439.00	482.90	1	483
Tankless condensing 0.93 UEF WH	EA	1,039.00		1,039.00	1,142.90	1	1,143
WH Vent piping, PVC, 2" dia.	LF	3.45	2.97	6.42	8.65	20	173
WH 2" PVC concentric vent kit	EA	22.49		22.49	24.74	1	25
WH Gas piping, 1"	LF	7.80	6.15	13.95	18.60	7	130
WH 15-amp circuit, toggle, 40' #14/2 NM	EA	57.00	83.50	140.50	199.00	1	199
WH GFCI 15-amp, 1-pole breaker	EA	41.99		41.99	46.19	1	46
Remove and install range, labor	EA				138.00	1	138
Remove and install dyer, labor	EA				297.90	1	298
Gas Range	EA	542.00		542.00	596.20	1	596
Gas Dryer	EA	528.00		528.00	580.80	1	581
Total to Remodeler							**9,828**
Total to Consumer							**12,786**
Houston						0.99	**12,658**
Baltimore						1.02	**13,041**
Denver						1.05	**13,425**
Minneapolis						1.00	**12,786**

- Second, Avista assumes a 50 percent discount to the retrofit cost from potential incentives and grants, such as those from the IRA.
- Third, Avista assumes a five-year loan with a 6.1 percent interest rate to cover the final cost of the retrofit.

Energy Costs

The third pillar of the Building Electrification Proxy Cost is the estimated increase to the customer's bill for the additional electric service. PacifiCorp provides electric service to Avista's gas customers in Roseburg, Medford, and Klamath Falls. Oregon Trail Electric Co-Op provides electric service to Avista's gas customers in La Grande. The electric rate forecasts for PacifiCorp

and Oregon Trail Electric Co-Op are not available to Avista;[25] accordingly, in lieu of using these unavailable rates, Avista used its own electric rate increase (Blended Power Cost and T&D Rate) as used by Avista Utilities' Washington electric branch to forecast an electric bill increase to its Oregon gas customers (WA-Avista electric rate increase). Next, Avista raised PacifiCorp's existing rates by the WA-Avista electric rate increase. This returned an assumed electric rate for PacifiCorp across the planning horizon, i.e., the third pillar in the Building Electrification Proxy Cost.

Rate Impact

Avista used the results of the above assumptions to forecast a rate impact.[26] In meeting with Staff, Avista noted that the assumed electric rate for PacifiCorp was highly variable, as Avista's Washington electric generation was "cleaner" than PacifiCorp's electric generation. Avista further noted that increased demand coupled with PacifiCorp's need to meet decarbonization requirements would likely increase rates for PacifiCorp and Oregon Trail Electric Co-Op customers beyond what Avista had forecasted.

Staff also notes that Avista's Building Electrification Proxy Cost includes electric distribution system upgrade costs, embedded in the electric rate forecast. This contrasts with supply side resources which rely on the pipeline distribution systems to serve customer end uses, but for which future distribution system cost, as embodied by customer growth, are excluded from the PLEXOS optimization.

Staff Review

In LC 79, the Commission found that electrification of end-uses should be evaluated in gas IRPs as a valid method of achieving CPP compliance.

> Although there is little dispute that electrification—both driven by external policies and that driven by an elasticity response to the cost of natural gas service—should be evaluated as an external factor influencing load forecast scenarios, there are significant questions about the degree to which and the methods by which gas IRPs should be required to model electrification as a proactive resource strategy.[27]

Following issuance of this order, Staff met with Avista to discuss the Company's Building Electrification Proxy Cost. Staff appreciates the Company taking the time to meet with Staff on this important topic in resource planning for natural gas IRPs.

Staff appreciates that the Company has made strides to include electrification as a resource in this IRP. Despite what appear to be critical flaws in the values used for the Building

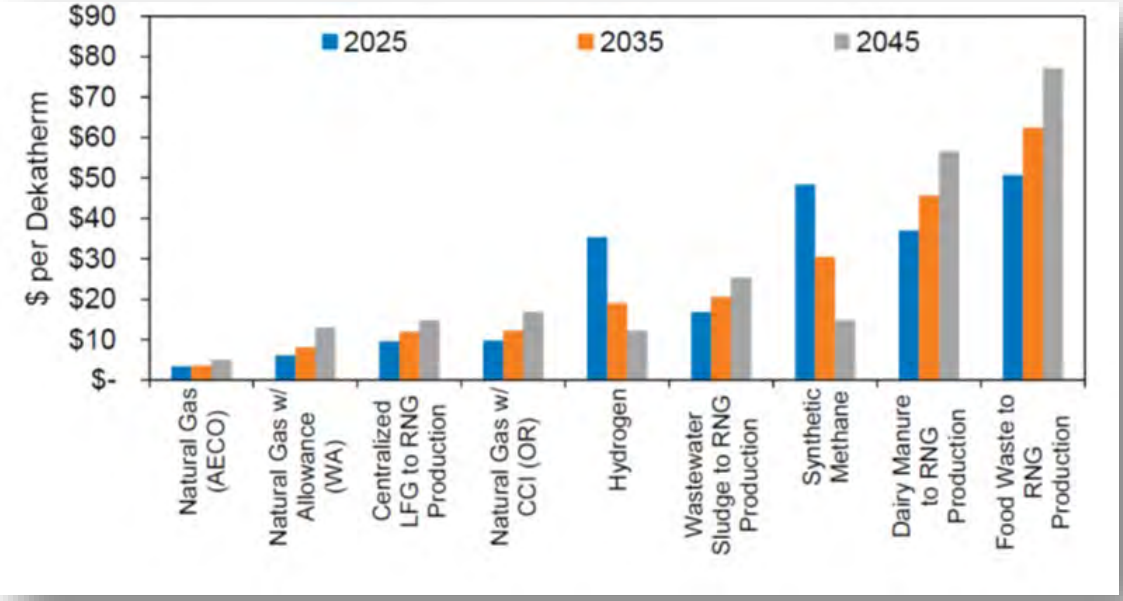
[25] In meeting with Staff, Avista requested that PacifiCorp share its internal forecasted rates in the future with gas utilities to reduce this uncertainty of planning for electrification as a resource option.
[26] Figure 3.8 of the IRP shows the base conversion cost for the retrofit coupled with the weather dependent energy cost for Washington residential space heat from 2023 to 2024.
[27] Order No. 23-281, p. 9-10.

Electrification Proxy Cost, Staff looks forward to working with stakeholders and the Company to refine this approach for the next IRP. Staff does have concerns, however, about how the Building Electrification Proxy Cost was applied in the Company's modeling.

Staff finds that Avista's method to model electrification is not a proactive resource strategy, but rather representative only of customer reactions to prices. As discussed above, Avista uses the Building Electrification Proxy Cost as the electrification resource input in PLEXOS when solving for energy demand and emissions goals. Building Electrification only enters the resource mix as a price elasticity indicator, that is, electrification is not modeled as a viable compliance resource for the utility, but an escape hatch for the gas customer when gas prices rise above a certain threshold.

Figure 2 depicts the gas resource options and costs to the company paid by the ratepayer.

Figure 2: Resource Options and Costs in PLEXOS Model - from Avista's IRP Figure 6.16



The Building Electrification Proxy Cost is not included in this figure. Were it depicted; it would be on the right side. This is because the Building Electrification Proxy Cost is not a cost to the company, but an investment made by the customer in their home or business. In other words, electrification is not modeled as supply cost to the utility, but as a build cost to the customer. To be properly included in this figure, the electrification resource cost would need to be calculated on a level field with the other resource options, that is, as an option available as a cost to the company.

In this respect, Staff found that a proactive resource strategy would consider whether it would be cheaper for the Company to incentivize gas customers to electrify than for the Company to

select a gas resource option. For example, energy efficiency is allowed to compete in price and resource strategy. Energy efficiency is selected where it would be cost effective to reduce customer demand to avoid additional utility costs, including compliance costs.

In a similar manner, the Building Electrification Proxy Cost should be allowed to compete in price and resource strategy. Currently, the proxy represents the cost for the ratepayer to retrofit their home, not the cost to incentivize the ratepayer to fuel-switch. The cost to incentivize the ratepayer to fuel-switch includes price and resource strategy. For example, an incentive of $1,000 to invest in a heat pump may be the tipping point for the gas customer to make the fuel switch to electric space heat. In this case, the Building Electrification Proxy Cost would be based on the tipping point financial incentive rather than the conversion cost to electrify space heat.

This proxy cost can be demonstrated with a demand curve based on incentives to electrify appliances. In practice, this could show up as a compliance strategy whereby the gas utility selects the least cost resource to meet demand and emissions requirements, among Community Climate Investments (CCIs) and decarbonized fuels like RNG and synthetic methane, and then, PLEXOS can chose to pay customers the incentive to electrify appliances or paying a penalty to comply with the CPP. In other words, a compliance strategy may need to reduce gas demand to comply - or face a penalty. The appropriate cost to model demand reduction is the *incentive cost* for the customer to electrify appliances, not the entire *retrofit cost* for the customer's home.

Of course, this strategy raises important questions such as whether a gas company can subsidize away demand if that strategy produces the least cost, least risk portfolio. And whether the cheapest way to meet compliance requirements is to pay customers to exit the gas system.

Finally, the Building Electrification Proxy Costs appear to only represent instances of customer conversion of an existing home or existing commercial operation from gas to electric. If this is correct, Avista's proxy cost would overestimate the cost to electrify new residential or new commercial construction (notwithstanding the errors in the values used). Further, any incentive to move customers to choose electrification *prior to* constructing a new home or commercial space will most likely be less than the incentive necessary for existing gas customers to choose to convert an existing home or commercial building from gas to electric. Staff recognizes valuation, modeling, and practical challenges of considering these avoided compliance cost impacts and welcomes feedback from stakeholders.

In Reply Comments, Avista should detail initial steps the Company will take in working with the TAC and Staff to further explore the modeling of electrification as a proactive resource strategy.

Section 4.6 – Requests for Avista

Request for Reply Comments 3: Avista should clarify why the cumulative, 20-year savings efficiency potential drops from 18 million therms in the 2021 IRP to 15.3 million therms in this IRP.

Request for Reply Comments 4: Avista should provide an update on the development of all new program offerings, including: timelines for implementation, the Company's thoughts on achieving the saving projected for 2023, and the building of programmatic infrastructure to ramp up to the greater savings forecasted for 2024.

Request for Reply Comments 5: Avista should discuss whether it intended to apply gas-to-gas costs as electrification conversion values, and if so, why that approach is reasonable.

Request for Reply Comments 6: Avista should respond to Staff's concerns about its use of gas to gas conversion costs in its modeling, and detail initial steps the Company will take in working with the TAC and Staff to further explore the modeling of electrification as a proactive resource strategy, and the differences between electrify existing and new construction.

Section 5: Distribution System Planning

Nick Sayen, Senior Utility Analyst

Avista's Action Plan does not foresee supply side or distribution resource additions needed in its Oregon territory in the next four years, providing a unique opportunity to respond to the Commission's interest in more forward-looking distribution system planning to better consider non-pipe alternatives on sections of utility infrastructure currently being monitored for future upgrades.

Section 5.1 – Summary

Avista discusses core aspects of its distribution system planning, noting, for example, there are two primary types of evaluations: capacity requirements, which may necessitate reinforcements or expansions due to new demand, and integrity assessments due to maintenance needs.[28]

In the 2021 IRP, and again in the 2023 IRP, two possible city gate station upgrade projects were identified in Oregon, in Medford and Sutherlin. The scope, cost, and timing of the Oregon projects are still to be determined. The IRP states that projects in the TBD category "have relatively small capacity constraints, and thus will be monitored. There are no plans to rebuild or upgrade TBD city gate stations at this time."[29] The 2023 Action Plan notes that based on current projections, no supply side or distribution resource capital additions need to be added in Oregon for the next four years.[30]

In addition to the Medford and Sutherlin projects discussed above, the 2021 IRP included a third Oregon project in Klamath Falls. Action Item 6 from the 2021 IRP was to provide an update on Oregon distribution projects to understand unexpected potential capital costs. Avista has been meeting regularly with Staff to provide updates, as part of the quarterly Purchase Gas Adjustment (PGA) meetings. Staff recommends Avista also include the latest information on distribution projects in future IRP Updates.

Staff notes Avista considered a need for a fourth Oregon project near Roseburg in the 2021 IRP,[31] which was not included in the 2023 IRP.[32] Staff has submitted data requests to better understand the circumstances of this project.[33]

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[28] *See* Avista 2023 Integrated Resource Plan at 8-1.
[29] *See* Avista 2023 Integrated Resource Plan at 8-9.
[30] *See* Avista 2023 Integrated Resource Plan at 9-6.
[31] *See In the matter of Avista Corporation, 2021 Integrated Resource Plan*, Docket No. LC 75, 2021 Integrated Resource Plan at 170, table 8.2 (March 26, 2021) (Melrose #2608 Gate Station, City Gate Station Upgrades).
[32] *See* Avista 2023 Integrated Resource Plan at 8-9, table 8.2 (City Gate Station Upgrades).
[33] See Staff DR 84.

Section 5.2 – Conservation and Non-pipe Alternatives (NPA)

The IRP states the Company's approach to considering conservation in distribution planning:

> The evaluation of distribution system constraints includes consideration of targeted conservation resources to reduce or delay distribution system enhancements, and while Avista does not depend on energy efficiency to address near-term system constraints however, the Company notes that over the longer-term, targeted energy efficiency may provide a benefit to offset potential constraints.[34]

Additional examples of NPA's include raising the existing pipeline pressure, demand response, and electrification of gas appliances. The IRP includes Avista's current parameters for considering non-pipe alternatives.[35] These include:

- Consideration against capacity reinforcements not related to safety, compliance, or road moves;
- Consideration when the upgrade cost is high enough to allow the possibility for the alternative to be cost-effective, parenthetically noting greater than $500,000, and when the cost of the alternative is lower than the cost of the reinforcement;
- Whether a NPA can be accomplished prior to when the upgrade is necessary;
- Whether NPAs can lead to demand reduction sufficient to defer the need

Order No. 23-281 in NW Natural's 2022 IRP included direction to NW Natural on several issues pertaining to gas company distribution planning, including but not limited to:

- Future distribution system planning should include a cost benefit analysis for non-pipe alternatives that reflects an avoided GHG compliance cost element consistent with a high-cost estimate of future alternative fuels prices.
- Future IRPs should include a database containing information about feeders, in service dates of pipes, and lowest recent observed pressures.
- In future IRPs, when a gas company is monitoring areas in the distribution system where system reinforcements may be needed in the future, whenever possible, ample time (five years) should be allowed for evaluation and analysis of targeted energy efficiency and target demand response, among other alternative solutions.

Staff notes that a minimum five-year analysis identified in this Order provides guidance on appropriate near-term and longer-term timeframes which Avista discussed in its approach to conservation in distribution planning.

In Reply Comments, Staff is interested in understanding the implications of Order No. 23-281 on Avista's current distribution system planning practices. For example, how might Avista include analysis of these evaluation elements in future IRPs or IRP Updates for the four Oregon

[34] *See* Avista 2023 Integrated Resource Plan at 8-5.
[35] *See* Avista 2023 Integrated Resource Plan at 8-9.

city gate projects discussed in Section 5.1. Staff would also like the Company to discuss how demand response offerings fit into its consideration of targeted conservation resources.

Section 5.3 – UG 461 and Line Extension Allowance

Staff understands that Parties recently reached a Second Settlement Stipulation Resolving All Remaining Issues in Avista's current rate case (Docket No. UG 461) and that this stipulation addressed line extension allowances. Specifically, item 14:

> 14. Line Extension Policy: The Parties agree that Avista's line extension allowance for connecting new customers would be $2,500 in 2024, $1,250 in 2025, $750 in 2026, and $0 in 2027. In its Compliance Filing, Avista will file revised tariffs (Rule 15 and Rule 16) effectuating this change.[36]

Staff is interested in learning how and if this change to line extension allowances may impact the Company's revenue requirements and scenario analysis in future IRPs. As a principle for portfolio analysis, all costs should accurately reflect investment changes between portfolios, especially portfolios with different load forecasts. In a scenario with load decreasing, the number of new distribution system upgrades would also be decreased, as compared to a scenario with load growth. Staff is unclear if Avista's approach to portfolio analysis can capture this difference, as we believe it should.

Section 5.4 – Requests for Avista

Request for Reply Comments 7: Avista should comment on including the latest information on distribution projects in future IRP Updates.

Request for Reply Comments 8: Avista should discuss how Order No. 23-281 may impact Avista's current distribution system planning practices. For example, by including analysis of evaluation elements in future IRPs or IRP Updates for Oregon city gate projects, how current targeted conservation resource practices may change, and how demand response offerings fit into its consideration of targeted conservation resources in the future.

Request for Reply Comments 9: Avista should discuss how and if the change to line extension allowances agreed to in the UG 461 Stipulation may impact the Company's revenue requirements, and scenario analysis in future IRPs.

[36] *In the Matter of Avista Corporation, Request for a General Rate Revision,* Docket No. UG 461, Second Settlement Stipulation Resolving All Remaining Issues (Aug.3, 2023).

Section 6: New Supply-Side Resources

Charles Lockwood, Utility and Energy Analyst

Avista's cost assumptions for decarbonized fuels both reflect federal incentives and are conservative relative to other Oregon natural gas utilities. However, they play a significant near term and rapidly increasing role in the PRS that appears unrealistic and costly.

Section 6.1 – Hydrogen and Synthetic Methane

Avista's expected costs for green hydrogen and synthetic methane show significant decreases through 2045. Avista projects that green hydrogen costs will fall from $35.43/Dth in 2025 to $12.19/Dth in 2045, and synthetic methane costs will fall from $48.35 in 2025 to $14.84/Dth in 2045. Recent studies and legislation provide some insight into the possible future cost trajectories of these technologies, and the accuracy of Avista's estimates.

While Staff's comments discuss the supply cost trajectories and availability of green hydrogen, Avista does not utilize the resource in the Company's Oregon PRS. Instead, the Company relies on synthetic methane, which is created via a form of carbon capture, either directly from the air or from waste combining with green hydrogen. Avista chooses to rely on synthetic methane instead of green hydrogen, as synthetic methane uses a 1:1 space for pipeline transportation or energy delivery per dekatherm, as compared to green hydrogen. Further, green hydrogen's energy to volume ratio is roughly one-third of the Btu content per volume as other resources. Therefore, Staff's discussion of the implications of green hydrogen procurement is germane to this IRP, even if the Company does not utilize the resource in its mix.

Green Hydrogen

Avista utilized three studies to determine the cost of green hydrogen in its modeling. These studies were conducted by Lazard, Black & Veatch, and Bloomberg.[37] After reviewing each of the associated studies, Staff finds that each of the organizations is generally considered an independent organization, and Avista considered each study in modeling its overall green hydrogen costs.

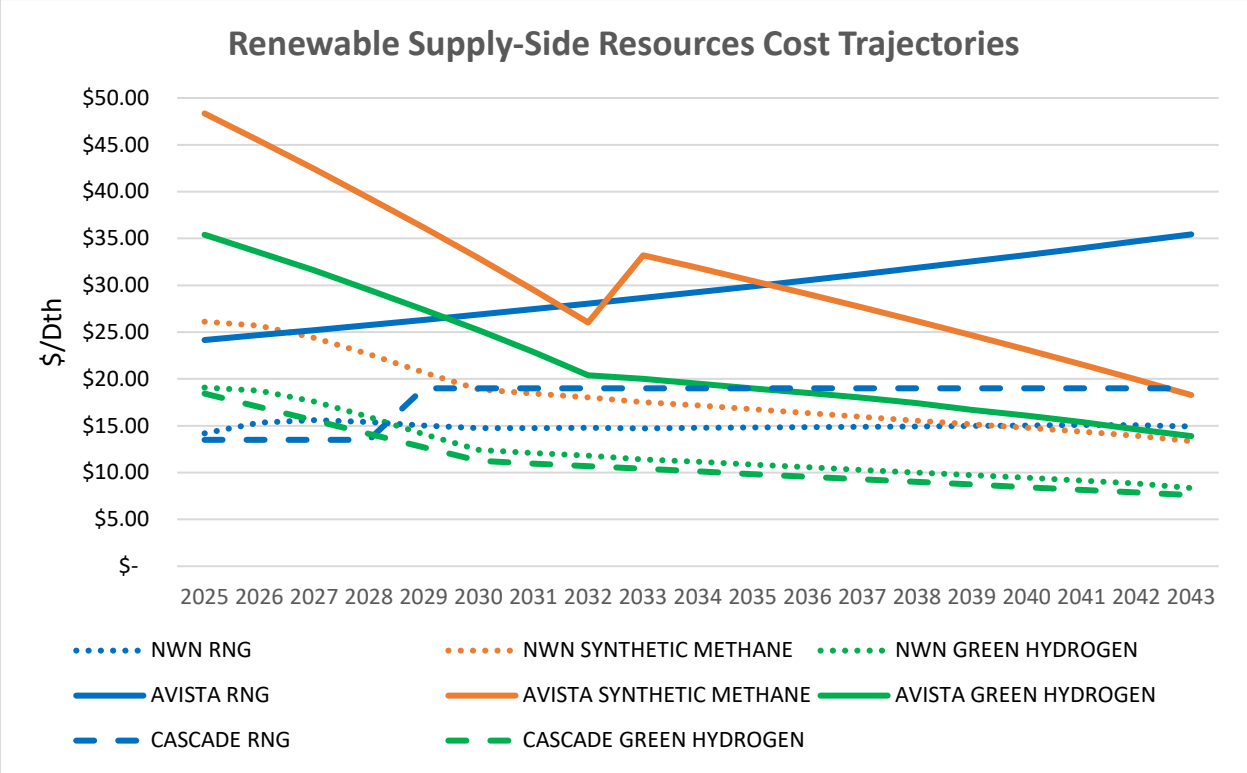
Additionally, before the filing of the IRP, Congress enacted the Infrastructure Investment and Jobs Act (IIJA) (November 2021) and Inflation Reduction Act (IRA) (August 2022). Avista's costs for hydrogen and synthetic methane reflect the anticipated effects of these policies, which include measures designed to significantly and quickly reduce the cost of alternative fuels.

Avista's cost trajectories can also be compared to other Oregon natural gas utilities' cost trajectories based on recent IRP filings. After reviewing both NW Natural and Cascade's most recent cost projections for all new supply-side renewables, not just green hydrogen, Avista's

[37] *See* Avista 2023 Integrated Resource Plan at 4-23; *see also* Avista Reply to Staff DR 9.

projections appear the most conservative. These are demonstrated in the Staff generated chart below.

Figure 3: Comparison of Renewable Supply-Side Resource Cost Trajectories



Overall, Staff has lingering concerns surrounding Avista's green hydrogen cost assumptions and projections. There are also serious questions surrounding the resource's ability to be produced on a large enough or cost-effective scale, as noted by Avista in its IRP.[38] This concern is compounded by the Company's heavy forecasted reliance on synthetic methane, which requires green hydrogen to be produced.

Staff's Final Comments in Docket No. LC 79 emphasized the need for clear documentation of translating the third-party studies to a hydrogen price forecast that reflected NW Natural's unique circumstances.[39] Staff maintains this principal when reviewing Avista's resource cost projections. Currently it is unclear to Staff how Avista translated the three studies to project the cost of green hydrogen, and therefore, Staff requests that Avista explain how the Company translated the information in these studies to its pricing. The need for transparency in the pricing of green hydrogen is emphasized by the Company's usage of synthetic methane, which is already fickle due to the changing cost of carbon capture.

[38] *See* Avista 2023 Integrated Resource Plan at 4-23.
[39] *See e.g., In the Matter of Northwest Natural Gas Co., 2022 Integrated Resource Plan*, Docket No. LC 79, Staff's Final Comments (March 30, 2023).

As mentioned above, Avista's cost projections are informed by three different studies, one from 2021 from Lazard, one from 2018 from Black & Veatch, and one from 2020 from Bloomberg, each of which includes different sensitivities and pricing assumptions to forecast green hydrogen pricing.[40]

Avista's first study, Lazard's Levelized Cost of Hydrogen Analysis employs a simplified methodology based on market data for low, medium, and high efficiency electrolyzers across several capacities and changes in the cost of electricity. Avista's second study, prepared by Black & Veatch, an independent engineering, procurement, consulting, and construction company with a focus on sustainable infrastructure, provides Avista with more information on performance and costs of hydrogen production for water electrolysis.[41] The study provides forecasted pricing for both distributed and centralized green hydrogen production, specifically providing cost estimates for capital, fixed and variable O&M, electricity, etc. Avista's third study, the Bloomberg Hydrogen Economy Outlook, provides a more direct lens at green hydrogen pricing, particularly the study forecasts pricing and availability given varying transportation, storage, and procurement methods. However, after reviewing each of the three studies, Staff remains unsure of how the Company used the three studies to create its cost projections.

Staff recognize the importance of green hydrogen and other fuel sources to help solve energy needs, however, Staff wants to ensure that these resources are vetted thoroughly to protect ratepayers and ensure reliable service. Therefore, Staff requests that Avista address in its Reply Comments the translation of the studies into the Company's price assumptions and how the Company modeled or otherwise addressed future price and availability uncertainty.

Synthetic Methane

Synthetic methane is emerging as an option for cleaner supply side resources. Avista describes synthetic methane as the preferred resource over hydrogen because of its ability to function exactly as fossil methane. This is unlike hydrogen, which among other challenges, has an energy to volume ratio is roughly one-third of the BTU content per volume as natural gas, RNG, or synthetic methane.[42]

The process for creating synthetic methane relies on combining captured carbon dioxide with green hydrogen to produce methane. However, like green hydrogen, synthetic methane is currently an expensive resource. In addition to the high cost of purchasing green hydrogen, carbon capture costs are estimated to range between $94 and $414 per MTCO2e depending on the source and technology.[43] Despite its high starting cost, application of tax credits and other

[40] See Avista Reply to Staff DR 9 (Attachment A).
[41] *See* Avista Reply to Staff DR 9 (Attachment B).
[42] *See* Avista Reply to Staff DR 11.
[43] David W. Keith et al., *A Process for Capturing CO_2 from the Atmosphere,* 2 Joule 1573 (2018).

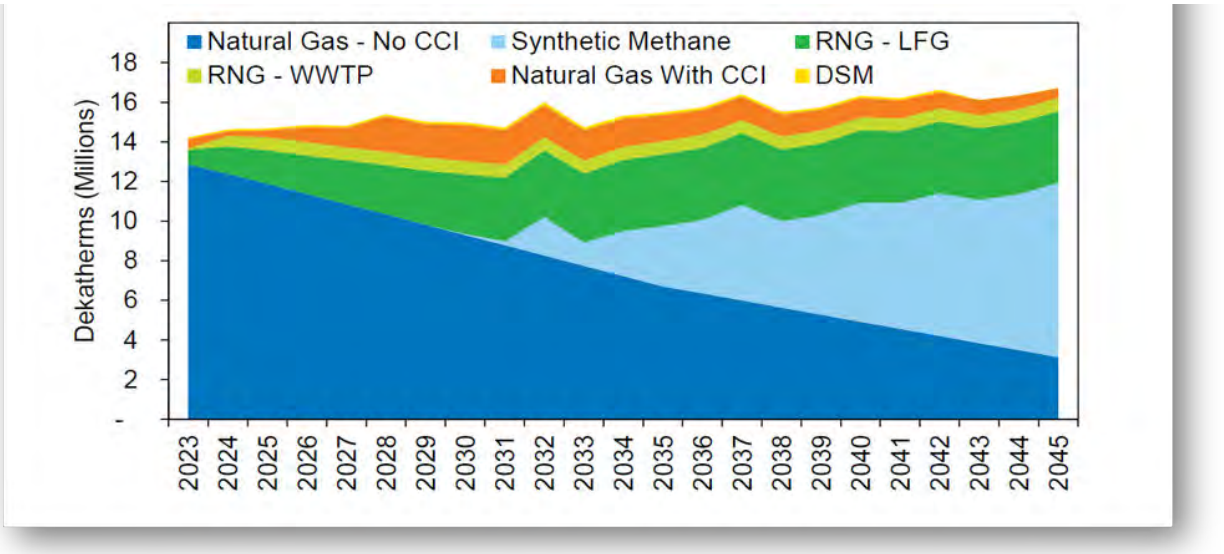
IRA incentives facilitate the inclusion of synthetic methane into the resource mix beginning in 2030.[44]

While Staff finds that the cost assumptions for synthetic methane are likely reasonable, Staff remains apprehensive regarding the pricing of synthetic methane after the IRA tax credits for carbon capture expire in 2033. This is particularly concerning as synthetic methane remains a prominent resource in Avista's Oregon PRS after the IRA tax credits expiration. Further, the Oregon Department of Environmental Quality (DEQ) is considering rule changes to allow only synthetic methane made from green hydrogen *and* biogenic carbon dioxide as a natural gas replacement in the CPP.[45] Therefore, in Reply Comments Avista should address the viability of synthetic methane post-IRA and should the DEQ rule change go into effect.

Hydrogen and Synthetic Methane Availability

Avista's PRS begins selecting synthetic methane as early as 2030 and then grows to 37 percent of its total supply by 2040, at which point it becomes, and remains, Avista's primary compliance approach to meet its forecasted load. While Staff appreciates that Avista's conservative price forecasts likely temper the volumes selected, it is concerned that the Company has not provided sufficient supporting documentation to show that a path to acquire these volumes is reasonable. Additionally, it is not clear how the PRS performs if the target volumes and prices to do not materialize.

Figure 4: Avista's Oregon Preferred Resource Strategy - Figure 6.19 in the IRP



Avista relies heavily synthetic methane for regulatory compliance and reliable service, yet the Company provides relatively little supporting documentation to demonstrate the availability of

[44] *See* Avista 2023 Integrated Resource Plan at 6-23, 6-24.

[45] *See* Oregon DEQ, Division 215, Climate 2023 Rulemaking Advisory Committee, Meeting #3, June 27, 2023.

this resource.[46] In Docket No. LC 79, the Commission identified the need for utilities to pay greater attention to stress testing portfolios that rely heavily on decarbonized fuels.[47] This need was prompted by several parties' assertions that NW Natural's assumptions skewed optimistically rather than presenting an objective view of the significant risks and uncertainties. Staff remains similarly skeptical in this proceeding. Broad deployment of green hydrogen and synthetic methane at the volumes and prices envisioned by this plan appear optimistic.

Staff is concerned that Avista's plan for the inclusion of synthetic methane is not adequately supported by studies. Avista states the Company will require further studies and lifecycle analysis if synthetic methane is selected as a resource, but Avista's Oregon PRS shows the Company's intention to select the resource. Furthermore, green hydrogen is a precursor to synthetic methane usage, yet Avista has not studied or consulted an independent organization on the implications for demand from highly intensive processes needing to procure green hydrogen, which may significantly alter the availability.[48] Staff's concern is further compounded by the potential CPP requirement that carbon dioxide inputs to synthetic methane be sourced biogenically in order to qualify for regulatory compliance goals.

Staff is also interested in further information regarding Avista's procurement strategy of green hydrogen for the development of synthetic methane. Avista's strategy will require a significant increase of green hydrogen to support its use of synthetic methane at the levels proposed. Similar to its questions about buying vs building RNG, Staff seeks additional information on the risks and benefits of different approaches to procure synthetic methane, including whether the company envisions ownership of any the processes required for development. Staff requests in Avista's next IRP that the Company address its strategy for synthetic methane procurement through the lens of on-system ownership of green hydrogen and/or carbon capture facilities and off-system contracts.

Avista's Oregon PRS shows synthetic methane as part of its portfolio in only seven years, and then being a key resource moving forward. This is concerning considering the acknowledged need for additional studies by the Company. Staff requests Avista provide in Reply Comments any supporting documentation it relied on regarding synthetic gas market development in the United States; price and availability ranges used in Monte Carlo analysis; and any NPVRR analysis it conducted to measure the severity of bad outcomes associated with missing synthetic methane targets or a future in which the synthetic methane procured cannot be used for CPP compliance. Without such information, it remains unclear if Staff would suggest the Commission to acknowledge Avista's long-term plan.

[46] *See* Avista 2023 Integrated Resource Plan at 7-15.

[47] *See In the Matter of Northwest Natural Gas Co., 2022 Integrated Resource Plan*, Docket No. LC 79, Order No. 23-281 at 9 (Aug. 2, 2023).

[48] *See* Avista 2023 Integrated Resource Plan at 4-23.

Section 6.2 – Renewable Natural Gas

Avista plans to acquire 8.64 million therms of RNG in 2023 and 21.80 million therms of RNG in 2024. While costs for green hydrogen and synthetic methane are expected to significantly decrease, RNG shows a steady increase in pricing. RNG is expected to increase due to market variability and inflation across all procurement methods including anaerobic production type such as dairy, food waste, solid waste, and wastewater.

For RNG pricing, Avista relies on the 2018 report by Black & Veatch, which forms the basis of Avista's RNG cost assumptions and was also considered in determining green hydrogen pricing. Using cost assumptions informed by the Black & Veatch report, the PLEXOS model is allowed to select RNG as an option.

In Avista's 2021 IRP, the Company relied on the same report for its cost assumptions of renewable resources, and Staff found that the Company had reasonably modeled the expected future costs. Staff believes the cost assumptions for RNG (and green hydrogen) as provided by the report are reasonable, but notes they are dated. In Reply Comments Avista should address any changes in RNG pricing that may have occurred in the last five years, not limited to innovations in RNG procurement technology and larger federal or state policies.

Renewable Natural Gas Availability

Based on Staff's review of the Black & Veatch RNG study, information provided in response to DRs, and overall discussions throughout the IRP, Staff is concerned with Avista's RNG availability assumptions and the ability to provide service on a reliable basis for its customers with RNG.

Avista is aiming to procure significant amounts of RNG, even higher percentages of total deliveries than NW Natural proposed in Docket No. LC 79. This sparks some concern for Staff regarding the Company's ability to procure the volumes envisioned in such a short time. NW Natural, which has described itself as a leader in the procurement of RNG, was only able to procure a fraction of its forecasted procurement.[49]

The assumptions for RNG availability provided by the Black & Veatch report appear reasonable and reflect what Staff is seeing in practice. In the report, Black & Veatch reported high levels of annual availability for each of the various RNG technologies, with all methods of RNG procurement having a very high annual availability factor of between 90-95 percent.[50] And while Staff will continue to review the report based on Avista's forthcoming Reply Comments, Staff believes that although the report supports the Company's assumptions, it says nothing about Avista's ability to secure RNG.

[49] *See e.g.*, *In the Matter of Northwest Natural Gas Co.*, *Annual Renewable Natural Gas Compliance Report,* Docket No. RG 99.

[50] *See* Avista Reply to Staff DR 9.

Avista currently has no RNG registered in the state of Oregon with either DEQ or the Commission and will need to secure approximately seven-times the amount of RNG as NW Natural currently has by the end of 2023, according to the Company's Action Plan. Avista's 2023-2024 Action Plan states the Company plans to acquire 8.64 million therms of RNG in 2023 and 21.80 million therms of RNG in 2024. Staff reviewed Avista's current RNG contracts and notes that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Staff also reviewed the Company's 2022 RNG RFP, which received fifteen unique bids. These bids consisted of RNG developers and commodity brokers, with nearly all bidders offering only off-take opportunities or off-take purchase options.[52] In total, Avista identified approximately forty-seven portfolios or projects throughout the country with an estimated total volume of approximately 190 million therms.[53] Yet, despite Action Plan need in 2024 for RNG, the Company did not select any of the RFP response offerings. Rather, the Company utilized that information in validating its own contracts as least cost resources. Further, Staff is concerned about the Company's recent RFP response offerings, which showed over half of the responding RNG projects are not anticipated to start until mid to late 2024 and beyond.[54]

Avista's procurement strategy must be aggressive to procure its RNG targets, but recent contracts demonstrate that the Company falls short of meeting those targets. Staff requests that Avista provide in Reply Comments more information about its strategy to acquire the millions of therms indicated in the Company's Action Plan and considering the plan, the reasoning behind the Company's decision not to select any of the RFP response offerings.

[51] See Avista Reply to Staff DR 3 (Confidential Reply).
[52] *See* Avista Reply to Staff DR 1.
[53] *See* Avista Reply to Staff DR 2 (Attachment A).
[54] *See* Avista Reply to Staff DR 2 (Attachment A).

Unrealistic assumptions that costly decarbonized fuels will play a significant near term, and rapidly increasing, role in the Oregon PRS is the second of four major issues standing in the way of Staff recommending acknowledgement of the long-term Plan.

In an effort to continue to understand pricing and availability, Staff request that in the Company's IRP Update it provide an update on RNG procurements, akin to what is required in SB 98 reporting on RNG procurements.

Section 6.3 – Renewable Natural Gas Evaluation Methodology

As Avista explores expansion of the Company's RNG portfolio and procurement, Staff wants to ensure clarity and transparency with stakeholders and customers. Avista's IRP provides a great insight into the Company's current practices.

Avista first discusses its primary considerations on its overall RNG program including how to evaluate available procurement options, pursuing potential RNG development opportunities under Washington and Oregon legislation and increased participation in RNG rulemaking and policy determinations.[55] After reviewing local and national natural gas utilities' RNG program models, Avista's considerations appear to be aligned with national standards.

The Company's cost-effective methodology shows costs for projects on a levelized basis as compared to other resources as found in the PLEXOS model for the IRP.[56] The methodology is derived from Docket No. UM 2030 and referenced in the Commission's Senate Bill 98 rulemaking.[57] Avista's evaluation is summarized in the Avista Renewable Resource Development and Procurement Decision Tree and further explains its calculations and components used in Appendix 5.[58]

Avista's evaluation methodology also considers the various benefits and disadvantages of ownership of RNG projects versus buying Renewable Thermal Certificates (RTCs) from third parties. Further discussion can be found in Section 6.4 Risks and Benefits of Resources, Ownership vs. Contractual Provisions.

After review of the Avista Renewable Resource Development and Procurement Decision Tree, the Company's overall RNG procurement strategy, Avista's current procurement of RNG, and other associated information, Staff finds that the Company's evaluation methodology is reasonable.

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[55] See *Avista 2023 Natural Gas Integrated Resource Plan*, https://edocs.puc.state.or.us/efdocs/HAA/lc81haa114738.pdf, page 4-18.
[56] See *Avista 2023 Natural Gas Integrated Resource Plan*, https://edocs.puc.state.or.us/efdocs/HAA/lc81haa114738.pdf, page 4-19.
[57] *See In the Matter of Public Utility Commission of Oregon, Investigation Into the Use of Northwest Natural's Renewable Natural Gas Evaluation Methodology*, Docket No. UM 2023, Order No. 20-403 (Nov. 5, 2020).
[58] *See* Avista 2023 Integrated Resource Plan at 4-19.

Section 6.4 – Risks and Benefits of Resources, Ownership vs. Contractual Provisions

As part of the IRP drafting and review process, Avista discussed the potential benefits and risks of ownership of RNG facilities versus purchasing arrangements. While Avista focused its discussion on the procurement of RNG, Staff believes it is important to consider future impacts of both RNG and hydrogen procurement.

In Docket No. LC 79, the Commission noted that as natural gas utilities shift to owning RNG production facilities or committing customers to long-term fueling agreements, the utilities may find the extensive testing of generating resource selection strategies in electric IRPs instructive.[59] Natural gas utility resource strategies must show that such strategies remain resilient in the face of an uncertain future in order to demonstrate a least-cost, least risk long-term plan. This is particularly true as higher cost, higher risk fuels like RNG, green hydrogen, and synthetic methane are incorporated into portfolios on a long-term basis. The Commission communicated that utilities should anticipate rigorous investigations of its strategy and resource selection.

Staff remains agnostic regarding the best ownership structure, assuming there is appropriate selection process and adequate customer protections. Utility ownership of facilities can have potentially long-term benefits, such as cost-of-service rates for fully depreciated assets.

There are other risks and benefits for the structural arrangements. For example, ownership could offer tax benefits that affiliate-ownership or contractual purchases of RNG may not offer. However, there are likely contractual protections afforded by the latter that ownership may not include. Thus, it is important to consider all the costs and benefits in modeling the resource options.

In response to Staff DR 7, Avista stated that the Company's RNG procurement strategy remains based on the lowest cost of compliance and does not demonstrate a utility bias towards ownership, due to the inclusion of third-party RNG off-take contracts supported by cost analysis documentation.[60]

Avista further acknowledges the complexities of developing RNG projects, and further discuss building versus buying in terms of project evaluation. Avista noted that building RNG projects is supported by both Oregon's Senate Bill 98 and Washington's House Bill 1257,[61] in addition to the local benefits project development brings including improved local air quality and support for the local economy. Lastly, since utilities are institutional credit worthy partners with the ability to be a long term off-taker for biogas, these arrangements are likely to be more desirable

[59] *See In the Matter of Northwest Natural Gas Co., 2022 Integrated Resource Plan*, Docket No. LC 79, Order No. 23-281 (Aug. 2, 2023), page 12.
[60] *See* Avista Reply to Staff DR 7.
[61] *See* Avista 2023 Integrated Resource Plan at 4-18.

for feedstock owners. Avista notes it may continue to investigate ownership opportunities as informed by future Request for Proposals (RFPs).

Currently, Avista buys RNG for the Company's voluntary RNG program (as directed under Washington House Bill 1257), due to limited volume requirements and the program's short-term nature. This strategy allows Avista to learn more about the demand from its voluntary RNG program, while minimizing risk and avoiding larger capital costs. Purchasing RTCs from the RNG market can be more expensive than ownership due to market competition with the transportation sector.

Staff remains comfortable with Avista's current RNG procurement and evaluation methodology, discussed above in Section 6.2.3. However, Staff requests that Avista continue to include and update its build versus buy decision-making in its next IRP, due to increasing compliance and emission reduction requirements which may lead to an influx of RNG and hydrogen facilities.

Section 6.5 – Requests for Avista

Request for Reply Comments 10: Avista should describe how the Black & Veach, Lazard's, and Bloomberg studies inform its green hydrogen price and availability assumptions and how it modeled future price and availability uncertainty.

Request for Reply Comments 11: Avista should include information regarding the Company's ability to procure the synthetic methane at the levels necessary for the Oregon PRS. This should include a description of supporting documentation it relied on regarding synthetic gas market development in the United States; price and availability ranges used in Monte Carlo analysis; and any NPVRR analysis it conducted to measure the severity of bad outcomes associated with missing synthetic methane targets or a future in which the synthetic methane procured cannot be used for CPP compliance.

Request for Reply Comments 12: Avista should provide a brief explanation of how RNG cost assumptions have changed since the 2018 report was published, and if so, further explain how the Black & Veatch study remains applicable.

Request for Reply Comments 13: Avista should explain its strategy to acquire the millions of therms of RNG indicated in the Company's Action Plan and its reasoning behind its decision not to select any of the RFP response offerings.

Request for Next IRP 2: Avista should describe its strategy for synthetic methane procurement through the lens of on-system ownership of green hydrogen and/or carbon capture facilities and off-system contracts.

Request for Next IRP 3: The next IRP should include an update of Avista's approach to hydrogen acquisition as it relates to build versus buy to ensure Avista's proposed levels of synthetic methane usage.

Request for Next IRP 4: In its next IRP, Avista should continue to include and update its build versus buy decision-making approach and engage with stakeholders on this topic in a TAC meeting.

Section 7: Current Supply-Side Resources

Claire Valentine-Fossum, Senior Energy Policy Analyst

As the planning horizon introduces increased demand, new resource options, and changing climate policy, Avista's supply-side resource strategies should incorporate the risks and uncertainties that come with these changes.

Section 7.1 – Natural Gas Price Forecast

Natural gas prices at Sumas, AECO, and the Rockies are the primary determinates of Avista's fuel costs. Avista uses a weighted price blend of two third-party consultants' forecasts and the U.S. Energy Information Administration (EIA) forecast to model the expected natural gas price curve. Avista's natural gas price curve shows prices sharply decreasing in the near term from the current high and then gradually increase across the planning horizon. It is unclear from the IRP how RNG demand from gas utilities and increased natural gas purchases by electric utilities switching from coal to gas may impact natural gas pricing. The EIA projects that U.S. natural gas production will increase 15 percent and LNG exports will increase 152 percent between 2022 and 2050.[62] It is not clear to Staff that Avista fully appreciates how the rising demand for LNG, RNG, and natural gas by electric utilities may impact natural gas prices and liquidity at the regional hubs serving Avista customers.

Avoided Costs

The price of natural gas is the most significant variable in determining the cost-effectiveness of energy efficiency measures and/or procuring new resources. In this way, higher forecasted prices of conventional natural gas can lead to a higher avoided commodity cost of gas. Accordingly, a higher forecasted natural gas price will have a corresponding effect on alternatives such as energy efficiency and RNG making these alternatives more cost effective.

As gas utilities switch to alternative resources, such as RNG, synthetic methane, or Natural Gas + CCIs, using the price of natural gas may become incongruous with market realities. In this regard, Staff is concerned that current avoided cost methodology will not fully capture the effects of the CPP on avoided costs. Accordingly, Staff would like Avista to explain in Reply Comments how the Company intends to measure cost effectiveness within a changing resource portfolio. For future IRPs, Staff would like the Company to discuss in a TAC meeting how Avista envisions avoided costs aligning with the CPP and market realities, and how that will be reflected in its next IRP.

[62] *See* U.S. Energy Information Administration, *U.S. natural gas production and LNG exports will likely grow through 2050 in AEO2023* (April 27, 2023) available at https://www.eia.gov/todayinenergy/detail.php?id=56320.

Section 7.2 – Transportation and Storage Capacity Resources

Avista holds firm transportation capacity on six interstate pipelines and ownership and leasehold rights at Jackson Prairie Storage. Avista's Transportation Contract Portfolio includes near-term contract expirations that Avista has the option to renew.[63] Notably, most of the base contracts of the Williams Northwest Pipeline (NWP).[64]

Avista holds firm transportation capacity on 6 interstate pipelines as shown in Table 1.

Table 1: Avista's Transportation Contract Portfolio[65]

Pipeline	Expirations	Base Capacity Dth
Williams NWP	2025-2042 (2035)	285,000
Westcoast (Enbridge)	2026	10,000
TransCanada (NGTL)	2024-2046	208,000
TransCanada – Foothills	2024-2046	204,000
TransCanada – GTN	2023-2028	210,000
TransCanada – Tuscarora	2023	200

Avista contracts for firm capacity to serve its core customers during expected peak days across the planning horizon. The result is that Avista contracts for capacity rights in excess of what is needed for most days across the planning horizon. Most of Avista's upstream pipeline capacity includes a high reservations charge whether natural gas is transported or not, sometimes referred to as a "Take or Pay" contract.[66] During such periods of lower capacity use, Avista offers this excess capacity into FERC-managed release markets to mitigate excess costs. Avista notes "[t]he recovery is market dependent and may or may not recover all pipeline costs but mitigates pipeline costs to customers."[67]

As discussed in Section 8.2, capacity is only modeled in PLEXOS as physical transportation pathways that map the natural gas system. Based on the learnings from the Synapse Report in Docket No. LC 79, Staff draws attention to the fact that PLEXOS does not have the option to select economic alternatives over transportation and storage capacity resources during

[63] *Avista 2023 Integrated Resource Plan - TAC #2* (virtual Technical Advisory Meeting recorded May 3, 2022), available at https://www.youtube.com/watch?v=4h8yn-LYHMc; *see also* Avista 2023 Integrated Resource Plan at 4-10.
[64] *Avista 2023 Integrated Resource Plan - TAC #2* (virtual Technical Advisory Meeting recorded May 3, 2022), available at https://www.youtube.com/watch?v=4h8yn-LYHMc.
[65] *Avista 2023 Integrated Resource Plan - TAC #2* (virtual Technical Advisory Meeting recorded May 3, 2022), available at https://www.youtube.com/watch?v=4h8yn-LYHMc.
[66] *See* Avista 2023 Integrated Resource Plan at 4-4, 6-10 to 6-11, 6-14; see also *Avista 2023 Integrated Resource Plan - TAC #2* (virtual Technical Advisory Meeting recorded May 3, 2022), available at https://www.youtube.com/watch?v=4h8yn-LYHMc.
[67] Avista 2023 Integrated Resource Plan at 4-13.

optimization. In this regard, Staff seeks transparency into Avista's strategy to mitigate transportation and storage capacity resource costs to customers. It is unclear, for example, what incentives exist for Avista to mitigate these costs. It is also unclear how successful Avista has been – or will be in the future – at using the release market given new compliance requirements, weather conditions, and other factors. In Reply Comments, Avista should discuss the extent to which the Company has been able to successfully mitigate costs from unused capacity resources in the past, Avista's release market forecast, and Avista's long term mitigation strategy.

Section 7.3 – Requests for Avista

Request for Reply Comments 14: As discussed in Section 7.1.1, Avista should explain how the Company intends to measure cost effectiveness within a changing resource portfolio in line with the CPP.

Request for Reply Comments 15: Avista should discuss the extent to which the Company has been able to successfully mitigate costs from unused capacity resources in the past, Avista's release market forecast, and Avista's long term mitigation strategy.

Section 8: Portfolio Evaluation

Claire Valentine-Fossum, Senior Energy Policy Analyst, and Nick Sayen, Senior Utility Analyst

Avista's Portfolio Evaluation approach, while improved by the ability to consider emissions, resulted in the loss of some important IRP elements. The IRP does not include NPVRR metrics, instead presenting an alternative scenario cost comparison in terms of annual levelized costs.

Avista did not use stochastic analysis to stress-test the PRS, or to conduct risk analysis, as the IRP Guidelines require. The failure to conduct such analysis – at a minimum on the PRS – results in the potential loss of valuable insight into the PRS's weaknesses, costs, and assumptions.

Avista's Oregon PRS appears to include the selection of higher cost renewable resources before maxing out the option to select lower cost CCIs available to the Company. CCIs appear to be the least cost CPP compliance approach. It is unclear to Staff why Avista's modeling does not select a higher volume of CCI in the Action Plan.

Section 8.1 – Scenario Analysis and Framework

Avista's 2023 IRP uses PLEXOS, a modeling software new to the company, to identify the company's PRS. Avista used a stochastic simulation to model a variety of price and weather events. These price and weather events are modeled in PLEXOS using weather forecasts, energy resource prices, and demand-side programs, including:

- Conventional natural gas price;
- Conventional Natural Gas + CCI price;
- Alternative Gas price (RNG by source, Synthetic Methane, and green hydrogen);
- Building Electrification proxy cost by major end-use; and
- Demand response by program;
- Potential cost-effective energy efficiency.

PLEXOS used these inputs, as well as the network of the capacity resources described below, to review five potential futures using a stochastic analysis. The stochastic analysis solved for the optimal outcome for all the five futures occurring at the same time. The IRP identifies this stochastic solution as the PRS. Avista then hardcoded the PRS into PLEXOS for a Monte Carlo analysis. The Monte Carlo analysis looked at a set of 500 potential draws within the five futures, randomly drawing values of distributions from inputs that Avista defined.

Section 8.2 – Capacity Resources and Preferred Resource Strategy

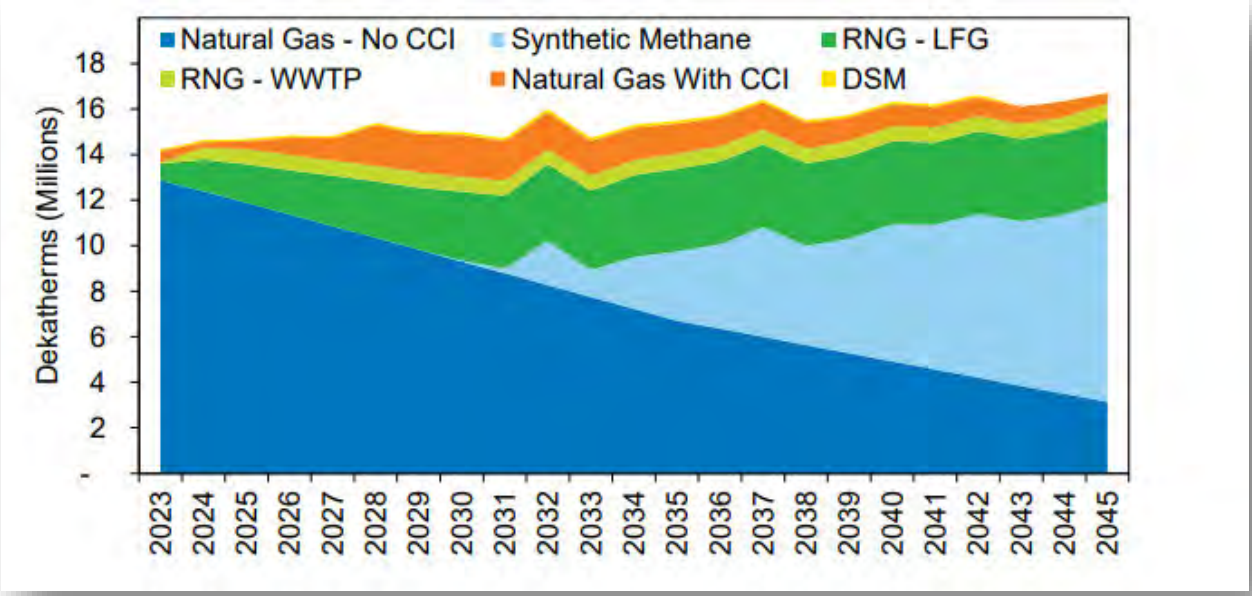
Avista used a deterministic analysis to model capacity resources, including transportation. The model includes the available supply basins for natural gas and the storage and transportation of this supply to Avista's demand regions. Avista entered the physical attributes of its capacity

resource assets into PLEXOS to mirror Avista's gas system. Firm contracts must be used or injected into storage under the model. There is no option to retire or abandon uneconomical assets or capacity contracts as part of portfolio optimization. Similarly, planned expansion of distribution system resources is not an option.

Preferred Resource Strategy

Avista states that the PRS accounts for all five futures. Avista's PRS is comprised of: natural gas; RNG from Landfill Gas (LFG) and Wastewater Treatment Plants (WWTP); energy efficiency; natural gas with CCIs; and conventional natural gas. In 2030, Synthetic methane enters the mix, taking over as the main fuel source as natural gas use decreases. This resource mix is demonstrated below in Figure 5, depicting Figure 6.19 from the IRP.

Figure 5: Oregon Preferred Resource Strategy, Avista IRP Figure 6.19



Avista then tested the PRS with 13 alternative demand and supply scenarios using a deterministic analysis. Each alternative scenario modifies a single demand or supply variable from the expected PRS base case; they do not represent all possible permutations. Avista classifies these alternative scenarios as portfolios, however Staff finds that they function akin to sensitivities to test the PRS rather than producing alternative portfolios to rank and select from. Staff discusses this further in Section 9.

Section 8.3 – Staff Review of Avista's Approach

Representation of all costs

Net Present Value of Revenue Requirement

IRP Guideline 1c Substantive Requirements. states:

> Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.[68]

Avista states that **"**Avista's PLEXOS® modeling software utilizes a PVRR cost metric methodology applied to both long and short-lived resources."[69] Avista further states that the Company "through its stochastic analysis, modeled 500 twenty three year futures via Monte Carlo iterations developing a distribution of Total 23 year cost estimates utilizing PLEXOS®'s PVRR methodology."[70] The IRP, however, does not include NPVRR metrics, instead presenting an alternative scenario cost comparison in terms of annual levelized costs.[71] To address this, Staff requests Avista provide in Reply Comments the traditional NPVRR analysis of the Preferred Portfolio and alternative portfolios/scenarios.

Current and Estimated Future Costs and Risks

The IRP Guidelines state that, "The [IRP] should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases." [72] The scenarios Avista presents in the IRP do not clearly consider the cost of distribution pipeline upgrades that will be required to accommodate load growth under the scenarios. Similarly, the IRP does not consider the risk of unnecessary distribution system upgrades,[73] long-term RNG procurement contracts, and expensive transportation and storage capacity for declining customer counts (or equivalently, stranded cost risk for the Company). In the past, when each portfolio had a similar amount of load, exclusion of such costs was acceptable since costs were likely to be the same in each portfolio. Now that different portfolios can have very different load forecasts and approaches to CPP compliance, a reliable portfolio analysis must consider these costs and risks in each portfolio.

As discussed in Section 4.5, Avista has detailed the potential conversion costs and electric rate impacts to the individual customer who elects to electrify a major end use. To this end, Avista raised a key equity concern of electrification, that is, that some gas customers may face economic barriers to converting from gas to electric end uses and will then, in addition to this

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[68] *In the Matter of Public Utility Commission of Oregon, Investigation into Integrated Resource Planning Requirements*, Docket No. UM 1056, Order No. 07-002. App. A at 2 (Jan. 8, 2007).
[69] *See* Avista 2023 Integrated Resource Plan Appendix 1.2, Guideline 1(c).
[70] *See* Avista 2023 Integrated Resource Plan Appendix 1.2, Guideline 1(c)
[71] *See* Avista 2023 Integrated Resource Plan at 7-19, figure 7.14.
[72] *In the Matter of Public Utility Commission of Oregon, Investigation into Integrated Resource Planning Requirements*, Docket No. UM 1056, Order No. 07-002. App. A at 2 (Jan. 8, 2007).
[73] Testimony, *In the Matter of Avista Corporation, Request for a General Rate Revision*. Docket No. UG 461, July 7, 2023, Staff/500 at 6:1-10:2 (testimony of Bolton).

economic difficulty, shoulder the legacy capital costs of the natural gas system built for a larger forecasted demand.

Similarly, in the NGFF report, Staff highlighted a 2021 report on the rate payer burden of natural gas stranded assets.[74] The 2021 report found that "a ten percent decrease in residential utility customers leads to only a five percent decrease in revenues, implying that the remaining utility residential customers bear a higher burden in costs. This is to say that should there be a large defection from natural gas utilities due to decarbonization, the remaining infrastructure costs will not scale down and will be paid by those remaining on the system."[75]

Staff identified two types of gas customers, low-income residential customers, and businesses reliant upon gas for specific end-use processes, that will shoulder the costs of new and existing infrastructure investments in the gas system as gas customers decline. These two types of gas customers are at risk of shouldering this cost shift because they lack the ability to easily substitute away from the natural gas system. For future IRPs, Staff would like the Company to discuss in a TAC meeting the risk and equity implications of shifting all current and estimated future costs to remaining gas customers, including the costs of distribution pipeline upgrades that will be required to accommodate load growth under the scenarios, long-term RNG procurement contracts, and capacity resource contracts.

Use of Stochastic Analysis

IRP Guideline 4b. states:

> At a minimum, the plan must include the following elements:
>
> b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions.

While Avista used stochastic analysis to *develop* the PRS, Staff understands that the Company did not use stochastic analysis to subsequently *stress-test* the PRS, or to conduct risk analysis, as the Guideline notes. Employed in such a fashion – to stress-test and conduct risk analysis – stochastic analysis entails allowing multiple variables to fluctuate in random fashion, generating unanticipated outcomes and provoking unexpected performance from the PRS. The IRP should have included alternative portfolio options, which too could have been subjected to stochastic analysis to assist in testing and comparison. The failure to conduct such analysis – at a minimum on the PRS – results in the potential loss of valuable insight into the PRS's weaknesses, costs, and assumptions.

[74] Docket No. UM 2178, *Staff's Final Report*, Natural Gas Fact Finding per Executive Order 20-04, at xxiii (Jan. 31, 2023); citing Lucas W. Davis, Catherine Hausman, Working Paper, *Who will pay for legacy utility costs?* NATIONAL BUREAU OF ECONOMIC RESEARCH, JUNE 2021.

[75] Docket No. UM 2178, *Staff's Final Report*, Natural Gas Fact Finding per Executive Order 20-04, at xxiii (Jan. 31, 2023).

Inadequate use of stochastic analysis is the third of four major issues standing in the way of Staff recommending acknowledgment of the long-term plan.

Resource Options and CPP Compliance

CCIs

Avista's forecast of CCI costs and Avista's CCI procurement plan, as part of an overall CPP compliance strategy, are unclear. CCI availability for gas utilities is based on a fixed percentage of retail sales (e.g., compliance obligations) as shown in the Figure 5[OBJ] from DEQ's CCP rules below. Avista's allowable percentage for the first compliance period through 2024 is 10 percent, and then increases to 15 percent.

Figure 6: DEQ CCP Covered Fuel Supplier Allowable Usage of CCIs - Table 6 in OAR 340-271-0450(3)

OAR 340-271-9000
Table 6
Covered fuel supplier allowable usage of community climate investment credits to demonstrate compliance as described in OAR 340-271-0450(3)

Compliance period	Allowable percentage of total compliance obligation(s) for which compliance may be demonstrated with CCI credits
Compliance period 1 (2022 through 2024)	10%
Compliance period 2 (2025 through 2027)	15%
Compliance period 3 (2028 through 2030), and for each compliance period thereafter	20%

Avista states that "CCIs are expected to be a least cost solution when compared to renewable resource options, due to the ability to pair CCIs with natural gas as a low quantity solution."[76] The Company's PLEXOS inputs for the cost of CCIs can be converted to approximate cost per dekatherms to facilitate a comparison across resource options. As the Company notes, this cost per dekatherm needs to be added to the cost of the natural gas that would need to be purchased to meet that load.[77] Staff calculates the approximate cost of CCI per therm over the next five years Table 2 below:

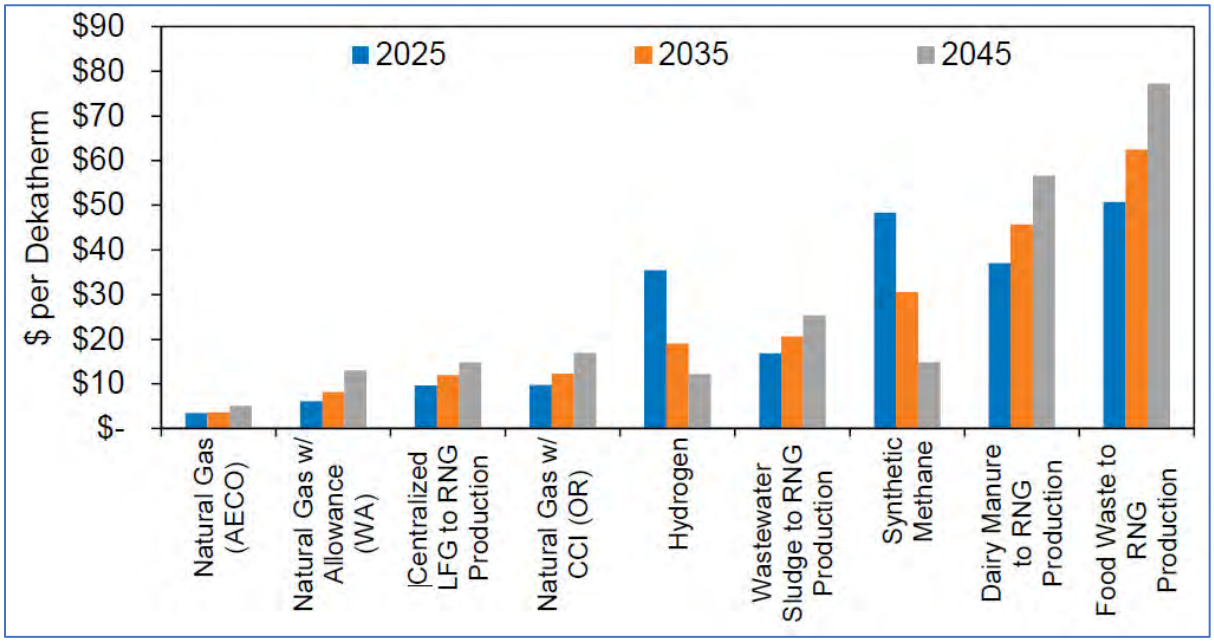
[76] *See* Avista 2023 Integrated Resource Plan at 6-25.
[77] See, e.g., Avista 2023 Integrated Resource Plan at 6-8 (summarizing the carbon policy resource utilization for the PLEXOS optimization).

Table 3: CCI Costs

Year	CCI $/lb CO2e (PLEXOS Input)[78]	$/metric ton[79]	$/therm (0.0053 MTCO2e/therm)[80]	$/dekatherm
2023	$0.0510	$112.35	$0.60	$5.95
2024	$0.0527	$116.17	$0.62	$6.16
2025	$0.0545	$120.15	$0.64	$6.37
2026	$0.0563	$124.17	$0.66	$6.58
2027	$0.0582	$128.30	$0.68	$6.80

Even with the cost of natural gas, CCIs are a lower cost resource than LFG to RNG and Wastewater Sludge to RNG, as shown in Figure 7 below.

Figure 7: Resource Options and Cost in PLEXOS Model - Avista IRP Figure 6.16



[78] *See* Avista 2023 Integrated Resource Plan, PLEXOS data files (listing the price per lb of CO2e for CCI).
[79] *See* Avista 2023 Integrated Resource Plan at 6-9, figure 6.8; *see also* Avista Reply to Staff DR 37 (listing the $ per MTCO2e input for Figure 6.8 of the IRP).
[80] Staff converted the PLEXOS input to $/therm based on the assumed emissions factor. See *e.g.,* Avista 2023 Integrated Resource Plan at 6-8; *see also* ENVIRONMENTAL PROTECTION AGENCY, GREENHOUSE GAS EQUIVALENCIES CALCULATOR – CALCULATIONS AND REFERENCES (May 30, 2023), https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references.

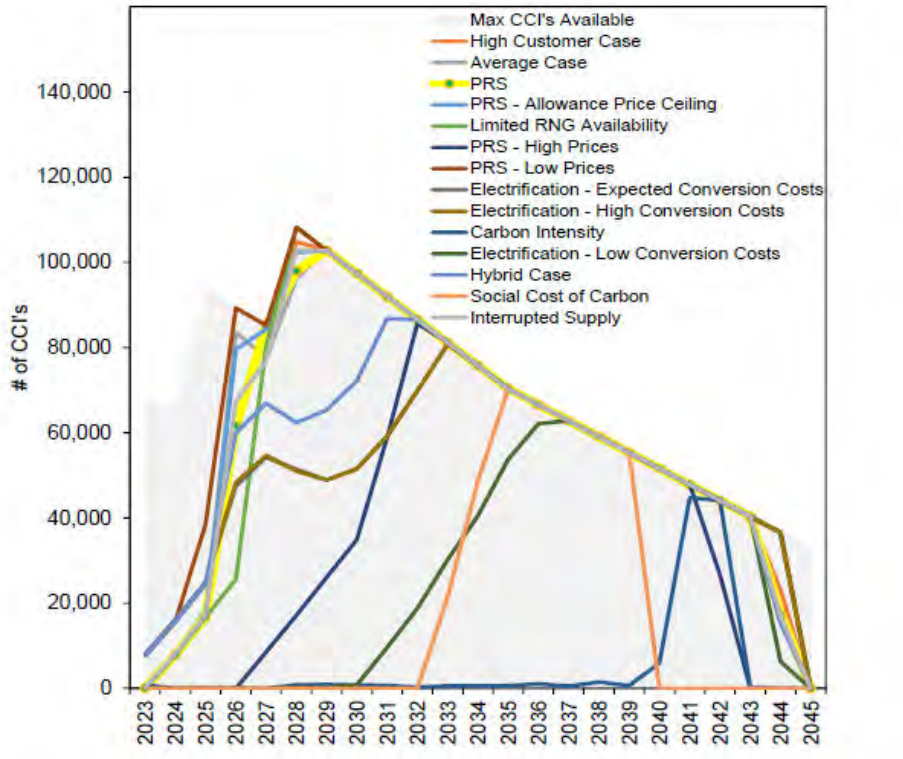
Given that CCIs appear to be the least cost compliance approach, it is unclear to Staff why Avista's modeling does not select a higher volume of CCI for compliance. In Table 3 Staff summarizes the expected CCI purchases from the ORS and those available, but not selected. [81]

Table 4: Avista's CCI ORS Expected Purchases and DEQ Caps

Year	CCIs expected to be purchased	Expected total cost of the CCIs to be purchased	CCIs available to be purchased by Avista, but not purchased	Percent of Available CCI used
2023	25,371	$2,758,577	42,261	38
2024	12,899	$1,449,228	52,028	20
2025	18,493	$2,148,314	74,839	20
2026	40,589	$4,876,774	48,686	45

This is also depicted by Avista in Figure 7.8, which shows that the PRS does not select all available CCIs until approximately 2027.

Figure 8: CCI Demand by Scenario - Oregon CPP from Avista Figure 7.8



Instead, Avista is procuring RNG as seen below in a portion of Table 6.4 of the IRP.[82]

[81] *See* Avista Reply to Staff DR 25. Avista states these figures are derived from Avista's PLEXOS models.
[82] *See* Avista 2023 Integrated Resource Plan at Figure 6.4.

Table 5: First Five years of Avista's Average Daily Resource Quantities by Year - Avista IRP Table 6.4

Year	Natural Gas - No CCI	Synthetic Methane	RNG - LFG	RNG - WWTP	Natural Gas with CCI (Dth equivalent)
2023	35,237	-	2,024	196	1,310
2024	33,960	-	3,762	1,460	666
2025	32,568	-	4,619	1,824	955
2026	31,173	-	5,306	1,824	2,095
2027	29,747	-	6,038	1,824	2,681

Avista notes that the number of CCIs available to Avista declines with a cap each year, noting that "additional resources [will] need to be brought onto the system on an annual basis through the end of the study timeframe. This will lead to an increased number of renewable energy sources needed as depicted in Table 6.4."[83] Staff is confused by this statement, as it appears that, at least for years 2023 through 2026, there are abundant CCIs available as the least cost resource.[84] In Reply Comments, Avista should conduct a sensitivity analysis to determine how NPVRR changes if CCIs are acquired up to DEQ limits, as needed, in each year that they are less expensive than other compliance options.

Transport and Interruptible Customers

The PLEXOS model calculates fuel resources to serve Avista's firm residential, commercial, and industrial classes. In Reply Comments Avista should clarify how PLEXOS accounts for the emissions from transport and interruptible customers, as well as how the Company intends to attribute CCP compliance costs to transport and interruptible customers.

Section 8.4 – Requests for Avista

Request for Reply Comments 16: Avista should provide the NPVRR for each scenario / portfolio / future. Provide all results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results. If levelized costs are in fact fungible with NPVRR, Avista should explain why the Company chose not to include NPVRR in the IRP.

Request for Reply Comments 17: Avista should conduct a sensitivity analysis to determine the NPVRR improvement by acquiring CCIs up to DEQ limits, as needed, in each year that they are less expensive than other compliance options.

Request for Reply Comments 18: Avista should clarify why the PLEXOS selected RNG over CCIs from 2023 to 2026 if indeed CCIs are the cheaper resource.

[83] *See* Avista 2023 Integrated Resource Plan at 6-24

[84] *See* Avista 2023 Integrated Resource Plan at 6-24.

Request for Reply Comments 19: Avista should clarify how PLEXOS accounts for the emissions from transport and interruptible customers, as well as how the Company intends to attribute CCP compliance costs to transport and interruptible customers.

Request for Reply Comments 20: Referencing the discussion in Section 8.3, Avista should provide PRS information that includes planned infrastructure costs, identified as new customer vs. maintenance of existing system. Include both transportation and storage assets as well as distribution assets (including line extension allowances).

Section 9: Alternative Scenarios

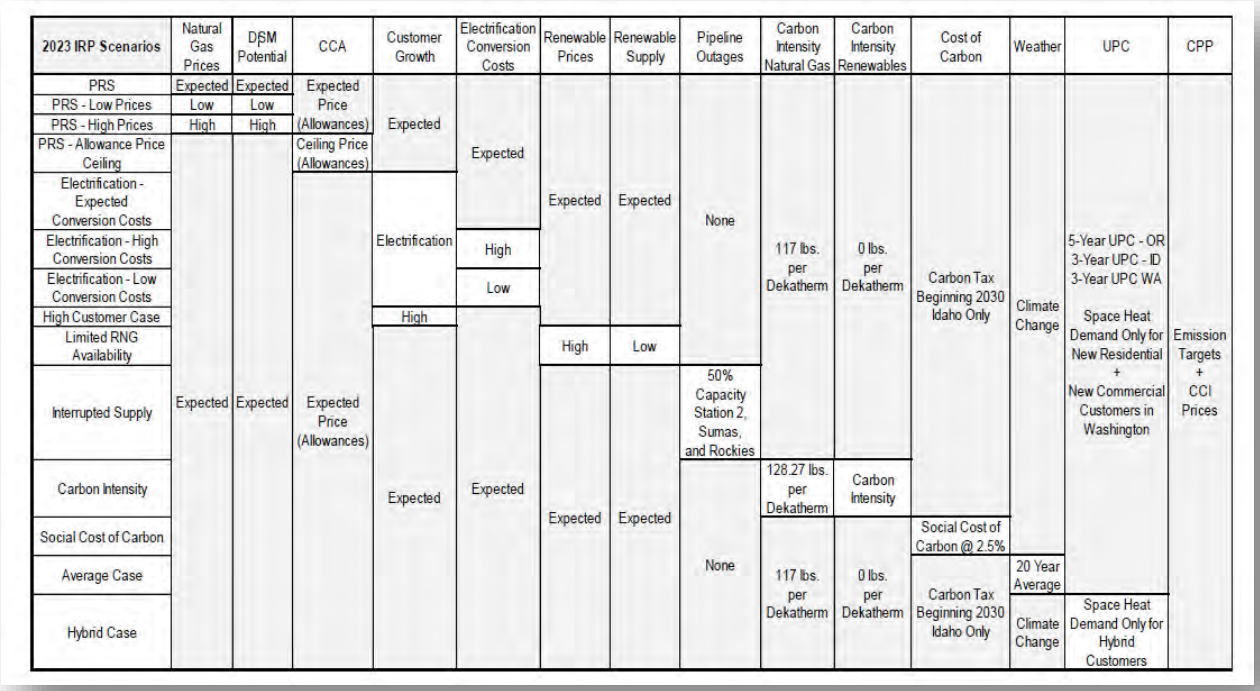
Nick Sayen, Senior Utility Analyst, and Claire Valentine-Fossum, Senior Energy Policy Analyst

Avista classifies alternative scenarios as portfolios. However, Avista only tested the PRS against alternative demand and supply scenarios with a deterministic analysis modifying a single demand or supply variable from the PRS. This does not represent all possible permutations, and thus the alternative scenarios function akin to sensitivities, rather than a set of alternative portfolios to be ranked and selected from. This approach does not meet the IRP guidelines.

Section 9.1 – Summary

As mentioned briefly in Section 8.2, Avista tested the PRS with alternative demand and supply scenarios using a deterministic analysis. This resulted in 14 total scenarios, including the PRS. Each scenario includes different assumptions about important variables such as customer growth, resource availability, weather, and price assumptions. And each scenario modifies a single demand or supply variable from the expected PRS base case; they do not represent all possible permutations. For example, scenarios exploring building electrification force a 2 percent decrease in customer growth and modify the cost of electrification but leave the remaining expected variables unchanged. Capacity resource expectations are the same across all scenarios. There is no incremental energy efficiency beyond what is hard coded in as gas demand for any scenario. Avista in Table 7.1 presents each of these scenarios and the variable that was held changed in each.

Table 6: 2023 IRP Scenarios - Avista IRP Table 7.1



2023 IRP Scenarios	Natural Gas Prices	DSM Potential	CCA	Customer Growth	Electrification Conversion Costs	Renewable Prices	Renewable Supply	Pipeline Outages	Carbon Intensity Natural Gas	Carbon Intensity Renewables	Cost of Carbon	Weather	UPC	CPP
PRS	Expected	Expected	Expected Price (Allowances)	Expected	Expected	Expected	Expected	None	117 lbs. per Dekatherm	0 lbs. per Dekatherm	Carbon Tax Beginning 2030 Idaho Only	Climate Change	5-Year UPC - OR 3-Year UPC - ID 3-Year UPC WA Space Heat Demand Only for New Residential + New Commercial Customers in Washington	Emission Targets + CCI Prices
PRS - Low Prices	Low	Low												
PRS - High Prices	High	High												
PRS - Allowance Price Ceiling	Expected	Expected	Ceiling Price (Allowances)											
Electrification - Expected Conversion Costs			Expected Price (Allowances)	Electrification										
Electrification - High Conversion Costs					High									
Electrification - Low Conversion Costs					Low									
High Customer Case				High	Expected									
Limited RNG Availability				Expected		High	Low							
Interrupted Supply						Expected	Expected	50% Capacity Station 2, Sumas, and Rockies						
Carbon Intensity								None	128.27 lbs. per Dekatherm	Carbon Intensity				
Social Cost of Carbon									117 lbs. per Dekatherm	0 lbs. per Dekatherm	Social Cost of Carbon @ 2.5%			
Average Case											Carbon Tax Beginning 2030 Idaho Only	20 Year Average		
Hybrid Case												Climate Change	Space Heat Demand Only for Hybrid Customers	

The scenarios can be characterized as follows:

- The PRS, as well as three variations of price assumptions;
- Three variations of electrification with differing price assumptions and a Hybrid Case representing partial customer electrification;
- High customer growth;
- Limited RNG availability, which constrains volumes significantly (50 percent);
- Interrupted Supply, which constrains major supply points significantly (50 percent);
- Carbon Intensity, which considers linkages to California's cap and trade program;
- Social Cost of Carbon, at 2.5 percent discount rate; and
- Average Case, which represents historical average demand.

The IRP presents selected results of these scenarios, for example quantities of Oregon CCIs, demand for natural gas, selection of synthetic methane and RNG as resources, levels of emissions, and impact on cost.

IRP Guidelines provide that the utility's plan must include:

- Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service

dates, durations and general locations – system-wide or delivered to a specific portion of the system;[85]

- Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;[86] and
- Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results. [87]

This approach is illustrative, and the results are useful; as the IRP states, the scenarios help in understanding PRS results and impacts of policy changes. However, in modifying a single variable these sensitives do not portray a complex future beyond the scope of the PRS, such as a future with high electrification costs, low RNG supply, and warmer winter months. Staff finds that while the "alternative scenarios" are labeled as portfolios, they are sensitives of the PRS rather than alternative portfolio options, and that the IRP does not include alternative portfolio options.

Inadequate development of alternative portfolios is the final of four major issues standing in the way of Staff recommending acknowledgment of the long-term plan.

As such, and because of the novel nature of electrification and attempts to model it appropriately, Staff has focused attention on just the electrification scenarios for further comment.

Section 9.2 – Electrification Scenarios

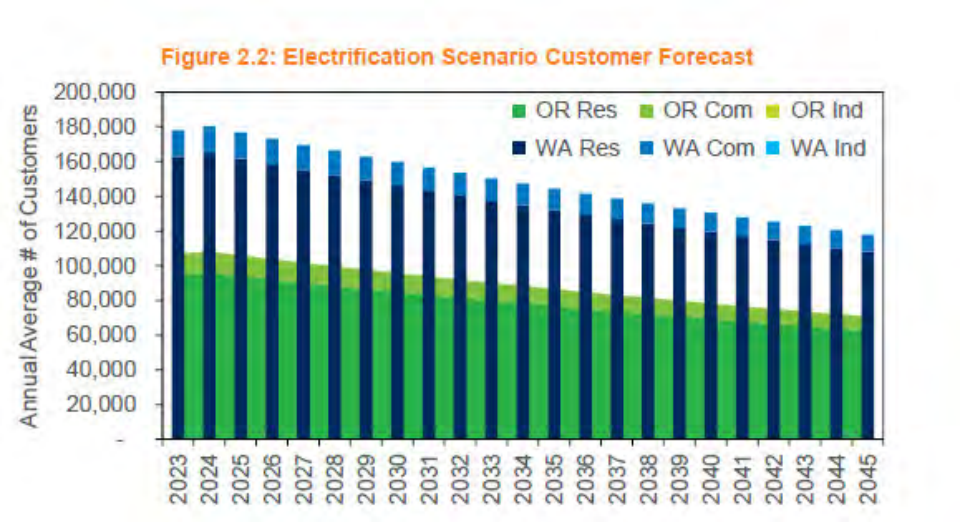
The electrification scenarios function as a sensitivity of the PRS by reducing gas demand by two percent.

According to Avista:

> To help quantify a loss of demand on the natural gas system, a building electrification scenario was created to consider a loss of customers as compared to the expected number of customers in Oregon and Washington with an average reduction of 98 percent from the prior year for the same month, by area and class as illustrated in Figure 2.2. In total an estimated 33 percent reduction in residential customers occurs in both jurisdictions by 2045. This equates to a loss of natural gas system demand of 6.9 million dekatherms per [sic] over the 23-year timeframe.[88]

[85] *In the Matter of Public Utility Commission of Oregon, Investigation into Integrated Resource Planning Requirements*, Docket No. UM 1056, Order No. 07-002 at Guideline 4(h) (Jan. 8, 2007).
[86] *In the Matter of Public Utility Commission of Oregon, Investigation into Integrated Resource Planning Requirements*, Docket No. UM 1056, Order No. 07-002 at Guideline 4(i) (Jan. 8, 2007).
[87] *In the Matter of Public Utility Commission of Oregon, Investigation into Integrated Resource Planning Requirements*, Docket No. UM 1056, Order No. 07-002 at Guideline 4(j) (Jan. 8, 2007).
[88] *See* Avista 2023 Integrated Resource Plan at 2-3.

Figure 9: Electrification Scenario Customer Forecast



Accordingly, these scenarios assume a fuel-switching component. In this way, the Electrification Scenarios function separately from electrification modeled as a resource, as discussed in section 4.5 above, which does not model electrification as a fuel-switching component of the demand forecast.

Avista ran four deterministic electrification sensitivities on the PRS. These sensitivities are labeled as: expected conversion costs, high conversion costs, low conversion costs, and hybrid option (electric heat pump plus gas for peak heating needs). As noted above, in each instance Avista forced PLEXOS to reduce demand by two percent. Additionally, Avista ran two limited RNG supply sensitivities on the PRS: high renewable prices and limited renewable supply.

The results showed that in either the cheaper electrification conversion costs sensitivity or the limited RNG supply sensitivity, Avista's customers would convert from gas to electric. The model selected the fuel switch to occur in 2023 in both instances, meaning it is selected for the entire planning horizon.

Staff notes that space heat is a large component of overall energy demand. In this regard, Staff would like to know more about the hybrid option sensitivity Avista has modeled. Specifically, Staff would like to know more about the assumptions of adoption, cost implications, and how hybrid adoption impacts demand during the winter months.

Staff believes it would also be helpful to see the percentage of customers exiting the gas system under each of the electrification scenarios; and how the electrification scenario may assist in reducing the CPP compliance costs.

Section 9.3 – Requests for Avista

Request for Reply Comments 21: Referencing the discussion in Section 9.2.1, Avista should provide the avoided costs of selecting electrification. If the PLEXOS model does not have information on the avoided costs of electrification, Avista should explain whether the PLEXOS model has any output that could be used to help inform the avoided cost and provide a detailed example.

Request for Reply Comments 22: Staff would like the Company to discuss how the Company modeled the Hybrid option of the electrification scenario, including cost and demand implications and the likelihood of hybrid heat pump adoption.

Request for Reply Comments 23: Referencing the discussion in Section 9.2.1, Avista should provide the percentage of gas customers leaving the system in the two instances where PLEXOS selects Building Electrification as a resource.

Request for Reply Comments 24: Referencing the discussion in Section 9.2.1, Avista should discuss how selection of the electrification scenarios may assist in reducing the CPP compliance costs.

Summary of Requests

Requests for Reply Comments

Request for Reply Comments 1: Avista should present a revised Action Plan with Action Items proposed over a consistent timeframe.

Request for Reply Comments 2: Avista should detail what steps the Company will take in working with the Technical Advisory Committee (TAC) to correct the Company's approach to climate modeling so future IRPs use a credible forecast for modeling, long-term investments, and decisions.

Request for Reply Comments 3: Avista should clarify why the cumulative, 20-year savings efficiency potential drops from 18 million therms in the 2021 IRP to 15.3 million therms in this IRP.

Request for Reply Comments 4: Avista should provide an update on the development of all new program offerings, including: timelines for implementation, the Company's thoughts on achieving the saving projected for 2023, and the building of programmatic infrastructure to ramp up to the greater savings forecasted for 2024.

Request for Reply Comments 5: Avista should discuss whether it intended to apply gas-to-gas costs as electrification conversion values, and if so, why that approach is reasonable.

Request for Reply Comments 6: Avista should respond to Staff's concerns about its use of gas to gas conversion costs in its modeling, and detail initial steps the Company will take in working with the TAC and Staff to further explore the modeling of electrification as a proactive resource strategy, and the differences between electrify existing and new construction.

Request for Reply Comments 7: Avista should comment on including the latest information on distribution projects in future IRP Updates.

Request for Reply Comments 8: Avista should discuss how Order No. 23-281 may impact Avista's current distribution system planning practices. For example, by including analysis of evaluation elements in future IRPs or IRP Updates for Oregon city gate projects, how current targeted conservation resource practices may change, and how demand response offerings fit into its consideration of targeted conservation resources in the future.

Request for Reply Comments 9: Avista should discuss how and if the change to line extension allowances agreed to in the UG 461 Stipulation may impact the Company's revenue requirements, and scenario analysis in future IRPs.

Request for Reply Comments 10: Avista should describe how the Black & Veach, Lazard's, and Bloomberg studies inform its green hydrogen price and availability assumptions and how it modeled future price and availability uncertainty.

Request for Reply Comments 11: Avista should include information regarding the Company's ability to procure the synthetic methane at the levels necessary for the Oregon PRS. This should include a description of supporting documentation it relied on regarding synthetic gas market development in the United States; price and availability ranges used in Monte Carlo analysis; and any NPVRR analysis it conducted to measure the severity of bad outcomes associated with missing synthetic methane targets or a future in which the synthetic methane procured cannot be used for CPP compliance.

Request for Reply Comments 12: Avista should provide a brief explanation of how RNG cost assumptions have changed since the 2018 report was published, and if so, further explain how the Black & Veatch study remains applicable.

Request for Reply Comments 13: Avista should explain its strategy to acquire the millions of therms of RNG indicated in the Company's Action Plan and its reasoning behind its decision not to select any of the RFP response offerings.

Request for Reply Comments 14: As discussed in Section 7.1.1, Avista should explain how the Company intends to measure cost effectiveness within a changing resource portfolio in line with the CPP.

Request for Reply Comments 15: Avista should discuss the extent to which the Company has been able to successfully mitigate costs from unused capacity resources in the past, Avista's release market forecast, and Avista's long term mitigation strategy.

Request for Reply Comments 16: Avista should provide the NPVRR for each scenario / portfolio / future. Provide all results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results. If levelized costs are in fact fungible with NPVRR, Avista should explain why the Company chose not to include NPVRR in the IRP.

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Request for Reply Comments 24: Referencing the discussion in Section 9.2.1, Avista should discuss how selection of the electrification scenarios may assist in reducing the CPP compliance costs.

Requests for Future IRPs

Request for Next IRP 1: Avista's scenario analyses should reflect the potential for Oregon policies mandating electrified space and water heating, reductions in line extension allowances, and other such policies that might reduce customer count expectations.

Request for Next IRP 2: Avista should describe its strategy for synthetic methane procurement through the lens of on-system ownership of green hydrogen and/or carbon capture facilities and off-system contracts.

Request for Next IRP 3: The next IRP should include an update of Avista's approach to hydrogen acquisition as it relates to build versus buy to ensure Avista's proposed levels of synthetic methane usage.

Request for Next IRP 4: In its next IRP, Avista should continue to include and update its build versus buy decision-making approach and engage with stakeholders on this topic in a TAC meeting.

This concludes Staff's Opening Comments.

/s/ Nick Sayen
Senior Utility Analyst
Oregon Public Utility Commission