BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 83

In the Matter of CASCADE NATURAL GAS, 2023 Integrated Resource Plan.	Staff Opening Comments

Table of Contents

1 Executive Summary

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 adopted the Climate Protection Program (CPP).[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.

Cascade's 2023 IRP includes numerous innovative approaches to utility planning. These include: a new approach to climate modeling and the use of wholesale gas prices as a regressor in the Company's use per customer demand forecast. In addition, this IRP includes the Company's first use of PLEXOS software.

1.2 Staff's Review

Staff looked to several sources of guidance in evaluating Cascade's 2023 IRP. First, Commission Order No. 21-127 acknowledging Cascade's 2020 IRP, included 10 recommendations beyond Cascade's proposed action items.[3] Staff finds that at least one recommendation was not adequately met, which requires the Company to use retail prices as a regressor in the demand

[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] See Docket No. LC 76, OPUC, Order No. 21-127, April 28, 2021, pp 7-31.

forecast. Staff has not yet taken a position on the other nine requirements and will review stakeholder comments before arriving at a conclusion on compliance with the other nine requirements.

Second, Commission Order No. 23-023, acknowledging Cascade's 2022 IRP update, directed the Company to use Appendix A when making a case for distribution system investments.[4] This appendix to the Staff Report provides a framework that Cascade should use to provide analysis and information on any proposed distribution system investments.[5] Staff needs more information from the Company before reaching a conclusion about the reasonableness of the distribution system investments Cascade has proposed in its 2023 IRP. This topic is covered in Section 4 of these Opening Comments.

Finally, Staff reviewed Cascade's 2023 IRP for whether it meets the Commission IRP guidelines set forth in Orders No. 07-002 and 07-047, appropriately integrates CPP compliance, and is consistent with the direction provided in Order No. 23-281 and the Natural Gas Fact Finding Investigation (NGFF).[6] Cascade's IRP includes a number of assumptions akin to those Staff took issue with in LC 79. Where Cascade's approach is like NW Natural's in LC 79, Staff intends to ensure consistency in its recommendations and is prepared to advance similar recommendations here. Staff's intent is to limit its Reply Comments requests and future comments to issues that are applicable to specific compliance issues, Cascade's Action Plan, and those issues that can advance dialogue on the topic of distribution system planning. Staff will also offer recommendations for future IRPs and interim actions Cascade should take as part of future IRP development processes.

This Executive Summary provides a compendium of Staff's major arguments and requests, with references to more detailed analysis in later sections.

- **Action Plan - Section 2**: Cascade's 2023 IRP Action Plan lacks quantitative or qualitative detail, along with timeframes to understand execution and, thus, is incomplete. Specifically, the Company should provide more detail about its anticipated renewable natural gas (RNG), Community Climate Investments (CCI), demand-side management (DSM), and storage procurements and distribution system investments, including what the actions are and the year or years in which the actions are expected to occur. Such detail is required for Staff to consider an acknowledgement recommendation regarding action plan items.
- **Demand Forecast - Section 3**: Cascade presents cost and availability assumptions for Green Hydrogen that are even more optimistic, and less supported, than those rejected by the Commission in LC 79, inclining Staff to recommend non-acknowledgment of the Company's long-term plan. Staff appreciates the important potential role this new

[4] See Docket No. LC 76, OPUC, Order No. 23-023, February 6, 2023, pp 19-23.
[5] Ibid., Attachment A, p 19.
[6] See Docket No. UM 2178, OPUC, *Staff's Final Report*, Jan. 31, 2023.

supply side resource could play in the Company meeting decarbonization requirements, but notes more support for cost, availability, and use case assumptions, as well as detailed risk analysis, is required to develop a reasonable plan for its inclusion.

Cascade's cost assumptions for RNG do not reflect a distinction in types of RNG sources and the IRP is unclear how the Company derived costs from the ICF report it cited. Cascade's near-term availability assumptions for RNG appear reasonable, but Staff questions whether the relatively high volumes selected by the model starting in 2033 reasonably reflect what Cascade could procure at the costs projected.

- **Distribution - Section 4**: Staff continues to review the Company's evidence in support of the need for the Prineville upgrade, a distribution system upgrade caused by growth. Cascade's modeling of capacity constraints in Prineville are not clearly supported by observed capacity constraints, and it is not clear to Staff that the Company has sufficiently pursued alternatives to upgrading the Prineville Gate. Staff needs additional clarification on the Prineville Gate upgrade before it can make a recommendation to the Commission on acknowledgement.

  Staff is conceptually supportive of Cascade's intent to pursue non-pipe alternatives (NPA), such as demand-side measures (DSM) to meet growth-caused capacity needs in Baker City and Ontario. However, the Company does not describe any DSM activities and explains that it may not know details about these activities until the end of the year. Without more information about these projects, it is impossible to know whether the Company is considering a reasonable suite of actions or whether it is adequately considering all available NPA. Staff is concerned that Cascade says it would reconsider pipeline reinforcements for both projects in three years if load reduction targets are not reached by the targeted DSM, and yet the Company appears to lack important information needed to implement the required DSM or any information on other NPAs that could address load.

  Cascade already plans five years in advance for distribution system upgrades which should provide a longer-term perspective on distribution system upgrades to document that non-pipe alternatives are being considered with sufficient lead time to be successful. Staff is reviewing Cascade's current distribution system planning to see what Commission directives might be needed to get this added transparency of pending distribution capacity needs beyond the Action Plan.

  The Company's line extension allowances currently do not factor CPP costs into the net benefit of funding a customer's line extension and should be calibrated to account for marginal CPP compliance cost.

- **New Supply-Side Resources – Section 5:** Cascade presents cost and availability assumptions for Green Hydrogen that are even more optimistic, and less supported, than those rejected by the Commission in LC 79, inclining Staff to recommend non-acknowledgment of the Company's long-term plan. Staff appreciates the important potential role this new supply side resource could play in the Company meeting decarbonization requirements, but notes more support for cost, availability, and use case assumptions, as well as detailed risk analysis, is required to develop a reasonable plan for its inclusion.

  Cascade's cost assumptions for RNG do not reflect a distinction in types of RNG sources and the IRP is unclear how the Company derived costs from the ICF report it cited. Cascade's near-term availability assumptions for RNG appear reasonable, but Staff questions whether the relatively high volumes selected by the model starting in 2033 reasonably reflect what Cascade could procure at the costs projected.
- **Demand-Side Management – Section 6:** Consistent with Staff's Opening Comments in LC 79, Staff finds Cascade has inadequately modeled DSM. Demand-side solutions in Cascade's preferred resource strategy represent four percent of its CPP emission reductions strategy in 2023 and then increases and plateaus in 2029 at ten percent for the remainder of the planning horizon. One factor contributing to a low utilization of demand-side options appears to be that Cascade's assumption of avoided environmental compliance cost is too low. Further, the Company should endogenously model demand-side resources, including electrification measures.
- **PLEXOS – Section 7:** Cascade's modeling appears to uneconomically select RNG before fully utilizing available, lower cost CCI's, which may be a function of imposed modeling constraints that should be further explained by the Company. Cascade's resource adequacy model appears high, and the Company should clarify the resource adequacy standard it models to and how cost-effective this standard is expected to be.

Staff makes several recommendations for Cascade to resolve these issues.

2 Action Plan

Cascade's 2023 IRP Action Plan lacks quantitative or qualitative detail, along with timeframes to understand execution and, thus, is incomplete. Specifically, the Company should provide more detail about its anticipated RNG, CCI, DSM, and storage procurements and distribution system investments, including what the actions are and the year or years in which the actions are expected to occur. Such detail is required for Staff to consider an acknowledgement recommendation regarding action plan items.

An IRP must include an action plan "that is consistent with the long-run public interest as expressed in Oregon and federal energy policies"[7] and includes the "resource activities the utility intends to undertake over the next two to four years to acquire the identified resources."[8] The Commission has previously stated that they, "cannot acknowledge an IRP if the analysis does not provide [them] with a reasonable level of confidence in the company's selection of a preferred portfolio."[9]

Cascade's 2023 IRP Action Plan describes general activities the Company anticipates doing but provides little quantitative or qualitative detail and describes only broad timelines for execution. While this is akin to Cascade's Action Plans in prior IRPs, the policy environment in which this IRP was developed, and the continued and heightened attention to distribution system investments called out in LC 76 and the NGFF, signal the need for more detail in this and future IRP Action Plans. This is especially the case with Renewable Natural Gas (RNG), Community Climate Investments (CCI), and Demand Side Management (DSM) procurement and distribution system investments, which should specify what the actions are and the year or years in which the actions are expected to occur.

[7] See Docket No. LC 79, OPUC, Order No. 23-281, August 8, 2023, p 2.

[8] See Docket No. UM 1056, OPUC, Order No. 07-047, February 9, 2007, Appendix A at 5.

[9] See Docket No. LC 79, OPUC, Order No. 23-281, August 8, 2023, p 7.

Figure 1: Action Plan, Figure 1-1 in Cascade's 2023 IRP

Functional Area	Anticipated Action	Timing
Resource Planning and Environmental Policy	Cascade will: • Continue to develop the Company's new PLEXOS® model. • Cascade will purchase the anticipated required CCIs, RNG, or environmental attributes to meet the carbon reduction goals laid out by the Climate Protection Program. • Cascade will purchase the necessary amount of RNG for the Company's voluntary RNG program. • Cascade will continue to investigate the cost and feasibility of a potential hydrogen plant as well as other hydrogen options as an alternative resource. • Continue to participate in the local climate community action plans around Cascade's service territory.	Ongoing, for inclusion in 2025 IRP.
Avoided Cost	Cascade will: • investigate incorporating a separate avoided cost for non-core customers. Cascade will also explore how environmental compliance costs from the CCA/CPP will impact the avoided cost calculation.	Ongoing, for inclusion in 2025 IRP.
Demand	Cascade will: • Incorporate end use forecasting into the load forecast model. • Incorporate income as an explanatory variable.	Ongoing, for inclusion in 2025 IRP.
DSM (Energy Efficiency)	The Company will execute the Demand Side Management action items as described on page 11-3.	Ongoing, for inclusion in 2025 IRP.

Distribution System Planning	Cascade will:
	• Implement various stages or review of the of the list of projects that require an increase in capacity for these projects:
	  ○ Prineville Gate Upgrade.
	  ○ Baker City Reinforcement (Targeted Load Management Candidate).
	  ○ Ontario Reinforcement (Targeted Load Management Candidate).
		Ongoing over the next four to five years.

2.1 Resource Planning – CPP Compliance Action Items

The Action Plan contains a general reference to the purchase of necessary compliance instruments for Oregon's CPP, including procurement of CCIs, RNG, or associated RNG environmental attributes. Staff needs more detail about these actions to inform its recommendations. Each should be presented in units of purchase by year, include detail about project timelines and status, and include clarification about what volumes and sources of RNG and/or environmental attributes will be used for compliance in Oregon.

Regarding timelines and status for RNG projects, Staff notes that in the IRP's first chapter the Company states: "Cascade expects to add RNG to the supply portfolio beginning in Quarter 4 of 2024." Given this near-term horizon, Cascade may have already committed to a project, raising concerns that the project may be too substantially complete for Commission acknowledgement. Staff needs additional timeline and status detail for these projects to consider an acknowledgement recommendation.

In LC 76 and in the LC 76 Update, Cascade did not seek acknowledgement of the Deschutes Landfill project. The IRP update merely introduced this project as an opportunity. If the Deschutes Landfill project has already begun, the Commission should not acknowledge it. If the project has not been procured, it should be explicitly added to this IRP's Action Plan for Commission acknowledgement before a future rate case.

Regarding how the Company intends to use RNG projects to comply with the CPP, in a meeting with the Company, Cascade told Staff that the Deschutes County Landfill procurement may not be for Oregon. The environmental attributes could go to either Washington or Oregon compliance. Staff appreciates that the Company faces uncertainty. However, the Action Plan needs to present the Company's anticipated plan, based on its assumptions and associated analysis. The Company should provide this additional detail about the Action Plan in reply comments. Further, Staff strongly encourages Cascade to begin discussions with DEQ on the CPP eligibility of RNG from any Cascade-owned, on-system in Oregon RNG facilities where the associated RTCs are retired for Washington compliance.

2.2 Demand Side Management Action Items

The Action Plan refers to a specific set of demand-side management action items on page 11-3. However, that page does not provide specific quantities of demand-side resource acquisition. Instead, Cascade provides a pledge to "acquire the projected cost-effective gas savings over the next two to four years."[10] Cascade goes on to refer to the targeted measures in Baker City and Ontario distribution that will provide non-pipe alternatives to distribution system projects in these cities. The Action Plan should contain the Company's anticipated demand-side resource acquisition quantities.

2.3 Distribution System Planning Action Items

The Company describes three specific distribution system investments: Prineville Gate Upgrade, Baker City Reinforcement, and Ontario Reinforcement. However, Cascade provides no timeline. The Company simply states that this will be "[o]ngoing over the next four to five years" which does not tell the Commission the expected start date or completion date. The Action Plan should include project start and completion dates. Staff notes that the Commission does not provide acknowledgement of projects that are underway.

2.4 Storage

At Cascade's last Purchased Gas Adjustment workshop, the Company announced plans to procure more storage.[11] Staff does not recall seeing a discussion of this resource need in the text of 2023 IRP, let alone the Action Plan. Staff met with Cascade on September 21, 2023, to discuss this development in more detail. The Company clarified that the primary driver of the storage need is an operational requirement to smooth out transport customer demand on the Northwest Pipeline, which imposes fees to enforce a tight tolerance on maximum and minimum demand. Cascade also clarified that the Company is always looking for storage opportunities but sees no immediate options for procurement. Cascade contrasts this operational need with a resource need. Staff notes that neither the IRP guidelines, nor the

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[10] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, p 11-3.

[11] Cascade Natural Gas. PGA Quarterly Meeting No. 3, August 29, 2023, slide 6.

associated rules make a distinction between operational needs versus other needs for resource procurement. The rules indicate that an energy utility should detail "…its determination of future long-term resource needs, its analysis of the expected costs and associated risks of the alternatives to meet those needs, and its action plan to select the best portfolio of resources to meet those needs."[12] Staff asks that Cascade describe this resource need in more detail in Reply Comments, including its rationale for not including "operational" needs in the IRP.

Recommendation 1: Staff recommends, in Reply Comments, Cascade provide a more detailed Action Plan that includes the specific investments of the Company's Preferred Portfolio and the year the investments are expected to occur.

Recommendation 2: Staff recommends, in Reply Comments, Cascade explain in detail the need for more storage and why the possibility for this need was not discussed in the 2023 IRP.

3 Demand Forecast

Cascade's demand forecast, upon which its Action Plan should rely, is missing retail price as a regressor, includes population data that diverges from that produced by Portland State University, and appears to be disconnected from demand forecasts used for its distribution system planning. While Cascade has been helpful and transparent in sharing code and data, the code sent to Staff is not structured in a way that can be fully reproduced. Staff finds insufficient evidence that Cascade's Action Plan is supported with a reasonable demand forecast. Further, Staff finds Cascade out of compliance with the acknowledgement of the prior IRP in LC 76 for not using retail prices as a regressor.

3.1 Demand Forecast Summary

Cascade forecasts growth in the Company's overall system to be an average of 1.1 percent over the planning horizon. This is driven more by Oregon than Washington. Demand in Oregon is forecast to grow at an average annual rate of 1.43 percent compared to Washington's 0.98 percent.[13] This growth will increase CPP compliance costs, highlighting the importance of a detailed Action Plan for the Commission to better understand what the near-term costs will be to meet decades of compound growth in gas sales.

The Company's load forecast is composed of customer count forecasts by citygate and rate class. This is multiplied by a UPC forecast, also by citygate and class. This leads to approximately 200 forecasts of demand by citygate and class that may be summed to arrive at the total forecast of system demand.

[12] See OAR 860-027-0400(2)(a)
[13] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, p 1-5.

Regarding the customer count forecast, the Company fits regression models by citygate and class by comparing seven different model specifications and selecting the model with the lowest Akaike Information Criterion (AIC). Some explanatory variables, or “drivers,” of customer count, such as population and employment, are included in the different model specifications, while others are pure econometric models employing solely Fourier or autoregressive integrated moving average (ARIMA) terms without any exogenous demographic or economic inputs. ARIMA terms are also considered as necessary for each model specification, to account for structure, or information, in the error series that might additionally inform the model. This forecast is missing the retail price variable. Besides that important variable omission, Staff finds the rest of the specification to be reasonable.

Regarding the second component of the demand forecast, the UPC forecast, the company fits a regression model by citygate and class with explanatory variables including heating degree days (HDDs) by citygate and month, daily average wind speed by citygate, and price by month. A weekend indicator variable, Fourier seasonality component, and ARIMA terms as necessary are also included in the UPC model. The UPC model specification appears reasonably well designed to capture the data generating process in question, but Staff will continue to inspect this element. In addition, wholesale gas price is included as a new explanatory variable in this IRP’s modeling of UPC.

Staff at present has been unable to independently verify the output of the Company’s forecast methodology as represented to Staff through the Company’s R code in response to OPUC IR 3. Staff needs to reproduce Cascade’s load forecast to assess the reasonableness of the significant load growth the Company predicts.

3.2 Retail Price Regressor - Order No. 21-127 Compliance

Action Plan item 2.b from Order No. 21-127 directed Cascade to include retail price as a demand forecast variable in this IRP.[14] Cascade did not do this. Staff would like to see this variable, as well as consideration of lags of this variable, included in the customer count regression specifications to gauge the impact of prices on customer counts and UPC.

Staff’s recommendation in LC 76 to include retail price as a regressor was envisioned to reflect the price that the consumer would be paying. Cascade did model *wholesale* gas prices in the use per customer (UPC). However, this is a less reasonable proxy of price because retail prices are determined by more than just wholesale gas prices. Staff would like to see Cascade re-run the Company’s demand forecast using retail prices as a regressor for both the customer count and UPC models. When doing so, Cascade should use the latest data available.

The wide array of models estimated and selected by the code across the multitude of citygates and classes can make comparisons across forecasts difficult as well. In future IRPs, Staff would

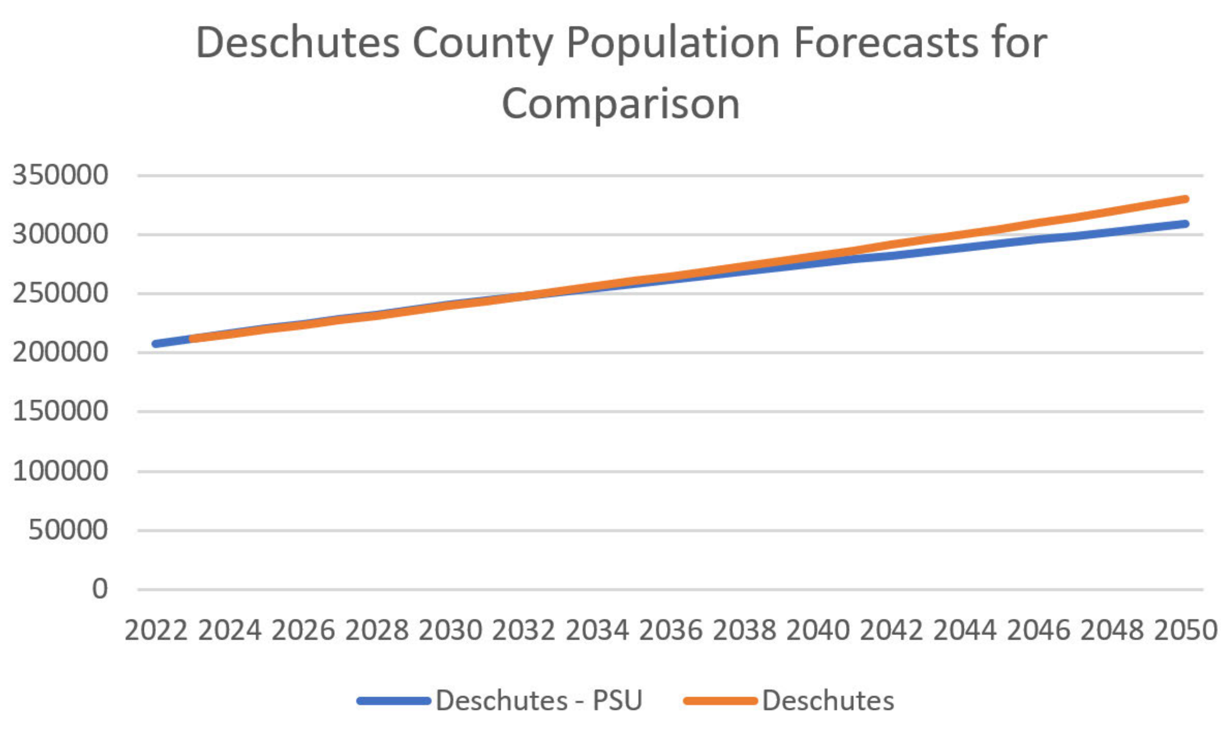
[14] See Docket No. LC 76, OPUC, Order No. 21-127, April 28, 2021, Appendix A, p 13.

appreciate having the Company's forecast inputs structured in the same manner as referenced and called by the forecast code.

3.3 Population Data

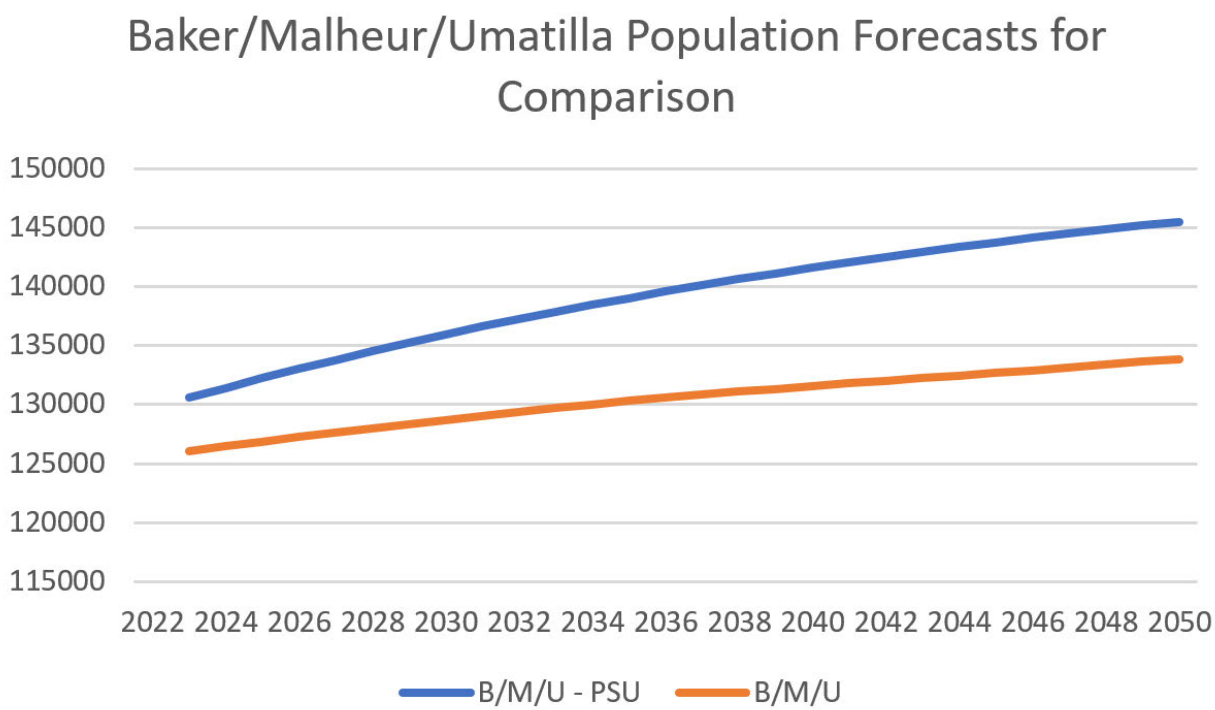
Staff notes that employment forecasts from the Population Research Center (PRC) at Portland State University (PSU) vary meaningfully from the Company's population forecasts furnished by Woods & Poole (W&P).[15] The PRC and W&P population forecasts may be compared by measuring the mean absolute percent deviation (MAPD) between the forecasts. Baker, Malheur, and Umatilla counties have MAPDs of 5.0, 15.5, and 3.9 percent respectively over each 2023-2050 forecast series, with the W&P forecast being the lesser of the two population forecasts. The absolute percent difference by year for Deschutes County is less than 1 percent for the years 2022-2035 but grows to 6.3 percent by the year 2050 with the W&P forecast being the larger of the two forecasts. The MAPD for Deschutes County for the 2022-2050 forecast horizon, comparing only the published forecast years from the PRC, is 2.4 percent.

Figure 2: Comparison of Company Deschutes Forecast with Portland State University



[15] [Population Estimate Reports | Portland State University (pdx.edu)](https://www.pdx.edu).

Figure 3: Comparison of Company Baker, Malheur, and Umatilla Forecast with Portland State University



These differences are likely the result of methodology and assumptions relied upon for each forecast series and deserve additional scrutiny before the next IRP. The differences in the Deschutes data are relatively small, possibly contributing to an overestimation after 2040. The differences in Baker, Malheur, and Umatilla counties, however, are relatively large, and may lead to a persistent underestimation of demand in eastern Oregon.

3.4 Demand Forecast for the Distribution System

The demand forecast that Cascade presents in Chapter 3 of the 2023 IRP is only an input to PLEXOS, which models the Company's systemwide resource need. At a meeting with the Company on August 17, 2023, Cascade explained to Staff that the modeling of the distribution system in Synergi uses a different demand forecast.

Staff finds the 2023 IRP provides an insufficient amount of discussion for this other demand forecast. In Reply Comments, Cascade should explain why a separate demand forecast was used in Synergi, rather than exogenously entering the demand forecast described in Chapter 3. The Company should also compare the results of the two demand forecasts in this IRP for Prineville, Baker City, Ontario, and the aggregate for the Company's Oregon service territory.

3.5 Recommendation for Cascade

Recommendation 3: Staff recommends, in Reply Comments, Cascade present a new demand forecast using the latest data available (since June 2022), rerunning the customer count and using per customer models with both retail price and a lag of retail price as regressors, using R code that can be replicated.

Recommendation 4: Staff recommends, in Reply Comments, Cascade explain why a separate demand forecast was used in the Company's Synergi model.

Recommendation 5: Staff recommends, in Reply Comments, Cascade compare the results of the demand forecast used in PLEXOS with the demand forecast in Synergi for Prineville, Baker City, Ontario, and the aggregate for Company's Oregon service territory.

4 Distribution

Following the Commission's directive from LC 76 and LC 79, Staff is closely weighing the necessity of Cascade's distribution system investments. Cascade's modeling of Prineville Gate capacity constraints is not clearly supported by observed capacity constraints and it is not clear the Company has sufficiently pursued alternatives to upgrading the Prineville Gate. Staff needs additional clarification on the Prineville Gate upgrade before it can make a recommendation to the Commission on acknowledgement.

Staff is conceptually supportive of Cascade's intent to pursue NPA such as demand-side measures (DSM) to meet growth-caused capacity needs in Baker City and Ontario. However, the Company does not describe any DSM activities and explains that it may not know details about these activities until the end of the year. Without more information about these projects, it is impossible to know whether the Company is considering a reasonable suite of actions or whether it is adequately considering all available NPA. Cascade already plans five years in advance for distribution system upgrades which should provide a longer-term perspective on distribution system upgrades to document that non-pipe alternatives are being considered with sufficient lead time to be successful. The Company's line extension allowances currently do not factor CPP costs into the net benefit of funding a customer's line extension and should be calibrated to account for marginal CPP compliance cost.

4.1 Prineville Gate Upgrade

The only pipe construction Cascade is seeking acknowledgement of in this IRP is an upgrade to the Prineville Gate. Currently, Staff has four outstanding concerns about this project:

1) Premature targeting of this project due to peak design day modeling based on an average daily temperature that is too low, potentially inflating load forecasts for the Prineville gate;

2) Premature targeting of this project due to the use of a non-industry standard heating degree day that results in an overestimation of demand at extremely low temperatures;
3) Outstanding questions about whether Cascade's modeling is validated by observed capacity constraints; and
4) Concerns about whether Cascade has reasonably explored all non-pipe solutions to this capital expenditure.

Background
Action Item 6 in Cascade's 2020 IRP included two projects related to the Prineville Gate. However, as noted in Final Comments, the Company decided not to seek acknowledgement on its distribution system plans until there was enough time for the engineering models to be updated and re-presented in an IRP Update with the intent of seeking acknowledgment on all plans.[16]

In the 2020 IRP Update, Cascade proposed the Prineville Gate Upgrade project, which included replacing the existing gate with a new gate with increased capacity and replacing existing piping and facilities with larger piping and facilities.[17] Cascade did not consider alternatives. This proposal was later withdrawn by Cascade during the December 6, 2021, Special Public Meeting to reassess for the 2023 IRP.[18] In Order No. 23-023, the Commission did not address acknowledgement of the Prineville Gate Upgrade because Cascade withdrew this project as an action item at the December 6, 2022, Special Public Meeting.[19] In the acknowledgement order, the Commission directed the company to:

> …demonstrate in a future IRP how it meets Staff's new criteria for assessing distribution system projects under the CPP. This includes: a better understanding of modeling parameters and marginal peak growth modeling; how CNG can/does engage with the 32 industrial customers located in Prineville as interruptible load; and, the modeling of non-pipe solutions to reduce peak demand.[20]

Attachment A to that order states:

> Staff seeks the analysis and information on proposed distribution system upgrades to determine rationale and thus inform acknowledgability under the CPP. Specifically, Staff seeks:
>
> - An understanding of the model parameters used to identify and justify an upgrade
> - Information to assess model performance against observed conditions at the proposed upgrade location, including scenarios and probability of those scenarios, e.g., Number of Heating Degree Day in targeted years at the investment location

[16] See Docket No. LC 76, Cascade, 2020 IRP, Final Comments, February 18, 2021.
[17] See Docket No. LC 76, Cascade, 2020 IRP Update, April 27, 2022, Appendix A.
[18] See Docket No. LC 76, OPUC, Order 23-023, February 6, 2023, p 2.
[19] Ibid p 8.
[20] Ibid.

- Minimum standards for operation around the proposed upgrades
- Alternative activities or investments analyzed or already enacted, particularly focused on minimizing growth of overall throughput of the network
- If a distribution system project was selected over an alternative investment, the rationale supporting the selection.[21]

Attachment A then goes on to provide a framework for distribution upgrades, along with a detailed set of questions, intended to clearly articulate what information should be submitted to support the justification of future distribution system projects. Cascade did not provide this information in sufficient detail for Staff to complete an assessment of the Prineville Gate upgrade. For example, this IRP does not describe the measures that are expected to be used to delay pipeline projects in Baker City and Ontario. However, Appendix I of this IRP provides more distribution planning detail than Cascade has previously included in an IRP filing, including current pressure drops and project cost estimates. The Company has also been forthcoming with more data as Staff follows up with discovery requests.

Purpose of Prineville Gate Upgrade

The stated purpose of the proposed Prineville Gate Upgrade project is to increase capacity of the existing gate station to meet predicted growth in demand.[22] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The upgrade project was selected **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Modeled Demand for Prineville

Cascade's peak design day model to determine load is based on an average daily temperature that Staff believes is too low, potentially inflating load forecasts for the Prineville gate and prematurely targeting this gate for an upgrade. Further, Cascade's recalibrated definition of heating degree day from the industry standard of 65⁰ F to a 60⁰ F threshold appears to overestimate demand at extremely low temperatures.

Rather than use economic variables, like Cascade's demand forecast, Cascade's peak design day model is driven by temperature. Staff finds Cascade is using an unreasonably low temperature. This temperature, commonly known as the design day HDD, is supposed to be selected by the Company from the coldest day in the past 30 years and determines the forecasted temperature-correlated load at that temperature. Cascade is using a peak design day model based on an average daily temperature of -11⁰ F, which occurred more than 30 years ago on

[21] See Docket No. LC 76, OPUC, Order No. 23-023, February 6, 2023, Appendix A, p 19.
[22] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, Appendix C, p 50.

December 21, 1990. Given the prediction of high load for such a low temperature that may not occur in the future due to changing weather patterns, Staff recommends Cascade base peak design day on an average daily temperature of -3.5º F, which occurred within the past 30 years on December 7, 2013.

In OPUC IR 12, Staff requested Cascade describe any changes to the marginal peak model for Prineville Gate since the proposed project was presented in the 2020 IRP Update. The Company responded that, in the 2020 IRP, the 2019 design day model of 62 HDD (-2º F) was used for Prineville, which is a regional HDD calculated by averaging all the districts belonging to the southern region service territory. Prineville is situated in the Bend area, which is considered one of the districts in the southern region. Since 2021, Cascade now creates a more granular design day HDD model by its various district. As a result, the Bend district model, where Prineville is situated, uses a peak design HDD of 71.

Redmond weather data is used for modeling the Prineville citygate.[23] Staff analyzed the Redmond temperature data since January 1, 1981, until end of May 2023 as supplied by Cascade in the workpaper for Figure 2-1 of the 2023 IRP. Staff found that the Prineville design day HDD of 70.5 (-10.5º F) occurred on December 21, 1990, which is more than 30 years ago. Staff recommends 63.5 as a more relevant peak design HDD, based on an average daily temperature of -3.5º F, which occurred within the past 30 years on December 7, 2013. Given the predicted high temperature-correlated load at the current peak design HDD of 71, the Company should reanalyze system capacity of the Prineville Gate upgrade to recalculate the required timing for reinforcements using a peak design HDD of 63.5.

In addition to the choice of historical temperature for the design day model, Staff questions Cascade's recalibration of the definition of a heating degree day away from industry standard of 65º. The Company applies a deterministic approach to estimating demand at the design day temperature by deriving a linear relationship between observed HDD and demand volume (in daily therms). By extrapolating the resulting line, the estimated demand volume can be determined at the peak day HDD. However, the Company uses a 60º F threshold to define the HDD rather than the industry standard of 65º F. Cascade justifies this recalibration by contrasting the linear relationship of both temperatures. The use of 60º has a slightly better correlation as shown by comparing Figures 4 and 5 below.

[23] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, Figure 3-1, p 3-4.

Figure 4: Linear Fit using 65 Degrees, Figure 3-2 from the 2020 IRP

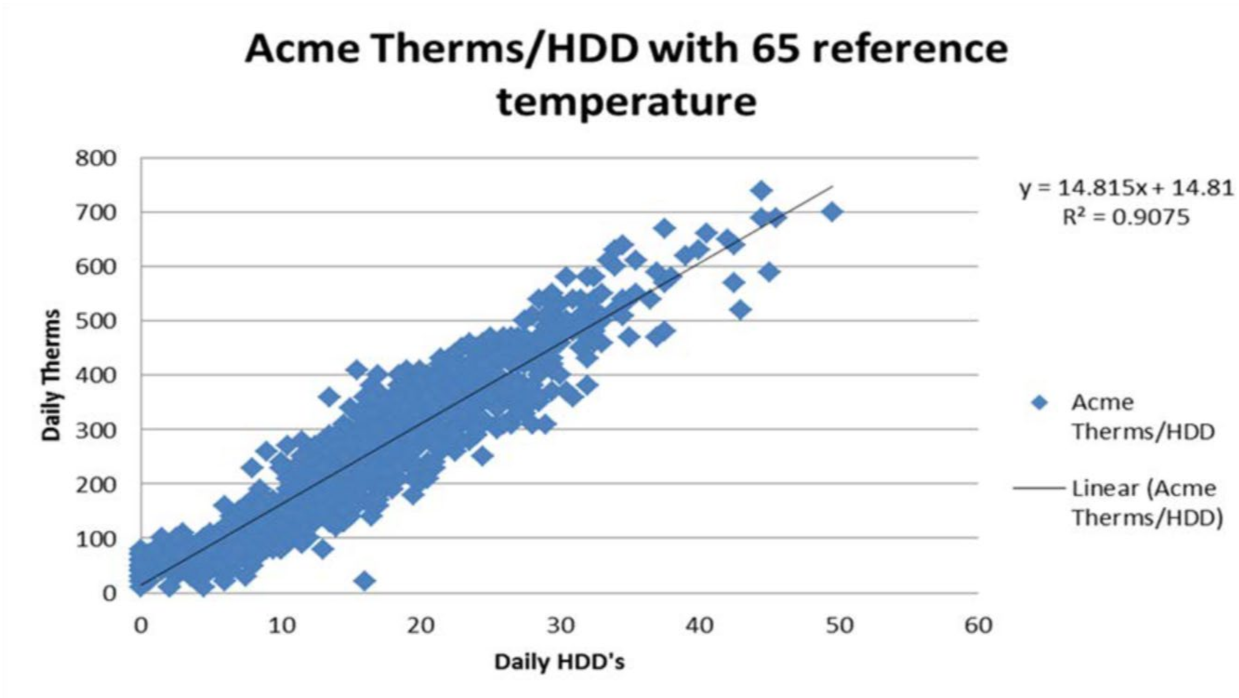
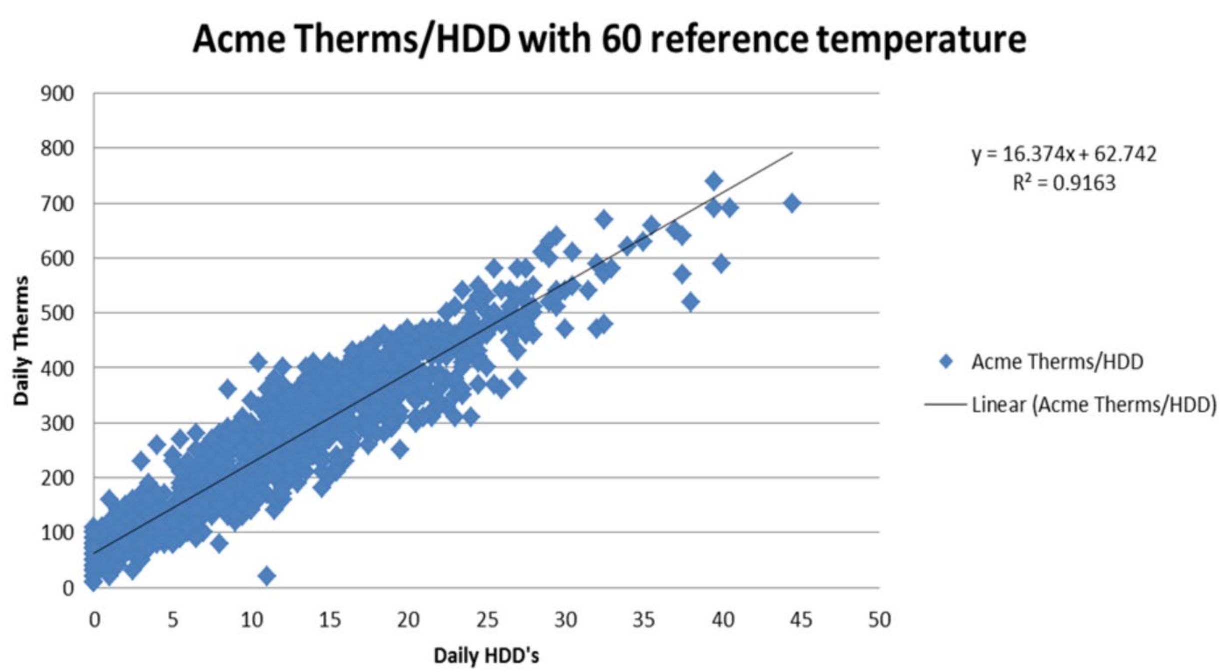


Figure 5: Linear Fit using 60 Degrees, Figure 3-3 from the 2020 IRP



Staff agrees with Cascade that the overall fit of this linear model using 60⁰ is slightly better with an R^2 of 0.9163 compared to 0.9075. However, that very small difference in fit is not the best metric to determine the accuracy of the HDD calibration. At low temperatures, the 60⁰ model's error skews significantly to overestimation while the industry standard 65⁰ is demonstrably more accurate at lower temperatures by having a more balanced rate of error between overestimation and underestimation. Using an HDD threshold of five degrees less increases the slope of the line by ten percent while improving the fit of the model by only one percent. Cascade's recalibration has increased the number of observations at high temperatures (low HDD), which skews the average away from the impacts of lower temperatures (high HDD), the very temperatures Cascade is trying to extrapolate. A qualitative description of why Cascade's recalibration has made this linear model less accurate is that at extremely low temperatures (high HDD), many customers' intake of gas can be maxed before temperatures reduce even further to the extremely low outlier level (highest observed HDD level in 30 years) that Cascade is trying to estimate. Staff finds Cascade's use of an alternative HDD definition unreasonable because it likely overestimates demand at extremely low temperatures.

Staff would like to understand how the volume on peak design day is deterministically derived in the 2023 IRP. The change in HDD calibration occurred in the 2020 IRP. This IRP does not provide the same discussion. Staff would also like to understand whether there is any stochastic methodology applied to Cascade's distribution system modeling. Staff considers it crucial to have accurate modeling of peak day demand, as the choice of a higher-than-expected volume or flow could lead overdesigning a project using the wrong peak day model. Ultimately, an overdesign could imply a false sense of timing for a reinforcement need while other non-pipe alternatives could have been considered.

System Capacity

Cascade's new method for determining total system throughput required at peak design day is unclear and may overstate expected volumes, thus resulting in false urgency for an upgrade that might otherwise be addressed with non-pipe alternatives. Staff explored this in the context of understanding the demand that would trigger a breach in the Company's reliability standards and has questions and concerns about Cascade's approach. Cascade needs to clarify how the Company extrapolates the total system throughput required at peak design day. In OPUC IR 9, Staff requested the exact level of demand that would breach the Company standards required for reliable operation of the Prineville gate. In response, Cascade stated that the level of demand at peak design day that would breach the Company's reinforcement standards at Prineville gate was 2,197 therms/hour for peak design day of an average daily temperature of -11⁰ F or 71 Heating Degree Day (HDD).[24] According to the Synergi model, this level of load corresponds to about 262 psig inlet pressure at the gate, which is roughly a 10 percent drop from the minimum operating pressure of 290 psig. According to the Company's system planning process, once the model is validated, it is 'ramped up' to its peak degree day to create a design

[24] Cascade calculates the Heating Degree Day (HDD) as 60 *minus* Temperature (F) assuming an HDD threshold of 60 °F.

day model.[25] This appears to be a change from how the Company determined its design day model in the past and, it is unclear to Staff how the Company extrapolates volume or flow rate from this process.

Model Validation

The Company's empirical data on observed capacity constraints of the Prineville Gate are difficult to compare with the Synergi model. This ambiguity raises questions about the validity of the model used to support the need for the Prineville Gate upgrade.

Staff has questions on the empirical validity of Cascade's Synergi model in Prineville, which the Company claims to be within 10 percent of observed pressures. In response to OPUC IR 9, Cascade provided a copy of the model verification report by a vendor, DNV-GL, for all of Cascade's twelve models within the Washington and Oregon service territories. Based on data from three measurement locations, the Company considers the Synergi model validated by this vendor's report which shows acceptable results under 10 percent absolute difference between measured and model values for both pressure and flow. Staff notes how small a sample size three observations presents.

In addition to the small size of the validation sample, Staff notes the Company's empirical data is difficult to compare with Cascade's Synergi model. Staff considers pressure, load, and temperature data on cold days to provide valuable information on how and why the system load was close to capacity. Staff requested details of cold day events in the last three years in OPUC IR 13 to understand more about what cold weather mitigation measures, such as bypassing of regulators, were taken during such events. Cascade wrote in response that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In the presentation of the 2023 IRP, Cascade showed the most recent lowest pressure event at the Prineville Gate on February 18, 2020.[26] On that day, the pressure at Prineville gate was 258.6 psig and going into alarm after breaching the alarm setpoint of 260 psig. The HDD was 27.4, which is equivalent to a daily average temperature of 27^{o} F.

Staff would like clarification from Cascade on four specific pressure readings. In response to IR 6, the Company provided pressure and flow (load) at the gate hourly data for the last three years. From this data set, Staff observed **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[25] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, p. 8-5.

[26] See Docket No. LC 83, Cascade, Presentation, July 25, 2023, slide 9.

[redacted]	[redacted]	[redacted]

[END CONFIDENTIAL]

The red three dots in Figure 6 below represent the three observations in Table 1 that have observed demand in therms per hour. Staff compared this observed demand with the Company's response to OPUC IR 9 that provided what the Synergi model would predict demand to be, and these three observations stand out. Figure 6 shows the relationship between pressure (the vertical axis) and load (the horizontal axis). **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]**

While pressure drops on cold days may be momentary, Staff seeks analysis from Cascade on the modeled load corresponding to such drops. Unless the observed pressure drops were caused by erroneous measurements, Staff is interested in understanding the factors that contributed to the pressure drops at the time and the reasons they deviate from what the model otherwise suggests. This analysis could be valuable to help determine how close the system was to reaching capacity and the circumstances surrounding such drops. Ultimately, the results of such analysis could help in determining the urgency and type of solution.

Non-pipe Alternatives

Cascade argues that non-pipe alternatives to the Prineville Gate upgrade are not available in time to meet its need. However, even if Cascade's timing of the Prineville Gate capacity need is ultimately well supported, Staff has not yet seen sufficient evidence that Cascade adequately considered alternatives to the Company's proposed capital expenditure.

In Order No. 23-281, the Commission made clear that it would heavily scrutinize gas companies' analysis of non-pipe alternatives to system upgrades. The Order recognizes that "gas companies may contribute to causing an immediate need for reliability upgrades when they fail to analyze all alternatives early enough and do not act with urgency in pursing those alternatives found viable and effective to mitigate costs and risks." The Commission will consider such factors as "relevant to [the Commission's] analysis of acknowledgment and cost recovery," particularly when there is continued growth in a service territory. This is the lens through which Staff examines the Prineville Gate upgrade and the non-pipe alternatives.

Staff has sought clarification from Cascade on the magnitude of demand-side reduction that would be required to forego the Prineville Gate Upgrade. In OPUC IR 10, Staff requested the Company provide details about the criteria Cascade uses to warrant reinforcement for the Prineville Gate. In response, Cascade provided the criteria it uses to identify a system deficit where the distribution system has reached or exceeded its capacity to serve customer demand. According to the Company's response to OPUC IR 13, where Staff inquired about how close the system was to the point of facing capacity issues, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In OPUC IR 7, Staff asks for **[BEGIN CONFIDENTIAL]** [redacted]

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[27] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

[redacted] [END CONFIDENTIAL].[29]

As provided in Cascade's response to OPUC IR 9, the Synergi model shows that a peak day demand of 2184 therms/hour at 71 HDD causes the pressure to drop to 261.95 psig, which is considered the threshold for system capacity. A reduction of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Cascade believes this reduction in demand would bring back the pressure up to a safe level for reliable operation of the system. However, Cascade does not believe demand-side reductions of this magnitude can be deployed in time to ensure reliability.

Even if Cascade's timing of the Prineville Gate capacity need is ultimately well supported, Staff does not see sufficient evidence Cascade has fully considered all alternatives to the Company's proposed capital expenditure. Staff agrees that the magnitude of reduction in demand the Company has identified would be difficult to quickly meet from long-term energy efficiency measures. However, Cascade needs to demonstrate how it considered short-term capacity measures during the Company's few anticipated short periods of system stress at the Prineville Gate. The option of bypassing the regulator at the gate should not be discarded by the Company and should be given more thought, as it is the easiest and least costly type of mitigation measure. Further, Staff would like to see the Company integrate short-term mitigation solutions into its cold weather action plan.

Staff questioned in OPUC IR 16 whether Cascade explored any short-term alternatives to the Prineville Gate upgrade, such as injecting gas using mobile CNG or LNG trailers in specifically localized points, contractual agreements or voluntary campaigns for load reduction, or geographically targeted demand response. The Company responded that it had not explored any of the short-term alternatives listed by Staff and that the immediate need for the upgrade did not allow for exploring targeted demand response as an alternative. This will be an important fact for the Commission to consider in a future rate case.

Even if demand response may take too long to deploy, another low-cost solution exists, namely, getting a firm commitment from TransCanada to execute a bypass. In response to OPUC IR 13, **[BEGIN CONFIDENTIAL]** [redacted] **[END**

[28] Mcfh is a measure of an hourly volume equivalent to one thousand cubic feet (Mcf) of natural gas.

[29] Based on the 2022 U.S. annual average heat content of natural gas delivered to consumers published by the U.S. Energy Information Administration (https://www.eia.gov/tools/faqs/faq.php?id=45&t=8), one thousand cubic feet (Mcf) of natural gas equals 1.036 MMBtu (1,000,000 British thermal units). Since one MMBtu equals 10 therms, therefore 63 Mcf = 63 x 1.036 x 10 = 652.68 therms.

CONFIDENTIAL]. However, as Cascade explained in its 2020 IRP Update, the operator of the site, TransCanada, does not always have staff to perform the bypassing task and may have higher operational priorities when bypassing is needed. In OPUC IR 8, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In response to OPUC IR 13, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Staff sees a bypass workaround as a least-cost alternative that could buy enough time to develop a portfolio of other non-pipeline solutions. Staff seeks further discussion on inclusion of the bypassing process in Cascade's cold weather action plan and the risks associated with such an option.

In Appendix I of the 2023 IRP, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In OPUC IRs 14 and 15, Staff sought clarification on the effectiveness of Cascade's interruptible load program to mitigate the risk of system stress at peak times. Staff also requested the details of the program and any means it could be expanded to use its full potential.

Staff understands from the response to OPUC IR 14 that Cascade's Interruptible Customer Curtailment plan is still in its infancy, as it was first implemented in 2022. While Prineville did not need interrupting load since the launch of the plan, Cascade's experience with other sites were not successful in reducing load during peak events, as customers chose to pay the penalty rather than reduce load.

Staff notes that in the 2020 IRP Update Final Comments, the Company had only two interruptible customers.[30] The Company states that the resulting volumes of interruption at peak periods for both customers are not adequate to reduce enough demand to mitigate issues with capacity. Given that Prineville has 32 firm industrial customers, Staff still does not see evidence that the Company has exhausted all possibilities to expand its customer base at Prineville. As a first step, Staff recommends that Cascade focus on the eligibility of each large firm customer in terms of key characteristics such as nature of business, maximum load curtailment quantity, daily load profile, seasonal load profile, advance warning requirements, etc. This level of granularity could quickly estimate the effect of the full potential of voluntary firm load curtailment. The deployment of such capacity measures directly from the Company among a handful of industrial customers may not necessarily take the three to four years to deploy that the Energy Trust of Oregon (Energy Trust) takes to deploy energy efficiency measures over a larger number of smaller demand customers.

Conclusion for Prineville

Staff has four concerns with the reasonableness of the Prineville Gate Upgrade project. First,

[30] See Docket No. LC 76, Cascade, Final Comments, February 18, 2021, pp 1-2.

the Company's modeling may use an unreasonable load forecast. Second, Cascade is not using an industry standard heating degree day. Third, Staff is not sure Cascade's modeling is confirmed by observed capacity constraints. And fourth, Staff is not sure Cascade has reasonably explored all non-pipe solutions to this capital expenditure.

4.2 Baker City and Ontario Reinforcements

Cascade proposes two reinforcement DSM projects, one for Baker City and one for Ontario, in the four-year action plan in the 2023 IRP. Staff seeks to better understand what portfolio of alternatives the Company is considering.

Background

These two projects did not include DSM when first proposed. In its 2020 IRP (Docket No. LC 76) in Action Item No. 6 in the 2020-2024 action plan, Cascade introduced a few projects related to a new gate at Baker City. In the 2020 IRP Update,[31] the proposed Baker City project was described as a piping reinforcement and a new gate station at a cost of $1.75 million to be completed in 2022. The proposal was selected over a single alternative of increasing the capacity of the existing gate station and piping reinforcement, both costing in total more than the proposed project.

Also in the 2020 IRP Update,[32] the proposed Ontario Reinforcement project was represented in the form of installing a new regulator station and new piping at a cost of $1.23 million to be completed in 2023. The proposal was selected over a single alternative of a larger size trunk line from the existing regulator station to feed the south side of Ontario, which would not provide any redundancy as compared to the proposed project.

In Cascade's Reply Comments to the Company's 2020 IRP Update,[33] Cascade stated the Company would reassess the Baker City Reinforcement and Gate Station project in its 2023 IRP. In its Final Comments to the 2020 IRP Update,[34] Cascade stated that it agreed that both the Baker City and Ontario Reinforcement Projects were good candidates for a DSM pilot and that it would have more details about the budgeting of those projects in the 2023 IRP.

Customer growth drives the need for these two projects. The purpose of the proposed projects is to increase system capacity or reduce core loading to support predicted growth in demand while mitigating or delaying pipeline investments. Cascade has elected to work with the Energy Trust to pilot a targeted DSM solution for both projects. The DSM projects each need to reduce 9 percent of the demand by 2027 to offset pipeline reinforcements. Cascade will allow the pilots to run for three years, starting from 2024, to determine if targeted DSM is effective to offset the need to implement reinforcements. Staff requested additional information about the DSM options being considered in IR 57 but was informed by Cascade that information on cost

[31] See Docket No. LC 76, Cascade, 2020 IRP Update, April 27, 2022, Appendix A, pages 3-5.
[32] See Docket No. LC 76, Cascade, 2020 IRP Update, April 27, 2022, Appendix A, pages 9-11.
[33] Docket No. LC 76, Cascade, Reply Comments, August 17, 2022, page 1-14.
[34] Docket No. LC 76, Cascade, Final Comments, November 9, 2022, page 1-4.

and options for the DSM projects is not anticipated from Energy Trust until the end of the year. Cascade did, however, provide cost information for the associated avoided pipeline solutions:

- For Baker City, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.
- For Ontario, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Staff is concerned that the Company may reconsider pipeline reinforcements for both projects in three years if load reduction targets are not reached by the targeted DSM. Without knowing the details of the DSM activities being piloted, it is impossible know whether the Company is considering a reasonable suite of actions. Further Staff seeks to understand whether Cascade is adequately considering other non-pipe alternatives such as injecting gas using mobile CNG or LNG trailers in specifically localized points or issuing a Request for Proposals (RFP) for load reduction at peak times. In reply comments Staff requests the Company describe how and when it will assess whether DSM activities are on track to meet load reduction targets and what other non-pipe alternatives it would consider if DSM alone appears unable to achieve the required load reductions. Staff also asks the Company to explain whether its modeling reflects DSM associated with these pilots.

4.3 Forward Looking Distribution System Planning

Per Order No. 23-281, the Commission now requires gas utilities to provide a plan for non-pipe alternatives at least five-years ahead of the anticipated distribution system investments.[35] This Order was issued after Cascade had largely completed LC 83, making full compliance by this IRP not possible. Instead, Staff is reviewing Cascade's distribution planning process to see what would need to change for the Company to comply with this new and important planning requirement.

The 2023 IRP describes Cascade's distribution system planning as a four-phase process:

1. Modeling system limitations given an assumed demand,
2. Identifying potential projects,
3. Evaluating and selecting projects based on priority and analysis results,
4. Scheduling projects into the capital budget.[36]

[35] See Docket No. LC 79, OPUC, Order No. 23-281, August 2, 2023, pp 15-16.
[36] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, Figure 8-2, p 8-11.

Staff finds the phasing of this planning reasonable, and Cascade already models distribution system capacity needs out five years.[37] The Company's pursuit of nonpine alternatives for anticipated distribution system capacity constraints in Baker City and Ontario are examples of how Cascade's current planning process may be adequate for compliance with Order No. 23-281. Cascade's assertion of an immediate need for the Prineville Gate Upgrade results not from insufficient lead-time of Cascade's planning, but rather from a failure to reasonably consider alternatives in the 2020 IRP.

4.4 Line Extension Allowances

A Line Extension Allowance (LEA) is the portion of the incremental distribution system construction costs caused by a request for new service by a customer that is borne by ratepayers. The principal behind an LEA is that the new revenue a customer brings on to a utility's system benefits all ratepayers by reducing average costs. That principle remains true today, but Staff is not sure new customers provide a net benefit to existing customers. New customers now also bring added CPP compliance costs. Cascade confirms that CPP compliance costs have not been factored into the Company's current LEA policies.

The LEA should be a portion, such as one third, of the difference between the present value of future revenues from a new customer and the present value of the marginal cost of adding that new customer. Cascade should revisit the Company's LEA policies by calibrating them with CPP compliance costs.

4.5 Recommendations for Cascade

Recommendation 6: Staff recommends, in Reply Comments, Cascade provide the rationale behind using a peak day model that is based on an average daily temperature standard of -11F that occurred more than 30 years ago.

Recommendation 7: Staff recommends, in Reply Comments, Cascade provide Synergi results for Prineville that use the lowest temperature in the past 30 years and an industry standard heating degree day calibration of 65 degrees Fahrenheit.

Recommendation 8: Staff recommends, in Reply Comments, Cascade provide a detailed demonstration of how the load on peak design day is accurately derived, and a risk analysis on the predicted timing of breaching system capacity over a range of probable maximum loads on peak design day.

Recommendation 9: Staff recommends, in Reply Comments, Cascade provide the full potential of interruptible and curtailable loads at Prineville, including an assessment of each eligible load for interruption or curtailment on a case-by-case basis to inform the feasibility of inclusion in Cascade's Interruptible Customer Curtailment plan.

Recommendation 10: Staff recommends, in Reply Comments, Cascade describe all short-term options for relieving system stress at Prineville, taking into consideration the expected frequency, duration,

[37] See Docket No. LC 83, Cascade, Response to OPUC IR 83, September 7, 2023, p 1.

and advance notice for periods of design day peak load, discussing practicality, costs, and risks of each option, including exploring practical means for the implementation of the existing option of bypassing the regulator at the gate.

Recommendation 11: Staff recommends, in Reply Comments, Cascade describe how and when it will assess whether DSM activities are on track to meet load reduction targets at Baker City and Ontario and describe what other non-pipe alternatives it would consider if DSM alone appears unable to achieve the required load reductions.

Recommendation 12: Staff recommends, in Reply Comments, Cascade describe how DSM is modeled in Synergi and confirm whether DSM is reflected in the Company's modeling of Baker City and Ontario.

Recommendation 13: Staff recommends, in Reply Comments, Cascade provide the net present value of adding a new customer, by rate class, that includes CPP compliance costs.

5 New Supply-Side Resources

Cascade presents cost and availability assumptions for Green Hydrogen that are even more optimistic, and less supported, than those rejected by the Commission in LC 79, inclining Staff to recommend non-acknowledgment of the Company's long-term plan. Staff appreciates the important potential role this new supply side resource could play in the Company meeting decarbonization requirements, but notes more support for cost, availability, and use case assumptions, as well as detailed risk analysis, is required to develop a reasonable plan for its inclusion.

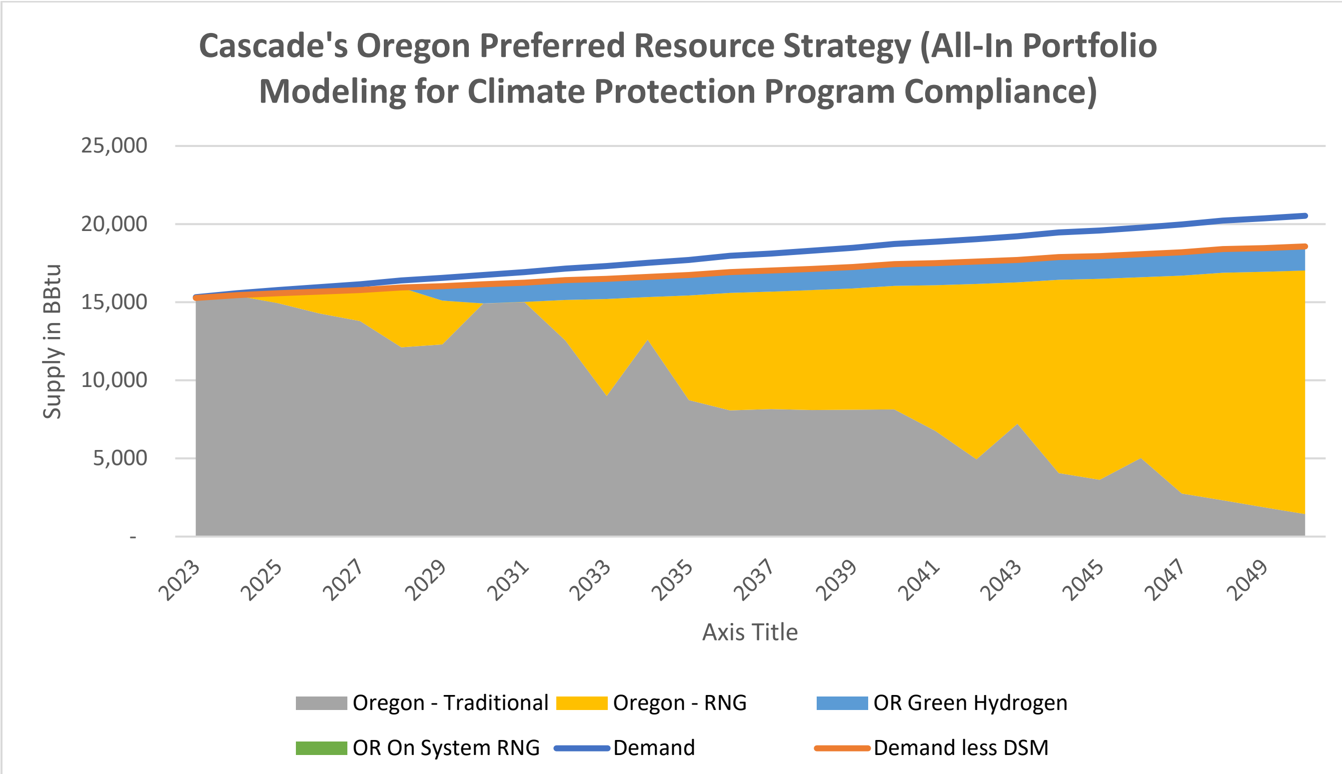
Cascade's cost assumptions for RNG do not reflect a distinction in types of RNG sources and the IRP is unclear how the Company derived costs from the ICF report it cited. Cascade's near-term availability assumptions for RNG appear reasonable, but Staff questions whether the relatively high volumes selected by the model starting in 2033 reasonably reflect what Cascade could procure at the costs projected.

5.1 Hydrogen

Cascade's Preferred Portfolio, the All-In Portfolio, modeling for CPP, begins selecting hydrogen as early as 2029, and it remains a steady resource for Cascade's compliance approach to meet its forecasted load, reaching approximately 17 percent of the overall resource mix by 2050.[38]

[38] See Cascade's Figure 9-14 and 9-15 Workpapers.

Figure 7: Cascade's Oregon Preferred Resource Strategy



Cascade's expected costs for green hydrogen show significant decreases through 2050. Cascade projects that green hydrogen costs will fall from $18.44/Dth in 2025 to $5.63/Dth in 2045. Recent studies and legislation provide some insight into the possible future cost trajectories of these technologies, and the accuracy of Cascade's estimates.

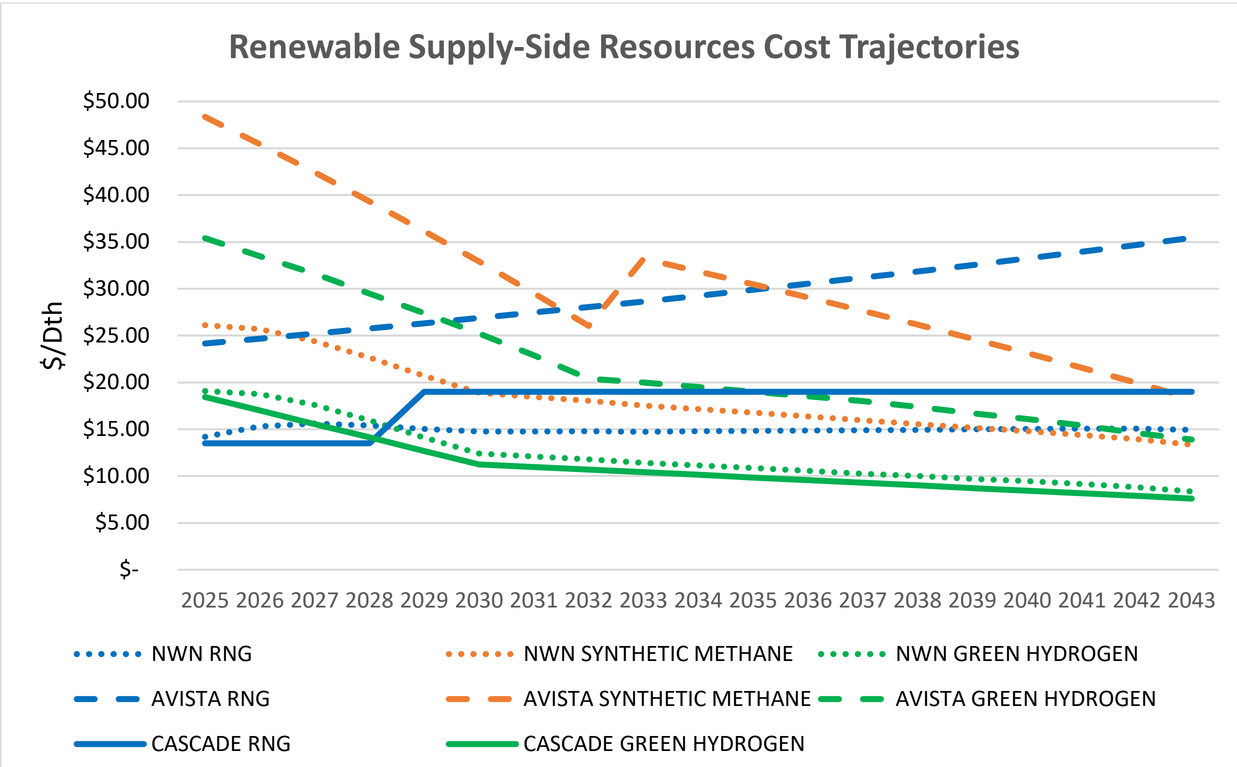
Cascade notes that, before filing the 2023 IRP, the Company had been closely monitoring hydrogen research, including the Hydrogen Shot, which is a program launched by the U.S. Department of Energy (DOE) and carries a goal of reducing the cost of green hydrogen by 80 percent to $1.00 per kilogram, down from $5.00 kg, in the next decade.

The Company's green hydrogen pricing comes from market intelligence based on a single article from S&P Global, an accredited financial organization.[39] The article by S&P Global briefly discusses the delivered cost of green hydrogen globally and prices impacts of a more developed hydrogen industry.

[39] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, p 4-20;
Green hydrogen costs 'can hit $2/kg benchmark' by 2030: BNEF, S&P Global, https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/coal/033020-green-hydrogen-costs-can-hit-2kg-benchmark-by-2030-bnef.

Cascade's assumed 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 Avista's most recent cost projections for all new supply-side renewables, not just green hydrogen, Cascade's projections appear optimistic, particularly regarding the cost of green hydrogen. These are demonstrated in the Staff generated chart below.

Figure 8: Comparison of Renewable Supply-Side Resource Cost Trajectories



Overall, Staff has concerns surrounding Cascade's green hydrogen cost assumptions. There are also serious questions surrounding the resource's ability to be produced on a large enough or cost-effective scale. And, while Cascade's Action Plan states the Company's intentions to investigate the cost and feasibility of a potential hydrogen plant and other hydrogen options as an alternative resource, Staff is concerned with Cascade's current projections given the costs are derived from a single-page article.[40]

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.[41] Staff maintains this principal when reviewing Cascade's resource cost projections. Currently it is unclear to Staff how Cascade translated a single article focusing on

[40] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, p 1-13.
[41] See Docket No. LC 79, OPUC Staff, Final Comments, March 30, 2023.

global pricing to project the cost of green hydrogen in the Pacific Northwest, and therefore, Staff requests that Cascade explain how the Company translated the information in the article into model inputs. The need for transparency in the pricing of green hydrogen is emphasized by the Company's projected usage of green hydrogen as a smaller, but consistent resource in its preferred portfolio. Cascade's assumed cost of hydrogen is even lower than those assumed by Northwest (NW) Natural, which makes the importance of methodological documentation more salient in this proceeding than it was in LC 79.

Staff recognizes 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. Electrolyzer size, capacity factor, and the manner of obtaining renewable energy are all important to the cost of hydrogen, and it is unclear what assumptions were used in this IRP.

Further, 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.[42] 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 at the volumes and prices envisioned by this plan appears optimistic without sufficient documentation.

Staff is concerned that Cascade's plan for the inclusion of green hydrogen is too near-term. Cascade's Oregon PRS shows green hydrogen as part of its portfolio in only six years. This is concerning considering the cost and availability assumptions appear to be derived from a single article, which lacks the necessary detail to support the assumptions used. Staff recommends Cascade provide in Reply Comments the price and availability ranges used in Monte Carlo analysis, any net present value revenue requirement (NPVRR) analysis it conducted to measure the severity of bad outcomes associated with missing green hydrogen targets, and how those sources translated into the Preferred Resource Strategy and Figure 4-5.

Staff's concerns about this IRP's assumptions for the role of hydrogen as a new supply side resource are the same as those Staff had in LC 79, namely that the assumptions are optimistic and need to be better supported. Currently, Staff does not plan to recommend acknowledgment of the long-term plan, in part due to concerns about new supply-side resource assumptions and modeling. The other factor, mentioned in Section 3, is the failure of Cascade's load forecast for use retail prices as an independent variable. Staff Recommends the Company re-engage with stakeholders in preparation for its next IRP such that it can develop and demonstrate that assumptions about hydrogen and the planned role it plays in CPP compliance are well supported and reflect stakeholder input.

[42] See Docket No. LC 79, OPUC, Order No. 23-281, August. 2, 2023 p 9.

5.2 Renewable Natural Gas

RNG plays a major role in Cascade's long-term compliance strategy, but plays a relatively smaller role in Cascade's mix until 2032. While costs for green hydrogen are expected to significantly decrease, RNG shows a quick rise in pricing between 2028 and 2030, when the price then flatlines. RNG is expected to increase due to market variability across all procurement methods including anaerobic production type such as dairy, food waste, solid waste, and wastewater.

For RNG pricing and availability, Cascade relies on a 2019 study from consulting firm ICF, supported by the American Gas Foundation. In Docket No. LC 79, NW Natural's 2022 IRP, NWN relied on an updated 2021 version of the ICF's report for RNG availability, and Staff found that the report was optimistic regarding its assumptions. Staff finds the 2019 AGF/ICF Study more conservative regarding pricing and availability, however Staff remains concerned with Cascade's usage of the report.

Cascade has not explained how it derived its RNG pricing from the 2019 AGF/ICF Study. When Staff asked the Company for further clarification on how Cascade determined the pricing of RNG from the study, the Company replied that the pricing was derived from Figure 29 of the 2019 AGF/ICF Study. However, Figure 29 shows only a supply-cost curve for RNG from landfill gas and does not include any information regarding timing or years covered by the curve. Staff understands that RNG procured from landfills has been historically one of the cheapest sources of RNG and may not be representative of prices Cascade faces for RNG coming from a variety of sources.[43]

In Cascade's IRP, the Company states it modeled the pricing of RNG by splitting prices into tranches. The first tranche, covering the first third of projected supply, is priced at $13/Dth, while the second tranche, covering the remaining two-thirds of supply, is priced at $19/Dth.[44] However, Staff remains unsure how this pricing was taken from Figure 29.

In the Company's Reply Comments, Staff requests Cascade provide further information on how Figure 29 was translated into the Company's overall projected RNG costs, if the Company will only be procuring RNG from landfill projects, and if not, why the Company projects pricing based on landfill cost projections solely.

Renewable Natural Gas Availability

Based on Staff's review of the 2019 AGF/ICF Study, information provided in response to IR 25, and overall discussions throughout the IRP, Staff is not concerned with Cascade's RNG availability assumptions and the ability to provide service on a reliable basis for its customers with RNG in the near-term.

[43] ICF. *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment* December 2019, pp 50-60.
[44] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, p 4-20.

Cascade is aiming to procure relatively small amounts of RNG in its short-term resource strategy and, according to the Company's Action Plan, will be purchasing anticipated RNG to meet carbon reduction goals laid out by the CPP and for the Company's voluntary RNG program, which is yet to be created in the State of Oregon.

The assumptions for RNG availability provided by the 2019 AGF/ICF Study report appear reasonable and reflect what Staff is seeing in practice. In the report, ICF reported reasonable levels of annual availability for each of the various RNG technologies, using conservative assumptions regarding the utilization of different feedstocks. Staff believes that although the report supports the Company's assumptions, Staff remains interested in learning about the interaction between the Company's various RNG projects and the Company's purchasing of RTCs and CCIs. If Cascade can produce an updated Action Plan with specific action items, then Staff could recommend acknowledgement of near-term CPP compliance costs.

According to Cascade's IRP, the Company is currently assessing, and to an unknown degree, possibly progressing twenty-one on-system projects, with ten of these projects being Cascade's highest RNG priority, referred to as Purchase Projects, where Cascade would on-board the RNG onto the Company's distribution system and purchase the environmental attributes to be utilized for the CPP, CCA, and voluntary RNG tariffs in Washington and Oregon.[45] Of the Purchase Projects, four are currently either under contract or at very advanced stages of contracting and are all anticipated to be in-service by late 2025 or mid-year 2025. These projects include the Horn Rapids Landfill & Lamb Weston RNG Project, the City of Pasco Process Water Reuse Facility, a landfill RNG project currently under a non-disclosure agreement, and the Deschutes County Landfill RNG Project. Combined, the four projects Cascade is either under contract or at very advanced stages of contracting, procuring approximately nine-million therms per year of RNG. Staff understands there are five additional RNG projects the Company anticipates advancing in the near term. Since the Company's preferred resource strategy anticipates almost 14 million therms per year by 2026, Staff seeks to better understand the Company's strategy for reaching these levels, given the projects and contracts still under development which supports Staff's need to see a more detailed Action Plan before weighing in on whether these investments are reasonable.

Risks and Benefits of Resources, Ownership vs. Contractual Provisions

As part of the IRP drafting and review process, Cascade discussed the potential benefits and risks of ownership of RNG facilities versus purchasing arrangements. 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.[46] Natural gas utility resource strategies must show that such strategies remain resilient in the face of an

[45] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, p 4-13.
[46] See Docket No. LC 79, OPUC, Order No. 23-281, August 2, 2023, p 12.

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 and green hydrogen, 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 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.

Cascade currently utilizes different proprietary models based on whether the Company is evaluating the purchase of RNG or the ownership of an RNG generating facility.[47] The Company compares the market value and revenue requirement per dekatherm per year of potential on system projects to off system contract opportunities, and if the on-system projects appear favorable compared to off system opportunities based on the model results, the Company will consider other risks and factors.

Staff remains comfortable with Cascade's current RNG evaluation methodology. However, Staff has questions about the amount of near-term RNG procurement relative to CCIs, discussed further in these Opening Comments in Section 7.

5.3 Recommendations for Cascade

Recommendation 14: Staff recommends, in the development of the next IRP, Cascade describe how supporting research informs its green hydrogen price and availability assumptions and how it proposes to model future price and availability uncertainty.

Recommendation 15: Staff recommends, in the next IRP, Cascade provide all supporting documentation it relied on regarding green hydrogen 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 green hydrogen targets, and how those sources translate into the Preferred Portfolio.

Recommendation 16: Staff recommends, in Reply Comments, Cascade provide an explanation of how RNG cost assumptions have changed since the 2019 report was published, and if so, further explain how the AGF/ICF study remains applicable.

Recommendation 17: Staff recommends, in Reply Comments, Cascade provide further information on how Figure 29 of the AGF/ICF study was translated into the Company's overall projected RNG costs

[47] See Docket No. LC 83, *Cascade, 2023 IRP, June 2, 2023*, p 4-11.

and if the Company will only be procuring RNG from landfill projects, and if not, why did the Company assume pricing based on landfill cost projections solely.

Recommendation 18: Staff recommends, in Reply Comments, Cascade identify the RNG projects the Company has already contracted and those where the Company is in an advanced stage of negotiating procurement of RNG.

6 Demand-Side Management

Consistent with Staff's Opening Comments in LC 79, Staff finds Cascade has inadequately modeled DSM. Demand-side solutions in Cascade's preferred resource strategy represent four percent of its CCP emission reductions strategy in 2023 and then increases and plateaus in 2029 at ten percent for the remainder of the planning horizon. One factor contributing to a low utilization of demand side options appears to be that Cascade's assumption of avoided environmental compliance cost is too low. Further, the Company should endogenously model demand-side resources, including electrification measures.

Staff's concerns regarding the role of DSM in CPP compliance are akin to those in Section 4 its Opening Comments in LC 79.[48] Staff appreciates the challenges of modeling uncertainty during the Company's transition to a decarbonized system. However, given these uncertainties, Staff has concerns with whether Cascade's assumptions and modeling used to evaluate different paths for CPP compliance and the resulting Action Plan meet IRP Guideline 1 requirements.[49]

Guideline 1a requires that all resources be evaluated on a consistent and comparable basis. However, Cascade's IRP struggles to evaluate and consider demand side options, such as energy efficiency and demand response, on a consistent and comparable basis to supply side options. Failure to consistently and comparably evaluate all resources subsequently affects its ability to meet Guideline 1b.

Guideline 1b requires that gas utilities consider the risk of commodity supply and price. Cascade's IRP considers these costs and risks in its modeling but presents a supply-heavy approach that exposes its customers to increasing variable fuel costs with high levels of price uncertainty. Staff is concerned that all financial risks are not fully present in the Company's supply-heavy approach.

6.1 Avoided Cost

The avoided cost Cascade provided the Energy Trust last year significantly underestimates the avoided cost Cascade faces. At the margin, this has resulted in an unknown amount of DSM that was not selected as cost-effective.

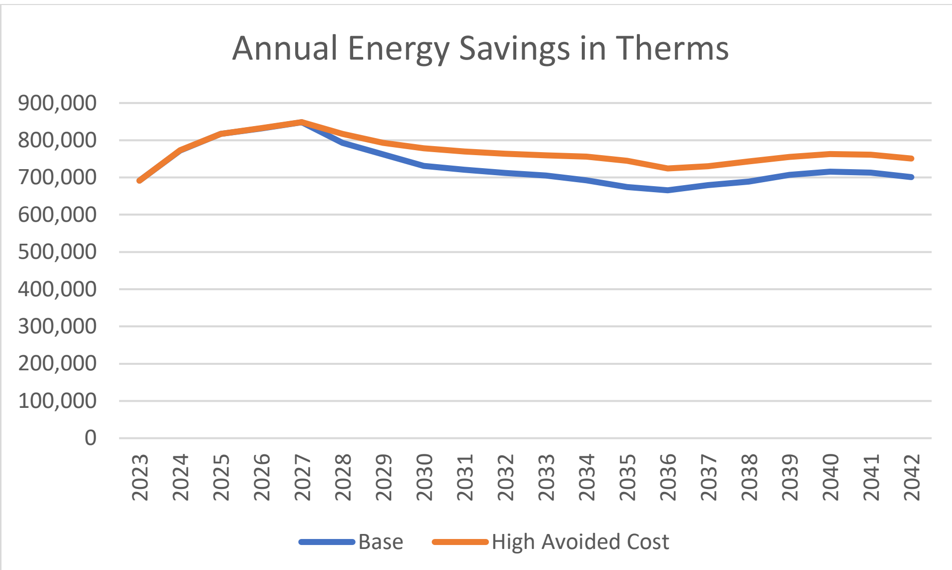
[48] See Docket No. LC 79, Staff's Opening Comments, December 30, 2022, p 29-35.
[49] Order No. 07-047.

Cascade has assumed too low of an avoided cost by underestimating the cost of CPP compliance. The Company used the social cost of carbon at $83.13/metric ton in 2023, which rises to $104.18/metric ton by 2042, but Cascade has no decarbonization options at that low price.[50]

Cascade did provide Energy Trust with a higher avoided cost. The Company provides the details of those assumptions in Appendix H of this IRP. The change in assumed environmental compliance cost is raised from approximately $4.5/Dth in 2023 to approximately $4.8/Dth.[51] The change by 2042 goes from approximately $5.9/Dth to approximately $8/Dth.[52]

The difference in avoided costs to Energy Trust's base case and the high avoided cost assumptions ultimately has a relatively limited impact on gross savings in therms.

Figure 9: Difference between Cascade's Base and High Avoided Cost Assumptions



Visible savings do not appear until 2027. So, the impact would not be expected to be material to the reasonableness of this IRP's Action Plan. This mimics the general limit to near-term deployment of DSM.

While the savings are modest, they may still be material to long-term resource selection in PLEXOS. Since these higher avoided cost assumptions are known to be more accurate, and the Company has already received results from Energy Trust, Cascade should have used these high avoided cost assumptions as the reference planning assumption. Doing so may have eliminated or delayed the selection of hydrogen as a resource.

[50] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, p 5-4.
[51] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, Appendix A, p 482.
[52] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, Appendix H, p 7.

In future IRPs, Cascade should ensure the Company's avoided cost assumptions reflect the most reasonable expectation of CPP costs, including both the cost of CPP compliance and the cost of noncompliance. Noncompliance is a potentially expensive reality that Cascade's Oregon ratepayers may face. The Company's low RNG availability scenario shows CPP compliance will not be feasible. That scenario should come with higher avoided costs to reflect penalty payments. The higher avoided cost may select more energy efficiency resources to mitigate some amount of those penalties.

While Figure 9 above presents the differences between two avoided cost assumptions under normal planning conditions, Staff observes that in Cascade's Increased Electrification scenario, the Company modeled no additional DSM. Staff would like to understand why Cascade finds high electrification reduces the rate of DSM selection.

6.2 Electrification Measures

Cascade has not modeled electrification measures as a resource option. Electrification exists in this IRP only as an external phenomenon. The Company performed a sensitivity on the preferred portfolio in a high electrification scenario.[53] Cascade found that, while this reduced CPP compliance costs, high electrification also raises customer bills more than any other scenario.

Cascade should model electrification measures as a proactive demand-side resource. A proactive strategy in reducing customer load and possibly growth may provide lower costs and less risk than the scope of investments Cascade has modeled in this IRP.

The conversation around assumptions and modeling of electrification as a proactive strategy is likely to occur in Avista's IRP process. Staff recommends Cascade engage in electrification assumption development and modeling conversations happening in Avista's current and next IRP.

6.3 Endogenous DSM Selection

Staff's informal comments on the draft IRP encouraged "the Company to allow [PLEXOS] to compete all resource against one another in developing a portfolio, including energy efficiency and demand response."[54] In Appendix C of the 2023 IRP, Cascade provides this response:

> Cascade has reviewed Staff's comments on Northwest Natural's 2022 IRP and Cascade agrees with Northwest Natural's response. There are several aspects of the avoided cost as well as realistic ramp rates and adoption curves that Plexos cannot model. Cascade would like to follow up on a question that NWN asked, does Staff see this as a replacement of Energy Trust's projections, or would this be in parallel?[55]

[53] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, pp 9-30 – 9-32.
[54] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, Appendix C p 37.
[55] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, Appendix C p 37.

The circumstances for DSM selection are different in Cascade's IRP than NWN. Staff ultimately agreed with NWN that improving the modeling of demand-side resources in PLEXOS was not a priority, because NWN was already selecting 94 percent of what Energy Trust has found to be technically achievable.[56] That is significantly higher than Cascade's 76 percent.[57] Another important difference is that NWN's forecasted load growth is significantly lower than Cascade's.[58]

Given these differences, Cascade's process of modeling DSM cannot keep pace with the changing carbon policy environment the Company is planning for. In this IRP, Cascade has followed the established process of using the last IRP's avoided cost assumptions to supply Energy Trust with the inputs to model the amount of cost-effective energy efficiency measures that are deployable. Cascade then uses this amount of DSM as an exogenous input to PLEXOS by reducing demand accordingly. This has three problems that may be a barrier to a significantly more optimal DSM selection.

1. The data lag from using avoided costs from the previous IRP delays the planning process's response time to a changing policy environment.
2. PLEXOS offers more granularity for modeling the optimal amount of DSM, as a resource, for Cascade's system than Energy Trust's RA model.
3. The diversity of potential DSM resources exceeds what Energy Trust offers.

Energy Trust does a great job acquiring energy efficiency for Cascade, but the scope of information flow should change. Instead of providing Energy Trust with avoided cost inputs in exchange for an assumed quantity of DSM, Cascade should use Energy Trust's expertise in DSM to receive reasonable resource costs assumptions that Cascade would enter into PLEXOS for selection. Then Cascade would supply Energy Trust and other DSM providers with a request for a quantity of demand-side resources.

This does not necessarily mean changes to how Energy Trust models energy efficiency or establishes a budget. This is a recommendation on how Cascade models DSM in the IRP. The Company should work with Energy Trust to vet assumptions about resource costs, shape, and constraints to ramping deployment. After modeling DSM in the IRP with the most reasonable assumptions available, Staff realizes that post-planning procurement may require additional modeling by Energy Trust. So, to answer the question the Company posed in reply to Staff's pre-filing comments, Staff expects the Company's DSM modeling improvements to be initially parallel to Energy Trust's current practices, rather than a replacement.

While the Company should work with Energy Trust to improve DSM modeling, including exploration of whether Energy Trust can provide fuel switching and demand response measures for modeling, ultimately Cascade should not be limited to the measures currently offered by

[56] See Docket No. LC 79, OPUC Staff, Final Comments, March 30, 2023, p 50.
[57] See Docket No. LC 83, Cascade, 2023 IRP, June 2, 2023, Figure 7-16, p 7-24.
[58] See Docket No. LC 79, NWN, 2022 IRP, September 23, 2022, p 106.

Energy Trust. To the degree that fuel switching and demand response are beyond the scope of the work Energy Trust can offer, Cascade should follow an IRP with a request for proposal (RFP) to acquire a diverse range of DSM the Company's modeling selects from a wide list of resources.

Cascade does not face a significant barrier to sharing transport customer data with Energy Trust from OAR 860-086-0040. The Commission granted a waiver to this rule to Avista.[59] NWN is seeking the same waiver.[60] Staff supports Cascade seeking this waver as well.

6.4 Recommendations for Cascade

Recommendation 19: Staff recommends, in Reply Comments, Cascade explain why the New Electrification scenario selects no new DSM.

7 PLEXOS

Cascade's modeling appears to uneconomically select RNG before fully utilizing available, lower cost CCI's, which may be a function of imposed modeling constraints that should be further explained by the Company. Also, Cascade's resource adequacy model appears high, and the Company should clarify the resource adequacy standard it models to and how cost-effective this standard is expected to be.

7.1 Economical CCI Utilization

Cascade contends that the early selection of RNG is fully endogenous to the Company's PLEXOS model, that Cascade did not force the model to make it begin procuring RNG in 2023. Cascade's assumed cost of RNG is higher than the price of CCIs, yet, in Cascade's preferred portfolio, PLEXOS does not utilize all available, lower cost CCI purchases before procuring higher cost resources in the second compliance period. This period covers 2025 through 2027. During that period, Cascade plans to utilize CCIs to meet 11.5 percent of emissions.[61] The CPP allows the Company to use up to 15 percent.[62] Cascade's anticipated purchase of CCIs, conditional on the Company using CCIs and RTCs in combination in the most economical way possible to meet compliance flexibility needs. It is not clear from the modeling that this is being accomplished by not fully utilizing CCIs and Staff would like the Company to explain the driver and any associated strategy behind this potential underutilization.

[59] See Docket No. UM 1631, OPUC, Order No. 23-253, July 13, 2023, p 1.
[60] See Docket No. UM 1631, NWN, Petition, September 27, 2023. p 1.
[61] CCI Percentages ES.xlsx, sheet titled "Emissions Charts" cell B37.
[62] OAR 340-271-9000, Table 6.

7.2 Resource Adequacy Standard

Cascade may be modeling too high a resource adequacy standard, which may require ratepayers to pay for more system capacity than is necessary. Capacity expansion software, like PLEXOS, generally requires a resource adequacy constraint. The model will acquire enough resources to meet demand given a specified risk tolerance for unserved demand.

In discussions with Staff, the Company explained that gas companies should model for zero events in ten years, in contrast to the standard electric company standard of one event in ten years. Based on our review of Cascade's PLEXOS modeling, Staff does not believe Cascade is setting a constraint for zero probability of unserved demand, though it could be perceived as effectively zero when compared to an electric company's loss of load expectation (LOLE) of 0.1. Instead, Cascade calibrates PLEXOS to remove any incidents of unserved demand.

Having no model runs with unserved demand is not the same thing as a gas company facing a probability of zero that some demand will go unserved in the next 20 years. The means by which Cascade models zero instances of unserved demand is to first enter a 99th percentile demand forecast into PLEXOS. Then Cascade imposes a $1 million penalty per mmbtu on unserved demand. This forces PLEXOS to select more capacity than would otherwise be required to serve a 99th percentile load that priced the cost of unserved energy in a way that allowed one event to be less expensive than the marginal cost of building out enough capacity that no demand gets unserved in a model run.

Staff wonders whether Cascade's resource adequacy standard is optimal. An optimal resource adequacy standard would be the equilibrium between the marginal cost of avoiding the last foregone event equals the expected cost of the event. Staff would like to understand the implied probability of an event that Cascade is modeling in PLEXOS, the difference in NPVRR of Cascade's preferred portfolio with one that allowed a single event to occur, and the expected cost of that event. If the Company has ever performed this analysis, such as Puget Sound Energy's 2005 study, Staff would like to see that as well.[63]

7.3 Recommendations for Cascade

Recommendation 20: Staff recommends, in Reply Comments, Cascade explain why no additional DSM was selected in Scenario 4 Increased Electrification.

Recommendation 21: Staff recommends, in Reply Comments, Cascade explain what drives the Company's PLEXOS model to select other supply-side resources before maximizing CCIs.

Recommendation 22: Staff recommends, in Reply Comments, Cascade explain what the probability of unserved energy is implied by the Company's PLEXOS assumptions, the difference in NPVRR of

[63] Puget Sound Energy. *2021 IRP* April, 21, 2021, p 9-14.

Cascade's preferred portfolio with one that allowed a single event to occur, and the expected cost of one unserved demand event.

Recommendation 23: Staff recommends, in Reply Comments, Cascade provide any study that assessed the cost-effectiveness of Cascade's resource adequacy standard.

8 Conclusion

Staff has had a productive exchange of information with Cascade to prepare these Opening Comments. Staff looks forward to more engagement as we consider recommendations for the Commission in Final Comments.

8.1 Summary of Recommendations

Recommendation 1: Staff recommends, in Reply Comments, Cascade provide a more detailed Action Plan that includes the specific investments of the Company's Preferred Portfolio and the year the investments are expected to occur.

Recommendation 2: Staff recommends, in Reply Comments, Cascade explain in detail the need for more storage and why the possibility for this need was not discussed in the 2023 IRP.

Recommendation 3: Staff recommends, in Reply Comments, Cascade present a new demand forecast using the latest data available (since June 2022), rerunning the customer count and using per customer models with both retail price and a lag of retail price as regressors, using R code that can be replicated.

Recommendation 4: Staff recommends, in Reply Comments, Cascade explain why a separate demand forecast was used in the Company's Synergi model.

Recommendation 5: Staff recommends, in Reply Comments, Cascade compare the results of the demand forecast used in PLEXOS with the demand forecast in Synergi for Prineville, Baker City, Ontario, and the aggregate for Company's Oregon service territory.

Recommendation 6: Staff recommends, in Reply Comments, Cascade provide the rationale behind using a peak day model that is based on an average daily temperature standard of -11F that occurred more than 30 years ago.

Recommendation 7: Staff recommends, in Reply Comments, Cascade provide Synergi results for Prineville that use the lowest temperature in the past 30 years and an industry standard heating degree day calibration of 65 degrees Fahrenheit.

Recommendation 8: Staff recommends, in Reply Comments, Cascade provide a detailed demonstration of how the load on peak design day is accurately derived, and a risk analysis on the predicted timing of breaching system capacity over a range of probable maximum loads on peak design day.

Recommendation 9: Staff recommends, in Reply Comments, Cascade provide the full potential of interruptible and curtailable loads at Prineville, including an assessment of each eligible load for interruption or curtailment on a case-by-case basis to inform the feasibility of inclusion in Cascade's Interruptible Customer Curtailment plan.

Recommendation 10: Staff recommends, in Reply Comments, Cascade describe all short-term options for relieving system stress at Prineville, taking into consideration the expected frequency, duration, and advance notice for periods of design day peak load, discussing practicality, costs, and risks of each option, including exploring practical means for the implementation of the existing option of bypassing the regulator at the gate.

Recommendation 11: Staff recommends, in Reply Comments, Cascade describe how and when it will assess whether DSM activities are on track to meet load reduction targets at Baker City and Ontario and describe what other non-pipe alternatives it would consider if DSM alone appears unable to achieve the required load reductions.

Recommendation 12: Staff recommends, in Reply Comments, Cascade describe how DSM is modeled in Synergi and confirm whether DSM is reflected in the Company's modeling of Baker City and Ontario.

Recommendation 13: Staff recommends, in Reply Comments, Cascade provide the net present value of adding a new customer, by rate class, that includes CPP compliance costs.

Recommendation 14: Staff recommends, in the development of the next IRP, Cascade describe how supporting research informs its green hydrogen price and availability assumptions and how it proposes to model future price and availability uncertainty.

Recommendation 15: Staff recommends, in the next IRP, Cascade provide all supporting documentation it relied on regarding green hydrogen 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 green hydrogen targets, and how those sources translate into the Preferred Portfolio.

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Recommendation 23: Staff recommends, in Reply Comments, Cascade provide any study that assessed the cost-effectiveness of Cascade's resource adequacy standard.

Dated at Salem, Oregon, this 5th of October, 2023.

Eric Shierman

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Eric Shierman
Senior Utility Analyst
Energy Resources and Planning Division